

DISSERTATION

FINANCIAL AND ENVIRONMENTAL IMPACTS OF NEW TECHNOLOGIES IN THE
ENERGY SECTOR

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ABSTRACT

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Energy industries (generation, transmission and distribution of fuels and electricity) have a long history as the key elements of the US energy economy and have operated within a mostly consistent niche in our society for the past century. However, varieties of interrelated drivers are forcing changes to these industries' business practices, relationship to their customers, and function in society. In the electric utility industry, the customer is moving towards acting as a fuller partner in the energy economy: buying, selling, and dispatching its demand according to its own incentives. Natural gas exploration and production has long operated out in rural areas farther from public concerns or regulations, but now, due to hydraulic fracturing, new exploration is occurring in more urbanized, developed regions of the country and is creating significant public concern. For these industries, the challenges to their economic development and to improvements to the energy sector are not necessarily technological; but are social, business, and policy problems. This dissertation seeks to understand and design towards these issues by building economic and life cycle assessment models that quantify value, potential monetization, and the potential difference between the monetization and value for two new technologies: customer-owned distributed generation systems and integrated development plans with pipeline water transport in hydraulically fractured oil and gas fields.

An inclusive business model of a generic customer in Fort Collins, Co and its surrounding utilities demonstrates that traditional utility rates provide customers with incentives that

encourage over-monetization of a customer's distributed generation resource at the expense of the utilities.

Another model which compares customer behavior incited by traditional rates in three New England cities with the behavior incited through a real-time pricing market corroborates this conclusion. Daily customer load peak-shaving is shown to have a negligible and unreliable value in reducing the average cost of electricity and in some cases can increase these costs. These models support the hypothesis that distributed generation systems provide much greater value when operated during a few significant electricity price events than according to a daily cycle. New business practices which foster greater cooperation between customers and utilities, such as a real-time price market with a higher fidelity price signal, reconnect distributed generation's potential monetization to its value in the marketplace. These new business models are required to ensure that these new technologies are integrated into the electric grid and into the energy market in such a way that all of the market participants are interested and invested stakeholders.

The truck transport of water associated with hydraulic fracturing creates significant local costs. A life cycle analysis of a hypothetical oil and gas field generic to the northern Colorado Denver-Julesburg basin quantifies the economic, environmental, and social costs associated with truck transport and compares these results with water pipeline systems. A literature review of incident data demonstrates that pipelines historically have spilled less hazardous material and caused fewer injuries and fatalities than truck transport systems. The life cycle analysis demonstrates that pipeline systems also emit less pollutants and cause less local road damage than comparable trucking systems. Pipeline systems are shown to be superior to trucking systems across all the metrics considered in this project.

In each of these domains, this research has developed expanded-scope models of these new technologies and systems to quantify the tradeoffs that are present between monetization, environment, and economic value. The results point towards those business models, policies, and management practices that enable the development of more equitable, efficient, and sustainable energy systems.

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Chapter 1

Introduction

Energy industries (generation, transmission, and distribution of fuels and electricity) have a long history as the key elements of the US energy economy and have operated within a mostly consistent niche in our society for the past century – focused primarily on minimizing cost and maximizing the reliability of services. However, varieties of interrelated drivers are forcing changes to these industries’ business practices, relationship to their customers, and function in society. In the electric utility industry, the customer is moving towards acting as a fuller partner in the energy economy: buying, selling, and dispatching its demand according to its own incentives, such as: reducing cost, improving local reliability, or reducing environmental damages and emissions linked to climate change. Natural gas exploration and production has long operated out in rural areas farther from public concerns or regulations, but now, due to hydraulic fracturing, new exploration is occurring in more urbanized, developed regions of the country and is creating significant public concern. For these industries, the challenges to their economic development and to improvements to the energy sector are not necessarily technological; but are social, business, and policy problems. They need to apply the tools of engineering, engineering economy, optimization and decision making to the applications and metrics of performance that are relevant to the energy industry today.

New technologies and business practices often develop incrementally as the market participants all “learn by doing”. Frequently, these learning curves describe how increased production and capacities will lead to increased understanding and reduced costs, but there are

also learning curves which refer to an increased understanding of the optimal market and utilization for new technologies – At the start of a product development cycle, research and development often drives progress, but as a product matures, market mechanisms and commercial incentives become increasingly important [1]. Optimizing the system utilization can become as important as improving individual aspects of new technologies [2]. Research and policies which smooth the integration of new technology are essential as energy utilities may suffer from some degree of “lock-in” with expertise and capital already committed to older, conventional systems [3].

This dissertation will focus on three new technological or business practice developments. Distributed generation is gaining ground with customers and challenging the conventional relationship between customers and utilities along with these conventional energy generation and transmission systems. The concept of real-time pricing is not new, but the possibility to extend this market to every customer is (with the introduction of the smart grid and/or advanced metering). This new business model has the potential to dramatically shift customer incentives and behaviors and has the potential to challenge many of our field’s perceived notions of the state of the electricity market. The expansion of hydraulic fracturing is the result of market forces (the high cost of fossil fuels) and recent technological developments, but this comes with numerous local economic, environmental and social costs. Many of these costs are related to trucking water to complete the fracturing process and could be easily mitigated with existing technologies. Social and market forces such as local opposition to hydraulic fracturing, regulatory pressure to mitigate social costs, and oil and gas companies attempting to minimize the costs of their operations will drive the utilization of these existing technologies forward.

The overarching theme of this dissertation asserts that in order for these new technologies to succeed, customers, utilities, corporations, and governing/regulatory bodies must work together to craft new business models, expectations, and practices which incent more sustainable market behavior. All of the technologies discussed in this dissertation have the potential to offer novel solutions to existing social concerns or problems concerning energy supply, but policies and practices that are focused on the benefit of one market participant at the possible expense of the others may result in an unsustainable marketplace.

Chapter 2 defines the research objective for this dissertation and splits the focus into three research questions. The research questions are briefly described and are each split into three to four proposed tasks. These tasks have been completed and the work performed and research accomplished for each task is summarized.

Chapter 3 quantifies the economic effect of customer-owned distributed generation on customers, distribution utilities, and generation and transmission utilities. An inclusive business model tracks the economic impact on each of three market participants in Fort Collins, Co: a generic customer, Fort Collins Utilities Light and Power, and Platte River Power Authority. The customer behavior is optimized according to incentives provided by its electric rates, and the utilities' revenues and expenses are modeled according to their contractual connections with the other market participants and their individual cost functions. The effects of rate case adjustments are also considered by quantifying the shift in customer incentives and monetization across a change in the billing rates from 2011 to 2012. The results of this research demonstrate that customer peak-shaving creates new costs for utilities which can become disproportionately higher than the value generated for the customer and thus potentially exposes any of the three market participants to unrecoverable stranded costs. This emphasizes the need for customer-utility

cooperation while planning and siting new distributed generation facilities so that all market participants become interested and invested stakeholders.

Chapter 4 compares the customer-optimized operation of distributed generation facilities while incented by traditional utility rates against the incentives provided by a corresponding real-time prices market for their region. Identical customers based on the New England ISO average system load were compared in three cities each with different utility rates and each with slightly different locational marginal prices. The three cities were Portland, ME; Rutland, VT; and Hartford, CT. This chapter quantifies the differences in customer dispatch behavior, monetization, and value for these distributed generation systems in both of these markets for each of these scenarios. The results of this comparison assert that customer load peak-shaving incented through utility rates is not always inherently a social good and in at least some of the situations described in this research can reduce the total social value, by increasing the average price for electricity, in the market.

Chapter 5 compares the local economic, environmental, and social costs associated with water transport for hydraulic fracturing in northern Colorado. A case study of several variations of a generic oil and gas field with fresh and produced water requirements based on data unique to the region is presented. Using this model, the local costs associated with trucking and pipeline systems in a variety of cases are quantified and compared. Recycling the produced water at central processing locations is also shown to have a beneficial effect of significantly reducing local costs. Pipeline transport systems are shown to be generally safer, spill less hazardous material, emit less pollution, and create fewer injuries and fatalities than trucking systems.

Chapter 6 summarizes the work in the dissertation. It describes how the work completed for each of the research questions furthered the state of the art in its field and presents opportunities for future work.

Chapter 2

Research Objectives

2 Research Objective

This dissertation follows three main lines of inquiry: distributed generation within a traditional business structure, customer demand side management within a real-time prices market, and the benefits and costs of replacing water trucking with water pipelines in natural gas exploration and development. In order to better approach these issues, the research work has been divided into three main questions and each question into a number of research tasks. Completing all of these tasks will satisfy the research objective to:

Utilize enterprise accounting and optimized policies to evaluate new energy business practices that improve system wide benefit and social welfare.

2.1 Research Question 1: Do customer controlled distributed generation systems meet criteria of a sustainable business model while under traditional rate structures?

Numerous studies have found that customer operated distributed generation provides specific monetary benefits for the customer. However, none of this previous work has discussed the potential economic impact on the customer's utilities or the rest of society. Discerning the full impact of distributed generation will help explain many utilities' previous reluctance to embrace distributed generation, thereby aiding future attempts to find a better partnership and sustainable

marketplace for customer generation and demand side management. Without a sustainable marketplace, distributed generation cannot succeed as each participant will only adjust its own behavior in order to maximize its own economic value at the detriment of the other participants. The following four sub-objectives were completed in order to quantify all of the financial impacts of distributed generation and determine whether it is already a sustainable business model under traditional business structures.

2.1.1 Compose case study built from an inclusive economic model

An inclusive economic model is defined here as a model that tracks the economic impact of a new behavior or technology on all of the affected market participants, not just the adopter of the new technology. For distributed generation, this model included the customer who owns and operates a small generation facility; the distribution utility which normally sells electricity to the customer; and the generation and transmission utility that produces, transports, and sells electricity to the distribution utility. This model provided a new insight into a field which has predominantly been focused solely on DG's economic impact on the customer who owns and operates the system.

2.1.2 Optimize customer siting and management of a potential distributed generation resource according to its opportunities and incentives

Previous research has clearly shown that in a traditional market, a customer owned DG resource is best utilized for peak shaving, or reducing the customer's cost at peak hours of electricity usage. This research corroborated the general consensus that a customer is incited to conduct a peak-shaving regime through an optimization of an average customer's daily load profile split into 96 fifteen minute intervals (for both a summer and winter season). This optimization presented some unique difficulties due to the weak correlation of each time interval

to the others in the series, but was accomplished through a combination of MATLAB's fmincon optimization routine [4] and another routine designed by the author specifically for this problem. The final results were then double-checked with a second call of the fmincon routine to ensure that the "best" optimization had been reached. This model demonstrated how DG costs affect the customer's utilization of its generation facility and DG's potential economic value for the customer.

2.1.3 Quantify economic effects from the DG resource upon the three market participants within the case study

Tracking only the economic impact on the customer, similar to the current state of the art, will not answer the question of whether or not customer-operated DG facilities create a sustainable business model. The economic impacts on all of the market participants defined in our inclusive business model need to be quantified to ensure that there are no "losers" from DG's induction into the market. These other participants include the distribution and the generation and transmission (G&T) utilities. These utilities are connected to the customer and to each other through their contract rates and cost functions. Our complete inclusive business model quantified the exact costs and revenues streams for the distribution and G&T utilities.

2.1.4 Perform a sensitivity analysis on potential rate case adjustments and their impact on the market participants

Customer-focused economic modeling of DG ignores the other market participants and how their future actions may influence the value of DG resources. Without a customer-utility partnership, utilities and ISOs could resolve new rates ignorant of the effects on customer DG facilities or perhaps even more likely as a negative reaction or as a rebuff to them. Both Fort Collins Utilities Light and Power and Platte River Power Authority substantially changed their

rates between 2011 and 2012 which presented an excellent opportunity to measure potential rate case effects on DG for all of the market participants in this model. This added another argument in favor of greater customer-utility partnership in a DG economy.

2.2 Research Question 2: Does increased price discretization in a real-time prices market create additional value and improved utilization for customer energy resources?

A billing structure split between connection, energy and demand charges may be the typical utility business model, but there is a newer model gaining ground: real-time pricing (RTP). Lately, some utilities, such as ComEd, have even begun to implement a voluntary real-time pricing billing structure for customers. Research question 1 demonstrated how traditional utility rate systems create poor incentives for customer behavior. Research question 2 will expand this analysis to include a hypothetical RTP business model.

There is more than one flavor of RTP. The current state of art for RTP for a typical customer analysis is the day-ahead hourly market. However, this market does not allow customers to respond in real-time to actual emergency grid events. Numerous studies have quantified the potential benefits of customer end-use energy systems in the real-time market, but few if any have looked at the potential differences between a day-ahead hourly and a smaller interval more up-to-date market (such as a five minute final price market).

The RTP market also raises the question of whether customer DG facilities are best financed and employed under a daily peak-shaving regime or primarily as emergency back-up systems. Historically, a significant portion of the research in the field has used homogeneous modeled price signals with a smooth, predictable profile as opposed to the actual historical data. Smooth data is easier to model and analyze through statistical methods but it does not capture the information of occasional highly fluctuating price signals due to severe grid events. Comparing

RTP signals with varying levels of resolution and the traditional utility rate structure quantifies the importance of monitoring these high price fluctuation events compared to daily peak-shaving.

The following three sub-objectives were completed to answer this research question and improve the state of the field for the RTP market.

2.2.1 Compose a customer optimization model for energy arbitrage in a real-time prices market

Within the RTP market, customers are better energy partners in the market as their price signals reflect actual costs and signals from the balancing and operation of the electric grid. Therefore, the customer optimization model in this market can remain relatively simple and tractable – the customer operates DG when it is cheaper than the current cost of electricity on the open market. As long as this condition is satisfied, the customer’s use of DG is not detrimental to the rest of society – its exact positive effects to society are the difference between the DG’s levelized capital and operational costs against the marginal generation and transmission it outsourced. This model focuses primarily on the customer and a perceived best case situation for the grid balancing authority: a lowest cost solution that satisfies the total electricity demand in the region. This customer model improved the understanding of the place for customer-operated DG in a RTP market and created the foundation that addressed the following two tasks in the research question.

2.2.2 Compare customer behavior between markets using day-ahead hourly, final hourly and final five minute real-time prices

Customers in a day-ahead hourly market may be better market participants than under a traditional billing structure, but there still remains a distortion between the customer incentives

and the electric market's actual needs. More up to date markets with more frequent updates of price information should yield a better overlap of customer incentives and market requirements. In an ideal case, where customers make dispatch decisions based on incentives created by the most current data available, then they are most like full business partners with the other utilities and the balancing authority for the region. The New England ISO maintains easily accessible public data for its day ahead hourly, final hourly, and final five minute RTP markets. This RTP model included all of these potential signals and compared the customer behavior incited by each of these markets. These comparisons quantified the value in making customers more complete market participants with the highest fidelity price signal available.

2.2.3 Compare value of extreme price events relative to normal daily cycling

Extreme price events in the RTP market often correspond with a temporary grid event such as an unexpected plant shutdown (trip), a power line fault, or a significant sudden swing in demand which forces the balancing authority to dispatch more expensive generation facilities that normally operate in the margins of the electricity market. Comparing customer's DG dispatch and economic value during these sudden grid events and those of normal everyday peak-shaving tested and validated three hypotheses: 1) Homogeneous models of customer energy sources without the capacity to predict or model extreme price events miss out on substantial economic value in the RTP market and are fundamentally incorrect. 2) Customer incentives for DG monetization in an RTP market already provide for significant overlap with the regulation market. 3) Daily peak-shaving is not necessarily inherently a social good – There are situations in which DG facilities provide value to a customer while simultaneously reducing the total value within the market. The current market structures do not optimally incent useful customer

behavior, but proving these hypotheses has demonstrated that if given an opportunity, customer-operated DG facilities may create a new significant value to society by offering grid balancing authorities a lower-cost option for emergency dispatch.

2.3 Research Question 3: Do piped water systems in hydraulic fracturing fields create monetary and environmental benefits for utilities and society?

Hydraulic fracturing has created a new and valuable source of oil and natural gas production in the US, however, there is a high fresh water cost and a comparable quantity of wastewater produced. Good stewardship of these water resources and liabilities is essential in order to mitigate the economic and environmental impact of hydraulic fracturing. Currently, natural gas exploration and development typically relies on truck transport for both streams of water to and from the wellheads. However, this heavy reliance on trucking creates some of the most significant public concerns surrounding increased hydraulic fracturing: truck traffic, increased accidents, local pollution, and road damage. In order to mitigate many of these concerns and improve the total economy of natural gas development and mining, an alternative water pipeline model with a central processing facility has been proposed and already introduced at select sites, such as in the Wells Ranch and East Pony fields. However, the exact costs and benefits of these pipeline networks are not yet known. With a better understanding of these networks, energy utilities will be better equipped to sustainably develop natural gas resources in the US with decreased collateral damage to the surrounding environment and public resources. The following three sub-objectives improved the state of the art of understanding these networks by comparing the economic, environmental, and social costs of trucking and pipeline water transport systems.

2.3.1 Define environmental and economic metrics of performance

Defining the relevant and important metrics of performance associated with integrated development plans (IDPs) is of primary import to best demonstrate the advantages and disadvantages of transitioning to water pipeline transport. Under increased public opposition to hydraulic fracturing, especially in Colorado, energy utilities will need to balance their economic decisions with public concerns and common goods. Demonstrating not only the private but also the public benefits of pipeline networks will greatly increase public acceptance of new pipeline construction in the associated development areas.

Economic and social costs are not limited to the relative cost of operation for the utility but also include the costs associated with road congestion, road damages and risk of accident, injuries and fatalities.

The environmental costs under consideration include accidental produced/wastewater spills and the greenhouse gas emissions emitted as a byproduct by both trucking and pipeline systems. The greenhouse gas emissions are tracked through a life-cycle analysis (LCA) which includes embedded, installation, operation, and infrastructure degradation (road repair) emissions.

The case study presented in chapter 5 of this dissertation compared variations on a single generic field. The effects of field development intensity, central processing facility location, produced water recycling, and the proximity to fresh water and disposal locations were all quantified.

Table 2.1: Ranking of Public Concerns in the Barnett Shale [5]

Ranking of Public Concerns in the Barnett Shale			
Safety	Health and Environment	Quality of Life	Equity
<i>Increased Traffic/Accidents</i>	<i>Freshwater Supplies</i>	<i>Road Damage</i>	Mineral Rights Ownership
Gas leaks and explosions	<i>Local Pollution</i>	Noise and Light Pollution	
Injection Well Placement		Aesthetic Changes	

2.3.2 Design an optimized water pipe network under system constraints

Despite advances in the geological sciences and survey techniques, natural gas exploration and development is still in many ways a process of trial and error. Development plans change quickly and often as the exploration company targets the regions that best produce natural gas. Therefore, the optimization of water pipeline planning needs to be quick and flexible. Designing a simple yet accurate optimization routine for these networks was a precursor to addressing the third sub-objective, but is also of interest as a future planning tool for utilities that are developing new regions (This tool is one of the deliverables of a RPSEA grant which funded this project and several other projects at Colorado State University).

The pipeline optimization routine has gone through several iterations within two main designs. Both versions are designed to minimize cost primarily through minimizing the required distance of pipeline required to service the oil field, and both use the same genetic algorithm for optimization [6]. Matlab’s GA was chosen for its ability to perform integer optimization while deciding between discrete pipeline route options. The first version of the pipeline simulator used direct straight line distance between wells and was temporally oriented, that is, it built and combined pipelines and treatment facilities as wellheads were constructed according to the production schedule. The final iteration of this design was able to predict future wells and consider the present vs. future value of pipelines in order to build the pipes in the optimal order and place mobile treatment facilities in the optimal locations at the best times.

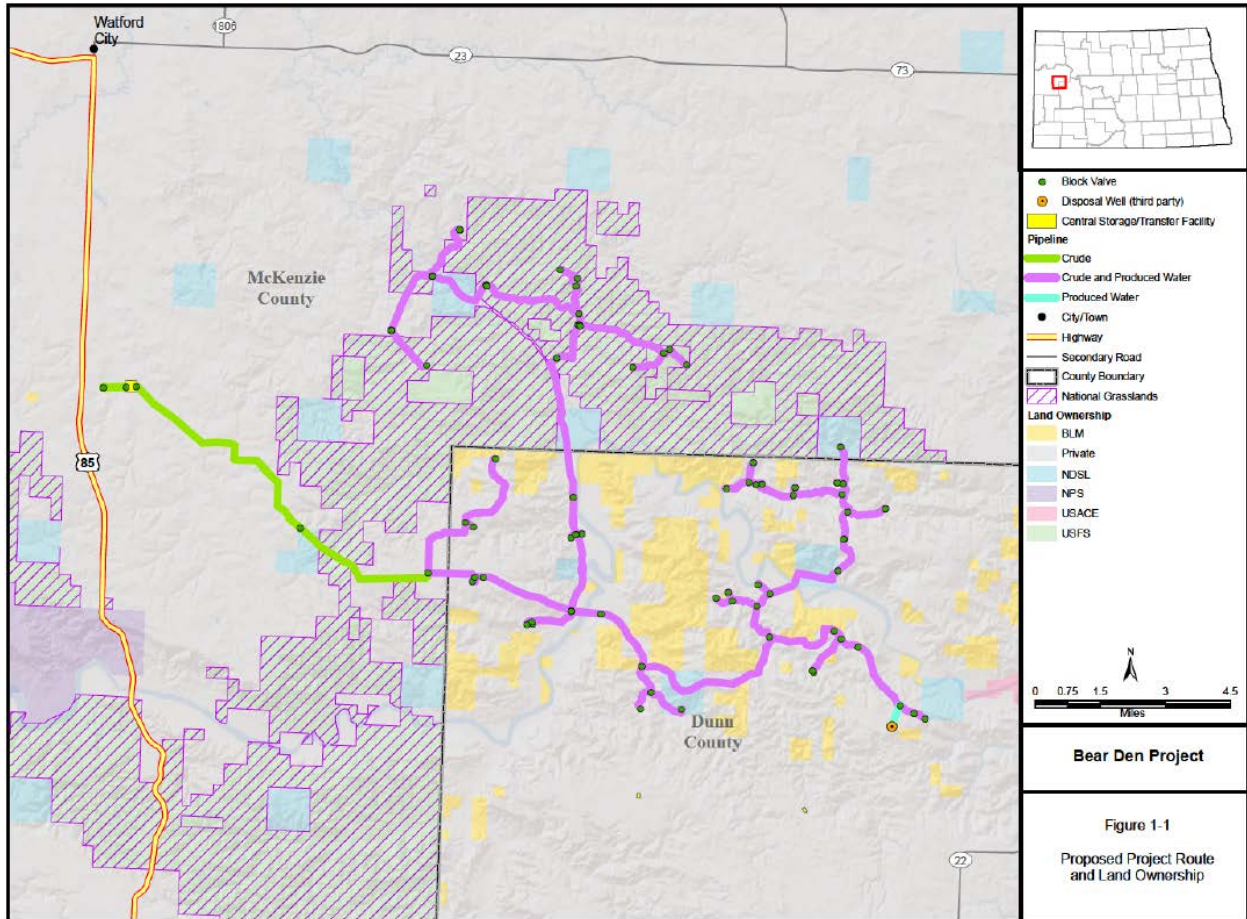


Figure 2.1: Proposed Bear Den Pipeline Network [7]

Unfortunately, this version was not practical for several reasons:

1. Production schedules are typically unreliable and are altered often throughout a field's development as the exploration company finds which regions in a play produce better than others.
2. The direct distance optimizer works well for sparse fields where the play is spread out unevenly such as in the Bear Den Project shown in Figure 2.1 [7]. However, the plays under consideration for this project are generally explored more thoroughly, as shown in the East Pony development plan [8] on the left side of Figure 2.2, with little open space. The optimized pipeline design of a packed field is not as complicated as a sparse field and does not require the simulation complexity of this approach.

3. Development occurs over a relatively short period compared to the lifetime of the field, so differentiating the present and future value of pipe construction during this construction window is not particularly interesting for this case study.
4. The computation time for this version was deemed too excessive.



Figure 2.2: East Pony Pipe Network Optimized for Minimum Distance Solution

The second and current pipeline optimization tool uses a simplified design based on heuristic assumptions in order to create a quicker and more reliable output. Every wellhead is combined into a single main access point at the center of a square mile node. Pipelines are restricted from nearest straight line distance to only traveling along the four cardinal directions (N, S, E, and W) similar to how many roads are oriented in Colorado. The optimization tool calculates every possible pipeline path to connect every node to the central treatment facility (multiple optimization runs can compare various treatment facility locations), and then finds the optimal combination of all of these node-treatment paths in order to minimize the total pipeline distance

for the network (pipes traveling along the same path are considered to be combined and only count once). Currently this tool allows for various additional features:

1. This tool can consider all pipeline paths from node to facility which contain either one, two or three turns. The optimization problem becomes excessively large beyond allowing pipeline paths with more than three turns.
2. Unowned or unleased property can be removed from consideration and all pipeline paths traveling through those regions discarded.
3. The tool allows for pipeline paths to at first travel a definable distance away from the treatment facility in order to find more optimal combinations or avoid blocked nodes from feature 2.
4. The number of pipes combined in a single node to node path is tracked as part of the optimization, there is a slight incentive within the routine to make larger combinations of pipes if possible, leading to a typical pipeline main and branch network result.

Figure 2.2 shows the optimization results for the East Pony region. A close inspection shows that the optimization toolset reached within 99% of the minimum pipeline distance for the region. This result directly influenced the design of the generic field used in the case study discussed in sub-objective 2.3.3.

2.3.3 Evaluate financial and environmental costs of a piped network and compare to existing standard practices (trucking)

The environmental and social impact of trucking water for these oil and gas fields is an active field of research. Many LCAs assume that utility companies will switch to a pipeline system in the future, and essentially treat those future systems as without environmental cost. The case

study of a generic field discussed in chapter 5 quantified and compared the economic, environmental and social costs of these two transport systems. This case study compared numerous varieties of this generic field and broke down the comparison to each type of water transport. Ultimately pipeline transport was historically shown to cause fewer accidents and spill less hazardous material, while this case study demonstrated that it also emits less pollution, creates less congestion, and damages the road system less than truck transport systems. The effect of recycling produced water at the central processing facility was also quantified using these metrics.

Chapter 3

Evaluation of Existing Customer-owned On-site Distributed Generation Business Models ^[9]

3 Overview

Distributed generation (DG) can enable localized energy choice, appropriate energy systems, and clean generation technologies. Under traditional business models, electric utility revenues are coupled to the volume of energy sales. Because DG decreases the net central station electricity generated, DG projects typically decrease profits for utilities and those entities along the value chain between the customer and the central station generator. This paper presents a case study involving Platte River Power Authority, Fort Collins Utilities Light and Power, and a model customer and identifies the aspects of the current utility rate structure that incents customers' DG development and installation. This study then quantifies the deleterious effect of DG on traditional utility business models, and proposes that new business models are required that can recognize and monetize any potential benefits of DG resources for generation and transmission utilities, distribution utilities, and customers.

3.1 Introduction

A variety of smart grid analysis and optimization studies have concluded that customer-owned and customer-operated distributed generation (DG) can realize specific economic benefits

for utility customers [10],[11], [12],[13]. These studies of DG operation and control have focused on rigorous minimization of customer costs, without consideration for the other stakeholders in the DG transaction. Previous research has already investigated multi-objective optimized solutions that balance customer economics with environmental concerns [14], but there has been little research that simultaneously considers the economic effects of DG on all of its market participants. If properly sited and implemented [15], DG facilities benefit utilities through grid capacity upgrade/expansion deferrals and reduced demand (i.e. reduced costs), but there is not currently a thorough understanding of the net economic effect of a DG facility for distribution or generation and transmission (G&T) utility stakeholders. Utilities are primary stakeholders in the electrical market and their participation and buy-in to customer-owned DG business models will determine the degree to which the capabilities of DG will be realized in practice [16].

Existing DG systems' business models [17] function by operating the distributed generator during any time when the levelized cost of generation using the DG resource is lower than the cost to purchase electricity from the utility [10],[11],[12],[13]. Although this business model is simple, transparent, and has been demonstrated to provide value to the electricity customer, the long-term acceptability and viability of DG must account for real-world utility/customer interactions and interdependencies. A complete and effective utility business model is asserted by EPRI to require the following: 1) revenues must cover costs, 2) services must be performed reliably, and 3) costs and revenues must be allocated equitably among the stakeholders [18].

Fort Collins, Colorado is the site of FortZED, a comprehensive community effort to create a zero-energy district in the downtown and university areas. The FortZED organizations participated in a US Department of Energy Renewable Distributed Systems Integration (RDSI)

smart grid demonstration. The RDSI attempted to lower the peak electrical load on two active distribution feeders (of approximately 15 MW capacity) by 20%-30% through the implementation of customer-owned and customer-controlled DG systems. During the development of the demonstration, a first order analysis performed by the Platte River Power Authority (PRPA) using its traditional business models indicated that the FortZED DG program, active for approximately 300 hours/year, could cost PRPA more than \$400,000 per year [19]. The primary driver of this financial impact was the reduction in the customer's charges related to coincident peak pricing, and secondarily, reduction in demand charges. This single real-world data point would suggest that traditional utility business models applied to DG may not meet the requirements for an effective business model as defined above. Beyond this local example, this hidden cost of DG is typical for many utilities and it has led to significant utility opposition against DG resources, limiting the use and benefit of these technologies [20].

The goal of this study is to build on this example and the current state of the art in analysis of customer-owned DG systems, to more completely understand how the demands of customer-owned and operated DG function within current business models. This paper presents financial models of the utilities involved in FortZED to more comprehensively understand 1) the business model that is currently motivating the development and control of customer-owned and operated DG resources, 2) the means by which utilities' costs and revenues can be impacted by the DG resources, and 3) which alternative business models can create economic value from DG technology. Armed with this information, stakeholders for the smart grid technology can understand the true costs and benefits of DG to the utilities and other stakeholders.

3.2 Methods

3.2.1 Modeling Scope

The financial model discussed in this paper was built as a case study representative of DG installations that are located within the Fort Collins municipal utility's service region. It models the finances of the customer, the distribution utility, and the generation and transmission utility (G&T) as three separate economic entities. These participants are connected through established rate agreements between the customer and the distribution utility (Fort Collins Utilities Light and Power, FCU) [21],[22] and through contract delivery rates between the distribution utility and the G&T utility, (PRPA) [23]. These established connections as well as additional information such as PRPA's posted avoided costs [24] for generation provided by Qualifying Facilities as defined in Section 201 of the Public Utilities Regulatory Policies Act provide the mechanisms to track costs and revenues of any DG scenario for each participant using existing methods of value monetization.

Potentially, this model could analyze different scenarios of DG ownership and operation, such as a utility-owned and remotely-dispatched DG facility at a customer location; however, this study will focus primarily on customer-owned DG operation and its effects on distribution and G&T utilities.

3.2.2 The Business Model for Customer-owned DG

The customer's desire to independently own, site, and control DG systems derives from the economic incentives available through a DG business model that has been proposed numerous times in literature [10],[11],[12],[13]. Figure 3.1 describes this business model conceptually for the operator of an on-site, customer-owned, customer-operated DG resource. Billing

determinants and a corresponding rate structure connect the technical abilities of the DG resource to an economic value for the customer. The electrical output of the DG system directly impacts the billing determinants (service connection, kW, kWh, kvar). The rate structure converts the billing determinants into the cost of electricity service (\$/connection, \$/kW, \$/kWh, \$/kvar) [18]. Overall, the DG resource provides value to the customer by modifying their cost of electricity service.

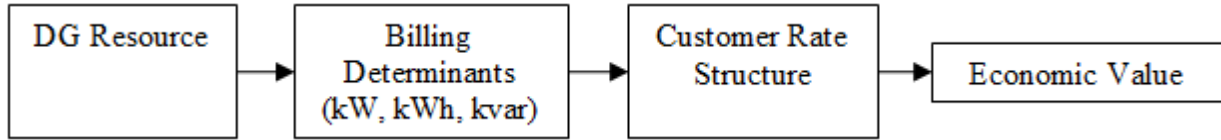


Figure 3.1: Traditional Customer Business Model for DG

Although this business model creates a pathway to connect a DG resource with economic value, it restricts the monetization solely to established billing determinants between the customer and the distribution utility. Other potential technical or economic benefits (such as availability of local backup generation, or government incentives [10]) are not monetized by this business model. Within this model, the customer is only able to monetize the purchase and operation of a DG resource through a reduction in total payments to the electric utility.

3.2.3 Distributed Generation Scheduling

Based on an understanding of this business model, the customer-owned DG can be controlled so as to reduce the customer's costs as much as is possible. For this study, the decision of when to operate the DG resource is formulated as a deterministic optimization problem. Daily customer load ($L(k)$) is given in 15 minute increments ($k = 1:96$), and the DG output power is assumed to be controllable at the same level of discretization ($D(k)$). The billing determinants and daily customer costs for utility demand charges, energy charges, and fixed charges can be calculated as $c(L(k)-D(k))$. The cost of operating the DG resource can be calculated as $e(D(k))$.

Therefore the optimization problem can be stated as: find a control sequence $D(k)$ that minimizes the cost function (f) subject to the following,

$$\text{Given: } L(k) \tag{3.1}$$

$$\text{Minimize: } f = c(L(k) - D(k)) + e(D(k)) \tag{3.2}$$

$$\text{Subject to: } L(k) - D(k) > 0, D(k) > 0 \tag{3.3}$$

Since there are no technical (size) limits considered on a potential DG facility, technology or fuel source in this model; the system is constrained so that the customer cannot export power: $L(k)-D(k)>0$, nor can the DG system absorb power: $D(k)>0$. This problem is solved by using a gradient-based approach to perform coarse optimization, and a pattern search algorithm to perform fine optimization.

Figure 3.2 shows an example customer seasonal load curve [25] used in this economic model and the affected load curve after a customer optimizes its DG utilization based on its billing structure: One example contains a demand charge on the customer’s own peak (FCU GS25) [26], and the other has a more severe penalty on energy use during the distribution utility’s coincident peak hour (FCU GS50) [27]. In both cases, the customer uses the DG installation to target and displace higher cost electricity during peak hours. This focus on reducing the high cost of peak load is also known as “peak shaving” and is a typical mode of operation associated with DG projects [10],[11],[12],[13].

Figure 3.2A shows the customer’s power demand curves for summer and winter without DG. Figure 3.2B shows the standard summer load curve compared to load curves with DG implementation under either simple peak rates (FCU GS25) or a combined peak and coincident peak rate pricing structure (FCU GS50).

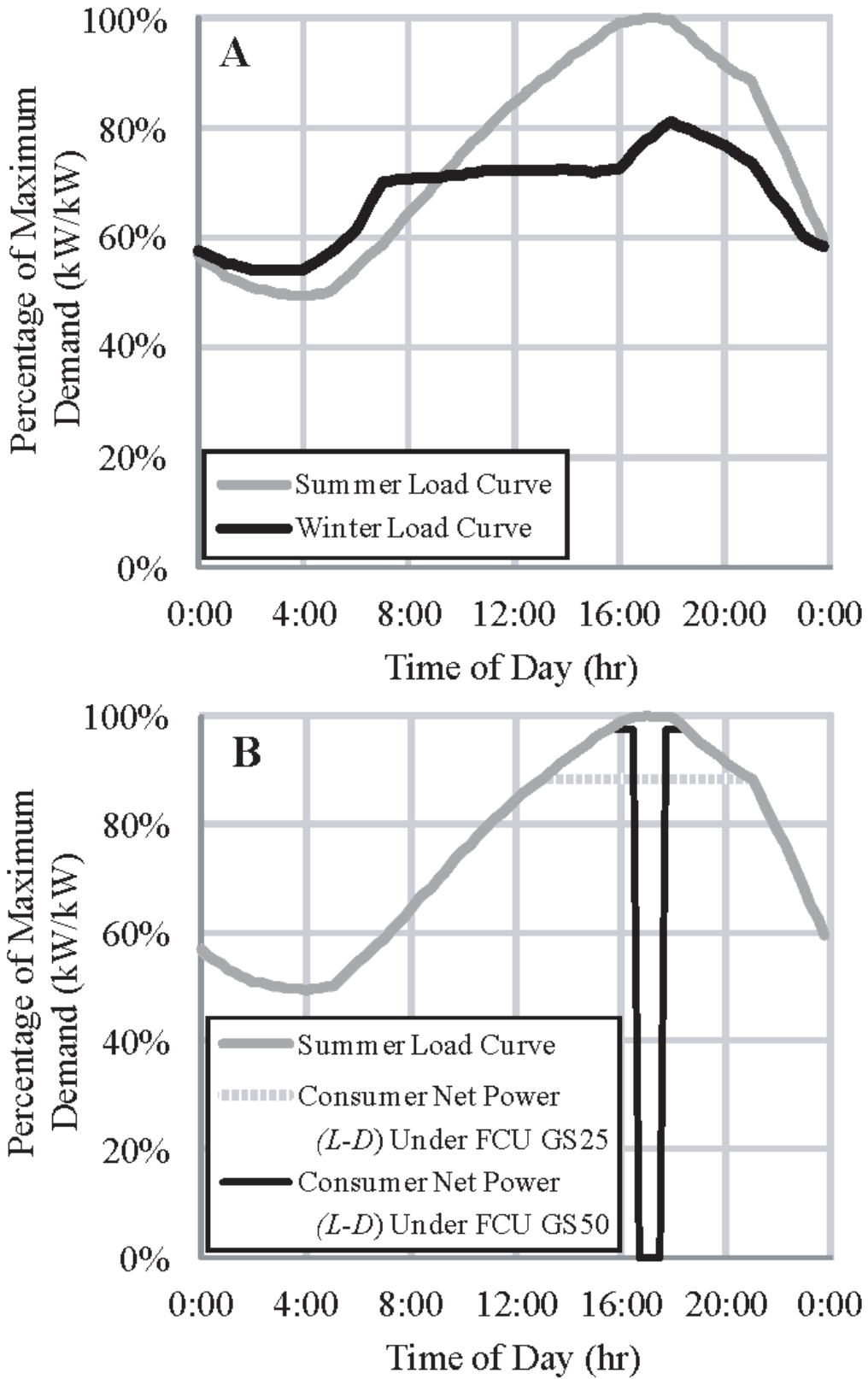


Figure 3.2: Example of Optimization Input and Output for the Case Study Customer.

Figure 3.3 shows the GS25 customer load curves optimized for levelized costs of DG between 0.07 and 0.15 \$/kWh. As the cost to build and operate a DG facility becomes cheaper, the customer can realize an economic benefit by displacing more and more of the peak load until the cost of DG electricity begins to approach the basic energy charge for base load electricity (in this model, approximately: DG rate = 0.06 \$/kWh). This exercise shows that under the traditional customer-owned DG business model, the customer is incented to respond to the relative price difference (cost savings) between its utility rates and its DG installation and fuel costs.

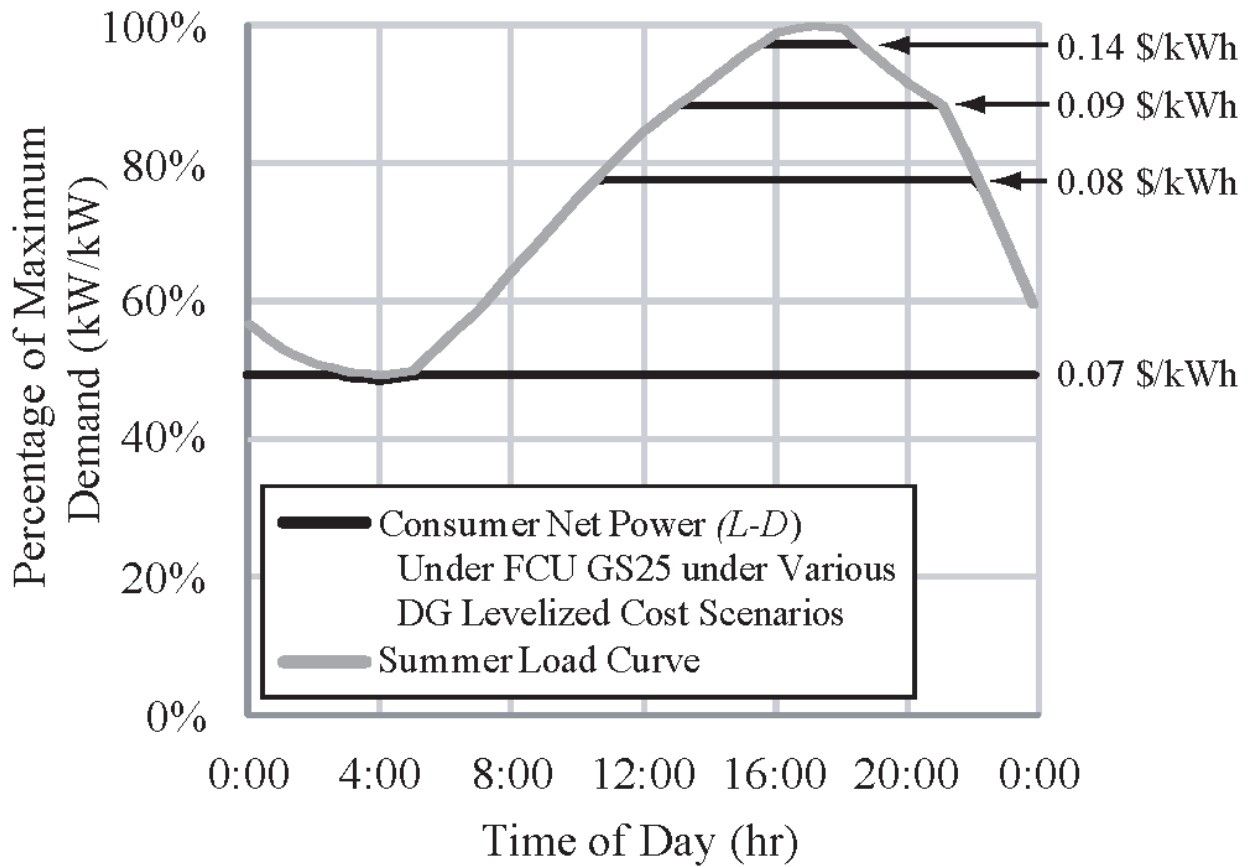


Figure 3.3: Optimized DG Use Profiles for GS25 Customer During Summer 2012: DG Implementation Increases as DG Cost Decreases.

3.3 Case Study Results

The results presented in the previous section are quite conventional and correspond qualitatively and quantitatively to results presented in the literature on optimal scheduling of DG resources for maximizing customers' benefits. In the following sections, we present the results of the case study in which we consider the effect of this type of generation scheduling on the balance sheet for the customer and for the utility stakeholders.

3.3.1 The Effect of Customer-owned DG on the Customer

An illustrative example of the effects of this business model on the customer's balance sheet can be constructed from a case study of a participant in the FortZED RDSI project. This example utility customer resides in Fort Collins as a GS50 customer [21] and operates a load profile similar to the published average for the PRPA region with a typical peak load of 75 kW at approximately 5:00 PM. This customer will choose to build and operate a dispatchable DG resource so as to realize the maximum possible economic benefit available. For this specific example, we estimate a levelized cost of \$0.11/kWh (including installation, fuel, and operation) for a DG resource [28]. Table 3.1 lists the cost elements and billing determinants of the utility-customer rate structure without and with the DG resource.

Table 3.1: Calculations Associated with Evaluation of the Customer Business Model for DG

Monthly Customer Balance Sheet Schedule GS50, Summer Season 2012					
<u>Billing</u>					
<u>Without DG (Baseline)</u>	<u>Determinant</u>		<u>Rate</u>		<u>Total</u>
Fixed Charge	1	Acct.	21.02	\$/Month	\$ 21.02
Demand Charge (co. peak)	74.9	kW	10.36	\$/kW	\$ 776.04
Energy Charge	40984	kWh	0.0372	\$/kWh	\$ 1524.59
Distribution Charge (peak)	75	kW	5.52	\$/kW	\$ 414.00
Tax and Franchise			6%	of subtotal	\$ 164.14
Total Utility Bill					\$ 2899.79
Levelized DG Costs	0	kWh	0.11	\$/kWh	\$ 0
Total Customer Costs					\$ 2899.79
<u>With 75 kW DG</u>					
Fixed Charge	1	Acct.	21.02	\$/Month	\$ 21.02
Demand Charge (co. peak)	0	kW	10.36	\$/kW	\$ 0
Energy Charge	38579	kWh	0.0372	\$/kWh	\$ 1435.12
Distribution Charge (peak)	72.3	kW	5.52	\$/kW	\$ 399.05
Tax and Franchise			6%	of subtotal	\$ 111.31
Total Utility Bill					\$ 1966.51
Levelized DG Costs	2405.1	kWh	0.11	\$/kWh	\$ 264.56
Total Customer Costs					\$ 2231.07
Customer Monthly DG Benefit					\$ 668.72
Customer Projected Payback Period					10.9 years

As shown in Table 3.1, if the customer does not purchase and use a DG resource, their monthly payment to FCU will be \$2889.79. By using a DG resource and controlling to perform peak-shaving as derived and presented in Figure 3.2 and Figure 3.3, the customer reduces their billing determinants and therefore their costs to the utility to \$1966.51. The levelized costs of DG operation are considered an offset to the difference in utility costs so that the net benefit of owning and operating the DG resource is \$689 per month. As long as this savings justifies a Minimum Acceptable Rate of Return (MARR) analysis on the initial cost of a DG system, this

net monthly value gain result justifies the ownership and operation of a customer-owned and controlled DG resource under the assumption that customers will use the least cost means to meet their needs for a required quantity, timing, and power quality of electricity service.

3.3.2 The Effect of Customer-owned DG on the Utilities

For utilities, the economic effects of an onsite, customer-owned DG resource are more complicated. Figure 3.4 illustrates the positive and negative economic signals (benefits and costs) of a customer-owned DG resource within the combined customer-utility business model. In this case study, FCU serves the Fort Collins, CO area as the municipal distribution utility. Here, we also include a model of the G&T utility. With the exception of a negligible amount of DG (primarily residential roof-top solar panels) FCU purchases 100% of its electrical power exclusively from the G&T utility, PRPA. PRPA employs conventional utility-scale generation assets (primarily coal with some hydropower, wind and natural gas peaking units) to supply FCU as well as some other investor-owned, municipal, and rural-electric cooperative utilities in the region.

As illustrated by the signs associated with the connections in Figure 3.4, the customer-owned DG resource has both a positive and a negative impact on the economic value realized by the distribution utility. The customer with DG will buy less electricity from the distribution utility (that therefore receives less revenue), but the distribution utility is also obligated to buy less electricity from the G&T utility (and therefore incurs less costs). The characteristics of the billing determinants and the scheduling of the DG resource directly impact whether the sum of these two effects creates or diminishes costs for the distribution utility. In other words, the distribution utility will gain value from the customer-owned DG resource only if money saved from reduced outlays to the G&T is greater than the loss in revenues from decreased electricity

sales to the customer. Distribution utility fixed and capital costs are outside of the business model [29].

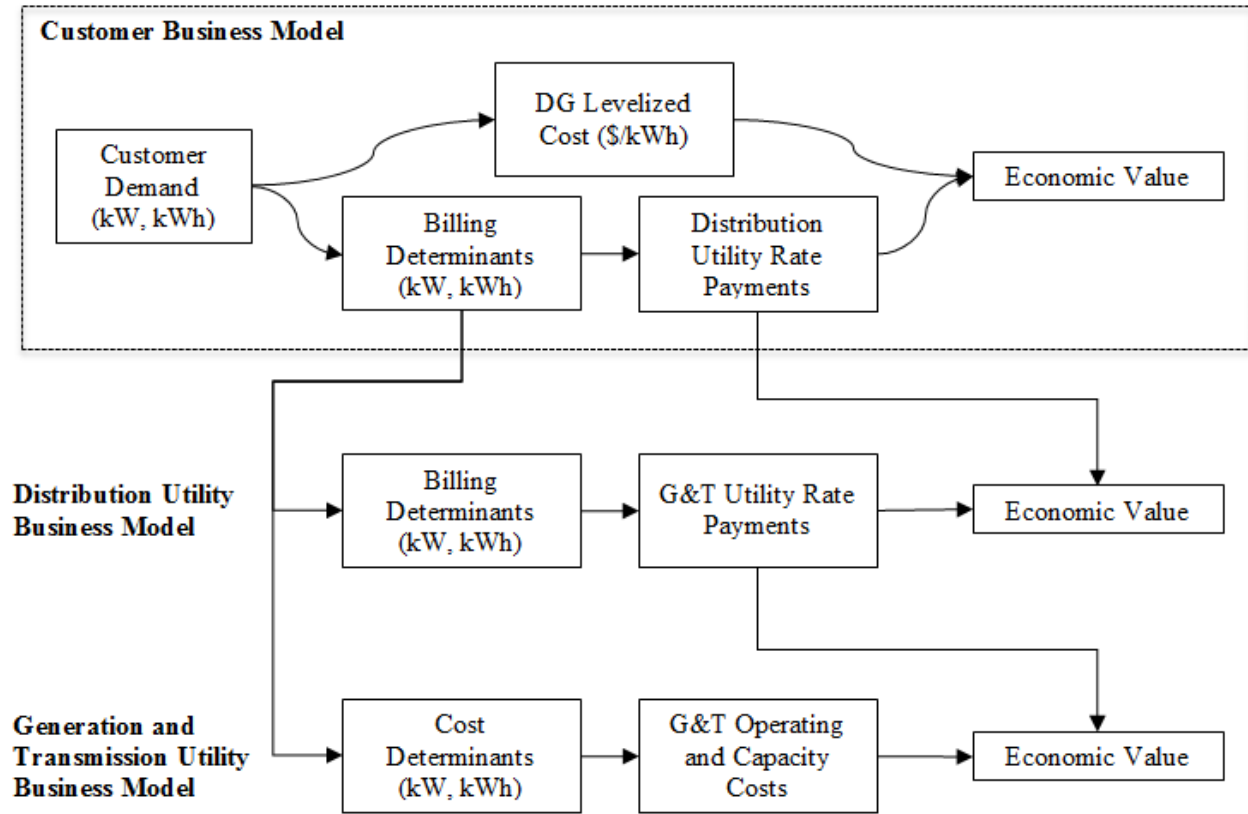


Figure 3.4: Traditional Customer, Distribution Utility and Generation and Transmission Utility Business Models for DG

G&T utilities obtain revenues from distribution utility payments based on the rate structures and contracts in place between the distribution utility and the G&T utility. The G&T utility's primary costs are concerned with the generation and transmission of electricity. As the DG resource offsets load demanded by the customer, the G&T will sell less electricity to the distribution utility (reduced revenues), but also require less fuel and transmission capacity (reduced costs). The net economic impact is the sum of these two effects. Therefore, similar to the previous case for the distribution utility, we can calculate the net effect of the DG resource by analyzing the separate effects of DG on the costs and revenues of the G&T utility.

For our case study, the G&T utility owns coal-powered generation resources that it runs at a high availability factor, and natural gas generation resources that it runs as peaking generation. In summer, the utility uses both resources to meet peak demand, and marginal electricity costs are those costs associated with the peaking generation [30]. In winter, the utility uses the coal-powered generation unit at high utilization and sells excess electricity in the electric wholesale market. Thus, in the winter months, the marginal costs of generation are related to the current price of electricity on the Palo Verde trading hub [31]. PRPA combines this price information with the associated plant and transmission infrastructure costs (capacity costs) to publish a set of rates for avoided costs that applies to certain Qualifying Facilities that supply power to the grid independent of the utility. This model uses these avoided energy and capacity rates to conservatively estimate the total avoided cost for the G&T utility.

The results of this analysis for the traditional business model are presented in Table 3.2. Table 3.2 completes the previous case study to show the economic impact of the sample customer-owned DG on the distribution and the generation utilities. As shown in Table 3.1, the customer realizes a net benefit from their optimized use of the DG resource of \$668.72 per month. For the distribution utility, this lost revenue is approximately offset by a decrease in their billing determinants and therefore costs from the G&T utility. To the distribution utility, the net value of the customer's DG operation is a negligible -\$39.98 per month. The G&T utility loses revenues from lower billing to the distribution utility that is not made up by the reduced costs of purchasing/generating electricity. The net loss to the G&T utility from operation of the customer-owned DG resources is \$505.97 per month.

This analysis demonstrates the means by which distribution and G&T utilities lose economic value through the operation of a customer-owned DG facility.

Table 3.2: Economic Effects of Customer-Owned DG on Distribution and Generation Utilities

Monthly Utility Balance Sheet Schedule GS50, Summer Season 2012			
<u>Customer (DG Operator)</u>			
Customer Monthly DG Effect			\$ 668.72
<u>Distribution Utility</u>			
<u>Without DG (Baseline)</u>		<u>With Customer-Owned DG</u>	
Revenues from Customer	\$ 2725.80	Revenues from Customer	\$ 1848.51
Expenses to Utility	\$ 2192.57	Expenses to Utility	\$ 1355.27
Profit	\$ 533.23	Profit	\$ 493.25
Distributor Monthly DG Effect			\$ -39.98
<u>Generation and Transmission Utility</u>			
Change to Revenues			\$ -837.31
Change to Costs			\$ -331.33
G&T Monthly DG Effect			\$ -505.97

This analysis is repeated at a range of DG facility costs and for two of the rate structures available to FCU customers (FCU GS25 and FCU GS50). Results are presented in Figure 3.5. In each case, the ratio of the stakeholder’s cost increase to its baseline cost (without DG) is plotted to show its sensitivity to DG levelized costs. A positive value to a particular stakeholder implies an economic incentive for customer-owned DG operation. A negative value for a particular stakeholder implies that that stakeholder is losing economic value as a result of the operation of the customer-owned DG. The fraction of monthly energy generated by the DG resource to the customer’s monthly baseline energy consumption is also plotted on the same axis.

Figure 3.5 illustrates a number of results of interest. First, customer-owned DG resources robustly create combined losses for the utility stakeholders (both distribution and G&T utilities) at a variety of customer rate schedules and DG conditions. Second, comparing these results among rate schedules shows that under the current business model, small customers (who would

operate under the GS25 rate schedule) will realize only small benefits from DG. The value realizable for such a customer is relatively insignificant (less than two percent of the customer's annual bill) and is only achievable if DG has very low levelized costs. Only larger customers that are under the GS50 rate structure will realize significant benefits from operating DG. Third, Figure 3.5 presents a plot of the net benefits to the society (defined as the signed sum of the value to the three stakeholders) as a function of DG levelized costs. For small customers operating DG under the conditions here, the sum of benefits to all stakeholders is uniformly negative, implying that although the customer is incented to operate the DG resource, the sum of costs to society is greater than the sum of the benefits. Whether larger customers operating DG creates benefit or detriment to society depends on the cost of the DG facility – at high cost even optimally dispatched DG creates more total losses than savings.

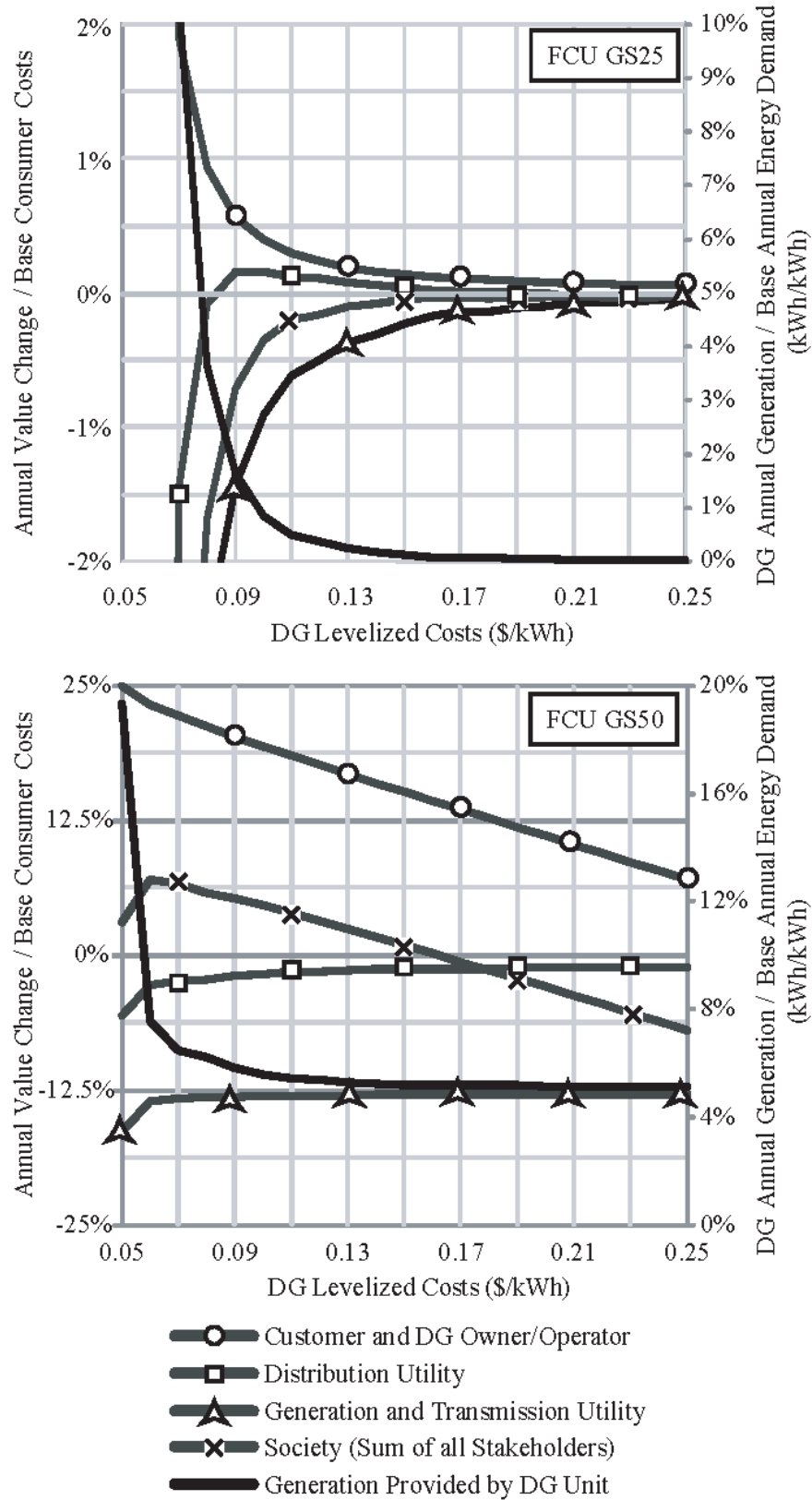


Figure 3.5: The Economic Effects of Customer-Owned DG Resources on Utilities and Society

3.4 Discussion

The results for this case study show that with the currently available utility business models, both the distribution and G&T utilities lose value when the DG resource is customer controlled and operated. The current business models to monetize the performance of onsite DG fail according to our definition of a complete and effective business model in that they do not allocate costs and benefits equitably among the stakeholders. A few near-term strategies exist to improve the traditional business model for customer-owned and operated DG. For the purposes of this discussion, we have classified them as either competitive or cooperative interactions among the stakeholders.

3.4.1 Cooperative Business Models

A majority of studies of the technological capabilities of DG have hypothesized that cooperative DG business models would evolve that would enable a connection between the technical capabilities of DG to economic value. The technical capabilities most commonly ascribed to DG are: generation capacity deferral, transmission capacity deferral, distribution capacity deferral, voltage control or VAR supply, ancillary services (A/S), environmental or emissions benefits, reduction in system losses, energy production savings, reliability enhancement, power quality improvement, combined heat & power, demand (charge) reduction, standby generation and more. These technical benefits of DG have been quantified by many studies [32], but there are disconnects between the technical capabilities of customer-owned, onsite DG and the business models that can monetize those benefits. Hypothetically, each of these capabilities could be monetized, but not all by the same entity (some benefits are only applicable to the customers, some are only applicable to the utilities).

Utilities have had difficulties monetizing DG technologies perhaps because these benefits do not rely on the traditional utility business models of economies of scale and economies of scope. Rather, DG depends on economies of mass production, of proximity to the loads that they serve, and of ease of operation [33]. The differences between traditional utility business models and the capabilities of DG suggest that cooperative interactions will require a complete revision of the business models for all stakeholders as well as some degree of technical development in siting and scheduling that can allow DG to achieve a positive societal benefit.

3.4.2 Competitive Business Models

More typically, competition among the stakeholders informs the development of new business models. As detailed in the results section, DG resources can provide economic benefits to the customer to the detriment of the distribution and generation utilities. In many real-world cases where DG installations have been proposed or implemented, we have found that utilities have chosen to restructure their rates in order to reduce their exposure to DG-generated losses.

The economics of a customer-owned distributed generation facility typically involves a large initial capital investment repaid over a projected period through reduced payments to an electricity provider. The length of these payback periods and the ultimate return on a DG investment is heavily dependent on the predictability of the electric rates between the customer and the utility. Small changes to rate structure can have a profound impact on the economics of a DG system, even pushing it outside of the definition of a “sound investment” for the customer.

As an example, the G&T utility in our FortZED case study, PRPA, has significantly shifted their contract rates between 2011 and 2012. The new 2012 rates deemphasize coincident peak charging (\$/kW) in favor of an increase to the energy charge (\$/kWh). The distribution utility, FCU, has also passed through a general restructuring of its rates including changes to the

demand, energy, seasonal, and block rates. Though multiple issues and negotiations certainly precipitated these changes, it is clear that it will have a large impact on DG recovery periods for customers and the distribution utility, and will thus be of interest to this model. Table 3.3 illustrates the economic impacts of these changes on a customer’s projected payback period.

Table 3.3: Comparisons within the DG Payback Period Analysis using 2011 and 2012 Rates

Payback Period Analysis	GS50 Customer	75 kW DG Resource
Capital Cost = \$651/kW	Variable Cost = \$0.11/kWh	Inflation = 3%/year
Payback Projected with 2011 rates		6.3 years
Payback Projected with 2012 rates		10.9 years

In this example, a customer sites and installs a DG facility in 2011 and projects a payback period of 6.3 years. After the first year (with only five years and 4 months until payback remaining), the utility switches the customer to the 2012 rates which reduces the customer’s ability to gather value from the DG resource and delays the remaining payback period by nearly four years (ten total years until payback under this rate switchover scenario). This example used a larger customer with coincident peak pricing rates. This problem becomes even more complicated for a smaller sized customer paying normal peak demand rates, in these cases, the customer will size a DG resource according to 2011 rates and find that under new rates, their payback period lengthens to beyond 20 years.

3.5 Conclusions

While a patchwork of inconsistent regulations require some U.S. utility companies to promote energy efficiency (EE), distributed generation (DG), and renewable energy (RE) projects, regulators and utilities have not widely implemented new business models that financially reward utility companies for selling less electricity or delivering more renewable

electricity. This project has evaluated a set of financial models for sample utility companies to understand the degree to which their revenues and finances will, in fact, be impacted by DG projects. This research demonstrates the need for new business models and rate structures between utilities and customers that can provide a healthy, sustainable incentive for well sited and operated DG facilities.

The case study of PRPA/FCU and our model customer can facilitate the introduction, evaluation and development of new business models specific to our case study. Through the development of generalized methods for business plan proposal and analysis, this work has provided a means to understand the true costs and benefits to stakeholders in this type of smart grid demonstration. Our future work will focus on quantifying and developing new electricity market business models that better internalize the costs and benefits of distributed generation projects between the three major market participants (G&T, distribution utilities, and customers) tailored to conditions in other utility companies' service territories.

Chapter 4

An Evaluation of Customer-Optimized Distributed Generation in New England Utility and Real-Time Markets ^{[34],[35]}

4 Overview

The full worth of distributed generation systems must be measured not only by the impact on the customer, but also by DG's impact on the grid and surrounding market participants. A case study comparing customer incentives created by utility rates with the real-time prices market in New England provides a new model to quantify the value of customer peak shaving with distributed generation technologies.

4.1 Introduction

Much of the previous research in smart grid analysis and customer demand side management (DSM) agrees that there are quantifiable, specific economic benefits for customers who own and operate distributed generation (DG) facilities [10],[11],[12],[13],[16],[36]. These same studies are far less specific in their analysis of the effect of these technologies on the other stakeholders in the electricity marketplace, including the generation and transmission utility (G&T), the distribution utility, and the rest of society (primarily other customers). As a field, we understand that, in general, the most expensive hours to generate and transmit electricity are contemporaneous with the hours of maximum energy demand, and thus we frequently treat customer daily peak shaving, as actuated through utility rates, as an economic and social good

[37],[38],[39],[40]. In this study, we seek to understand how sensitive the economic valuation of DG is to its actuation signal, and whether or not conventional peak-shaving is the optimal customer behavior that yields the maximum benefit to the customer and other stakeholders [41],[42].

4.2 Background

EPRI proposed a market trajectory of DG in 2001 with considerable optimism, predicting that 25% of new generation would come from distributed sources by 2010 [43]. Although the integration of DG has not kept up with those goals, the general sense of optimism has persisted, fed both by the quantifiable financial value of DG to the consumer, but also the potential system-level benefits associated with DG facilities [44]. These potential benefits associated with DG and other customer energy systems have been quantified in previous research [32] and include utility investment deferral, voltage control, line loss reduction, new sources of standby generation and several others. However, as the prevalence and integration of DG has steadily increased with time, and DG's effect on the grid and the electricity market has become better understood, the value of these ancillary benefits has become more ambiguous [45],[46],[47],[48]. Intermittent, non-dispatchable DG sources offer no real benefit to reliability [47],[49], a DG unit has a better impact on line loss reduction when generating constant power rather than peak-shaving [50], and adapting the grid to handle high DG integration has a cost: Without active management technologies, the grid may not be able to handle multiple customers acting as independent players in the energy market [51]. Line safety, power quality and increased congestion in other systems (such as natural gas pipelines) could create new expenses that may offset DG's benefits [48]. Without customer-utility coordination, improperly sited DG facilities may contribute to issues related to voltage flicker, harmonic distortion, overcurrent protection,

capacity limits, etc. [52],[53]. Additionally, unless these customers are actively participating in the frequency control market, DG systems will likely exacerbate frequency oscillation during significant events [51]. Combined heat and power DG systems, while efficient, are dispatched according to a customer's individual heating and cooling needs and are less responsive to market signals, thereby potentially creating a new layer of difficulty in market demand prediction [54],[55]. Price volatility is another concern in that while DSM is often expected to reduce price volatility [56], unilateral customer behavior creates a new source of volatility in the market [57].

The potential benefits to DG can best be realized, and the potential costs best avoided, through increased customer-utility coordination and cooperation [52],[53],[58],[59]. Coordinated planning between utilities and customers is essential since customers are able to purchase and construct DG facilities on a much quicker timescale than the legal time it takes for a utility to execute projects and grid upgrades [53]. For example, optimal siting discovery and policy is important to preserve DG's potential ancillary benefits [60], but customers may not be well-informed and without this increased level of cooperation, utilities do not have any control or input on the siting of customer-owned DG [52]. Much of the research assumes that customers have perfect information of the electric market while modelling the results of DG siting decisions [61], but this is hardly the case under a traditional monthly tariffs rate structure which at best only approximates (and at worst ignores) price effects according locational and temporal differences. These traditional rates typically are the same for all customers in a large region and split charges between fixed/energy/demand rates which provide value and incentive towards daily customer DG peak-shaving. Many of the challenges to DG integration hinge on this lack of customer market participation and cooperation with utilities. But, DG systems, when properly incented as smaller, more nimble generation units, may be able to adapt faster and better to

changing price signals than utility investment in larger facilities [62]. The RTP market is one step towards improvement in customer-utility cooperation as it connects customers to the actual prices in the market and incents optimal DG siting through different regional and distribution-level prices. Previous research has already indicated that the potential valuation of DG technologies would be greatly enhanced in the RTP market [63].

RTP is a relevant and realizable means to improve the value of DG through improved coordination between customers and utilities. RTP and advanced metering are DSM-enabling technologies, but these also rely on increased customer involvement and market participation [62],[64]. Advanced metering and correct pricing systems are essential to measuring and tracking DG's ancillary services to the grid and in shifting the grid system from the passive control "top-down" model to an actively controlled "bottom-up" approach which allows greater DG integration [45],[46],[54]. Customers in the UK [65],[66] and Hong Kong [67] appear to welcome smart grid technologies, but similar interest may be limited to only a subset of American customers [68],[69]. Whether or not smart grid and RTP should be optional or mandatory in the United States may be a matter of dispute [70],[71], but previous successes with Time of Use (TOU) rates have demonstrated that customers, when armed with a greater understanding of the factors which determine electricity prices and an improved source of billing information, are capable of shifting their load profiles in order to meet mutually beneficial objectives [72],[73]. In a case study in the UK, customers responded positively to instantaneous feedback on electricity use and costs related to appliance use and were able to shift more power use than those customers who only received mailed-in paper feedback [66]. Customers still have their own priorities, and it is not entirely clear what form future markets will take, but it is clear that some change towards a greater flow of information will occur [74],[75]. Already in the

American Midwest, customers with ComEd are able to purchase electricity at an optional RTP [76].

For customer-owned distributed generation to succeed, it must exist within a sustainable customer-utility business model – revenues must cover costs, and value must be allocated equitably among the shareholders. DG systems cannot flourish if the costs outweigh the benefits, and these benefits cannot be fully realized without buy-in from both the customer and its utility. Utilities’ traditional business models are unprepared to accommodate DG technologies sustainably [58],[59],[9],[77]. These unsustainable markets may create significant potential for economic benefits that may be accrued by DG operators, but “gaming” these traditional utility rates comes at a cost to the rest of society. In previous research, the authors developed a case study of municipal generation, transmission, and distribution utilities in the Fort Collins, CO. region to demonstrate that customer-optimized peak-shaving within traditional pricing and business models can create quantifiable losses for utilities. These losses could be passed back to other customers through higher rates, or utilities may hedge against future DG losses by adjusting the rate structure (such as by deemphasizing demand costs) leaving DG customer-operators with significant stranded costs.

To extend this previous analysis (which only considered demand and energy pricing), we seek to develop a series of case studies inclusive of the “higher quality” actuation signal that would incent a DG unit using the RTP market [78]. The case study is presented along a continuum of increasing customer information: traditional utility rates, the day-ahead market, the final hourly market, and the five minute spot price market. This research will compare the customer DG response incented by utility rates at three communities within the New England Independent System Operator (NEISO) region with the DG response incented by the real-time

distribution locational marginal prices (DLMP) at each community. We will quantify the potential value of daily peak-shaving incented by utility rates by comparing the customer's optimized DG operation profiles to measure the correlation, value, and market value with a "more-idealized" RTP DG dispatch. At the core of this study is the comparison of the relative magnitude of time-of-day price variations against the sharper price spikes which occur on a less predictable timescale.

4.3 Methods

This case study will compare an identical customer at three nodal locations within the New England Independent System Operator (NEISO) region: Portland, ME (node 4179); Rutland, VT (node 4459) and Hartford, CT (node 4534). Each of these locations has its own distribution utility: Central Maine Power Company (CMP), Green Mountain Power (GMP), and Connecticut Light and Power (CLP) respectively. The NEISO website maintains publicly available historical data for the real-time prices in the day-ahead hourly, final hourly, and final five minute markets as well as hourly net system demand [79]. The customer in this case study has a load profile geometrically similar to the net system demand but scaled down such that its absolute maximum peak load during 2013 is 350 kW. This customer size compromises between categorizations on the various utilities' rate sheets. It is also appropriately large such that building and operating a DG facility of 100 kW primarily focuses on load displacement rather than power insertion (electricity sales) into its local network. This case study will primarily consider the levelized costs for the purchase and operation of a DG facility at \$100 and \$125 per MWh. These DG costs are slightly higher than has been published for technologies such as microturbines and fuel cells [80], but energy costs, especially natural gas costs, are higher in New England and show signs of remaining high for the foreseeable future [81]. The DG facilities in this case study are

assumed to be freely dispatchable for use in peak-shaving or electricity sales [82]. These units face a capacity limit based on the size of the unit, but have no temporal (such as with a combined heat and power system), fuel (limited byproduct feedstock), or energy limit (such as a battery) [83].

This case study will take a broad view by considering the hourly RTP signal and utility rates over a multiyear period for Rutland, VT; and a more in depth analysis by considering the most recent twelve months in the analysis for all three regions, utility rates and RTP types. The broad view or historical analysis will compare monthly trends for the final hourly RTP price, the utility electric rates, as well as the customer behavior while incented by either signal. The in-depth analysis over the final twelve months will compare the DG valuation and dispatch resulting from the various RTP markets and the utility rates at the three different locations.

4.3.1 Datasets

Data for the real-time prices in the day-ahead hourly, final hourly, and final five minute markets as well as hourly net system demand were acquired from the NEISO. There are occasional lapses in the data record for the five minute market which are covered through linear interpolation for lapses less than two hours and by duplicating the final hourly price signal for longer lapses. The missing data accounts for less than 0.39% of the intervals for the in-depth simulation year. The records for the final hourly market, day-ahead market and hourly system demand data over that same period are fully sound.

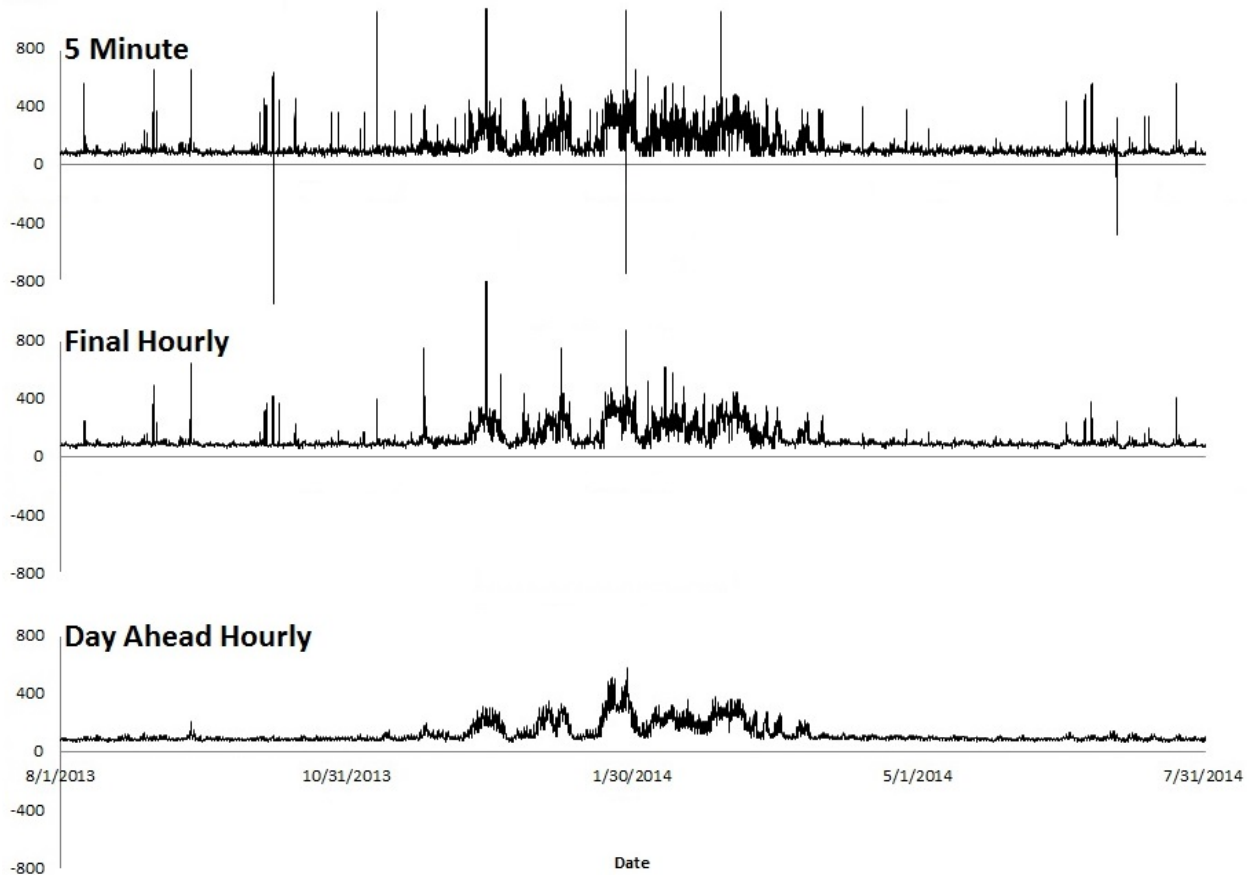


Figure 4.1: DLMP Comparison (\$/MWh) Node 4459 - Rutland, VT

4.3.2 Tariff Models

The various utility rates available to the customer were compiled from each utility’s publicly available ratesheets.

In Portland, ME, the customer tariff is modeled with distribution costs according to CMP’s medium general service at primary voltage [84] and G&T costs set monthly by NextEra Energy Power Marketing [85],[86],[87]. Portland’s distribution costs are modeled as per the ratesheet as a split between service, energy, and demand charges. The demand charge is based on the customer’s own 15 minute peak. NextEra’s G&T rates for medium class customers are represented with a monthly varying energy charge which could theoretically accommodate for seasonal effects or planned plant shutdowns.

The customer tariff in Rutland, VT is modeled according to the GMP rates for customers previously covered by the Central Vermont Public Service Corp. before its merger with GMP [88]. These rates also cover service, energy, and demand charges with a declining block rate for the energy charge and a small free block for the first few kW of maximum demand. The demand is also defined as the customer's own 15 minute peak.

The Hartford, CT customer's tariff is modeled according to CLP's small time-of-day general electric service ratesheet [89]. The rates are split into a variety of small line items charged by either energy or demand, many of the larger of which are split into on-peak and off-peak time regimes. The on-peak regime is defined as weekdays from 12pm – 8pm during Eastern Standard Time and 1pm - 9pm during Daylight Savings Time. The demand is measured as the customer's highest average 30 minute demand during the on-peak hours.

As the utility rates described above are for distribution level costs, and the RTP market rates are wholesale nodal prices more analogous to G&T costs, some effort must be made to model distribution costs for the modeled RTP market. The formation of distribution level LMPs, or DLMPS, is an ongoing field of research [90],[91],[92] without a clear industry precedent. For this research, we have added a modeled cost of distribution to each customer's available RTP based on the difference between the utility rates and the nodal prices for each region. The RTP rates for each region are increased uniformly such that the customer, before owning and operating a DG facility, pays the same total bill over the in-depth period from the start of August, 2013 to the end of July, 2014 whether or not that customer chooses to pay utility rates or through the RTP market. Figure 4.1 shows the resulting DLMP rates that are used for this case study for Rutland, VT.

4.3.3 Customer DG Models

The customer's size (max peak of 350 kW) and proposed DG facility size of 100 kW were selected to represent a realizable DG size that might be implemented for peak load reduction, but would not be a significant source of "net metering". The majority of the DG use will be put towards load displacement rather than injecting electricity back to the distribution network. The customers in these two models (utility rates and the DLMPs) will follow separate rules for net metering based on the policies of several of the utilities in this region. The customers who pay traditional utility rates can sell electricity back to the grid for monthly billing credits equivalent to their energy charge for electricity [93],[94],[95]. There is no reimbursement for a negative demand charge or against the fixed rate charges. The levelized distribution charges under consideration for this case study have been selected so that none are below the available energy cost of electricity. This study is more concerned with understanding customer behavior than in exploring the technical constraints of DG, and if a customer can generate electricity more cheaply than its utility's energy (fuel) cost, then there is no reason why it should not generate that electricity without limit. Therefore, with the DG's cost set above the utility energy charge, the utility rates paying customer under consideration in this model will not attempt to net meter and will only utilize the DG facility as a tool to peak-shave its own load. As the customer's load profile matches up with its demand charges and TOU rates in the region, this limitation does not have any material impact on the peak-shaving behavior or total DG valuation for the customers in this study. The RTP customer will also utilize its DG facility to offset its own electricity costs based on its DLMP, and will also be able to sell electricity back to the distribution utility according to the LMP (a lower rate than the DLMP). Two of the utilities in this study already have a similar mechanism in place for selected customers and small generators [96],[97], and this

allows the RTP customer to dispatch its own resources according to the ideal situation presented by the RTP market while still preserving some value for the distribution utility who provides the infrastructure for the customer's participation.

4.3.4 Optimization

The customer is expected to optimize their own DG facility with the objective of minimizing the sum of DG operational costs, and electricity purchases from the grid.

As previously stated, the customer's load profile matches the shape of the hourly total system demand for the New England region. Since demand charges are often assessed on fifteen minute intervals (k), this hourly data was expanded through linear interpolation into a fifteen minute increments ($L(k)$) for the traditional utility customer. Similarly, the signal was expanded into five minute intervals (m) for the five minute RTP customer. The DG facility is assumed to be dispatched on whichever is the smallest time window of interest for the customer ($D(k)$, $D(m)$, $D(12*m)$), that is, a utility customer may dispatch the facility on a fifteen minute interval in order to properly perform peak shaving, a five minute RTP customer may dispatch the DG facility for five minute intervals, and similarly an hourly RTP customer may dispatch the facility on hourly intervals in order to displace or sell electricity.

For this study, the decision of when to operate the DG resource for utility rate customers is formulated as a deterministic optimization problem. The billing determinants and daily customer costs for utility demand charges, energy charges, and fixed charges can be calculated as $c(L(k)-D(k))$. The cost of operating the DG resource can be calculated as $e(D(k))$.

Therefore the utility rate optimization problem can be stated as: find a control sequence $D(k)$ that minimizes the cost function (f) subject to the following,

$$\text{Given: } L(k) \tag{4.1}$$

$$\text{Minimize: } f = c(L(k) - D(k)) + e(D(k)) \tag{4.2}$$

$$\text{Subject to: } L(k) - D(k) > 0, D(k) > 0 \tag{4.3}$$

According to the utility rates model, the customer receives certificates against its energy charges for electricity exports to the grid. Therefore, a utility rates customer with a dispatchable DG resource will only export to the grid if it can do so below this utility energy charge. This model does not include an upper boundary on the quantity of fuel or DG dispatch time available to the customer, so this ultimately leads to a DG utilization of 100%. In order to maintain a focus on peak-shaving behavior, DG costs below the customer's energy charge which lead to the optimization results that violate the condition against exporting power $L(k)-D(k)>0$ are not included in this model. Additionally, battery or other types of energy storage facilities are not under consideration for this model (these facilities have both capacity and energy constraints) so therefore the DG system cannot absorb power, under the constraint $D(k)>0$.

The decision of when to operate the DG resource for a RTP customer is more straightforward. Essentially, a RTP customer has a single decision point: This customer will operate the DG facility if grid supplied electricity is more expensive than its own generation costs. Since the customer is able to purchase electricity at its DLMP and export electricity at the nodal LMP, the decision expands into three possible solutions: 1) The customer will operate the DG facility at full power ($D(m)=100$ kW) when the current LMP is above the DG cost, 2) The customer will operate the DG facility at less than full utilization in order to displace only its own load subject to $L(k)-D(k)>0$ when the DG cost is between the current LMP and DLMP, 3) The customer will not dispatch the DG facility when the DG cost is above the current DLMP. For a

DG facility of maximum capacity of 100kW, the problem can be stated for a 5 minute RTP customer with the following where the LMP and DLMP cost functions are represented by $LMP(m)$ and $DLMP(m)$,

$$\text{Given: } L(m), LMP(m) \text{ and } DLMP(m) \quad (4.4)$$

$$\text{IF}[LMP(m) > e(D(m))], \text{ then } D(m) = 100kW, \text{ max DG power} \quad (4.5)$$

$$\text{IF}[LMP(m) < e(D(m)) \text{ AND } DLMP(m) > e(D(m))], \text{ then } D(m) = L(m) \quad (4.6)$$

$$\text{IF}[DLMP(m) < e(D(m))], \text{ then } D(m) = 0 \quad (4.7)$$

$$f = DLMP(\text{MAX}(0, (L(m) - D(m)))) - LMP(\text{MAX}(0, (D(m) - L(m)))) + e(D(m)) \quad (4.8)$$

Where the cost function f is defined by three terms, the remaining energy payments at the $DLMP(m)$ to the utility after energy displacement, value generated for the customer through electric sales/import into the grid at the $LMP(m)$ and new costs imposed by the operation of the DG facility $e(D(m))$. The hourly RTP customers dispatch according to the same decision tree at an interval of one hour or $(12*m)$.

4.4 Results and Discussion

4.4.1 Sample Results

For a generic customer as portrayed in each of these case studies, the incentives related to the electricity price and billing structure are the primary factors which determine the customer-optimized behavior. Figure 4.2 compares six of the different billing structures over a sample weeklong period within the in-depth case study: the three different utility rates and the three different RTP timescales for the Rutland, VT customer. The solutions for Portland and Rutland are similar, although the customer in Rutland generates significantly more power, and thus

shaves more of its peak. The customer in Hartford, CT, exposed to a steep TOU demand and energy price, optimizes the DG use by treating the entire TOU window as similar to coincident peak pricing, running the DG facility at full power during the higher price window each day. This is regardless of the customer's actual peak or shape of the surrounding system load and based solely on the pre-specified time window associated with the higher TOU rate. Although there are also some difference between the different RTP markets, more immediately obvious is the major differences between the customer-optimized DG response created by traditional utility rates and the responses created by the RTP rates. The RTP signal focuses on fewer, shorter events of a higher DG utilization intensity.

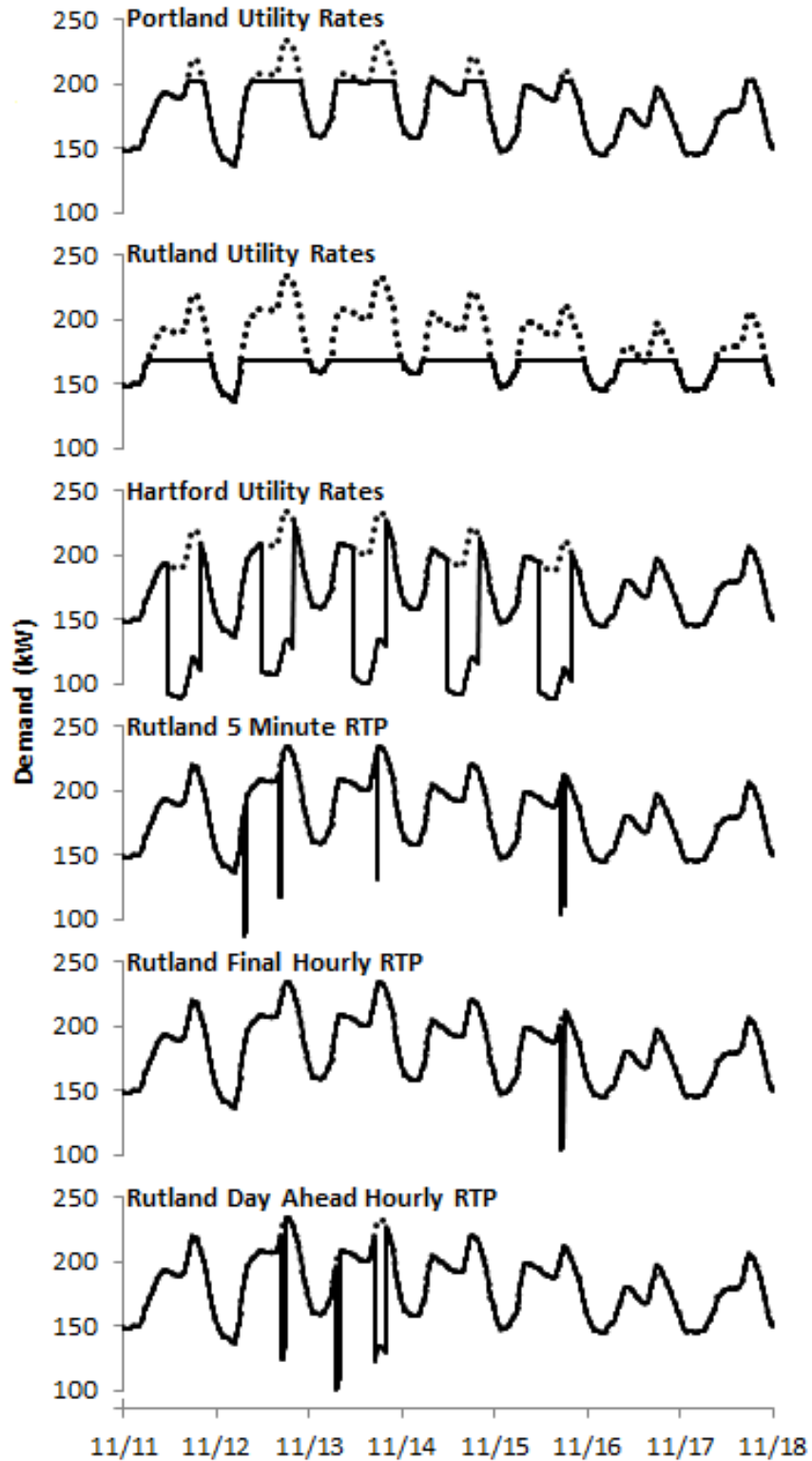


Figure 4.2: A Comparison of Customer-Optimized DG Use and Peak Shaving for Identical Customers Incited by Three Utility Rates: Portland, ME, Rutland, VT, and Hartford, CT; and Three Different RTP Timescales in Rutland, VT (node 4459) for the Week of Nov. 11, 2013 to Nov. 18, 2013

4.4.2 Utility Rates Compared to Real-Time Pricing

The first objective of this study is to compare the dispatch behavior, economics and summed value that is realized by identical customers incented by either utility rates or RTP. Figure 4.3 further describes this disconnect between utility rate and RTP incented behavior. We can see graphically that there is no obvious correlation between optimized daily peak shaving and RTP dispatch behavior even at a monthly timescale. Table 4.1 further quantifies this at the smallest interval common between the two models (15 minutes for this comparison). This demonstrates the lack of correlation between utility rate incentives and RTP-incented dispatch. Even only comparing the on/off status of the DG facility and disregarding the magnitude of the dispatch shows that daily peak shaving compares unfavorably with the actual needs of the grid described by the RTP market. At approximately a total on/off agreement of 50%, the agreement between the utility rate and the RTP customers on the best time to operate the DG facility is no better than random.

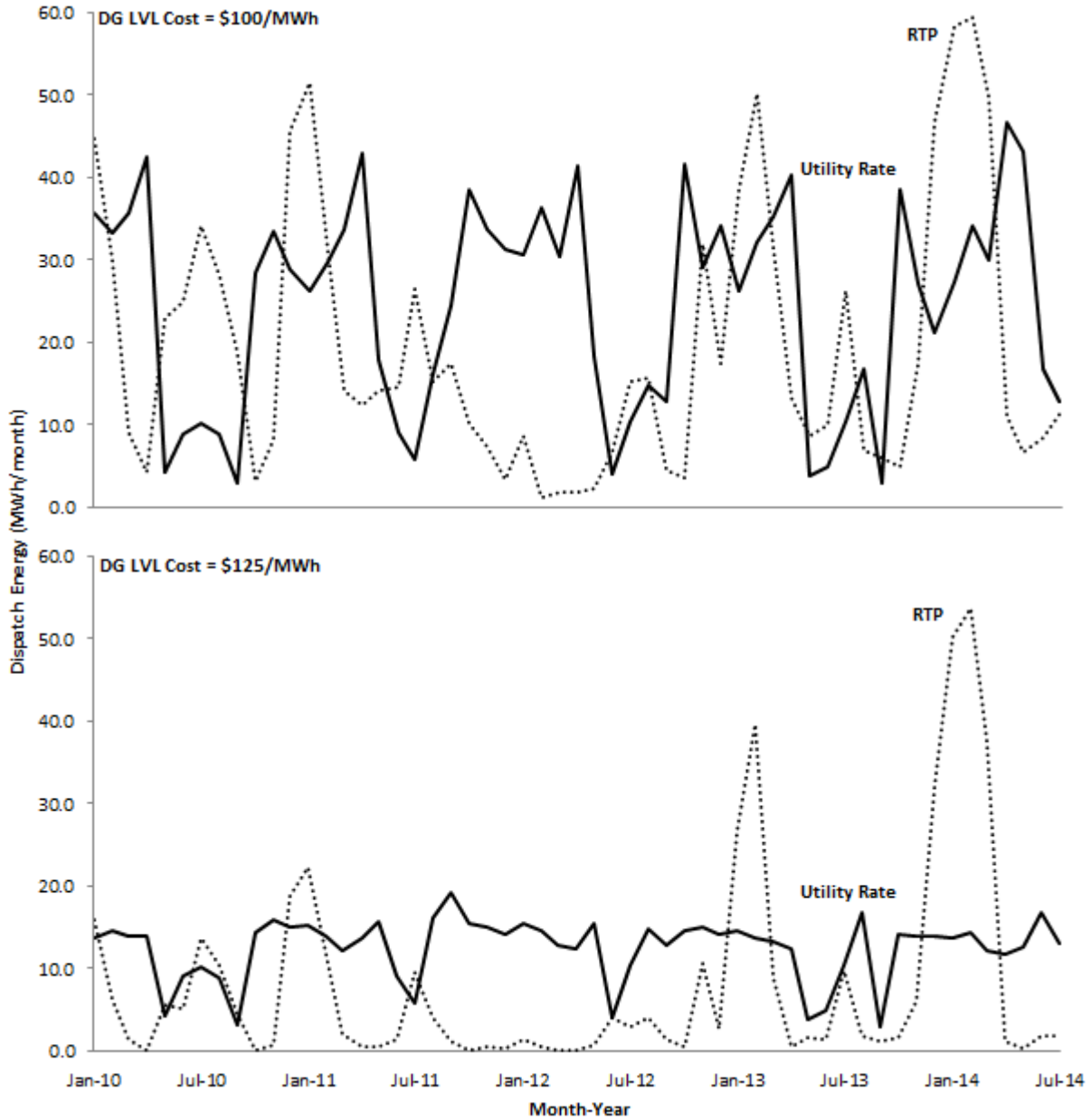


Figure 4.3: DG Dispatch Comparison in Rutland, VT (node 4459)

Table 4.1: Correlation of Utility Rate Incited DG Dispatch to RTP Incited DG Dispatch

DG Utilization Correlation at \$100/MWh					DG Utilization Correlation at \$125/MWh				
2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
0.249	0.305	0.290	0.408	0.303	0.395	0.269	0.327	0.376	0.231
Percent On/Off Agreement at \$100/MWh					Percent On/Off Agreement at \$125/MWh				
2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
51.7%	41.9%	35.1%	58.1%	53.8%	54.1%	43.2%	43.0%	56.1%	52.1%

The final twelve months under consideration in this simulation were marked by particularly high RTP costs over a protracted period during the winter. Figure 4.4 shows the difference this makes in the monthly DG valuation across the broad 4.5 year view as well as daily across the final twelve months. This valuation disagreement is vital to quantifying the impact of daily peak shaving. Electricity cannot be stored on the grid, if the RTP market is accepted as an ideal, then the earlier months when the traditional rates customer is gathering more value than the RTP customer represent that customer removing more value from the market than it could possibly provide from the DG resource. Likewise, the daily peak shaving customer is unable to adequately respond to a significant technical or economic network event and fails to dispatch and gather value once additional generation is more desperately needed during the high price months at the end of the simulation time window.

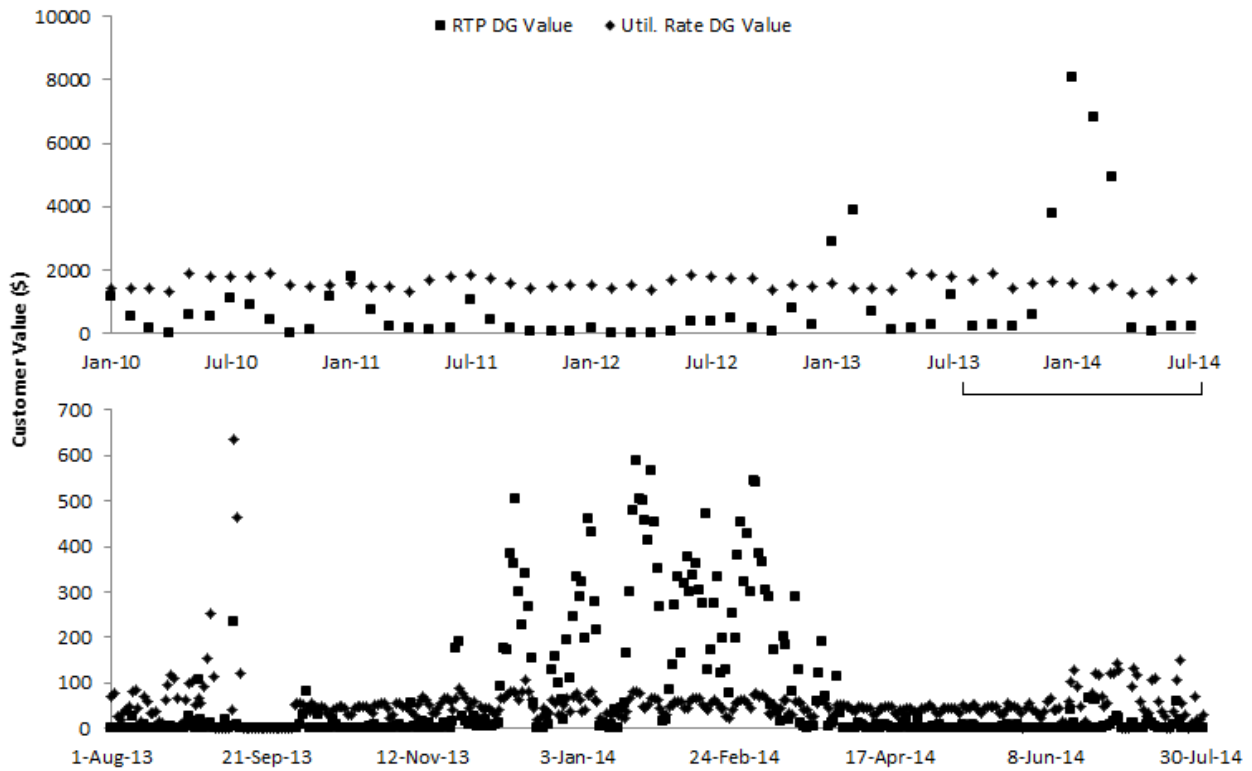


Figure 4.4: Customer DG Value Comparison at a DG Levelized Cost of \$100/MWh, Monthly (2010-2014) and Daily (Aug13-Jul14); Rutland VT (node 4459)

Customer peak-shaving requires everyday customer involvement in the electric grid in order to maintain a low monthly peak demand, but as the RTP market demonstrates in Figure 4.5, the actual need for customer support is far less than everyday use. Figure 4.5 displays the sorted sum of customer DG value (by day) for each of the years under consideration in the model. The majority of DG value in the RTP market is obtained during a relatively small fraction of the days in the calendar year. The DG valuation reaches at least 63.2% of its total value on day 54 in 2010, day 36 in 2011, day 26 in 2012, and day 35 in 2013; while at least half of the days of each year offer little to no opportunity for DG dispatch or value. Additionally, each year offers a significantly different opportunity and incentives for a DG customer in the RTP market which would be difficult for a utility rate to match equitably for all customers in a traditional market.

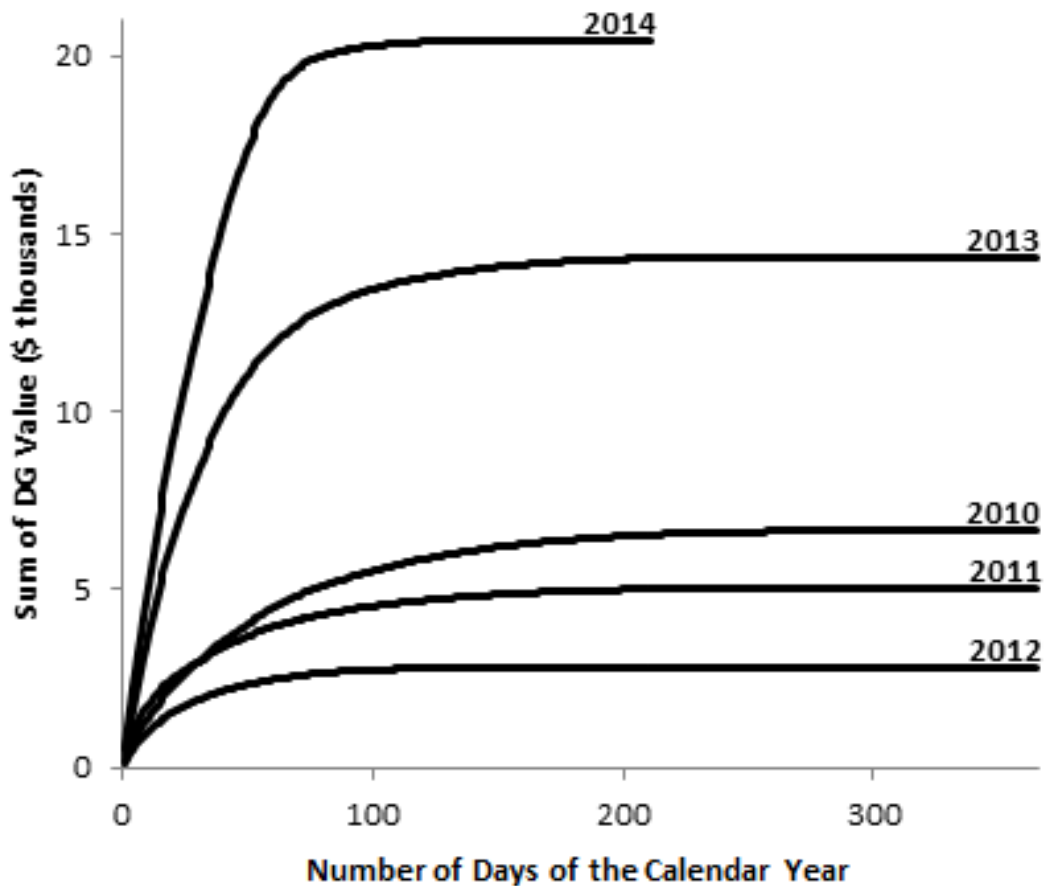


Figure 4.5: Sorted Sum of Daily Final Hourly RTP Customer DG Values in Rutland, VT (node 4459) for a Levelized DG Cost of \$100/MWh

Figure 4.6 describes a metric of peak-shaving economic performance by inputting the utility rate incented DG dispatch signal into the RTP market. This quantifies the actual RTP market value customer daily peak-shaving incented by utility rates. The actual value of the customer's daily dispatch does not match the value attributed to it through the utility rates. The final result for a DG cost of \$100/MWh over the 4.5 year period is that the utility rate customer's DG dispatch was worth less than 7% of its utility rate valuation to the market. At \$125/MWh, the utility rate incented dispatch nets a negative market value, essentially increasing electricity prices in the market by frequently dispatching higher cost DG incorrectly during relatively low price periods.

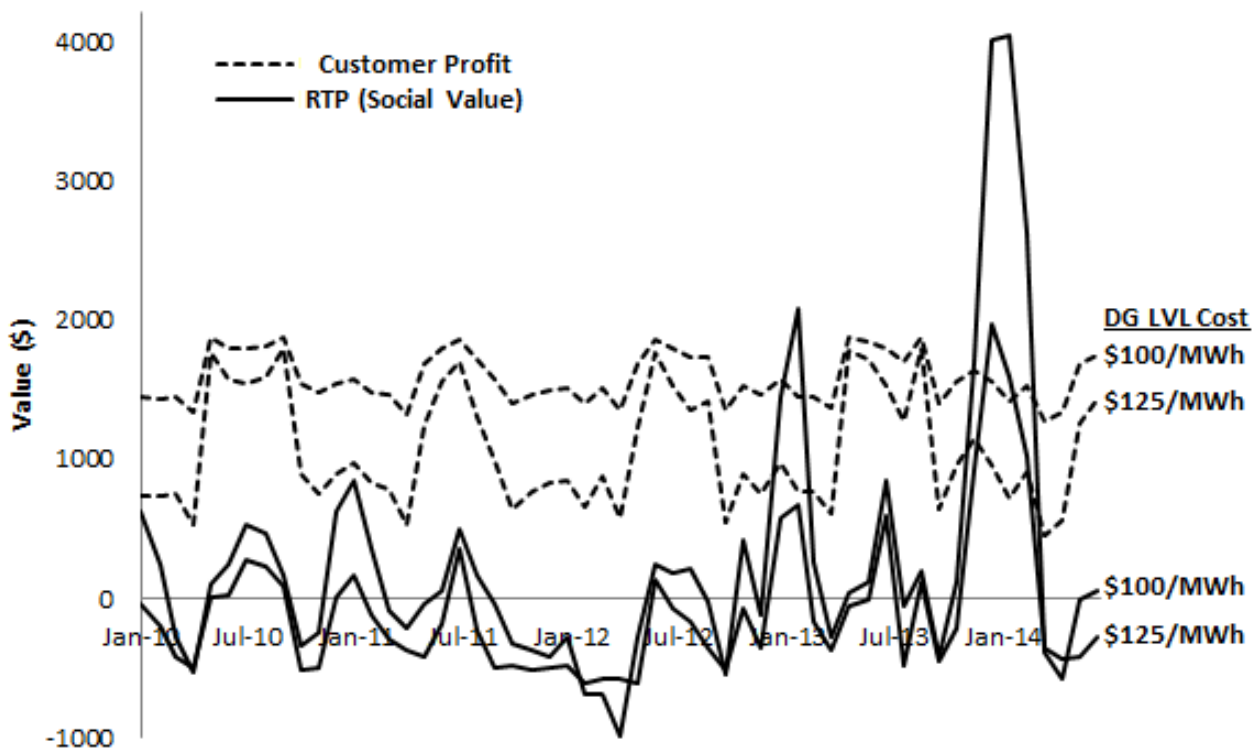


Figure 4.6: RTP Value of Customer Optimized Utility Rates Incented Dispatch; Rutland, VT (node 4459)

4.4.3 Sensitivity to Regional and Price Information

A comparison of three regions under study during the 2013-2014 period shows that these different utility tariff models or rate structures can lead to significantly different customer incented DG value and behavior. If we consider the higher resolution 5 minute RTP as the highest quality price signal that describes the dispatch requirements of the electric grid, then the correlation between the DG utilization as incented by the other rate structures and the 5 minute RTP is a metric of the effectiveness of the other rate structures. As shown in Figure 4.7, the statistical correlation between the final hourly RTP DG use and the 5 minute RTP DG use varies between 0.863 and 0.922 across the three regions in the study, representing a relatively high correlation between the two dispatch schedules. The statistical correlation of the day ahead hourly and the five minute RTP DG use is lower, ranging from 0.623 in Hartford to 0.827 in Portland. The utility rates in each region incent a DG use that correlates very poorly (0.185 in Hartford, 0.258 in Rutland, and 0.482 in Portland) with the 5 minute RTP DG signal.

These results demonstrate that the poor correlation of DG use between utility rates and the RTP market extends beyond just the rates for customers in Rutland, VT, but is robust across a variety of utility rates and market structures. As previously suggested by Figure 4.2, the daily peak shaving customers dispatch their facilities on more days, and for greater total time intervals, than the RTP customers, but each daily peak shaving event is typically for smaller, less intense output. The DG customer is more focused on short interval high cost periods that call for full DG dispatch. This continuum analysis of increased customer information also demonstrates that there is a measurable difference in optimized behavior between the three different RTP signals under consideration. The differences between traditional utility rates and the RTP market do not appear to be an issue which could be addressed through more complex utility rate structures. For

example, the Hartford customer arguably has the most complicated rate structure in this study based on its TOU energy rate and demand charge. Despite this complexity, the Hartford DG customer has the poorest correlation between its dispatch and the ideal (5-min RTP) dispatch while simultaneously “gaming” the most profit from its DG resource.

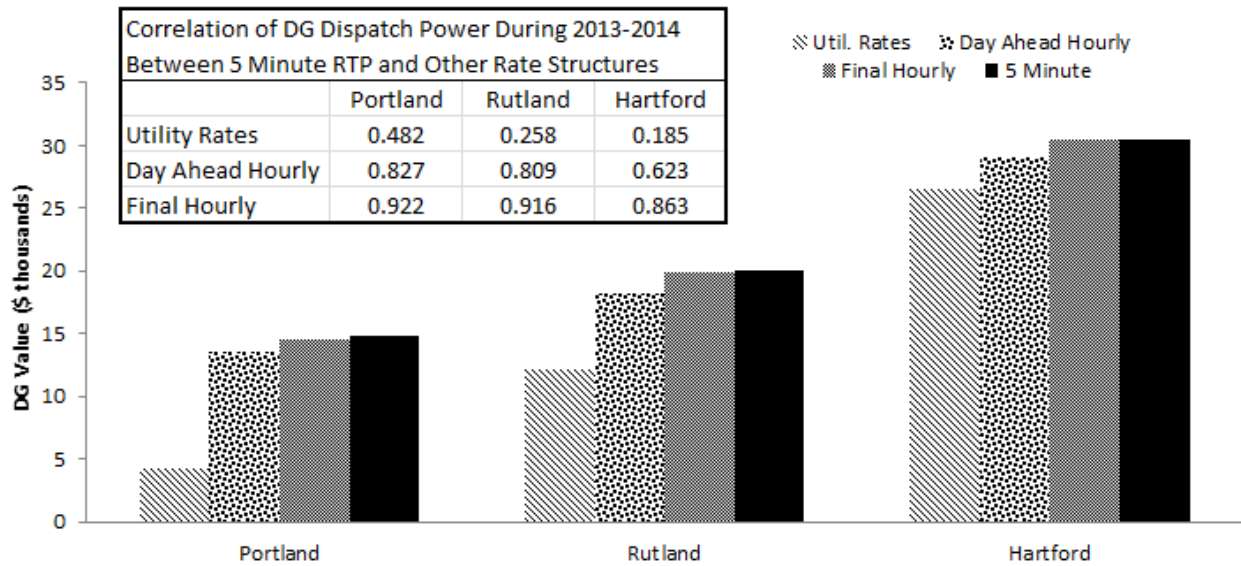


Figure 4.7: A Comparison of Optimally Dispatched Customer DG Value and Utilization at a Levelized DG Cost of \$125/MWh (Aug. 2013 - Jul. 2014)

These results have demonstrated that there exist fundamental differences in behavior, economics and summed value between daily peak shaving incented by traditional utility rates and the RTP market. If the RTP market is held as an ideal, then these results demonstrate that utility rates, which have been the subject of DG optimization and evaluation research, do not incent the behavior that can be considered a social good for the utilities and other surrounding customers.

4.5 Conclusions

Customer-owned and operated DG systems are a new technological resource that will continue to develop in the new energy marketplace. There are numerous financial, policy and

technical issues related to DG that may either provide new benefits or costs to society. This project has evaluated some of the differences between customer incentives in utility rate and RTP markets in order to quantify some of the potential benefits and costs associated with one of the primary drivers for customer-owned DG systems: daily electricity peak-shaving. This research demonstrates the need to move policy and customer-utility interactions beyond the traditional business models in order to adapt to new technologies such as these DG systems.

This study demonstrates that there are quantifiable and very significant differences between the DG dispatch of a RTP customer and a rate-incented customer. The two incented dispatches are so poorly correlated that a customer can create more costs than benefits in the marketplace through daily peak shaving (disregarding technical or ancillary benefits/costs). In this study, utility rates allow DG system operators to gain profits disproportionate to their contributions by “gaming” the demand charge. On the other hand, the RTP market allows DG customers to realize a comparable profit while realizing benefits for all market participants.

Sustainable business models for DG require further research and policy development for DG to gain greater utility acceptance and to achieve higher levels of grid integration. The technical factors relating to DG systems are very site-specific and will require greater customer-utility participation, but this research demonstrates that the financial impacts can be improved by making customers better, more informed participants in the electricity market. Future work could improve the assessments made here by developing a better method for determining the actual DLMP for a customer and by increasing the time period under consideration in order to better compare the total payback and valuation between the two cases.

Chapter 5

A Life-Cycle Comparison of Trucking and Pipeline Water Delivery Systems for Hydraulically Fractured Oil Field Development ^[98]

5 Overview

Hydraulic fracturing is a key energy technology that has unlocked significant new reserves of oil and natural gas in the US. However, it requires a significant amount of fresh water and produces a comparable amount of wastewater all of which is typically transported by truck. Heavy truck transport of water is an expensive and inefficient process that damages roads, increases accidents and road fatalities, increases congestion and emits pollution. Integrated development plans incorporating pipeline systems for the transport of water are a proposed alternative that will mitigate many of these issues while also making recycling the wastewater at centralized processing facilities with recycling more attractive. A life cycle analysis of a generic oil and gas field demonstrates the economic and environmental value of these pipeline systems compared to trucking systems for the northern Colorado region.

5.1 Introduction

Hydraulic fracturing is a key energy technology that has significantly increased the U.S. production of natural gas to the point that the EIA has predicted that even with increased natural

gas utilization; the U.S. will become a net exporter by 2017 [99]. Despite advances in alternative energy technologies, the energy sector is still a fuel-dependent economy, and many label natural gas as a potential bridge fuel to a cleaner mix of generation technologies. However, there is considerable public concern about the potential social, environmental, and economic impacts of hydraulic fracturing [100] leading often into direct and organized public opposition [101],[102],[103]. By reducing heavy truck traffic, integrated development plans involving piped water transport could mitigate many of the most severe public concerns over hydraulic fracturing while also improving the economics of developing and processing natural gas and other outputs.

Integrated development plans (IDPs) as defined in this paper include a central processing facility (CPF) connected by pipe to each well (or pad) in an oil and gas field. The CPF will filter and recycle produced water into new fracking fluid thereby reducing the future fresh water requirements for new wells in the field. Additionally, the CPF is connected by pipeline to a freshwater source as well as an adequate site for disposal of untreatable wastewater. For comparison, the IDP pipeline system will be compared against a trucking system which employs an identical CPF. The defined metrics of comparison will be those systems that minimize the economic, social and environmental costs associated with the transport of fresh, produced and wastewaters.

5.2 Background

Anderson and Theodori's interviews into the reactions to hydraulic fracturing in the Barnett shale demonstrate that the core public concerns with hydraulic fracturing relate to the transport of the wastewater byproduct known as produced water [5] (also referred to in the initial phase as flowback water). Residents in the Barnett study cited increased traffic, decreased road safety,

and road damage [104] as among their chief concerns with hydraulic fracturing. Other studies have shown that public roads in counties that do not receive any benefits from gas drilling could also be adversely affected [105]. Randall found that dust, noise and road damage are on the top of citizen concerns in areas where shale gas is extracted [106]. Cooley and Donnelly also note concerns over wastewater, spillage, and air quality based on interviews with various state and federal representatives [107]. The local costs associated with hydraulic fracturing are at such a level that Theodori and Anderson have shown that while local residents of the Barnett shale describe positive attitudes about the potential benefits of hydraulic fracturing at the onset of new drilling/fracturing, public opinion in previously explored regions of the play has significantly decreased towards a plurality of disapproval over a span of ten years. For instance, at one point a group of citizens in Texas attempted to block the construction of an injection well through the court system with the argument that the increased truck traffic and road damage would not be in the public interest [108]. Greater public education on the potential costs and benefits of oil and gas development may improve public opinion at the onset of development [109], but if the current hydraulic fracturing practices create such a negative impact on community opinion in once-receptive regions, this will likely only exacerbate public opposition in regions already hostile to new or expanded oil and gas operations.

In 2009 Clark and Veil noted that trucking and injecting wastewater was the typical business practice for handling this wastewater byproduct, but noted that there was definite potential for an improvement of transport and for a beneficial reuse [110]. Road damage and emissions related to trucking fresh and produced water is frequently featured predominately in hydraulic fracturing LCAs and related studies [105],[111],[112],[113],[114],[115]. Some of these life cycle analyses anticipate a significant reduction of future costs and damages based on

energy companies adopting more IDP friendly plans – piping water rather than trucking and beginning to clean and recycle the wastewater byproduct [116],[117]. Pipeline systems and recycling could offer direct economic benefit to the field developers as well – truck transportation is the most expensive aspect of water handling [115].

The primary challenges related to the successful implementation of IDPs for oil and gas fields are not technical. Various industries and local municipalities have been transporting, filtering and treating water for decades, and there are already numerous technological possibilities for transferring the state of the art into transporting and recycling produced water [118]. Tailoring these processes into an integrated water management plan for oil and gas fields requires a detailed understanding of the water use and characterization of the wastewater (produced water) in these fields [119]. Additionally, quantifying the potential economic, social and environmental costs and benefits associated with integrated development plans requires a model that can estimate both the impacts of these integrated development plans and the costs associated with a more traditional and less integrated truck delivery of water supplies to and from the fields. In support IDP planning in the Denver-Julesburg basin, Goodwin, Bai and Carlson have modeled both freshwater requirements as well as the volume and composition of the produced water byproducts associated with hydraulic fracturing in the northern Colorado region [120],[121],[122] with the ultimate goal of modeling the feasibility of integrated development plans (IDPs) and developing a toolset to help energy companies improve their decision making process [119].

In order to expand and continue operations, energy companies must manage not only costs and find new technologies for harvesting natural resources economically; they must also manage public opinion and operate as cleanly as possible with minimal social and environmental

impact. IDPs have the potential to improve both the economics and the social license to operate for hydraulic fracturing, but they are difficult to plan, require more significant upfront costs than trucking, and their economic, social, and exact environmental benefits are still unknown. The Colorado Oil and Gas Conservation Commission has previously encouraged development of these technologies and methodologies with pipelines and water management systems already in place in the Piceance Basin [123]. This remains a key issue for the state of Colorado with legislation pertaining to the right of way status for pipeline companies and IDPs under consideration [124].

Based on our understanding of the field, the goal of this research is to compare pipeline and trucking transport systems across several metrics. The current state of the art expressed in the literature in this field is used to quantify and compare the risks of incidents, injuries and spillage for both of these systems. A model of an oil and gas field generic to the northern Colorado Denver-Julesburg basin is developed and then used to compare the local social cost (road damage) and environmental impact (greenhouse gas or GHG emissions) associated with truck transport and pipeline systems. Additionally, variations of this generic field model will quantify the beneficial impact of reducing the fresh and wastewater transport requirements by recycling produced water into new fracking and prove the robustness of the comparison by including a range of levels of field development and proximity to the surrounding source locations (fresh water and injection wells).

5.3 Risk Analysis

Increased traffic and accidental spills are major local safety concerns related to the transport of water for hydraulic fracturing [125]. Produced water spills may adversely affect both terrestrial and aquatic environments. The chemical and physical composition of produced water

is dependent on the source geology, but typically includes organic constituents and hydrocarbons, metals, salts and other dissolved and suspended solids and the remnants of the injection fluid and proppants (sand/silt) [7]. Grubert and Kitasei describe the truck transport of produced water as one of the major pathways to water contamination [126]. Pipeline systems eliminate nearly all of the truck miles associated with water transport, and thus improve road safety, but both systems carry risks of accidental or uncontrolled spills of hazardous materials.

The average fatal crash rate for all vehicle types for the state of Colorado is approximately one fatal crash per 100 million vehicle miles travelled (VMT); but heavy trucks create higher risks. According to the US Dept. of Transportation, the fatal crash rate for single trailer trucks ranges from ~1.5 to ~4.5 fatal crashes per 100 million VMT depending on road type. Depending on location, hydraulically fracturing a single well can create thousands to hundreds of thousands of truck miles associated with water transport alone. Truck transport of the water demands for a field of hundreds or more wells multiplies a significant risk of fatal vehicular accidents. Some measure of increased truck traffic would occur during the construction of a pipeline system, but as shown in the results, it is insignificant compared to the traffic associated with truck-based water transport systems.

In terms of public safety, pipeline systems are generally considered safer than truck transport. Between 1994 to 2009, trucks were responsible for several times as many incidents, injuries and fatalities as pipelines per ton-mile of transport of hazardous materials [127],[128]. Figure 5.1, constructed from data combined from the US Dept. of Transportation Bureau of Transportation Statistics [127] and the American Petroleum Institute [128] demonstrates that historically in the transport of crude and refined oil products, trucks have spilled more barrels per barrel-mile of transport than pipelines since 1980. However, the magnitude of spilled material

involved in each truck accident is generally lower than the material spilled in a pipeline accident (limited to the size of the carrying capacity of a truck/trailer combination). Also, the hazardous material is generally spilled on top of relatively impermeable and low-impact road surfaces. Individual pipeline spills have the potential to spill a larger quantity of fluid per spill and these spills may occur on much more ecologically vulnerable surfaces and closer to water resources [129].

Pipeline systems could offer a benefit compared to truck transport of reduced spill volume of environmentally damaging produced water as long as the pipeline network is well designed according to best industry practices and is located sufficiently far from ecologically vulnerable areas or fresh water sources. The research presented in this paper assumes that the pipeline systems are located adjacent to the same roads that would be used for truck transport to minimize the increase spill vulnerability and to maintain a generic transportation distance for comparison between the two transport methods. This may not be a realistic expectation for each oil and gas field and coordination with local governing agencies may be required to ensure that pipeline systems are well located such that the damage related to accidental spills, which will inevitably occur, can be adequately managed and contained.

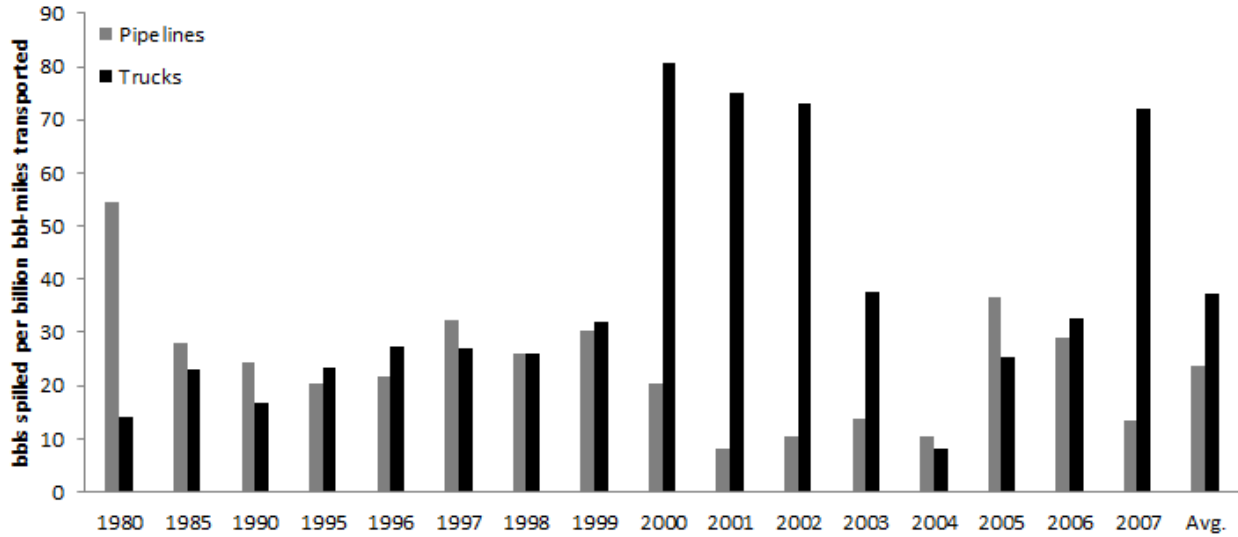


Figure 5.1: Combined Crude Oil and Petroleum Spills during Domestic Transportation

5.4 Methods

In order to quantify the differences between pipeline and truck systems, this paper has proposed a case study of a generic oil and gas field in northern Colorado. The water requirements and wastewater production are modelled from observations unique to the region and various field sizes, levels of development, location, and recycling technologies are considered in order to compare the benefits and costs of pipelines and trucks over a broad range of possible utilizations. The case study will incorporate a five year construction period for all of the wells in the fully developed field and a total 20 year lifetime for all of the fields. The construction period is organized such that the wells are drilled and fractured at a constant rate – Fields with lower levels of development (fewer nodes and fewer total wells) will be drilled at the same rate and thus the field will be fully drilled and fractured in less than the initial five year period.

5.4.1 Field Layout

The generic oil and gas fields under consideration are presented in Figure 5.2. Each of these variations of the same field contains 49 one square mile nodes arranged in seven rows by seven columns. Each node contains two pads each with eight horizontal wells (for a total of sixteen wells per node). The fields vary by the level of development (A: 48 nodes, B: 36 nodes, C: 24 nodes, D: 12 nodes) and by the location of the central processing facility for water collection and recycling (case 1: centralized, case 2: central edge, case 3: corner). This leads to 12 different field combinations (A1, A2, A3, B1, B2, B3, etc.) for use in this study. All of the roads and pipes within the fields are assumed to travel only by cardinal directions (north, south, east and west). Pipes are split into branch lines as they run along nodes from the CPF to the wells, for the purpose of reducing the length of pipe required and thus the capital and installation costs.

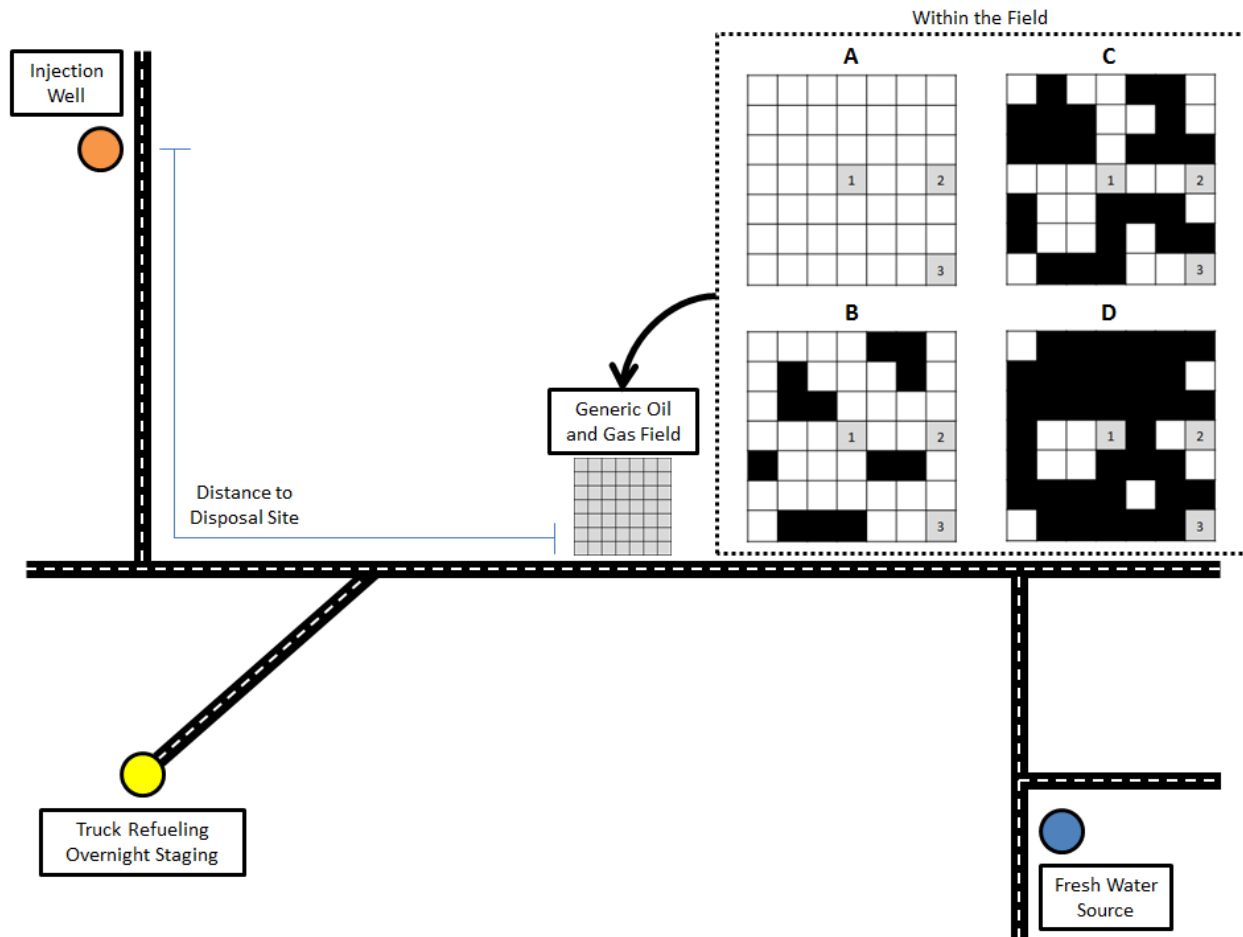


Figure 5.2: Layout for Varying Levels of Field Development (A: 48 sq. miles, B: 36 sq. miles, C: 24 sq. miles, D: 12 sq. miles) and Central Processing Facility Locations (1, 2 and 3) and the Surrounding Field Inputs and Outputs (Fresh Water, Injection Well and Truck Staging)

Trucking and pipeline costs are heavily impacted by the proximity of the field to its inputs (such as a fresh water source) and outputs (such as an injection well). The distance to the fresh water source, the produced water injection site and the heavy truck overnight staging/storage and refueling are all independent variables in this case study and vary through a range of 0, 30, 60 and 90 miles.

The average required fracking fluid volume for horizontal wells in the northern Colorado region has been previously quantified [121]. A daily time function of the produced water output for each well is modelled for 20 years based on unpublished data [122] unique to the region. The

CPF will recycle the produced water into new fracking fluid in both the trucking and the pipeline models at a capacity range of 0%, 30%, 60% and 100% of the produced water output. The remaining produced water will be trucked for off-site disposal as wastewater.

5.4.2 Truck Transport Model

The truck transport system creates social costs related to increased traffic and road damage, and environmental costs from emissions released during the construction and operation of the trucks and during repair of damaged roads. All of these costs are a function of the VMT of the transport trucks that service all of the wells in the field during its 20 year lifetime. Each of the trucks in this model has a transport capacity of 150 barrels of water. Each well requires trucks to deliver fresh water to the CPF, transport the fracking fluid (which may contain some recycled produced water) from the CPF to the well, transport the produced water from the well back to the CPF for recycling, and to deliver the wastewater (un-recycled produced water) from the CPF to a disposal site. Additionally, at the end of each workday, the truck operators will drive the trucks to an overnight staging and refueling site as they return home.

Road damages and the associated social costs are frequently [130] quantified through an Equivalent Single Axle Load (ESAL) analysis developed by the American Association of State Highway and Transportation Officials (AASHTO) [131]. The case study presented here uses this method based on a similar oil and gas road damage study performed for Boulder County [132]. Each water truck has an associated ESAL on asphalt roads while empty (1.363) and filled (2.6) and each of the roads within and surrounding the field has an ESAL design lifetime. Therefore, each truck trip-mile incrementally damages the local road system as it reduces each road's remaining useful lifetime. The majority of roads in Colorado are asphalt [133], so for simplicity, all of the roads in the model are assumed to be asphalt. The road repair costs used for

the different types of roadways in this case study are of the same order as the Colorado Dept. of Transportation's estimated average costs for resurfacing, reconstruction and repair [133]. Bridges, which are infrequent but significantly more expensive to repair, are not included in this analysis. Each of the trucks travels along a generic path combined of all types of roads (principal arterial, minor arterial, collectors and local roads) based on the average utilization of each of these types of roads in the US [134]. The average speed of the trucks on each of these types of roads and the distances traveled influences the number of transport trips that each truck can do per workday.

Increased road congestion is a secondary social cost related to truck transport but is not included in the results presented here. However, these costs are not insignificant, the state of Colorado estimates that in 2009 congestion cost licensed motorists approximately \$913 per person in Denver, \$460 per person in Boulder and \$229 per person in Colorado Springs [133]. The US DOT has some estimates for the congestion costs per mile that heavy trucks create on rural and urban interstates [135] and these range from approximately an additional 2.5% of the road damage costs described in this study for rural environments to 22 percent of the road damage in urban locations.

Truck transport creates three primary sources of emissions: tailpipe criteria and GHG emissions, truck embedded emissions (associated truck construction), and road repair and construction. Tailpipe or operation emissions is the largest of these three and is released as each truck travels and transports the water from site to site and also while the truck idles during work events (while the operator fills or empties the storage tank). A 60-80 kip (1 kip equals 1,000 lbs.) truck operates at approximately 5.9 mpg while traveling and 0.786 gal/hr. while idling

[136]. Each gallon of diesel emits approximately 24.18 lbs. (10.97 kg) of GHG as it is burned [137],[138].

The World Bank has quantified the average worldwide emissions created by the construction of a variety of road types such as expressways, national, provincial, and rural roads [139] and this case study will consider those as analogous to the definitions of principal arterial, minor arterial, collectors, and local roads in the road damage model. The emissions model will consider only the emissions associated with constructing and setting the pavement as relevant to the road damage created by heavy truck transport and excludes all of the emissions associated with road structures, furniture, culverts and earthworks.

Each heavy truck used to transport for the oil and gas field has an average lifetime defined in terms of miles traveled. The required VMT to service the all of the wells in the various fields of this study is so great that the embedded emissions related to the construction of the number of trucks required to service the field must also be considered. The construction of each of the trucks in this model releases 116,078 lbs. (52,652 kg) of GHG emissions and each truck has a lifetime of 750,000 miles (1,207,008 km) [140].

5.4.3 Pipe Network Model

The social costs and emissions of the pipe network system are calculated with identical boundaries to the truck transport model. The pipeline system defined in this model has several parts. A single pump at a fresh water source transports fresh water to the CPF. The CPF has a central pump system capable of delivering the fresh water through in-field pipelines to each node. Each node has a single pump that returns produced water from the pad/wells back to the CPF. Finally, a single pump transports the un-recycled wastewater from the CPF to a disposal site. The “in-field” pipes all run by cardinal direction and are connected and combined at each

node to minimize the total length of pipes in the system. That is, if the nodes in field A1 (Figure 5.2) are numbered from left to right and then down by column, a pump in node 1 in the top left corner transports water through nodes 2, 3, 4, 11, and 18 to the CPF at node 25. The required flowrates are defined such that each node will be able to deliver all of its 16 wells' produced water output during a time window each day that does not interfere or restrict the other nodes in its branch-line. The pipeline system also creates social costs and emissions related to road damages and reconstruction during the installation phase. However, the bulk of the emissions are a combination of three factors: the pumps' operational emissions created while driving the water to/from the wells and the CPF and while delivering fresh water to and removing wastewater from the CPF, the installation emissions related to trenching and constructing the pipeline network, and the embedded emissions related to the construction of the pumps and pipes for the system.

The road damage created by the pipe installation is insignificant compared to the truck transport case, but it is calculated by the same method with a different set of ESALs for trucks that handle the equipment delivery (0.621) and maintenance and operation (0.143) and is presented in the results section.

Typically, the electricity consumed by the pumps in a pipeline network is the most significant factor in a pipeline LCA [141]. The US power grid emits GHGs as it generates and transmits electricity for everyday use. Previous LCAs have quantified emission factors for energy use in the US [137],[138]. The total energy consumed by each pump within the system can be estimated as the product of the required pump power and utilization time of each pump in the system (eqn 4). The pump power depends on the mass flow rate, the liquid density, the pump efficiency and the output pressure (eqn 3). The output pressure of the pump must equal the sum

of required pressure at the exit of the pipe, differential height gains/losses and the frictional pressure losses the pipe system (eqn 1). The field in this model is on flat ground and the differential height gains/losses are assumed to be zero. The pressure losses in the pipe system are estimated with the Hazen-Williams equation (eqn 2).

$$P = P_s + P_d \quad (5.1)$$

$$P_d = \frac{4.52 * Q^{1.85}}{C^{1.85} * d^{4.87}} \quad (5.2)$$

$$Power (kW) = \frac{P * Q * S.G.}{1618.5 * n} \quad (5.3)$$

$$Energy (kWh) = Power (kW) * Utilization Time (h) \quad (5.4)$$

The pipes in this system are based on the FlexSteel composite pipe product [142] with a Hazen-Williams friction coefficient of $C = 150$. The fresh water, fracking fluid, produced water and wastewater flows are all assumed to have the fluid properties, such as specific gravity, of water. The pipe diameter d varies for each part of the system and was optimized from the options in the FlexSteel catalog for the minimal combination of pump energy and embedded pipe emissions. All of the pumps in the system have an operating efficiency (n) of 0.75, and all parts of the pipeline system are designed for 20 psi static pressure at the outlets.

The installation emissions for the pipeline system were estimated from the methods used in a similar potable water transport project LCA performed in Arizona [141]. These methods were originally based on an emission calculator developed by Sihabuddin and Ariaratnam to quantify emissions from an underground utility project [143]. These emissions include the operation of a backhoe, excavator, crew truck, drill rig and roller.

The embedded emissions are defined as the sum of the emissions created during the fabrication of all of the pipes in the system as well as all of the pumps. The pipe composition was modelled as a combination of steel and HDPE. The composition and total weight of all of the pipe construction materials were estimated from the FlexSteel product specification sheet [142]. The weight of the pumps was empirically estimated by comparing pump power to pump weight in a Nocchi product catalog [144]. The embedded emissions associated with the water pumps were modeled as having the same emissions per unit mass as electric motors according to the specifications and estimated embedded emissions in the GREET database [137],[138].

5.5 Results and Discussion

The pipeline systems are shown to reduce both GHG emissions and social costs borne by the local residents in the form of road damages. Road congestion was not included in these results (as mentioned in the methods) but these would only add further to the costs associated with trucking systems. These benefits are robust across all of the different field types, proximities to water sources and disposal sites, and percentages of recycling at the CPF facility. A small subset of the results is presented below.

5.5.1 Sample Results

The GHG emissions associated with the piping networks proposed in an IDP compared to the emissions of a traditional trucking system for all the field types in this case study are presented in Figure 5.3. These are the in-field emissions only, they do not include emissions for fresh water transport to the field, wastewater removal to the disposal site, or for refueling and staging the transport trucks. The IDP pipe network shows a robust reduction of GHG emissions within the field in all cases. Trucking systems are adversely affected if the CPF is not optimally located

within the center of the field, but are not directly affected by the level of development in the field. The slight decline in truck emissions per well from the A-type fields to the D-type fields is due to a slightly unsymmetrical elimination of nodes within the fields (more nodes that were distant to the CPF than were near were removed in D). Piping system emissions are less affected by CPF location, but are best utilized in densely developed fields.

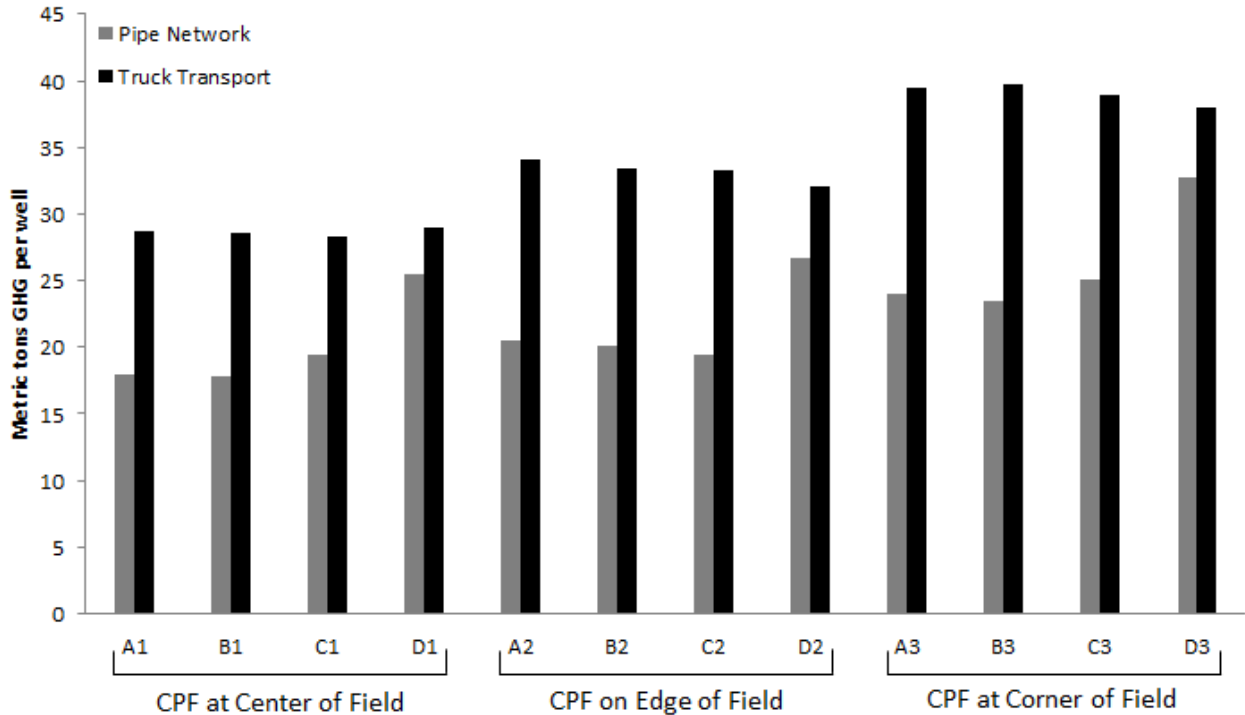


Figure 5.3: Lifetime Emissions per Well Comparison for In-field only Transport

The complete emissions per well with both systems including transporting water inputs and outputs to and from the field for a small subset of cases is shown in Figure 5.4. Whereas the benefits to transitioning to a piping system within the field are slight (as illustrated in Figure 5.3), there is a considerable reduction in emissions once the field import and exports are included. The distances listed for each case are uniform for all three locations and are a small subset of the possible combinations of the distance to the fresh water site, the disposal site, and the truck refueling and staging location. However, this subset is a representative of the robust range of

this comparison. These results also demonstrate a beneficial reduction of transport emissions due to increasing levels of water recycling at the CPF.

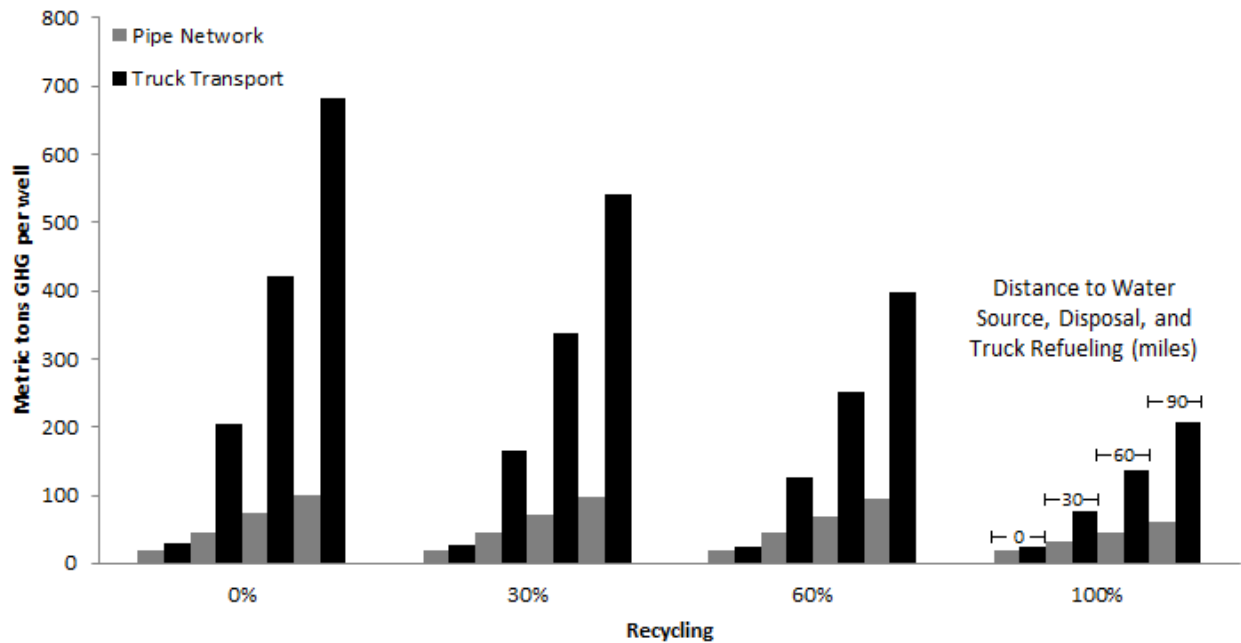


Figure 5.4: Lifetime Emissions per Well Comparison for a Range of Field Proximities to Inputs/Outputs

Figure 5.5 breaks down the GHG emissions associated with piping and trucking systems. The primary source of emissions from trucking systems comes from the tailpipe of each truck as it transports the water. However, the emissions from asphalt repaving, resurfacing and reconstruction are not insignificant. The IDP case is unusual in that the embedded energy of the construction of the pipeline network rather than the operations of the pumps is the largest source of emissions for the system. Hydraulically fractured wells return more produced water in the first few months after completion than over the rest of the lifetime of the well. The utilization rate of the pumps and pipes in this field is a small fraction of the system’s capacity in the final 15 years of the project after all of the wells are constructed. This does present difficulties in optimizing a pipeline system.

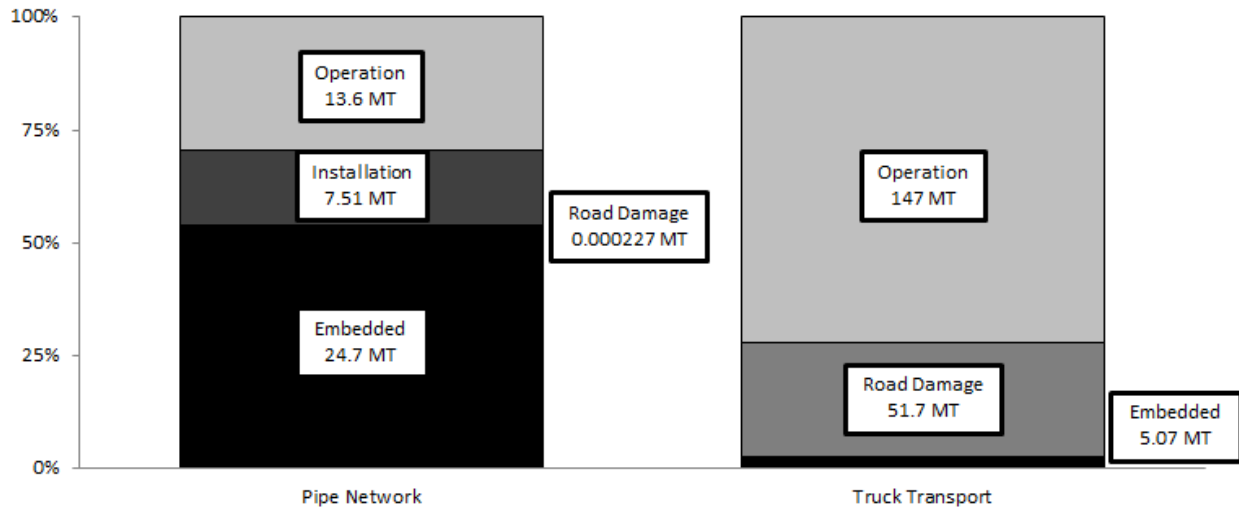


Figure 5.5: Lifetime Emission per Well Breakdown of Pipe and Truck Comparison for Field A1-30,30,30 (Field A1, 30 miles from fresh water, 30 miles from disposal, 30 miles from overnight staging and refueling, and 0% recycling)

The road damage comparison in Figure 5.6 demonstrates that trucking systems create overwhelmingly larger social costs than IDP pipeline systems. The values here are corroborated by previous studies such as the Boulder County road damage study which found that each well drilled in Boulder County would create \$30,600 in roadway costs for roads in Boulder County alone [132]. This number was later revised down to \$20,600 by the Boulder County Board of Commissioners after a review by local utilities and researchers at Colorado State University [145] (The Boulder County study relied on truck trip data from the Marcellus shale formation which was not accurate for oil and gas development in Colorado [146]). The cost in this previous study represents the damages to roads only within Boulder Co. and any damages outside the county were excluded. Boulder Co. is a relatively urbanized region of Colorado and has a total area of 751 square miles (approximately 27 miles in width and height) which suggest that the typical distance from a fresh water source to any well or from any well to an interstate or highway out of the county (and towards a disposal site) would be relatively small. The case study presented here considers all of the road damage for all roads in all counties and also

considers longer distances more likely found in the more rural, larger counties of Colorado such as in Weld Co.

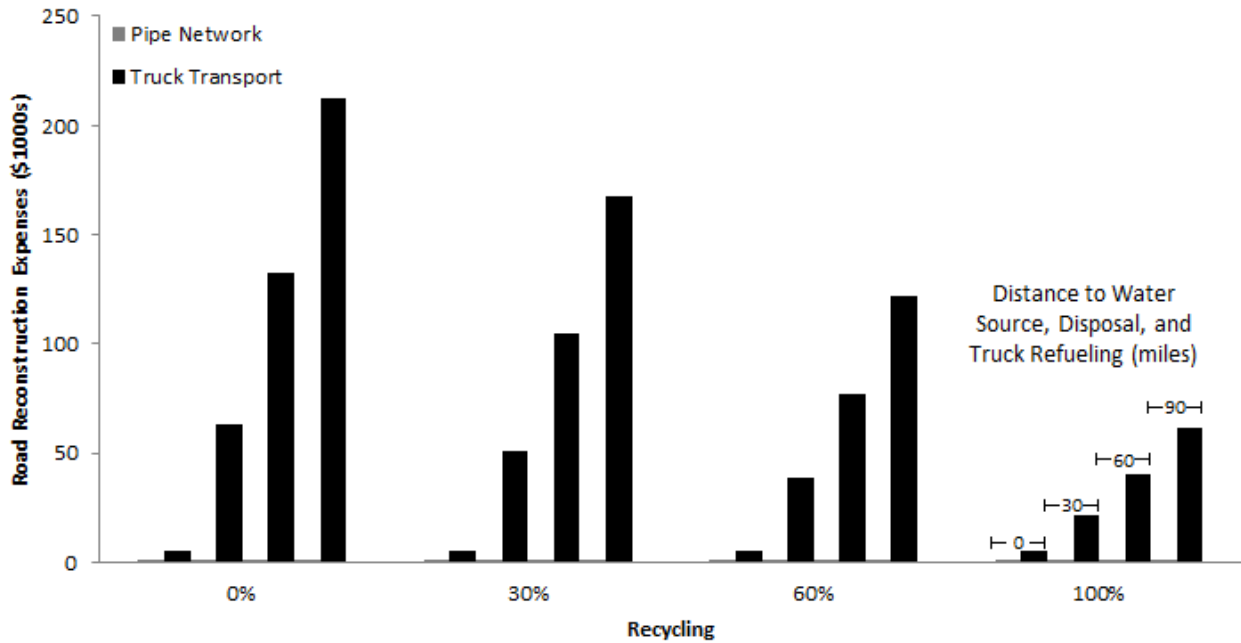


Figure 5.6: Lifetime Road Damage Costs Comparison for a Range of Field Proximities to Inputs/Outputs

Figure 5.7 breaks down the emissions and road damage costs associated with each type of truck transport action in the same case as Figure 5.5 (Field A1, 30 miles from each of the field inputs and outputs and 0% recycling). Over 20 years, each well returns a sizeable fraction of the fracking fluid as produced water, but fresh water supply remains the largest transport requirement. The Fill / Drain work events relate to the amount of time each truck spends idling while either waiting in line to deliver fracking fluid to a well for completion or while the operator fills or drains the truck tank with water.

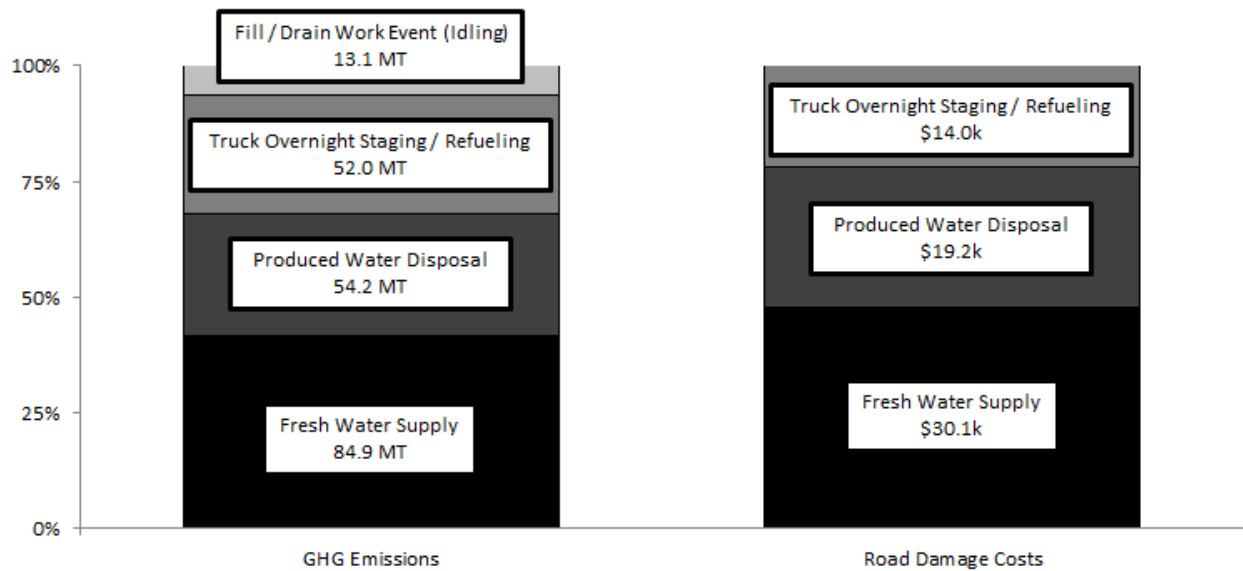


Figure 5.7: Truck Transport Emissions and Road Damage Costs Breakdown per Well for Field A1-30,30,30

5.5.2 Comparison to Actual Field in Northern Colorado

This generic case study was built to encompass a range of possible cases within the northern Colorado region. The East Pony oil and gas field described in Chapter 2 and located in northeastern Colorado [147] is such an example. This field is considerably larger and has more wells than any of the types presented in this case study, though it is most similar to the A1 case. The average distance to the nearest four water sources of suitable capacity is 31.1 miles (Rohn pond, Everitt well, N. Timmerman pond and the Hwy 52 well). The average distance to the nearest two injection wells is 42.8 miles (High Sierra C7 in Cornish, Co and C8 in Grover, Co). The distance to Lucerne, Co, one of the nearest towns with a gas pump and a likely location for truck operators to store vehicles overnight, is 65.4 miles. This likely is one of the more distant fields in Colorado but it does demonstrate the need to consider a broad range of conditions while comparing trucking systems to IDP pipeline networks. Figure 5.8 compares the emissions for pipeline and truck water transport in this field using the A1 case as the production plan. Figure 5.9 further breaks down the truck transport emissions and costs.

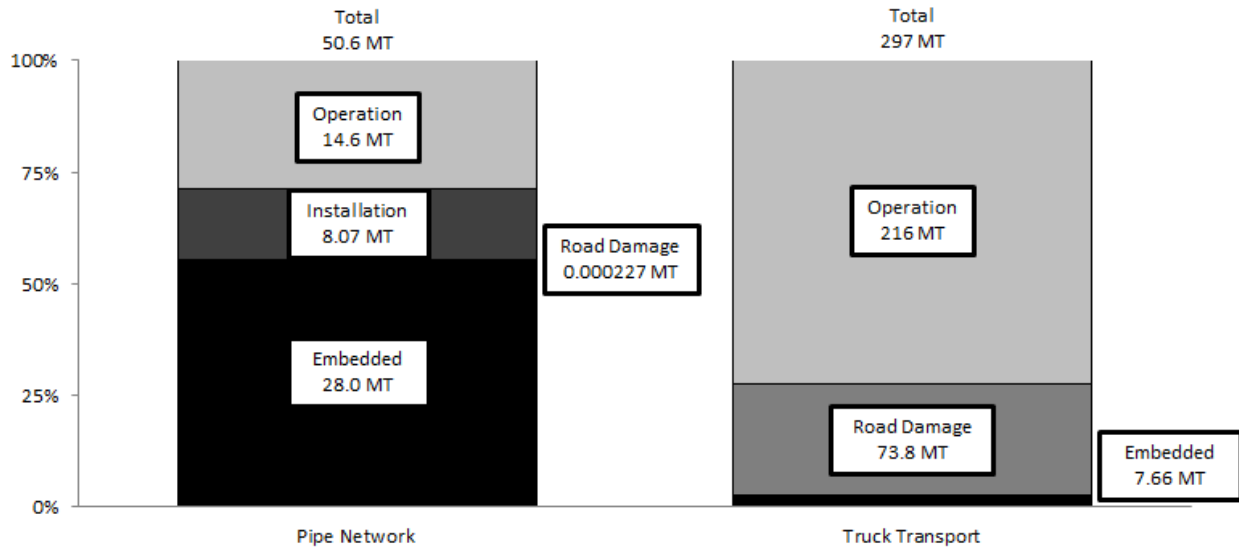


Figure 5.8: East Pony Pipelines vs. Truck Transport Comparison of Emissions per Well

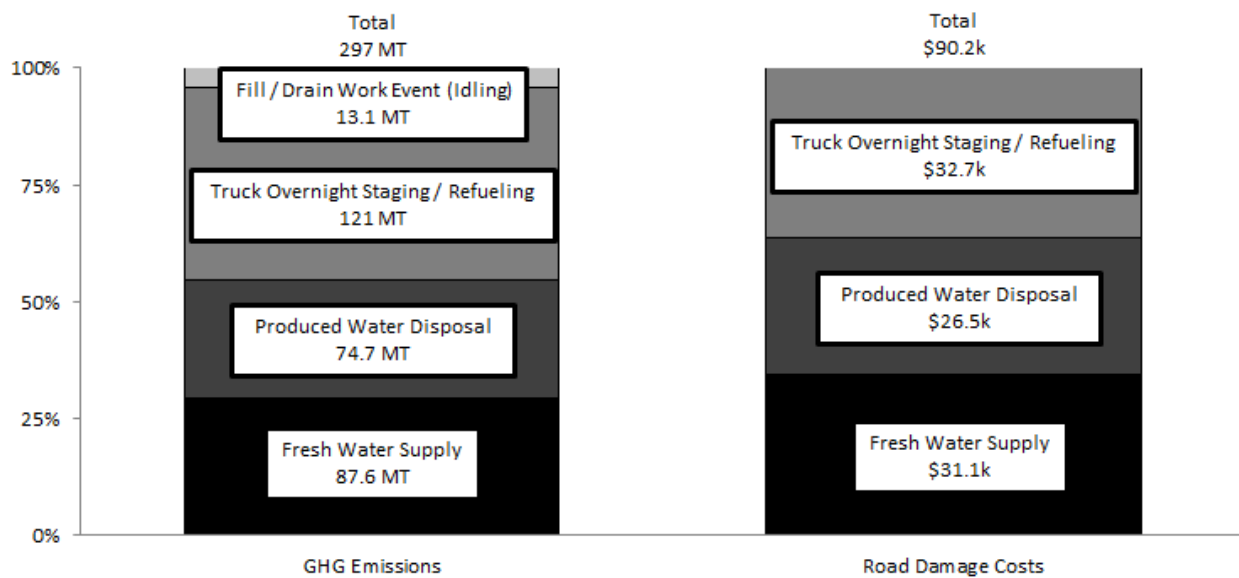


Figure 5.9: East Pony Breakdown of Truck Transport Emissions and Costs per Well

5.6 Conclusions

Hydraulic fracturing is a key component of the US' future energy economy, but it creates significant social and environmental costs for local communities. Many of these costs could be mitigated by transitioning water transport from trucking systems to an integrated development plan with a pipeline system. Pipeline systems are generally considered safer and historically

spill less hazardous material than trucks, but the location of pipeline spills may increase the severity, so cooperation of utilities and local governing agencies while establishing the pipeline routes should be a priority. Pipeline systems uniformly emit less GHGs than trucking systems and dramatically reduce damages and costs to the local road infrastructure, especially for long range bulk transport, such as a single pipe that supplies all of the water for a field of wells. Utilities already have shown interest in developing and constructing IDPs as they may also reduce their operational costs. This work offers a first estimate at the value of these systems; future work could explicitly calculate the benefits and costs of switching to IDPs for specific oil and gas fields as well as optimize the IDP design plan.

Chapter 6

Summary

6 Overview

Energy system development requires not only technological innovation but also business and policy innovation. Without continuous business practice and policy development, older, conventional systems may “lock-in” utilities and energy developers into a single technology or business structure leaving them unable to respond to and incorporate in new technologies, business models, and opportunities. As customers become larger partners in the energy economy, their incentives and market power must be considered. Better price information has the potential to improve the correlation of customer electricity demand with supply and to connect their demand side management monetization with value. In the case studies considered in this work, higher fidelity price signals and greater utility-customer cooperation are required to ensure that distributed generation technologies are integrated into the electric grid and into the energy market in such a way that all of the market participants are interested and invested stakeholders. As oil and gas companies coordinate with local communities, the costs associated with hydraulic fracturing can be safely mitigated by transitioning from truck transport systems to integrated development plans with pipeline transport.

The overarching theme of these results assert that in order for these new technologies to succeed, customers, utilities, corporations, and governing/regulatory bodies must work together to craft new business models, expectations, and practices which incent more sustainable market

behavior. All of the technologies discussed in this dissertation have the potential to offer novel solutions to existing economic, social, and environmental problems concerning energy supply, but policies and practices that are focused on the benefit of one market participant at the possible expense of the others may result in an unsustainable marketplace.

6.1 Publications

The research presented in this dissertation has resulted in the following peer-reviewed publications and presentations:

The research of Chapter 3, a DG case study in the Fort Collins, CO service region was published in the *Electricity Journal* in 2014 [9].

The research of Chapter 4, the comparison of DG utilization in traditional and real-time price markets in the New England ISO service region was presented at an American Society of Mechanical Engineers conference in Boston in 2014 [34] and published in the *Electricity Journal* in 2015 [35].

As of the time of the completion of this dissertation, the research of Chapter 5 is pending publication in a peer-reviewed journal for the year 2015 [98].

6.2 Contributions to the State of Art

The research presented in this dissertation offers the following contributions to the state of the art:

1. An inclusive business model case study was constructed to analyze and quantify the economic effects of customer-owned DG systems on both customers and utilities in Fort Collins, CO. This was a novel approach for a field where a significant portion of the current research only studied the effects of DG on the customer while ignoring the

- effects on utilities. This model provided a framework to understand and evaluate previously unanalyzed real-world issues associated with DG including the historical utility resistance to customer-owned systems, and liability associated with customer's stranded costs after a rate change.
2. An economically-optimized DG actuation model was constructed to compare the value and actuation behavior of DG in both DLMP and traditional utility rate structures. This model was exercised using three New England utilities as long-term case studies. The model quantifies the difference in customer-optimized DG utilization, monetization and value between these two business models. DG systems were shown to be poorly valued as peak-shaving units in the RTP market; they obtain much more value by responding to irregular and infrequent grid events. These results provide evidence to support the argument that traditional rate structures create distortions which disconnect DG monetization from its economic value. This model was novel in its approach, comparing customer incentives driven by utility rates against a spectrum of timescales in the RTP market.
 3. The value of daily customer peak-shaving was quantified against the actual DLMP of electricity. For the cases presented, the monetization of daily peak shaving is higher than the economic value in the RTP market for all of the regions and time periods considered. Whereas conventional utility rates (TOU, Seasonal, conventional) are often used as a surrogate for the RTP of electricity, the robustness of these results demonstrate this variety of utility rate structures fail to incent DG operation in a way that values DG utilization equivalent to its monetization. These results demonstrate that daily peak shaving does not always constitute an inherent public good, and that

studies of DG valuation should use RTP market signals as a standard of valuation. This is contrary to simplifications implicit in many studies and common to the field.

4. An LCA which compares the economic, environmental, and social costs of trucking and pipeline water transport systems was developed. This case study quantified many of the costs that local communities will face during the construction and development of hydraulically fractured oil and gas fields. This is of value to the state of Colorado and its local communities as they consider the local cost of oil and gas development. This study is novel in that it quantifies the value of reducing truck traffic by implementing IDPs at hydraulically fractured oil and gas fields and demonstrated that these benefits are robust for a variety of field types and locations. The breakdown of costs and emissions for these transport methods suggest that the bulk transport of fresh and produced water to/from an oil field can be minimized in order to mitigate transport costs.

6.3 Future Work

Future work can expand this analysis of DG systems to include other related customer-owned demand side management systems, such as energy storage, intermittent “non-dispatchable” systems such as PV or wind, demand response, and combined heat and power. The RTP market may still be an ambitious target for future energy policy, but newer billing structures which offer a higher fidelity price signal than even a TOU rate could be proposed, modeled, and tested. A constrained RTP market which sends customers an RTP signal with upper and lower price bounds may be such an example.

A case study specific to one hydraulically fractured oil and gas field with accurate field measured data of the actual emissions, road damage, and repair costs would be a tremendous

complement to the generic case study presented here. CPF design and development is an ongoing field of research. An optimal IDP solution may also involve joining up nearby fields to one CPF or splitting large fields into multiple, smaller fields – A better appreciation of the processes and economics of size of the CPF would increase the value of this report.

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