Valuing Distributed Energy Resources

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A dissertation submitted in
partial fulfillment of the
requirements for the degree of

Doctor of Philosophy

University of Washington

2015

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Program Authorized to Offer Degree:

Electrical Engineering

University of Washington

Abstract

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Due to their small scale, it is often difficult for Distributed Energy Resources (DERs) to compete with large centralized resources when their value is based purely on the cost of energy and capacity. In order for the true value of DERs to be realized, it is important that these resources be applied and compensated for a wide range of services beyond energy and capacity requirements, specifically, local requirements such as voltage profile improvement, reactive power support and congestion relief to name a few. This value creation process is crucial to the maximum realization of DER potential and fair, competitive compensation for small or distributed resources. The goal of this work is to first quantify the benefit of DERs to a wide range of interested entities. We then propose value-based pricing methodologies to determine how these resources should be compensated as well as "fair cost allocation methods" (allocation proportional to benefits) to allocate the cost of compensating resources that increase costs as well as benefits. This valuation methodology considers network models, distributed renewable energy resource models, market models as well as policy impact models. Finally, this work also provides contributions to methodologies that

quantify the economic value of societal and environmental benefits of DERs through energy policy.

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Acknowledgements

I first thank God, for everything and for all of the beautiful people in my life. I thank my parents for their continuous and loving support. In particular, I acknowledge the hard work and dedication of my late mother, who homeschooled me up until college and instilled in me a love for knowledge from a tender age. I thank my sister Sabah, for reading all of my papers and never complaining and my sister Ahlehm, for being my academic competition. I also thank my entire and extended loving family – my big brothers, aunts, uncles, cousins, foster sisters, nieces, nephews, and best of friends – for cheering me on every step of the way.

I gratefully acknowledge my advisor Daniel Kirschen, for his guidance, endless support (academic, career and professional development), encouragement, humble character and extraordinary mentoring. I also thank each of my committee members: Miguel Ortega Vazquez, for his support and much-welcomed humor; Richard Christie, for his dependable honesty and much appreciated open-door policy for students; and Sapna Cheryan, for playing an important role in my outreach efforts, starting from my senior year as an undergraduate. I also thank my Norwegian hosts from NTNU, Professors Sjur Westgaard and Stein-Erik Fleten, for their helpful input as well as their kindness and hospitality during my research collaboration in Norway. And although he was not a member of my reading committee, I do thank Mohamed El-Sharkawi, for both his tough questions during my qualifying exam as well as his sincerity in wanting students to succeed and excel.

And then, there are those who have been crucial to my reaching this point, but perhaps do not realize their importance: Erica Coleman, the first person I met in the EE Department and whose kindness alone convinced me to join the Electrical Engineering Department instead of the Mechanical Engineering Department; Eve Riskin, for her help and advice as I transitioned from an undergraduate to a graduate, and for being one of my biggest supporters at UW; Ana Wieman and Dawn Wiggin, for seeing the potential in me for graduate school before I saw it in myself; and Joyce Yen, for being an excellent mentor and role model for me throughout my service as coordinator for PEERs Leaders; Brenda White, for giving me an opportunity that truly added value to my research.

I also thank the members (and visitors) of the Renewable Energy Analysis Lab for helping to make the past five years, as memorable as they were enjoyable: Marco (my biggest supporter from the farthest distance), Karen (my mentor and role model), Yishen (my number one fan in the lab and fellow late night worker), Yury (for always lending a hand), Ting, Hrvoje, Ryan, Mushfiq (for raising the bar), Zeyu (my "Value of DERs" buddy), Abeer (for National Day sweets), Tobias (my early morning, late night and weekend lab partner), Pierre (the kindest of us all), Kelly (for being so thoughtful), Jesus (for being patient with my imperfect brain), Agustina, Rebecca, Ahmad, Yushi, Drew, Pan, Bolun, James, Matthias, Yao, Ricardo, John, Daniel (for just being all around awesome), Anna, Mohammed, Omar, Yang, Weiling, Marcel and Yao;

And last, but certainly not least, I thank my internship supervisors: Ali, Erin, and Sean; my EE colleagues: Julie, Nicole, Maryelise, Mayoore, and Ruth; my students: Tom, Jeffery, Deanna, Vivian, Pari, Anastasia, Taylor, Stuart and Yussuf; all of my wonderful PEERs Leaders: Annie, Leslie, Abdul, Megan, Dale, Mayoore, Rachel, Victoria, Kelly, Rafael, Serena, Carmen, Edison, Kim, Christina, Nuvala, Cezanne, Jennifer, Quoc-Anh, Elise, Ila, Tanner, and Shiri; and all of the dedicated members of the EE Department and EE Advising.

Thank you all.

Dedication

In loving memory of my mother…

Chapter 1. Introduction

Evolution of the Electric Grid: From passive to active customers:

Perhaps one of the most transformative aspects of smart grid realization is the evolution of the demand side. For decades, the demand side has been treated as passive and the traditional design of electricity markets, retail rates and distribution networks has reflected that view. The increasing penetration of smart grid devices, such as smart meters, and smart appliances, is facilitating the opportunity to maximize the value of an active demand side, in particular, the value of distributed energy resources (DERs). Here, an active demand-side includes customer owned and operated energy resources, customer participation in dynamic prices, customer participation in energy markets, and any means of deliberate and conscientious energy consumption behavior. This evolution of the demand side is driven in part by a shift away from the traditional focus on cost reduction and another shift towards a future-centered policy, including the expansion of advanced metering infrastructure, increased competition and customer choice, and the adoption of very ambitious renewable portfolio standards, some of which include distributed generation provisions.

Advances in technology have resulted in a wide array of smart devices including smart meters, smart appliances, smart inverters, and advanced distribution network monitoring. Many of these technologies allow for unprecedented automation and control as well as provide load serving entities, markets and customers alike with new information, creating opportunities for passive consumers to become active consumers or even prosumers. In 2012, Green Button, an industry-led effort to provide customers with access to their energy usage data in a standard and user-friendly format, was officially launched. The Green

Button initiative has been officially adopted by at least 50 utilities, representing over 60 million customers. These customers (with smart meters) now have access to detailed consumption data that allows them to make informed decisions about their usage in order to manage their bills. Nest® thermostats have built-in intelligence that allows these devices to learn customers' temperature preferences and quickly adapt to their occupation schedules at home, saving both energy and money. Technology is also assisting in removing barriers to demand response participation in wholesale markets. According to the latest FERC report "Assessment of Demand Response and Advanced Metering", demand response in 2013 had the potential to reduce peak demand in wholesale markets by an average of 6.1% and advanced metering had reached a penetration of over 30% (FERC 2014).

In addition to technological innovations, strong state and federal policies are playing an important role in increasing the penetration of distributed energy resources. These policies often set energy portfolio standards for distributed generation (DG) or provide attractive financial incentives to foster investment in DERs. As of 2014, 23 states had adopted renewable portfolio standards (RPS) with provisions requiring as much as 4.5% penetration of distributed generation by 2025 (DSIRE, 2014). Furthermore, in order to financially incentivize and foster customer-sited DG, 43 states have adopted net energy metering policies. These policies, in addition to various other state and federal incentives, have proved quite successful in spurring rapid deployment of distributed generation. According to the EIA, between 2010 and 2014, overall solar capacity grew from 2,600 MW to over 12,000 MW, roughly half of which is distributed or net-metered.

In addition to promoting DER penetration, policies are also seeking to encourage an active demand-side through more customer choices. Traditionally, customers have been forced to buy electricity from the single utility that services their area. However, after the introduction of competition into wholesale markets in the 1990's, some regions began to open up competition at the retail level as well. This was achieved by separating distribution utilities (that had previously both owned the distribution infrastructure and serviced end-use customers) into wires-only utilities (which remained a monopoly) and retail energy service providers (which had to face competition). Of the 19 states that currently have retail choice, the vast majority currently restrict this choice to commercial and industrial customers (EIA, 2014). However, in 2002, Texas passed legislation introducing retail competition to all customer classes and has since become a national leader with a large and growing portion of the state having access to competitive retail energy service providers (Figure 1-1). From 2002 to 2015, the number of residential and non-residential customers in Texas with access to retail competition has risen to 64% and 71%, respectively. According to the Texas Public Utility Commission, an impressive 90% of those customers with an option to switch retail energy service providers have actually exercised that right (PUC Texas, 2015). In addition to promoting choice of energy service provider, there is also an increase in customer choice of retail rates, in particular, at the residential level. Traditionally, only the largest customers have had access to real time wholesale prices. This restriction, though based on various practical reasons, has limited the ability of residential customers to maximize bill savings. In 2006, Illinois became the first state to mandate that residential customers be offered the option of real time pricing. Although customers in Illinois have been slow to adopt real time pricing, utilities in some states have conducted dynamic pricing pilots and concluded that there is actually strong customer interest in switching to other types of time-of-use pricing. A recent pilot conducted by Sacramento Municipal Utility District (SMUD) determined that 75% of the customers who chose to be placed on critical peak pricing rates believed that the rate allowed them to save more money than their standard, flat energy rate (Potter 2014). Clearly, customer choice is an essential element of an active demand side.

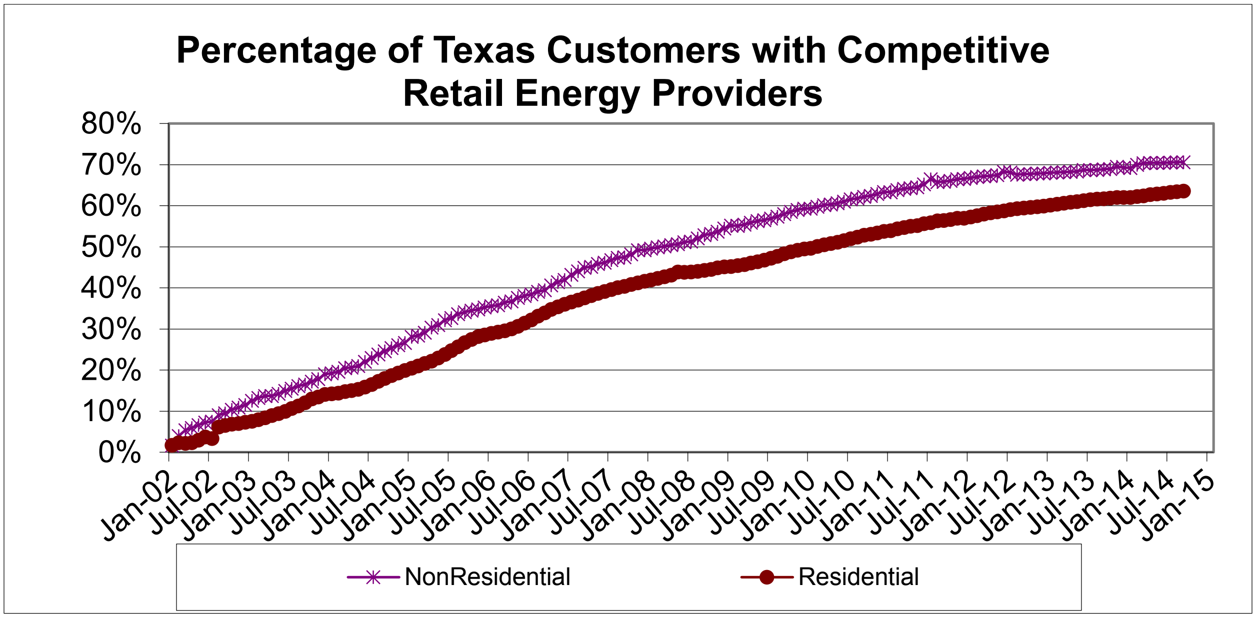

Figure 1-1. Percentage of Texas customers with retail competition (PUC Texas, 2015).

<u>Factors Slowing the Evolution of an Active Demand Side</u>

There has most certainly been significant progress towards promoting an active demand side as well as smart grid realization overall. However, despite these unquestionable advances, there are a few aspects concerning DER integration that have unfortunately lagged behind in the evolution process:

- retail rate design,
- market mechanisms to accurately reflect the <u>complete</u> value of DERs, and
- <u>sustainable</u> DER incentives.

Rate Design:

In terms of rate design, utilities have generally charged their residential customers using a flat, energy-only rate (sometimes with a very small nominal monthly customer charge). Only larger commercial and industrial customers are charged with rates that include energy, demand and customer charge components. Figure 1-2 breaks down retail rate components for various customer classes. The figure also breaks down the types of costs that determine the revenue required by utilities which must be collected through rates. These costs include customer service costs, operational costs, fixed costs, as well as a reasonable return on investment. Customer costs, such as billing, metering, and customer service, are a function of the number of customers the utility serves. Fixed costs include generation capacity and distribution capacity such as wires, transformers and other infrastructure costs that are a function of the system peak. Only operational costs such as energy or ancillary services are a function of customer usage. This means that the flat energy-only rate forces utility revenue to be a function of usage when a significant portion of the utility's cost to serve its customers is not dependent upon energy usage at all. Although this represents a misalignment in utility costs and customer rates, this rate design has historically been both practical and socially desirable. This is because a flat rate does not require special metering technology (demand meters) and because it is simple for the average residential customer to understand – use more, pay more. In addition to being practical, flat energy-only rates were also sufficient to provide stable revenue for the utility. The utility only needed to accurately forecast how much energy it would sell and the flat rate could then be set such that the revenue required by the utility would be collected. However, as incentivizing energy efficiency becomes more important, as the demand-side begins to invest in DERs, and as smart meters become ubiquitous, flat energy-only rates are quickly becoming obsolete as well as a potential threat to the current utility business model. While there are dynamic rates such as real time pricing and time-of-use pricing, these rates are discrete and/or time varying with wholesale energy prices. New dynamic retail rates need to be developed that not only reflect the time and location dependent value of energy but also reflect the value of non-energy services provided by the utility.

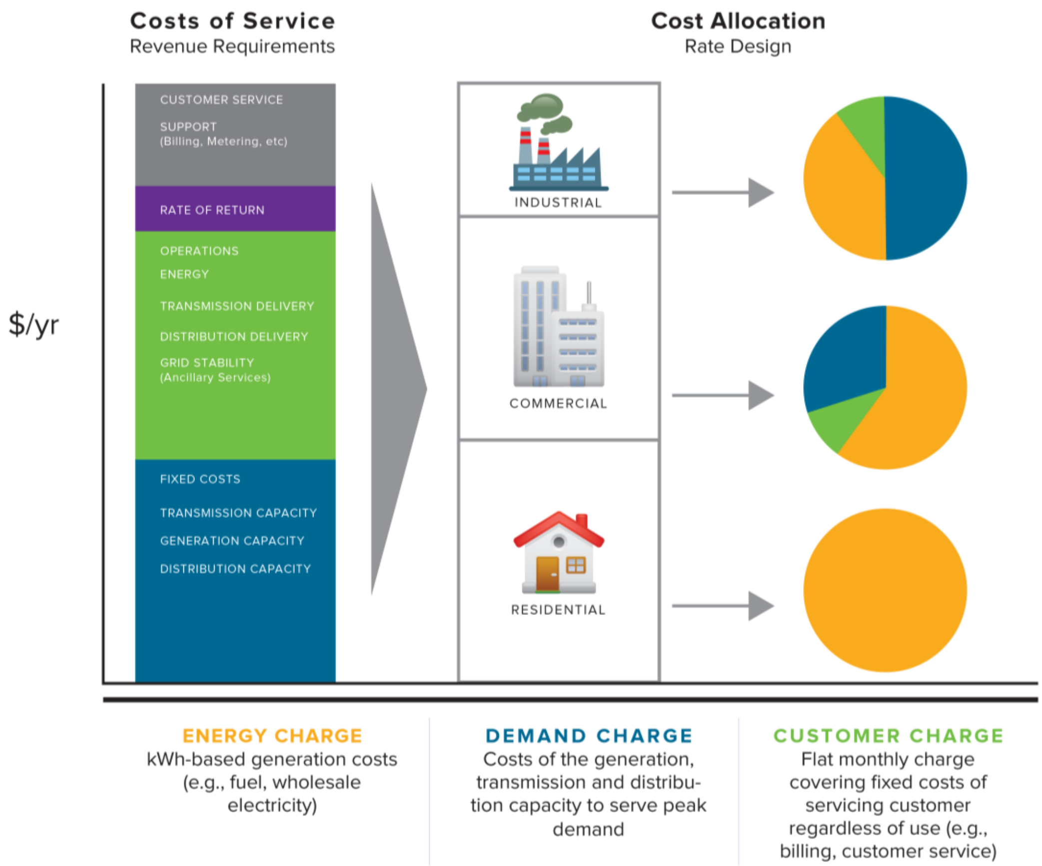

Figure 1-2. Misalignment of variable/fixed costs and variable/fixed rates (source RMI)

Market Mechanisms to Accurately Reflect the Complete Value of DERs:

One of the primary reasons that DERs are such an important part of smart grid realization is that these resources are capable of providing additional benefits in a way that the current bulk power system cannot. These benefits are enjoyed by a wide range of parties including, utilities, load serving entities, wholesale markets, customers, and society at large. However, mechanisms to accurately value and price many of these benefits do not exist. Figure 1-3 illustrates the misalignment of services valued in the market (blue solid arrows) and total services provided (blue dotted arrow), as well as the misalignment of payments and costs. For example, the solid blue arrow extending from the "DG Customers" to the "Utility/Grid" represents energy that DG customers produce and feed into the grid. The dotted portion of the arrow represents additional grid services that DG customers can provide, such as voltage support and peak load reduction.

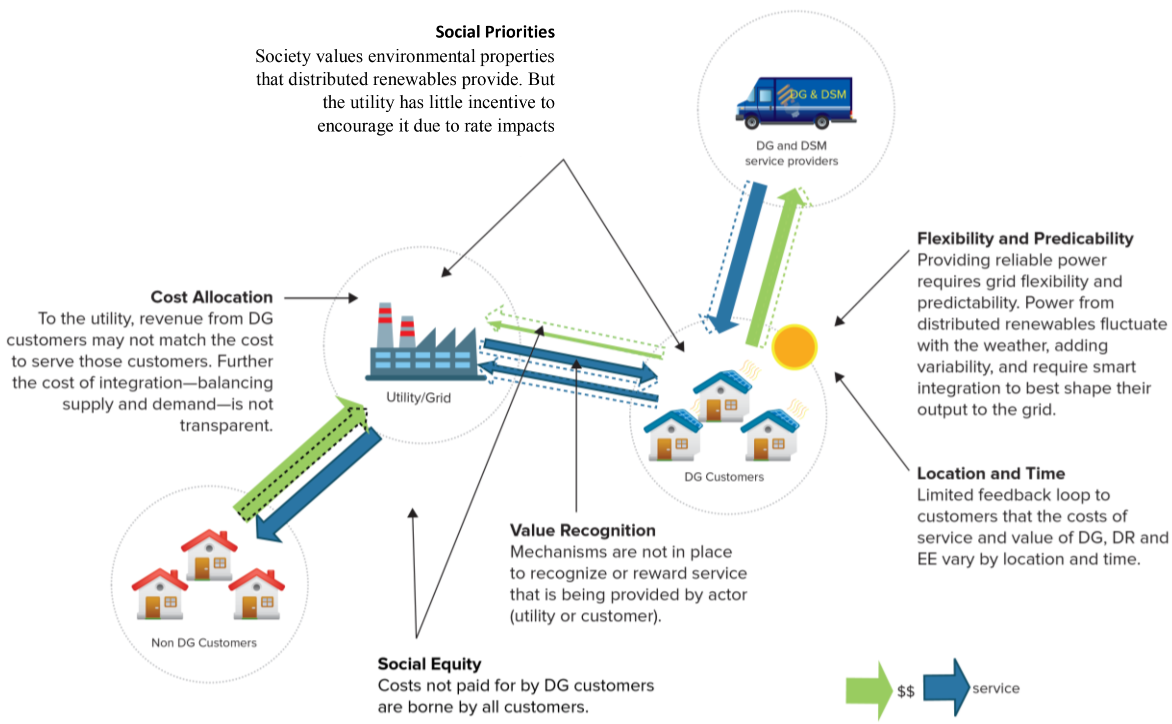

Figure 1-3. Issues caused by the misalignment of services and value-based compensation (Source: Adapted from RMI)

However, these additional services are not specifically priced for retail customers and as a result, they cannot currently be compensated for that. At the same time, the utility also provides unique services to customers with distributed generation. For example, the utility absorbs excess customer generation and also provides backup electricity when the customer's generation is insufficient. This "battery service" is not currently reflected in retail rates. Thus, the battery service cost avoided by customers with DG is allocated to all customers through retail rates but, due to net energy metering, disproportionally so to non-DG customers. With net energy metering, when the utility absorbs excess customer generation, the customer is credited at their retail rate for that generation. This compensation based on netting of consumption with over-generation, or net energy metering (NEM), is currently the subject of strong criticism. As of August of 2014, there were at least 20 states with pending legislation to alter or end the policy altogether. The main issue being that when customers reduce their bills through NEM, they avoid costs for utility services (absorbing excess and providing for shortfall) and those costs are then shifted disproportionately to non-NEM customers, presenting an equity issue. Furthermore, if the utility is not allowed to increase rates, then the utility might not be compensated for some services it provides to the NEM-customers, leaving the utility (and its shareholders) vulnerable to declining revenue and decreased profit margins. In the long term, this policy is unsustainable as it lacks a mechanism to prevent over payments to DG resources and fails to recognize services provided by the grid. If utilities are to embrace an active demand-side through DER integration, it is neither fair nor wise to enforce DG incentives that place utilities at odds with DG. Future, sustainable DER incentives would benefit from being value-based as well as co-optimized with new retail rate structures. In addition, new business models will be needed for utilities to thrive in the presence of high penetration DERs. Currently, utilities' main product is energy (as evidenced in current rate structure). But as customers reduce consumption through demand response (DR) and DG and even energy efficiency (EE), utilities will most definitely need to reinvent their business model in order to remain relevant and to stay profitable.

The Challenge:

Given the lagging development of market models to value distributed energy resources, poor retail rate design and unsustainable DG incentives, a significant growth in DER penetration can unfortunately cause potentially devastating financial consequences to utilities. Therefore one of the greatest challenges of realizing an active demand-side is the economically efficient grid-integration of DERs. Since distributed resources tend to be small scale and therefore, more expensive than conventional resources, current market mechanisms are not appropriate to reflect the value of DERs. Although market prices are ideal for discovering the price of a resource, neither wholesale locational marginal pricing nor current retail rates (either dynamic or flat) reflect the complete suite of services exchanged between various entities in the presence of distributed energy resources; thus, some grid services are unpriced (used for free) and the providers of such services are uncompensated. This problem is only exacerbated by shortsighted and unsustainable policies that incentivize DG and at the same time provide utilities with a perverse incentive to resist additional DERs.

Solution:

We propose that the solution to this challenge is the development of a price signal optimized to be economically efficient, smart data-driven, fair, sustainable, and effective.

- Economically Efficient: Economically efficient DER integration must result in optimized value-based prices, taking into consideration not only cost minimization, but also network, market, and resource constraints as well as various societal objectives.

- Smart Data-Driven: A smart data-driven pricing model produces local prices that are a function of both existing wholesale market and network data as well as newly available smart grid data.
- Fair: Multiple facets of "fairness" should be considered, including the costs and benefits accrued to all concerned parties and societal values and perceptions of equity.
- Sustainable: Sustainable DER policies and incentives must ensure that benefits of DERs to any market participant outweigh all costs that are ultimately indirectly shifted or directly allocated to said participant.
- Effective: To be effective incentives must be sufficient to achieve DER integration goals (whether policy-oriented goals, or benefit-oriented goals).

<u>Research Scope:</u>

DERs: Since there are numerous types of resources included in the definition of DER, we have narrowed the scope of this work to include demand response (DR) and distributed solar generation (DSG).

(Net) Value: By "value" of DER, we imply a net value considering both the benefits and costs associated with DERs:

a. Benefits: Economic value of network, market, environmental and societal benefits
b. Costs: Integration, installation, and incentive costs

Energy Market Beneficiaries: Because DERs provide benefits to a wide range of parties, we analyze and determine the value of DERs to each of these entities with the ultimate goal of ensuring that whenever costs allocation is necessary (as is typically the case with policy-driven incentives), those costs are allocated in proportion to the benefits each entity accrues. We consider the following groups:

a. Utilities: Load serving entities that own the distribution network and bill the end-use customers.
b. Consumers: Customers who purchase electricity from a utility and do not own DERs
c. Prosumers: Customers who both purchase electricity from a utility and own and operate DERs
d. Society: General public

<u>Dissertation Questions:</u>

This work addresses the value of DERs from two separate viewpoints: from the wholesale market point of view and from the retail market point of view. From each market angle, we answer the following questions:

1. What is the complete, **(net) value** of **DERs** to **energy market beneficiaries?**
2. How can that value be expressed in optimized pricing models?
3. What is the role of policy in ensuring optimal DER integration (and compensation)

Chapter 2. Literature Review

In his book, *Small is Profitable*, Lovins presented over 200 technical, economic, social and environmental benefits of DERs (Lovins, 2002). However, due to their small scale, it is often difficult for distributed energy resources to compete with large centralized resources when value is based purely on the cost of energy and capacity. In order for the true value of DERs to be realized, it is important these resources be applied and compensated for a wide range of services beyond energy and capacity requirements, specifically, local requirements such as voltage profile improvement, reactive power supply and congestion relief to name a few. This value creation process is crucial to the maximum realization of DER potential and fair, competitive compensation for small and/or distributed resources. In this section, we present a review of the literature concerning the benefits of DERs and quantification of their value in monetary terms. The review is separated into two parts. In Part I we present an overview of the value of demand response and methods to quantify and price that value. In Part II we address the value of distributed solar generation. Additionally, we look at some of the regulatory concerns regarding valuation of distributed resources.

PART I: VALUE OF DEMAND RESPONSE

2.1 Demand Response in Wholesale Markets

Currently, demand response resources can participate in wholesale markets for energy, capacity and ancillary services. During the mid-2000's the Department of Energy funded several studies to quantify the benefits of demand response and provide recommendations for achieving them (The Brattle Group, 2007). Several of these studies indicated that the economic benefits of demand response would be greater if various regulatory, technological and market barriers were removed (Heffner & Sullivan, 2005) (Department of Energy, 2005). In response to these findings, several ISOs established a number of incentive-based demand response programs (Peterson, et al., 2010). Under these programs, demand response resources receive an incentive payment if they can reduce load during emergencies (emergency DR) or during times of high energy prices (economic DR). The goals of these wholesale demand response programs were to reduce overall costs and also to increase reliability.

2.1.1 Quantifying DR Value to Set Wholesale DR Price

Although there are a variety of uses for DR, the focus of this review is on economic DR and the primary benefit of economic demand response is the reduction of locational marginal prices (LMP). In 2004, the New York Independent System Operator (NYISO) conducted a study on the market value of demand response and quantified this value as the sensitivity of market clearing prices to DR (Breidenbaugh, 2004). This study found that while it is possible for demand response to provide positive benefits, in many of the ISO's areas, demand response caused net negative benefits as it was being deployed when market prices were too low to justify DR payments. As a result, NYISO raised the minimum market-clearing price at which DR could participate in the market.

In 2010, the Brattle Group was retained by ISO-NE to investigate DR participation in wholesale energy markets. The result of this study was the development of the following five alternative DR compensation approaches (Newell & Madjarov, 2010).

1. **"LMP-RR":** All consumers are on fixed retail rates, but those providing load reductions are paid the locational marginal price (LMP) less the avoidable retail generation rate (RR);
2. **"RTP":** all consumers are on dynamic rates equal to the real-time LMP (i.e., real-time pricing or "RTP");
3. **"Full LMP in High-Priced Hours":** all consumers are on fixed retail rates, but those providing load reductions are paid the full LMP in the subset of high-priced hours that correspond to ISO-NE's present Day-Ahead Load Response Program hours (i.e., the 5-10% of hours with the highest LMPs);
4. **Full LMP When Price Savings > DR Payment:** All consumers are on fixed retail rates, but those providing load reductions are paid the full LMP in the subset of hours when energy procurements savings due to DR-induced LMP reductions exceed the cost of funding DR payments; and
5. **Full LMP in All Hours:** all consumers are on fixed retail rates, but those providing load reductions are paid the full LMP in every hour.

Each of these five options was evaluated on the standard measure of economic efficiency from welfare economics: consumer surplus (benefit to consumers in excess of amount paid), producer surplus (revenue of producers in excess of production cost), and economic surplus (total value society achieves in excess of total costs). Ultimately, the preferred payment methodology (or valuation methodology) was LMP-RR method, where DR participants are paid market price of electricity minus the additional cost they would have incurred to purchase the electricity first. Eventually, this method was rejected by FERC in favor of FERC Order 745.

In 2011 the Federal Energy Regulatory Commission (FERC) issued a ruling, Order 745, requiring ISOs to pay economic demand response resources that participate in wholesale energy markets full LMP and to allocate that cost to all who benefit from the LMP reductions caused by said demand response resources (FERC, 2011). Economists harshly criticized the economic efficiency of Order 745 (Bushnell, et al., 2011) (Pierce, 2012) and eventually, that ruling was overturned in May of 2014 (United States Court of Appeals, 2014) (FERC, 2014). However, even before this ruling, several ISOs voluntarily paid LMP for load reductions and dealt with cost allocation in various ways.

From 2006 to 2007, PJM paid full LMP to demand response when the LMP was above $75/MWh and paid LMP minus generation and transmission charges (LMP-G&T) when the LMP was below $75/MWh. This period is known as the “incentive period”, as DR was, at times of high LMPs, provided an additional incentive equal to generation and transmission charges. From 2007 until the issue of Order 745, the incentive was dropped, and demand response was paid LMP-G&T (PJM Interconnection, 2013) at all times. During the incentive period as well as the LMP-G&T period, the cost of acquiring demand response cleared in the market was allocated solely to the load serving entity (LSE) responsible for serving the demand response provider (Heffner & Sullivan, 2005).

ISO-NE’s early demand response programs limited participation to times of high real time prices (100$/MWh). However, the load reductions were voluntary and thus never cleared the real time market. Costs from DR payments were allocated to loads on a pro-rata basis as an out of market charge. From June 2005 until the issue of Order 745, ISO-NE expanded its program to allow DR to participate in the day-ahead market *after* the day-ahead market had cleared. Demand response offers with a price smaller than the day-ahead clearing price were accepted. DR thus had no effect on the day-ahead prices but could have an impact on the real time prices (Hurley, et al., 2013). Day-ahead DR compensation was also allocated to loads on a pro-rata basis.

Up until the issue of Order 745, NYISO allowed demand response to submit bids in the day-ahead energy market when LMP was above a minimum threshold. That minimum varied from $50/MWh to $75/MWh. The minimum value was imposed primarily to prevent "free riding," or bidding load reduction that would have occurred regardless of the market clearing process and to assure that the load reduction would in fact be cost effective. Resources that cleared in the day-ahead market were paid the full market clearing price (Lawrence & Neenan, 2003).

This brief historical review of DR compensation in wholesale energy markets not only serves to illustrate the wide range of potential pricing mechanisms but also shows that regardless of the price paid for DR resources, those payments have been addressed through cost allocation.

2.1.2 DR Cost Allocation and Net Benefits

While there is no denying the economic benefits of demand response, there are two undesirable consequences that are a direct result of paying for load reductions in wholesale energy markets. First, when a demand response resource curtails, the ISO experiences a reduction in revenue, a phenomenon known as "the billing unit effect". Since the ISO must compensate both generators and demand response providers for the resources that clear the energy market, the difference between market revenue and payouts is negative. This “missing money” is illustrated by the red shaded region shaded in Figure 2-1

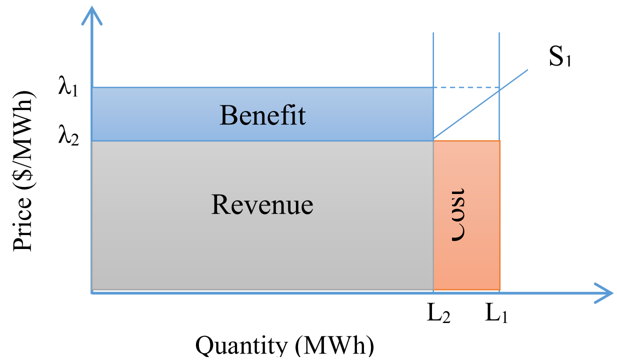

Figure 2-1. Illustration of the billing unit effect. S1, L1 and λ1 are respectively the supply curve, load, and energy price without demand response. L2 and λ2 are the load and energy price with demand response.

This negative balance represents money owed to demand response resources and must be addressed through cost allocation. Second, because of this out of market cost allocation requirement, an additional mechanism must be in place to prevent uneconomic purchases of demand response. Several ISOs have addressed the latter issue by only allowing economic demand response when LMPs are above a particular threshold (PJM Interconnection, 2013) (Hurley, et al., 2013) (Lawrence & Neenan, 2003). Several cost allocation methods have been proposed including assignment of costs (FERC, 2011)

1) to the LSE associated with the DR provider[1],
2) to all purchasing customers[2] ,
3) in part to the LSE and in part broadly to all customers[3],
4) to retail customers that bid demand response into the wholesale market[4], and
5) in a settlement method that incorporates DR costs into the dispatch algorithm[5]

[1] Proposed by PJM, MISO, CAISO, Detroit Edison, EEI, NUSCO, and National Grid (Order 745 comments, May-Sept. 2010)
[2] Proposed by NEPUC, , Steel Manufacturer’s Association, Ohio Commission and Wal-Mart (Order 745 comments, May-Sept. 2010)
[3] Proposed by PJM and ISO-NE (Order 745 comments, May-Sept. 2010)
[4] Proposed by DC OPC who also conceded that this would be complex and potentially unfair. (Order 745 comments, May-Sept. 2010).

(FERC, 2011) (FERC, 2010).

Of the five above methods, the first, second and third are currently implemented by various ISOs However, after the recent overturn of Order 745, it is expected that these will change.

2.1.3 Summary of Current Wholesale DR Valuation and Pricing Methodology Problems

The main problems with current DR pricing mechanisms in wholesale energy markets are the following:

1) DR is treated as an energy, or supply-side resource and therefore the majority of proposed and implemented pricing mechanisms directly involve the LMP instead of considering DR as a demand-side resource and pricing based on the added value of DR, or DR's *impact* on LMP.
2) When DR participates in energy markets, revenue from energy purchases are used to procure both megawatts and "negawatts". This results in an inevitable need for cost allocation (due to the billing unit effect). Current cost allocation methods are based on each buyer's share of the total load and do not consider how individual buyer's benefit from DR may differ as a function of transmission constraints.

An improved valuation methodology would first and foremost consider DR as a demand-side resource with unique, non-generation properties (there is no production of energy in a "negawatt"). Finally, if out of market payments are resorted to, then a fair cost allocation

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[5] Proposed by Consumer Demand Response Initiative (CDRI) in "Integration of Demand Response into Day Ahead Markets". This fifth method has the benefit of functioning as what FERC coined a "Dynamic Net Benefits Test." With a NBT, the cost of DR is incorporated into the dispatch algorithm for both conventional generation as well as DR, thus DR would only be dispatched when it is cost effective. However, after a FERC mandated study into the possibility and practicality of such a methodology, ISONE came to the conclusion that such a process would be prohibitively complex and require substantial changes to existing ISO software to include simplifications that could potentially result in anomalous market outcomes (ISO-NE, 2012).

method is needed to ensure that each market participant is not burdened with a proportion of cost that is in excess of its benefit from DR.

2.2 Demand Response at the Retail Level

Quantifying the benefit of DR at the retail level is unique in that there is only one buyer: the host utility which serves the DR resource. The traditional business model of utilities has been such that utilities, being regulated entities, are allowed to recover, through retail revenue, the costs to serve their customers and also to earn a reasonable rate of return on investment. This, unfortunately, provides the utility with a perverse incentive to encourage energy consumption and load growth leading to high capital investments. To overcome this flaw, public utility commissions have begun to offer utilities incentives to encourage energy efficiency and some utilities are implementing various decoupling mechanisms to separate profits from sales (Shirley & Taylor, 2009). However, many utilities continue to be dependent upon retail sales for sufficient revenue collection. Thus, DR has a potentially negative impact at the retail level. In order for DR compensation to be optimal, it must be properly aligned with the avoided utility costs resulting from DR. This is best accomplished through restructuring retail rates to reflect actual utility fixed and variable cost components.

2.2.1 Quantifying DR Value to Set Retail DR Price

Currently, at the retail level, there are essentially two means to reward demand response: time-based (dynamic pricing) or incentive-based. Under time-based programs customers receive time-varying prices to which they have the option to respond. When customers reduce or shift load in response to time-varying prices, their only "financial reward" is the potential to avoid using electricity during periods of high prices in order to reduce their electricity bills. Under incentive-based programs, customers are offered a financial reward (in addition to their reduced bills) for agreeing to reduce load or allow the utility to control their load during certain agreed upon times of the year.

Within these two broad categories is a wide range of retail DR programs. According to a 2012 FERC survey (Figure 2-2), by far, the majority of current retail DR is offered through incentive-based programs (FERC, 2012). Economists argue, however, that the more efficient and fair way to reward demand reductions is through dynamic retail rates that are properly aligned with wholesale prices (Bushnell, et al., 2011) (Pierce, 2012). Real time pricing (RTP), time of use pricing (TOU), and critical peak pricing (CPP) are the more commonly studied (and implemented) dynamic rates (Faruqui & Sergici, 2009).

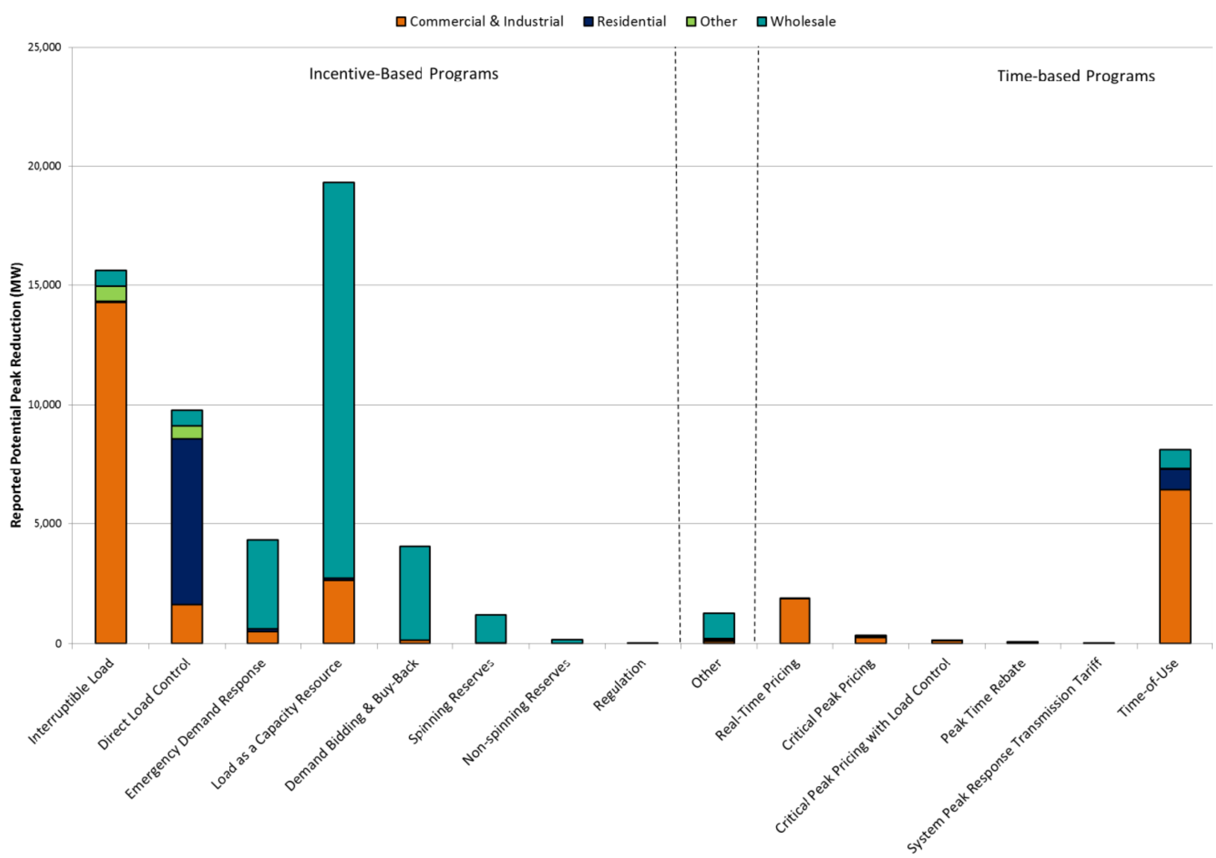

Figure 2-2. Demand Response Potential by Customer Class and DR Program Type (FERC, 2012)

While many utilities offer dynamic rates to their large customers, fewer opportunities are available for residential customers, who consume almost 40% of the electricity generated in the US. However, the number of residential customers being provided with (and exercising) customer choice is growing rapidly (O'Connor, 2010). In 2006, Illinois became the first state to require that all customers be given the option of real time pricing (Assembly, 2006). Texas has a thriving competitive retail market, and as a result, customers have a wide range of suppliers as well as rates to choose from. Unfortunately, customers on real time pricing are at risk of being exposed to extremely volatile and sometimes high prices. Because residential customers are in general risk averse, it is not surprising that many customers choose to remain on flat rates (Illinois Commerce Commission, 2014). Incentives therefore provide a low-risk option for voluntary demand reductions. One of the most common incentive programs offered to residential customers is direct load control (DLC), where customers are offered a fixed incentive in exchange for allowing their LSE to control a portion of the customer load. The advantage of this method is that a consumer can determine in advance whether the incentive is attractive enough to participate and the LSE has increased certainty in DR availability. The main disadvantage for the customers, however is that they must give up control over their comfort. The disadvantage for the LSEs is that they inevitably purchase phantom DR, or load reductions that would have occurred even without incentives.

2.2.2 Summary of Current Retail DR Valuation and Pricing Methodology Problems

1) Current retail rates typically do not reflect utility costs. Therefore, DR compensation based on current retail rates might not reflect the actual value of DR to the utility.

2) Current dynamic pricing only considers real time conditions in the wholesale market. No current rate design includes a local component to reward DR for relieving local issues in the distribution grid.

2.3 Benefits of Distributed Solar Generation

Distributed solar generation (DSG) provides a wide range of traditional and non-traditional benefits. These benefits can be enjoyed by the utility, by ratepayers, or by society at large. Several value of solar meta-studies have developed a number of ways to classify the benefits of distributed solar generation, notably that prepared by Rocky Mountain Institute in 2013 (Hansen & Lacy, July 2013). In order to better examine the role of policy in monetizing non-traditional benefits, we have broadly classified benefits of solar into those that can be readily monetized and those that cannot. Figure 2-3 provides a more granular breakdown of these various components. In general, energy and capacity related benefits can be monetized straightforwardly while environmental and social externalities cannot. This represents a challenge for those seeking to value solar as it becomes necessary to "price the priceless" (e.g. clean air, good health, longevity, etc.)

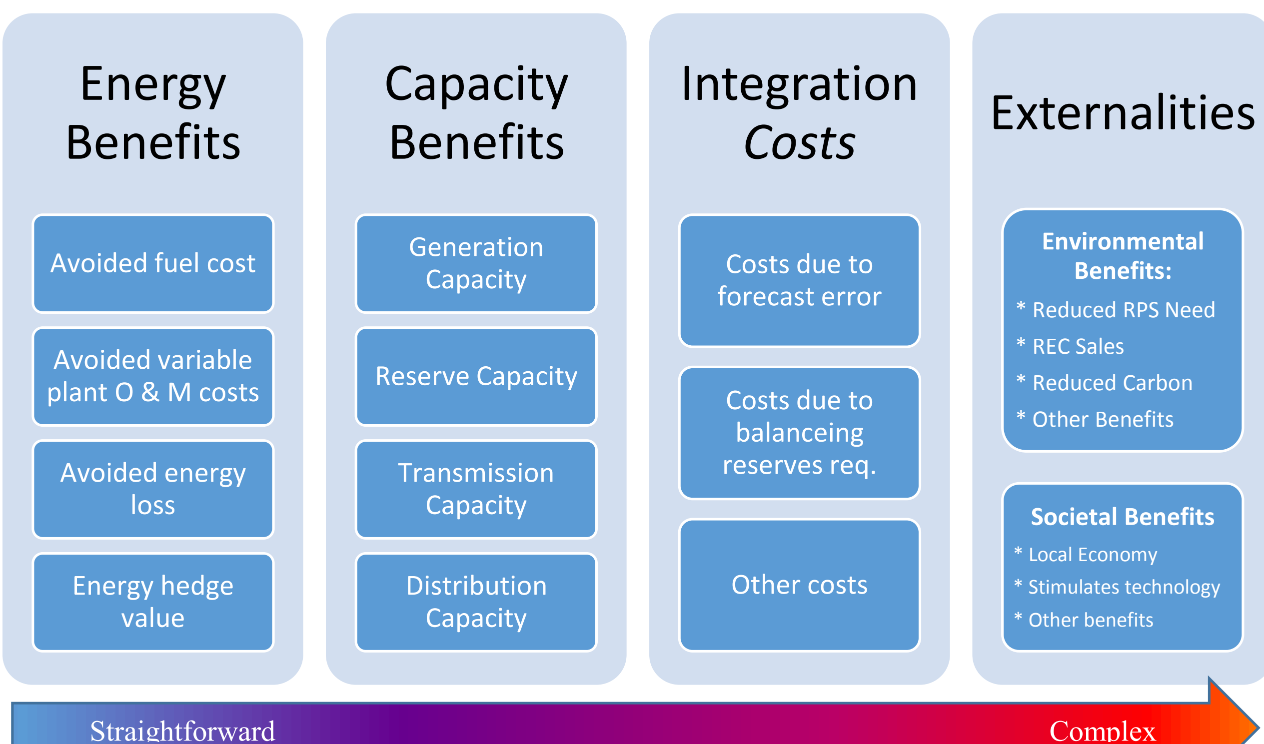

Figure 2-3. Breakdown of distributed solar benefits (in order of increasing level of difficulty to monetize)

2.3.1 Policies that Might Monetize Non-Traditional Value Components: "Pricing the Priceless"

Environmental and social externalities represent the largest segment of solar benefits that are not fully monetized at present. Attempts at defining environmental externalities include the Environmental Protection Agency (EPA) social cost of carbon (SCC) estimate. In 2013, the Interagency Working Group on the Social Cost of Carbon updated the estimated cost of carbon in 2015 to be $39/ton (in 2011 dollars) (Environmental Protection Agency, 2013). While this update represented a 54% increase over previous estimates, a number of environmental groups, including the Natural Resources Defense Council, the Environmental Defense Fund, and the Institute for Policy Integrity, have criticized the valuation methodology for omitting various benefits and therefore consider the estimate too low, albeit the most accurate estimate currently available (Howard, 2014). The EPA also realizes the shortcomings of its integrated assessment models to fully capture the economics of various scientifically established impacts of climate change, meaning the current SCC estimate very likely underestimates damages due to carbon (Environmental Protection Agency, 2013). Ultimately, this type of cost estimate represents an attempt to price an externality based on a detailed analysis of externality costs. We refer to this type of methodology as a value-based analysis and it is a core part of value of solar analysis. However, due to the difficulty in pricing externalities, it is often necessary for policies to define that value. Figure 2-4 presents a graphical representation of the relationship between policy and the value of solar.

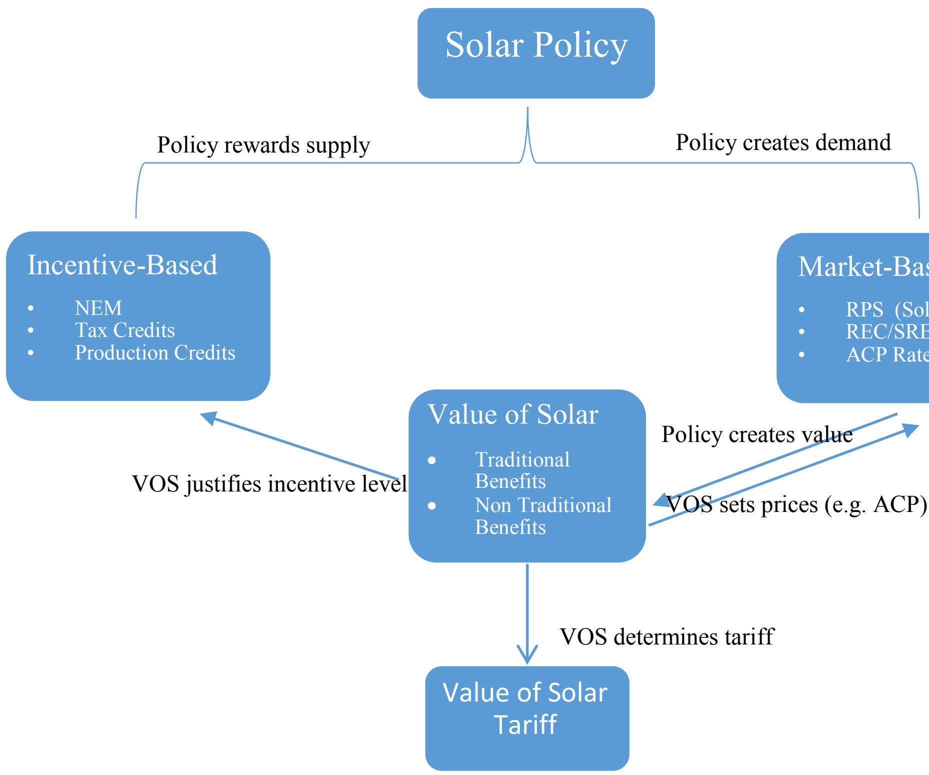

Figure 2-4. Relationship between policy and the value of solar

In general, policies related to solar currently fall into two categories: incentive-based and market-based. Incentive-based policies reward PV owners for their investments, often allowing them to sell production at above market prices. Market-based incentives work by creating a demand for solar that otherwise would not exist. This includes solar carve-outs of renewable portfolio standards. In this way, solar does not have to compete against other less expensive renewable generation, but still can still participate in markets, including renewable energy credit marketplaces.

Perhaps the most common means for market-based incentives to create demand is through renewable portfolio standards (RPS). Forty-six states and the District of Columbia have in place either voluntary or mandatory RPS. Fewer parts of the country have particular carve outs for solar (Figure 2-5) and even fewer states provide markets to buy and sell solar renewable energy credits (Table 2-1). This is potentially an area where value of solar studies might be used to complement existing markets or justify the creation of new state solar renewable energy credit (SREC) marketplaces. If the value of environmental externalities is high enough, it may be possible for an SREC market to flourish given an appropriate RPS and value-based alternative compliance payment (ACP) rate[6]. However, this process begins with "pricing the priceless," a complex task often achieved through detailed forensic economics.

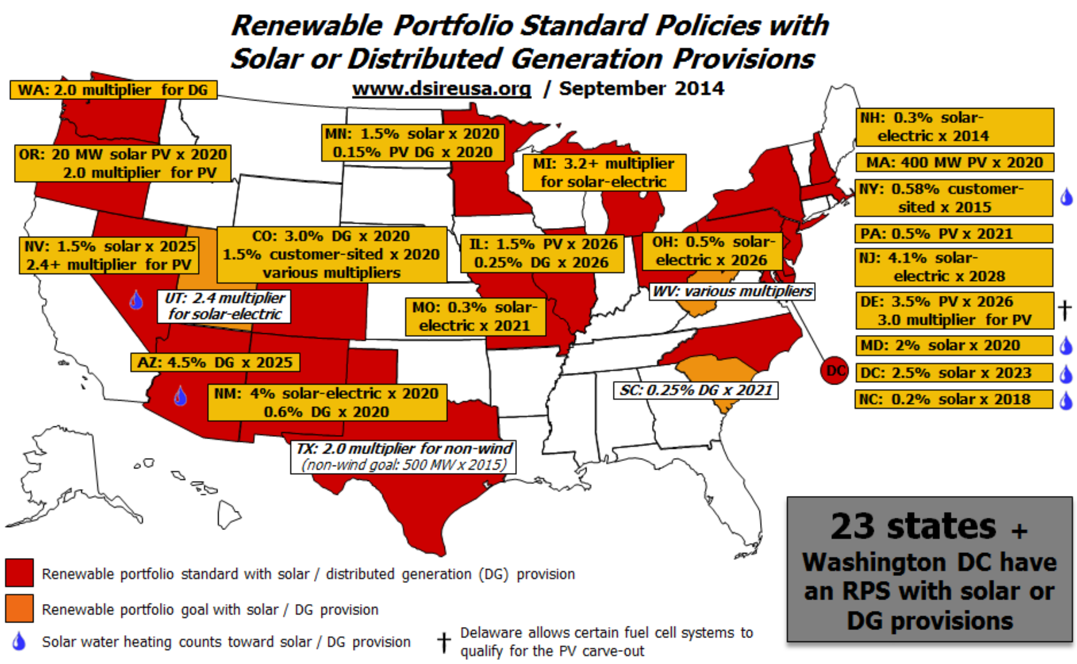

Figure 2-5. States with solar specific renewable portfolio standards (Source: DSIRE, 2014)

Table 2-1. States with active SREC markets

Massachusetts	New Jersey	Ohio (In-State)	Ohio (Adjacent-State)
Pennsylvania	Delaware	District of Columbia	Maryland

[6] The ACP is a penalty fee that LSEs pay for failing to procure enough RECs in a given year. This penalty rate is set by RPS rules (Platts, 2012)

Incentive-based policies, while based on reducing the cost of solar and driving initial investments, are not necessarily founded on an actual valuation analysis (i.e. an analysis that compares costs and benefits to ensure cost-effective policy). One of the most common of these incentives is net energy metering (NEM, a policy that allows customers with distributed generation to be compensated for feeding excess generation to the grid. With NEM, customer's meters "run backwards" during times of excess generation and thus, the customer only pays for the net energy taken from the grid. In theory, if customers feed back to the grid as much as they draw from the grid, then they pay nothing at all. Critics of NEM point out that it allows PV owners to avoid paying fixed costs and to shift those costs to non-NEM customers. Because of the unsustainability and potentially unfair cost shifting from NEM customers to non-NEM customers, several states have begun to show signs of a shift away from NEM:

- In California, lawmakers let net metering continue but directed its PUC to devise a new program by 2017 to ensure that non-solar customers aren't burdened unfairly in paying for the grid (California Legislative Information, 2013).
- In Arizona, regulators voted in November to allow the largest utility to tack a monthly fee of $5 onto the bill of customers with new solar installations. Arizona Public Service originally sought a $50 surcharge. (Arizona Corporation Commission, 2013).
- Colorado's PUC is considering a proposal to halve credits for solar energy households. Other states, including Louisiana and Idaho, are also contemplating changes in net metering rates (Lappe, 2013).
- In Oklahoma, Senate Bill 1456 allows regulated utilities to apply to the Commission to charge a higher base rate to DG customers through a partial decoupling of rates and directs utilities to create a new class of customers (and tariff) for those who

install distributed generation, to better assign fixed charges for DG (Oklahoma Legislature, 2014).

Solar proponents, however, state that the unpriced environmental benefits of solar more than make up for the price premium granted through net metering. Clashes between these two sides have initiated a number of "value of solar" studies – notably in Vermont, where lawmakers have already determined that depending on economic assumptions and whether the value of emissions reduction is included, net solar benefits can be either positive or negative (Public Service Department, 2013), and recently in Utah, where a bill to eliminate NEM was later changed, in a last minute compromise, to evaluate the value of solar to the grid (Bramble, 2014).

2.3.2 Quantifying DSG Value to Set Retail DSG Price: Value of Solar Tariff (VOST)

Currently, value of solar tariffs (VOST) are emerging as a contender to NEM. VOST is a tariff that is based on the actual value that solar brings to the utility and is defined as a sum of several distinct, individually calculated value components. Austin Energy was the first utility to implement a VOST (Austin Energy, 2013). In 2014, Minnesota became the first state to implement and mandate VOST methodologies and policy statewide (Minnesota Department of Commerce, Division of Energy Resources, 2014). Recently, the Pacific Northwest Utilities Conference Committee (PNUCC) also began to develop a regionally appropriate VOST methodology for utilities in the Pacific Northwest (PNUCC, 2015).

While both the Minnesota and PNUCC methods largely consider identical value components, there are important differences. Table 2-2 provides a high level comparison of the two solar valuation methodologies.

Table 2-2. High level comparison of selected valuation methodologies

Value Categories	[7]CPR Method (value)	Modified PNUCC Method (net value)
Energy	Based on: 1) a combination of guaranteed and escalated **fuel costs**, as well as 2) **variable plant O & M costs**. *Guaranteed fuel prices discounted at a risk free rate to account for **energy hedge value**.	Based on 1) forecast energy **market prices** and 2) estimated value of "energy efficiency risk premium" from Avista's 2013 Integrated Resource Plan (to account or energy hedge value)
Capacity	Has 4 capacity components: • Generation, reserve and distribution capacity components valued according to capital costs. • Transmission capacity components valued at market price. Has 2 capacity factors: • Generation, reserve and transmission components are based on a capacity factor (ELCC) that measures the average PV output during peak hours of peak months. • Distribution component based on a capacity factor (PLR) that measures peak load reduction.	Has one capacity component: • Generation (peak) capacity components based on cost of new natural gas plant. Has 1 capacity factor: • Generation, transmission and distribution components are all based on the same capacity factor (CF). This capacity factor is based on the average PV output over all hours of an entire year.
Environment	Based on: • EPA estimated social cost of carbon as well as state defined emissions costs.	Based on: • reduced RPS need
Integration (Cost)	Assumed to be small and therefore cost is mentioned, but **not considered**.	Estimated **based on integration study** performed by an Idaho utility.

From Table 2-2, we observe that both methods consider four main categories of solar benefits: energy, capacity, environmental externalities, and integration costs. However, they differ in both the number of components considered within each main benefit category as well as in methodology to determine the economic value of each component. In addition,

[7] Both Austin Energy and the state of Minnesota employ a VOST methodology developed by Clean Power Research (CPR).

the CPR method is a levelized value and quantifies the lifetime benefit each of the individual value components considered. On the other hand, the PNUCC method calculates the value of solar in a single year and only the capacity value is levelized. To calculate the value of solar tariff, both methods calculate the avoided cost of each value component individually. After all components have been determined, they are weighed with an appropriate capacity factor and the final value of solar tariff is then the weighted sum of each of the individual components.

2.3.3 Summary of Current DSG Valuation and Pricing Methodology Problems

For several years, net energy metering has been a simple and steady tool to value PV generation. VOSTs are fairly new and it is expected that the implementation of these tariffs and their design will develop over time. Currently, there are a few VOST characteristics that are often debated:

1) **Inconsistent Values**: Current value of solar tariffs are determined based on individually calculated value components. This means that a crucial step in this process is identifying all of the values attributed to PV generation. Then, a methodology to express the economic value of the various value components must be selected. There are a number of ways to express the same value component, each method producing sometimes drastically differing values. Because of this inconsistency, some are calling for a more standardized approach that fosters greater consistency in value, particularly, the externalities (Keyes & Rabago, 2013).
2) **Long Term Contracts**: It is necessary to make an extremely large number of assumptions to calculate the 25-year levelized value of solar. Any deviation in one or more of these assumptions could either place the utility at financial risk of honoring a less than valuable contract or undervalue solar. Some critics of the policy propose

shorter term contracts (5-10 years), after which these assumptions are updated and the value of solar is reassessed. However, solar proponents fear that this will have a negative impact on financing options and will discourage investment (Jossi, 2014).

3) **Buy All Sell All**: Current VOST policies force customers to sell all production at the VOST rate and buy all consumption at the prevailing retail rate. This is attractive to a PV owner so long as the retail rate is lower than the VOST rate. However, due to the fixed nature of the VOST and increasing nature of retail rates, eventually, the VOST rate may drop below the retail rate, and the customer would find more value in self-generating. But under this current policy design, PV owners lose the right to self-generate.

2.4 Gap in Current DER Valuation Practices: Consensus of the literature

There has been much research at the national level investigating the benefits of DERs and providing recommendations for their grid integration. The main consensus is that there are numerous energy and non-energy benefits of these resources. However, the traditional design of retail markets is not set up to reflect the non-energy value of local resources. In terms of DR integration, the DOE has recommended fostering price-based programs, improvements in incentive-based programs and standardization of valuation methodologies (Department of Energy, 2005). In terms of DSG integration, the need for a methodology that can be consistently applied to various regions has also been highlighted (ICF International, 2014).

In addition to standardized approaches, valuation methods themselves must be holistic and capable of both recognizing the wide array of potential DER benefits and allocating the cost of DER compensation to the recipients of those benefits. E3 has identified capturing of area-dependent, local value of DERs to the distribution grid as the most challenging aspect of DER valuation (Energy and Environmental Economics Inc., 2011). Part of the focus of our proposed valuation methodology has been to bridge this particular gap.

Chapter 3. Valuing Demand Response in Wholesale Markets

This chapter addresses the value of DR in wholesale energy markets. In Part I, we propose a value-based methodology for pricing DR. While the value of wholesale DR is traditionally viewed as LMP reductions, this methodology considers local value of DR to LSEs in a market where DR is dispatched post market setting and therefore does not impact LMPs. The local value of DR is defined as the LSE's increased gross margin. In Part II, we address the issue of cost allocation for the case when DR is allowed to lower wholesale energy prices. We propose a method that allocates the cost of DR to those market participants who benefit from LMP reductions. This allocation is not only proportional to the size of the market participant's benefit, but also to the magnitude of the market participants' contributions to DR.

3.1 Proposed Methodology

We propose a market mechanism for valuing demand response proportionally to the benefits it provides to wholesale market participants. This benefit comes in the form of increased gross margin for LSEs, reduced bills for DR participants, and possibly reduced rates for non-DR participants. While it is also possible that market prices can ultimately be reduced, we will show in subsequent sections that allowing DR to reduce LMP results in uneconomic DR.

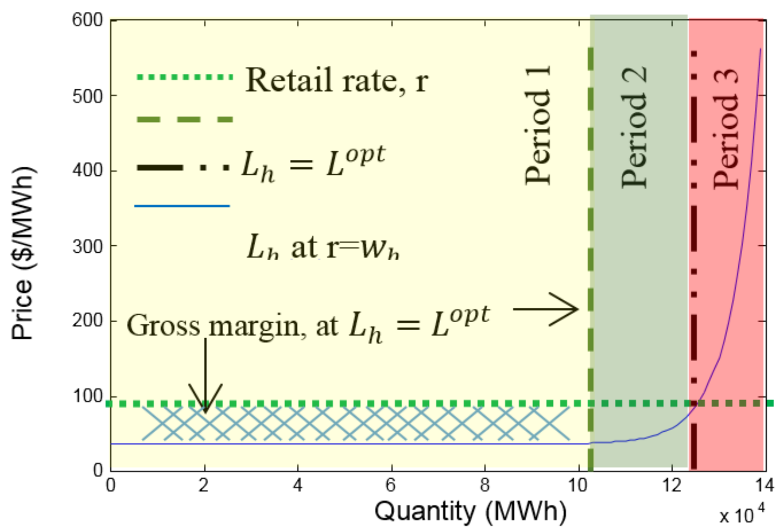

Figure 3-1. Illustration of gross margin at $\mathbf{L^{opt}}$.

Assuming a reference flat retail rate, the gross margin from an LSE's perspective (without DR) is the difference between the retail and wholesale prices multiplied by the volume of energy sold (Equation 3.1). This margin is illustrated in Figure 3-1.While wholesale prices vary widely over the day and over the year, retail prices are usually fixed and typically larger than the LMP. However, at peak loads, the LMP can rise above the retail rate and it is during these hours (Period 3) that the retailer "loses money" and there is a potential to purchase DR, if it can reduce the extent of these losses. Clearly, this is only economic if the cost of purchasing DR is less than the loss without DR. In such a case, DR increases the LSE's gross margin by decreasing the extent of loss-making periods.

Figure 3-2 shows a high level schematic of the roles of market players. Here, demand response acts as a "demand side resource" and not as a competing generation resource. This is an important distinction as it requires the creation of a new type of "supply curve" to price demand response.

From the supply side, LSEs bid loads into the market based on forecasts. Generators submit offers based on, presumably, their marginal costs. From this information, the ISO establishes a supply curve and sets the day-ahead LMPs. Next, the demand side is given an opportunity to adjust loads, and therefore, adjust the energy scheduled in the day-ahead market (but not adjust the LMP). From the demand side, consumers offer DR via their LSEs, who are also the ultimate buyers of DR. These LSEs use the LMPs and the retail rates to determine, and bid, the amount of DR that maximizes their gross margin. From this information, the ISO is able to generate an aggregate "supply curve" for demand response.

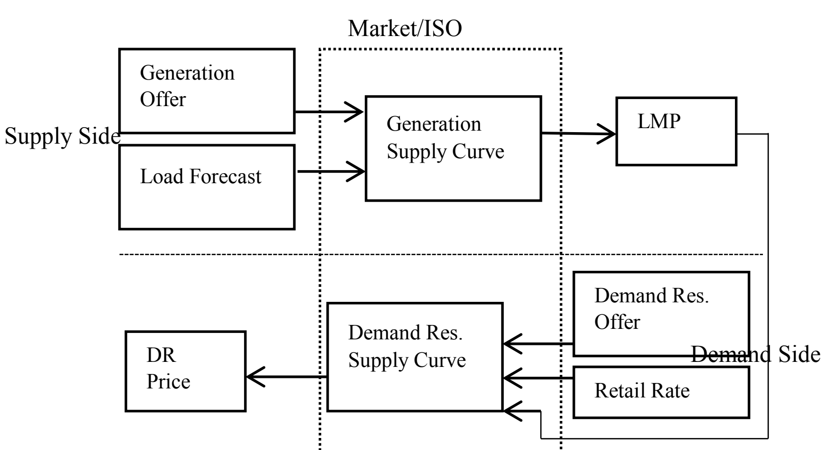

Figure 3-2. Proposed process to determine demand response

Like Order 745, the proposed method includes a threshold at which DR is deemed economic. We define economic DR as that which does not leave the market in negative balance. In other words, DR is economic as long as the market does not under-collect revenue to pay both generators and DR participants. However, it will be shown in Section V that once the DR supply curve is established and LSEs include the cost of DR in their gross margin calculation, the amount of DR they purchase will not approach this threshold. In the following subsections, we detail the calculations of the above process.

3.1.1 Generation Supply Curve and Optimal Demand

The premise behind this method is that for a given generation supply curve for the day, there is a specific load that maximizes g, the gross margin for the LSEs:

$$g = \sum_h^H \big(r - w_h(L_h)\big) * L_h, \quad (\$) \qquad (3.1)$$

Here, r is the reference retail rate, w_h is the hourly wholesale price, h is the hour (*h=1…H, H=24*), and L_h is the hourly demand (3.1). The foundation of an optimal load level is valid when demand is responsive to day-ahead prices and LSEs can bid loads into the market based on expected or forecast generation supply curves.

For each (daily) generation supply curve the optimal demand, L^{opt}, is the L_d that maximizes gross margin (3.2), (d=1…D, D=365).

$$\max_{L_d} \sum_h^{24} \sum_d^{D} \big(r - w_h(L_d)\big) * L_d \qquad (3.2)$$

3.1.2 Required Demand Response

Using historical or forecast demand, we can then estimate the demand response D_h^d required to achieve the optimal load, L_d^{opt}, where D_h^d is the demand required in hour, *h*, on day, *d*. We define D_h^d as follows:

$$D_h^d = L_h^d - L_d^{opt}, \qquad (\mathrm{MWh}) \qquad (3.3)$$

D_h^d>0 for a load reduction (e.g. peak shaving), and D_h^d<0 for a load increase (e.g. valley filling).

3.1.3 Demand Response Value

The value, V_h^d, of the demand response is then the difference in gross margin with and without demand response divided by the required load modification (3.4).

$$V_h^d = \frac{(r - w_h(L_h - D_h^d)) * (L_h - D_h^d) - (r - w_h(L_h)) * L_h}{D_h^d}, \left(\frac{\$}{MWh}\right) \tag{3.4}$$

3.1.4 Classification of Demand Response

We define three price periods during which demand response may occur (Figure 3-1):

Period 1: $r > w_h$ and $D_h^d < 0$

Period 2: $r > w_h$ and $D_h^d > 0$

Period 3: $r < w_h$ and $D_h^d > 0$

Period 1 occurs when load is low and retail prices are higher than wholesale prices, indicating that an increase in load (negative D_h^d) would increase the LSEs' gross margin. Period 2 occurs when load is high but the retail price is still above wholesale, indicating that a decrease in load may be beneficial but only for purposes not related to gross margin. Finally, period 3 is when load is exceptionally high and the wholesale price is higher than the retail price, indicating that a decrease in load would decrease the loss that the LSEs might incur.

3.1.5 Fitting of Demand Response Supply Curve

We calculate the value, V_h^d, for each of these three periods and plot V_h^d vs. D_h^d to form the desired supply curve, where the curve in each period is approximated by a suitable function, p_i, (i= Period 1, Period 2, Period 3).

$$p_i = f(D_h^d), \quad (\frac{\$}{MWh}) \tag{3.5}$$

3.2 Case Study

3.2.1 Data

We tested the proposed pricing mechanism using data from the PJM day-ahead market. Daily generator offers for 2012 were collected to create the daily day-ahead generation supply curves. These curves were then smoothed as specified in PJM's net benefits test per Order 745 using the function shown in Equation 3.6 (PJM, 2011), where a, b, c, and d are constants derived from fitting a power function equation to the supply empirical data.

$$w_h = a^{b*L_h-c} + d \tag{3.6}$$

PJM hourly load data for 2012 was used as the baseline load (before DR). The average retail rate was based on information from the EIA website (U.S. Energy Information Administration, 2013).

3.2.2 Cases

In order to examine the effect of allowing DR to set LMP, we considered two different cases. In Case 1, DR can set the energy price, and the new LMP is a function of the reduced load ($LMP_{new} = f\left(L_h - D_h^d\right)$). In Case 2, DR cannot set the energy price and LMP is a function of the original load ($LMP_{old} = f(L_h)$).

3.2.3 Evaluation Metric

To evaluate the total benefit of DR, we consider the market balance, B, after the settlement of revenue R, payments for generators P_{gen}, and payments for demand response P_{dr}. In Equations 3.8 and 3.9, $p\left(D_h^d\right)$ is the price for DR.

$$B = R - P_{gen} - P_{dr} \tag{3.7}$$

So for the two cases, we have

$$B_{case1} = LMP_{new}\left(L_h - D_h^d\right) \quad - LMP_{new}\left(L_h - D_h^d\right) - p\left(D_h^d\right)D_h^d \tag{3.8}$$

$$B_{case2} = LMP_{old}(L_h) - LMP_{old}(L_h - D_h^d) - p(D_h^d)D_h^d \tag{3.9}$$

As a benchmark, we also compared our method to that of DR compensation according to FERC Order 745:

$$B_{745} = LMP_{new}(L_h - D_h^d) - LMP_{new}(L_h - D_h^d) - LMP_{new}D_h^d \tag{3.10}$$

After settlement the balance can be of the following:

B<0: under collected revenue, costs must be allocated

B>0: over collected revenue, benefit must be distributed

B=0: balanced market

3.3 Results

3.3.1 Determining the Demand Response Supply Curve

Figure 3-3 shows the generation supply curve for a day in July. The long vertical black and blue lines indicate the load when supply elasticity equals 1 (PJM's FERC 745 compliant threshold for demand response) and the load when the gross margin is maximized, respectively. The short vertical lines represent the 24 hourly loads of the day. Clearly, the hourly loads span all three price regions (16 hours in period 1, 4 hours in period 2, and 4 hours in period 3). Although the distribution of load into these regions varies from day to day, on all days the load that achieves maximum gross margin is significantly higher than the threshold of economic DR as defined in PJM's or FERC 745 net benefits test. This means that for loads between the black and blue lines of Figure 3-3, the FERC 745 method pays customers to reduce loads, while the proposed method would encourage customers to increase their loads to maximize the LSE's gross margin.

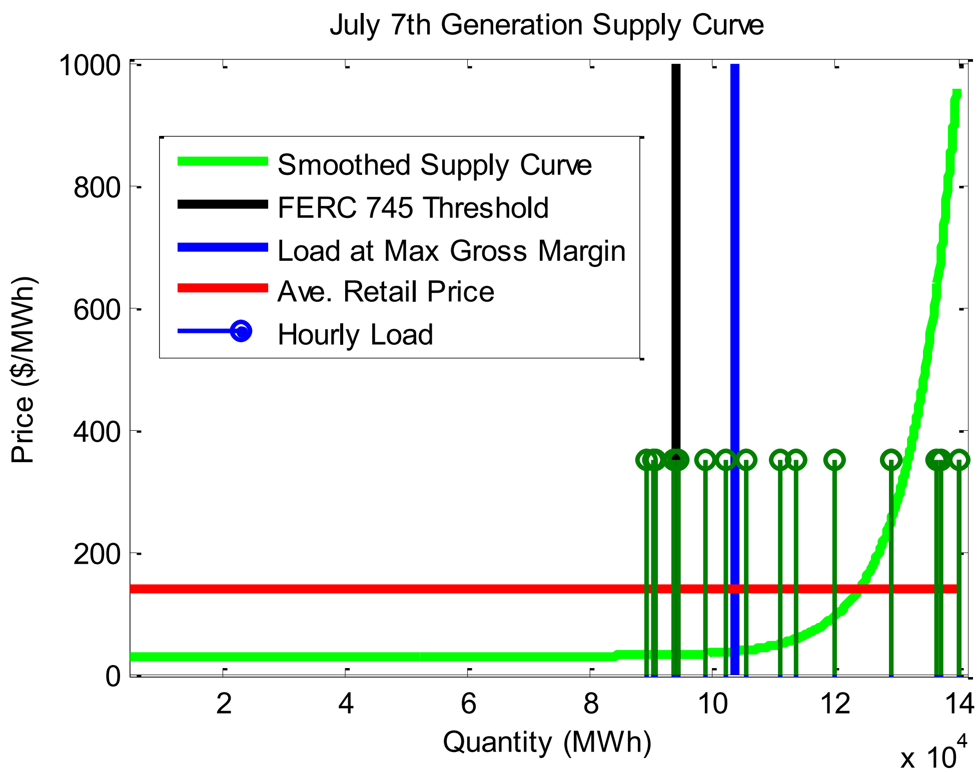

Figure 3-3. Comparison of FERC 745 determined threshold of economic DR and LSE defined threshold at maximum gross margin

Figure 3-4 shows the load that maximizes the gross margin for each day of the year. This load is constant for each day as there is only a single generation supply curve per day. The variation in these daily optimal load levels is due to the daily fluctuations in generation supply curves. Since load is actually time varying, the difference in the expected load shape and the daily optimal creates a desired demand response profile, D_h^d (Equation 3.3).

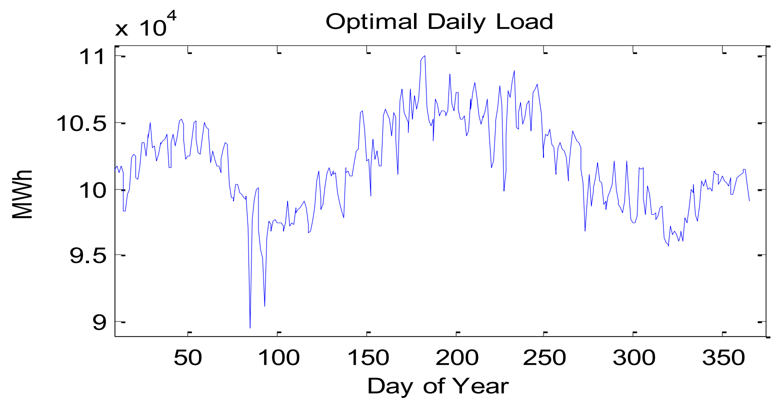

Figure 3-4. Optimal Daily Load (based on max gross margin)

In order to calculate V_h^d, we first compare the gross margin with and without demand response as well as the respective loads (Figure 3-5 and Figure 3-6). Although the difference in optimal and actual gross margin is large during price period 1, as Figure 3-6 shows, it would take a large amount of "negative demand response", or load increases, to collect that benefit. The largest dollar per megawatt hour region is in price period 3.

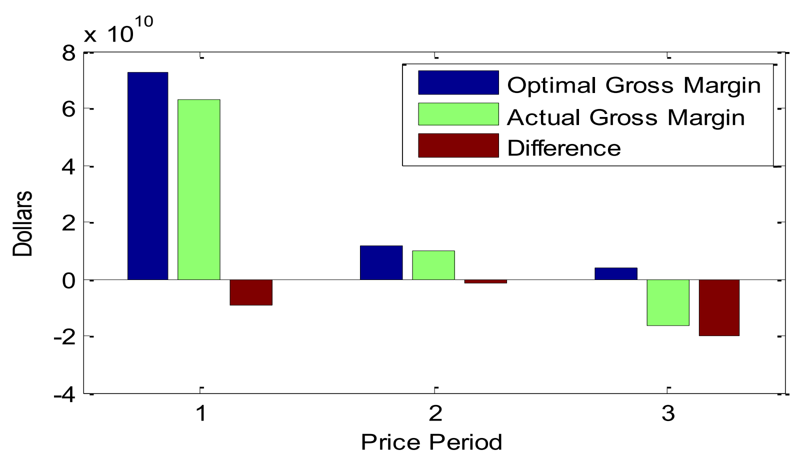

Figure 3-5. Comparison of gross margin with and without optimal DR

Figure 3-7 is the resulting piecewise DR "supply curve". As expected, the value of "negative demand response" (period 1) is relatively small. The highest price is in period 3 and can reach 3-4 times that of the maximum LMP. However, as we will see in the next section, it is very unlikely that such high levels of DR will be deemed economic.

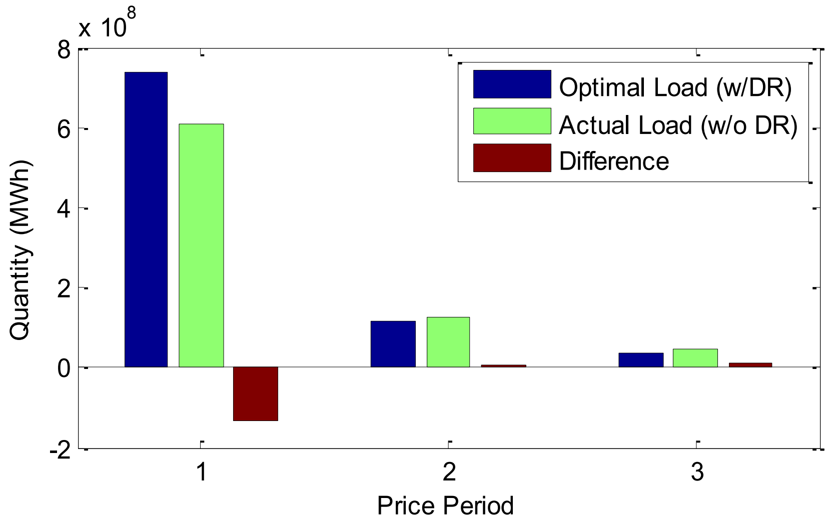

Figure 3-6. Comparison of load with and without optimal DR

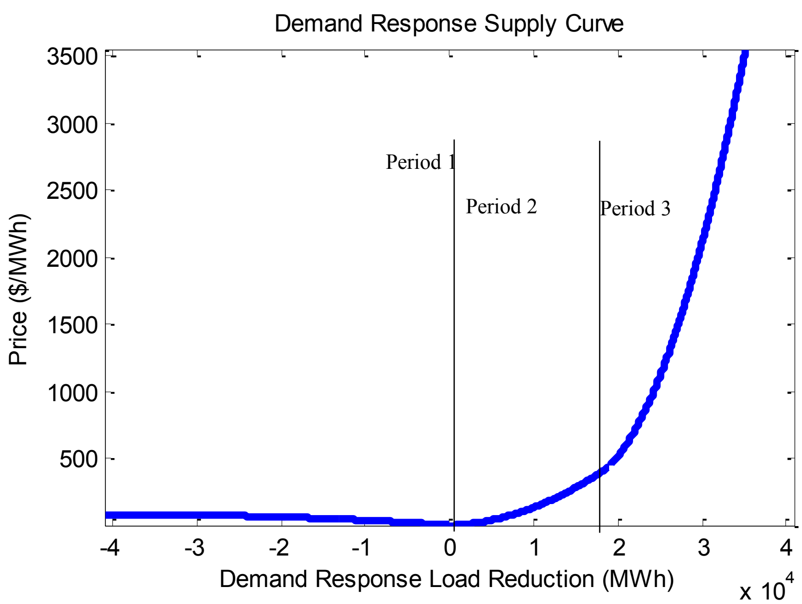

Figure 3-7. Piecewise demand response curve: negative demand response (x-axis) implies load increase; positive demand response implies load decrease.

3.3.2 Benefits Evaluation

We evaluated the benefits of load reductions (periods 2 and 3) for two cases: Case 1, where DR is able to reduce LMP and Case 2, where DR is not allowed to reduce LMP, but can only balance supply and demand. Table 3-1 shows the economic benefit of demand response for these two cases. For Case 1, the revenue is determined by the amount sold in the energy (supply side) market. Here, DR reduces both the LMP, as well as the amount of energy sold in the market. This reduces the overall revenue in the market, but more importantly, results in a negative market balance, and nothing with which to pay DR. Thus, the cost of DR must be allocated. As for Case 2, since DR is sold separately from energy, the actual amount of energy sold does not change, and therefore, neither does the LMP. In this case, more revenue is collected than used to pay the generators. This results in a positive balance from which DR can be paid.

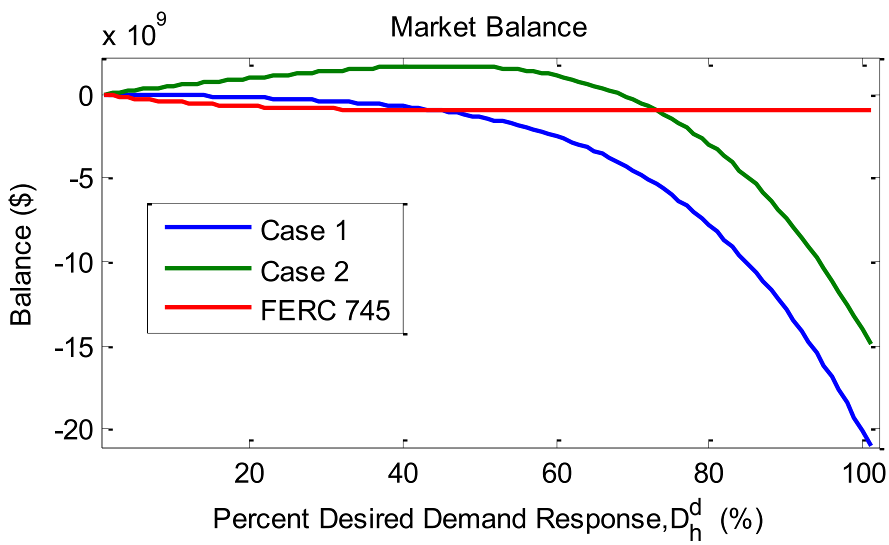

Figure 3-8. Market Balance Comparison

Figure 3-8 compares the market balance in each of the two cases as well as the balance when compensation is according to FERC Order 745. What we observe is that when demand response is allowed to set LMP (Case 1 and FERC method), the balance is always negative. However, when the proposed method is used, and DR is not allowed to set the LMP (Case 2), then for increasing purchases of DR, the market balance first grows increasingly positive, peaks, then drops as greater, (but less economic) payments go to DR.

Eventually, at about 70% of the DR required to maximize the LSE gross margin (before DR payments), the balance becomes zero. This represents the point where the market is perfectly balanced. In other words, this point marks the maximum DR that the ISO should allow to be purchased, regardless of the LSE's bid. From a market point of view, this quantity of DR is optimal. If more DR is purchased, then the balance becomes negative, and costs must be allocated. However, we are also interested in 'optimal DR' from all points of view.

Table 3-1. Yearly total revenue and payments with increasing DR: Comparison of Case 1, Case 2, and FERC 745 method.

(all values in "10^{10} dollars")

D_h^d	*0%*	*20%*	*40%*	*60%*	*80%*	*100%*
Case 1						
Rev.	5.783	4.515	3.849	3.487	3.281	3.157
Gen.	5.783	4.515	3.849	3.487	3.281	3.157
DR	0	0.02	0.079	0.274	0.858	2.193
Bal.	0	-0.02	-0.079	-0.274	-0.858	-2.193
Case 2						
Rev.	5.783	5.783	5.783	5.783	5.783	5.783
Gen.	5.783	5.659	5.535	5.411	5.287	5.163
DR	0	0.02	0.079	0.274	0.858	2.193
Bal.	0	0.104	0.169	0.098	-0.362	-1.574
FERC						
Rev.	5.783	4.515	3.849	3.487	3.281	3.157
Gen.	5.783	4.515	3.849	3.487	3.281	3.157
DR	0	0.073	0.092	0.095	0.096	0.098
Bal.	0	-0.073	-0.092	-0.095	-0.096	-0.098

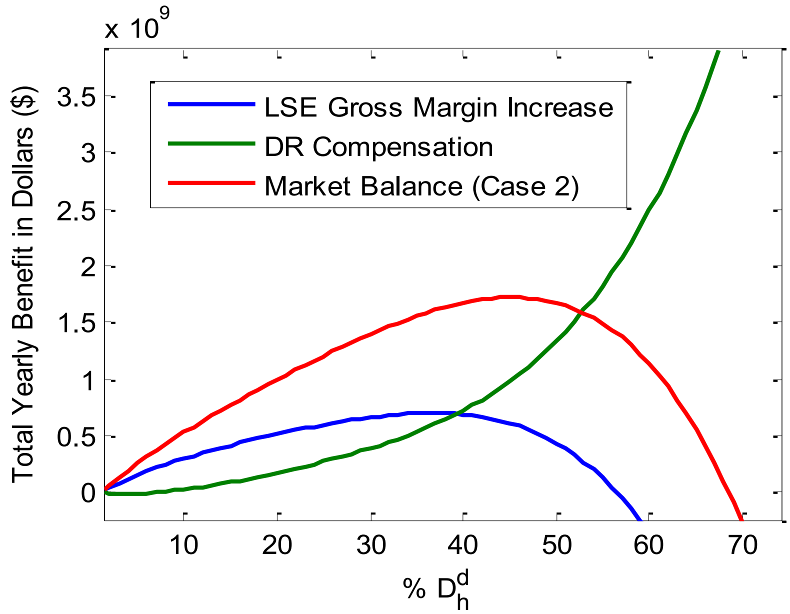

Figure 3-9. Comparison of market participants' yearly total benefits with increasing DR

Figure 3-9 compares the total yearly gross margin increase for LSEs after DR payments, the compensation for DR participants, and the market balance. Clearly, "optimal" is defined differently for different participants. The optimal DR from the market's point of view is when the balance is zero, or in this case, 70% of D_h^d. DR participants have an unbounded benefit that increases with increasing load reductions. The LSE experiences an increase in gross margin for DR participation up to 58% of D_h^d, but is "optimal" at about 40% of D_h^d. Since it is the LSE that chooses to purchase DR, we conclude that the LSE will only bid up to this amount of DR.

3.4 Conclusion

We presented a pricing mechanism in which the demand side participates in wholesale electricity markets as demand resources, and not as a competitor to generation. The prices for demand response are based on the value that it brings to the market. We find that when demand responds in such a way as to maximize gross margin and reduce LMP, the market balance is negative. However, when demand is not allowed to set LMP, it has the potential to not only cause a positive market balance, but also a perfectly balanced market. The maximum amount of economic DR can be easily identified. It is important to note that developing a supply curve for DR is only half of the story. If our goal is to increase total benefit, it would appear that the next step is to determine how to allocate the positive balance if DR is less than the optimal value from the market's point of view. Furthermore, if DR is allowed to set LMP (Case 2 or FERC 745 method), the market balance is inevitably negative and cost allocation is necessary.

Current cost allocation methods are quite broad and based on each energy buyer's share of the total load. In an uncongested network, this results in a "fair" allocation of costs, i.e. an allocation proportional to the benefits that each party accrues. However, in a congested network, this is no longer the case, as price separation occurs between nodes. We therefore propose a cost allocation method based on LMP sensitivity that accounts for the effect of congestion on the distribution of benefits between nodes with different LMPs. Since this sensitivity-based method only takes into account the cost allocation per node, we also propose a means of allocating costs between individual load serving entities (LSEs) at a single node. Due to this refinement, LSEs are rewarded according to their individual contribution to demand response. Finally, we define a fairness index to evaluate the performance of the proposed method as compared to a load-based allocation.

3.5 Current Cost Allocation Methods

3.5.1 PJM & ISO-NE Method (load-based), $\boldsymbol{F_i^L}$

In the PJM energy market, demand response costs are allocated to all market participants with real-time exports from PJM and to load serving entities (LSEs) within zones where the LMP is greater than the net benefits threshold price. The cost allocation factor, F_i^L, of the i^{th} LSE (or market participant with real-time exports) is based on its share of the total load:

$$F_i^L = \frac{L_i}{\sum_i L_i} \tag{3.11}$$

where L_i, is the i^{th} LSE's load.

ISO-NE has an almost identical load-based allocation scheme except that certain loads are excluded from the load share. All costs are allocated proportionally to real time energy buyers' share of the real-time load obligation (RTLO) minus any real time load associated with dispatchable asset related demand (DARD) pumps (Parent, 2013). Thus, L_i for ISO-NE is the RTLO minus RTLO associated with DARD pumps.

3.5.2 MISO (reserve zone and load-based), $\boldsymbol{F_i^{L,Z}}$

MISO stakeholders were in favor of including a congestion component in the cost allocation process (MISO Demand Response Working Group, 2013). This was achieved by considering the location of the load reduction as well as price separation in the operating reserve market clearing prices (MCP). The MISO footprint is divided into six reserve zones. These zones were created in part to identify minimum required operating reserves to meet zonal reliability requirements. When transmission constraints are present within a given zone, out-of-merit reserves must be procured within this zone and price separation in zonal MCPs will occur. Thus, the absence of higher MCPs in a zone with dispatched demand response resources indicates that constraints in that zone are not binding. In this case, costs are allocated to real time buyers in the zone where the dispatched demand response resource is located as well as all other zones, on a pro rata basis (3.12). L_i^z is the i_{th} load located in zone z.

$$F_i^{L,Z} = \frac{L_i^z}{\sum_z \sum_i L_i^z} \quad , \quad z = 1,2 \dots ,6 \tag{3.12}$$

If the zone with dispatched demand response resources does have higher MCPs, then constraints in that zone are binding and the cost of demand response resources in that zone is only allocated to real time energy buyers in that particular zone (3.13).

$$F_i^{L,Z} = \frac{L_i^z}{\sum_i L_i^z} \quad , \quad z \in [1,2, \dots ,6] \tag{3.13}$$

It is important to note, that this cost allocation is only implemented when the energy price (LMP) is at or above a threshold price. If the LMP is less than the threshold, then the load is reconstituted and allocated to the host LSE (MISO Demand Response Working Group, 2013).

3.6 Proposed LMP Sensitivity-Based Cost Allocation

When binding constraints are present, an individual market participant's share of the overall market benefits is no longer simply a function of its share of the load. We therefore propose the use of LMP sensitivities to weigh the load share and thus reflect the impact of congestion on benefit distribution. Figure 3-10 illustrates this method. First, the total amount to be allocated is determined. Next, a portion of this cost is allocated to each node based on LMP sensitivity. Finally, a second allocation is performed at each node to determine the costs allocated to individual LSEs at each node. This second allocation is based, in part, on the contribution of each LSE to demand response. This indirectly allows LSEs that encourage demand response to be rewarded for their efforts and also provides an additional incentive to offset lost income due to load reductions.

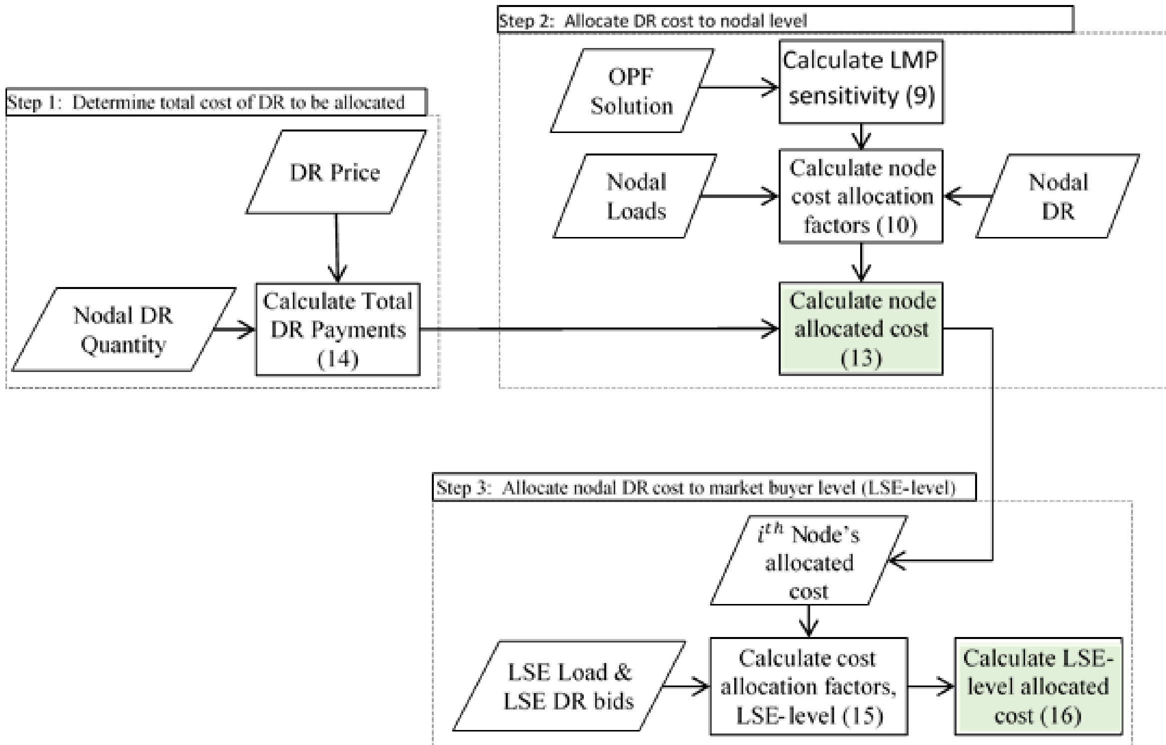

Figure 3-10. Proposed cost allocation flowchart

3.6.1 LMP Sensitivity

LMPs are determined using an optimal power flow (OPF) and reflect the price of energy at each node considering all binding transmission constraints. Conejo et al. derive a generalized expression of LMP sensitivity, and in particular, the sensitivity of LMP with respect to demand and other parameters (Conejo, et al., 2005). This formulation involves differentiating the OPF objective function as well as the Karush-Kuhn-Tucker optimality conditions with respect to the optimization decision variables and the system parameters. A description of the OPF problem is given in Appendix 1. Equations (3.14)-(3.17) summarize in matrix form the linear equations used to derive these sensitivities. Equations (3.15)-(3.16), make use of standard derivative notation (i.e. $\boldsymbol{F_x} = d\boldsymbol{F}/d\boldsymbol{x}$ and $\boldsymbol{F_{xa}} = d\boldsymbol{F_x}/d\boldsymbol{a}$). $\boldsymbol{U}$ is a matrix containing first and second derivatives of the OPF objective function, $\boldsymbol{F}$, equality constraints $\boldsymbol{H}$, and inequality constraints $\boldsymbol{G}$, with respect to the decision variables $\boldsymbol{x}$. $\boldsymbol{S}$, is a matrix containing derivatives of $\boldsymbol{F}$, $\boldsymbol{G}$ and $\boldsymbol{H}$ with respect to the OPF parameters $\boldsymbol{a}$.

$$\boldsymbol{U}[d\boldsymbol{x} \;\; d\boldsymbol{\lambda} \;\; d\boldsymbol{\mu} \;\; dz]^T = \boldsymbol{S}d\boldsymbol{a} \tag{3.14}$$

$$\boldsymbol{U} = \begin{bmatrix} \boldsymbol{F_x} & \boldsymbol{0} & \boldsymbol{0} & -1 \\ \boldsymbol{F_{xx}} & \boldsymbol{H_x^T} & \boldsymbol{G_x^T} & 0 \\ \boldsymbol{H_x} & \boldsymbol{0} & \boldsymbol{0} & 0 \\ \boldsymbol{G_x} & \boldsymbol{0} & \boldsymbol{0} & 0 \end{bmatrix} \tag{3.15}$$

$$\boldsymbol{S}^T = -[\boldsymbol{F_a} \;\; \boldsymbol{F_{xa}} \;\; \boldsymbol{H_a} \;\; \boldsymbol{G_a}] \tag{3.16}$$

Specific sensitivities are given by (3.17):

$$\begin{bmatrix} \frac{\partial \boldsymbol{x}}{\partial \boldsymbol{a}} & \frac{\partial \boldsymbol{\lambda}}{\partial \boldsymbol{a}} & \frac{\partial \boldsymbol{\mu}}{\partial \boldsymbol{a}} & \frac{\partial z}{\partial \boldsymbol{a}} \end{bmatrix} = \boldsymbol{U}^{-1}\boldsymbol{S} \tag{3.17}$$

As Eq. (3.17) shows, this formulation can be used to calculate the sensitivity of the decision variables, dual variables, and the objective function with respect to the parameters, including demand. (Conejo, et al., 2005) provides the details of the above sensitivity derivation.

Equation (3.18) is the subset of the columns of (3.17) which contains the sensitivity of the LMPs, or $\boldsymbol{\lambda}$, with respect to the parameters $\boldsymbol{P}$, $\boldsymbol{Q}$, and $\boldsymbol{c}$, where $\boldsymbol{P}$ is the real power demand, $\boldsymbol{Q}$ is the reactive power demand, and $\boldsymbol{c}$ represents all the other parameters, including line parameters, voltage limits, generator capacities and generator cost coefficients.

$$\frac{\partial \boldsymbol{\lambda}}{\partial \boldsymbol{a}} = \begin{bmatrix} \frac{\partial \boldsymbol{\lambda}}{\partial \boldsymbol{P}} & \frac{\partial \boldsymbol{\lambda}}{\partial \boldsymbol{Q}} & \frac{\partial \boldsymbol{\lambda}}{\partial \boldsymbol{c}} \end{bmatrix}^T \tag{3.18}$$

For simplicity, the proposed cost allocation methodology can be performed using a DCOPF and only the sensitivity with respect to the real power, $\boldsymbol{P}$, need be considered. Equation (3.19) is the subset of the rows of (3.18) which contains the sensitivity of the LMPs at all nodes to real power changes, at any node. $\boldsymbol{W}$, is a symmetric $N \times N$ matrix, where N is the number of nodes at which an LMP is calculated. Thus each element of $\boldsymbol{W}$, or $W_{i,j}$ is the sensitivity of the LMP at node i with respect to load changes at node j, where $i = 1 \dots N$ and $j = 1 \dots N$.

$$\boldsymbol{W} = \frac{\partial \boldsymbol{\lambda}}{\partial \boldsymbol{P}} \tag{3.19}$$

3.6.2 Nodal-Level, Sensitivity-Based Allocation Factor, $\boldsymbol{F_i^S}$

Equation (3.20) defines a cost allocation method based on LMP sensitivity calculated using Equation (3.19).

$$F_i^S = \frac{\sum_j \frac{\partial \lambda_i}{\partial P_j} * D_j * L_i}{\sum_i \sum_j \frac{\partial \lambda_i}{\partial P_j} * D_j * L_i} = \frac{\sum_j W_{i,j} * D_j * L_i}{\sum_i \sum_j W_{i,j} * D_j * L_i}\,, \tag{3.20}$$

F_i^S is the cost allocation factor of the market participants at the i^{th} node, and D_j is the demand reduction at node j. The allocation factor of the i^{th} node thus depends not only on the load share but also on the location of the load reductions. Note that cost allocation is only necessary when $\sum_j D_j > 0$.

3.6.3 Fairness Index, K

In order to compare allocation methods, we define the fairness index as the variance in the benefit to cost ratios of market participants located at each node. If all market participants are allocated costs in exact proportion to their benefits, then K=0. Larger values of K indicate that some market participants have been allocated more or less than their "fair share" of costs. Equations (3.21)-(3.24) show how this index is calculated.

$$K = \frac{1}{N}\sum_{i}^{N}\left(\frac{B_i}{C_i} - \frac{1}{N}\sum_{i}\frac{B_i}{C_i}\right)^2 \tag{3.21}$$

$$B_i = \Delta\lambda_i * L_i = \left(\lambda_{i,wo_{dr}} - \lambda_{i,w_{dr}}\right) * L_i \tag{3.22}$$

$$C_i = F_i * T \tag{3.23}$$

$$T = \sum_{i} \lambda_{dr} * D_i \tag{3.24}$$

In Equations (3.21) to (3.23), F_i, B_i and $C_i$are the i^{th} node's cost allocation factor, benefit and allocated cost (nodal level), respectively. T is the total cost of demand response, or the sum of all the individual payments to dispatched demand response (3.24) where λ_{dr} is the price for DR. And finally, $\lambda_{wo_{dr}}$ and $\lambda_{w_{dr}}$ are the LMPs without and with load reduction D_i. In order to calculate this index, two OPF solutions must be carried out to determine the actual benefit (change in price multiplied by the load) and analyze the fairness of the proposed method. However, an important feature of the proposed cost allocation method is that it allocates costs proportionally to benefits without the need for running multiple OPFs ex-post.

3.6.4 LSE-Level, Contribution-Based Allocation Factor, $F_{i,m}^{C}$

Once the total cost of DR has been allocated between the nodes, it must then be divided among the buyers (LSEs) at each node. We propose that these LSE-level allocation factors $F_{i,m}^{C}$ be determined based on each LSE's load share, and each LSE's contribution to DR, as defined by Equation (3.25).

$$F_{i,m}^{C} = \frac{\alpha_{i,m} * (\alpha_{i,m} + 1 - \beta_{i,m})}{\sum_m [\alpha_{i,m} * (\alpha_{i,m} + 1 - \beta_{i,m})]} \tag{3.25}$$

$$\alpha_{i,m} = \frac{L_{i,m}}{\sum_{n=1}^{M} L_{i,n}}$$

$$\beta_{i,m} = \frac{D_{i,m}}{\sum_{n=1}^{M} D_{i,n}}$$

Here, $L_{i,m}$ is the load of the m^{th} LSE at the i^{th} node. $D_{i,m}$ is the load reduction achieved by the m^{th} LSE at the i^{th} node, and $m = 1 \dots M$, where M is the number of LSEs at node i. Thus, $\alpha_{i,m}$ is the load share of the m^{th} LSE at the i^{th} node and $\beta_{i,m}$ is the demand response share of the m^{th} LSE at the i^{th} node. In Equation (3.25), the first $\alpha_{i,m}$ term in the numerator reflects an individual LSE's load share, while the second $\alpha_{i,m}$ term ensures a minimum cost allocation regardless of DR contribution. The term $(1 - \beta_{i,m})$ reflects the LSE's individual contribution to DR (or the lack thereof). Finally, the cost $C_{i,m}$ allocated to the m^{th} LSE at the i^{th} node is defined as:

$$C_{i,m} = F_{i,m}^{C} * C_i \tag{3.26}$$

3.7 Case Study

The load-based and proposed sensitivity-based cost allocation methods were first tested on a modified version of the 6-bus test system found in (Wood & Wollenberg, 1996) and illustrated in Figure 3-11. The parameters of this system are listed in Appendix 2. There are three load buses. We assume that there is a single LSE at Bus 4, two LSEs at Bus 5, and three LSEs at Bus 6. We analyzed the cost allocation methods for two test cases.

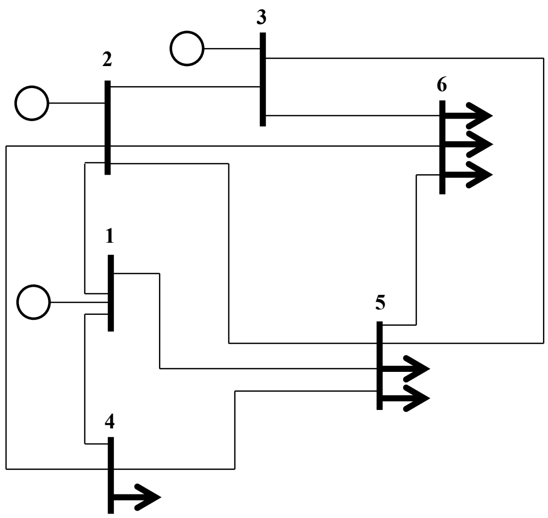

Figure 3-11. Six-Bus Test System

For Case 1, we assume a 1% load reduction at each of the load buses in order to simply observe how the proposed cost allocation method performs. For Case 2, we consider a variety of load reduction scenarios (load reduction amount and location are randomly selected) in order to examine and compare statistical properties of the fairness index, K, for both the proposed sensitivity-based cost allocation method as well as the load-based method.

3.8 Results: Case 1

Table 3-2 gives the solution of the OPF and Table 3-3 provides the values of the dual variables. Only the binding constraints are considered in the sensitivity matrix calculation.

Table 3-2. OPF Solution (Decision Variables)

Bus	P_g(MW)	Q_g *(MVAR)*
1	132	37
2	161	93
3	60	83

Table 3-3. OPF Solution (dual variables, λ and μ):

Constraint	Bus	Upper Limit ($/MWh)	Lower Limit ($/MWh)
Real Power Balance Constraint	Bus 1	8.98	0
	Bus 2	9.16	0
	Bus 3	9.43	0
	Bus 4	9.73	0
	Bus 5	9.87	0
	Bus 6	9.71	0
Reactive Power Bal. Const.	Bus 4	0.48	0
	Bus 5	0.49	0
	Bus 6	0.24	0
Line Const. (from)	Bus 2(from) Bus 4(to)	0.09	0
Line Const. (to)	Bus 3(from) Bus 5(to)	0.07	0
Voltage Const.	Bus 1	3.0773	0
Real Power	Bus 1	0.3448	0
Generator Const.	Bus 3	0	0.1296

3.8.1 Determine total cost of DR

Given the OPF solution, the total payment made to DR resources is the sum of each node's demand response multiplied by its price. Here, we assume DR is paid full LMP ($\lambda_{dr} = \lambda_{i,w_{dr}}$), though this is not necessary and the price can be higher or lower. These payments, listed in Table 3-4, represent the total cost of DR that must be allocated.

Table 3-4. Demand Response Cost

Bus	λ_i *($/MWh)*	D_i *(MWh)*	*Cost ($)*
4	9.73	1.2	11.68
5	9.87	1.15	11.35
6	9.71	1.04	10.10
Total			**33.13**

3.8.2 Allocate the DR cost to each node

Given the OPF solution, we can calculate the sensitivity matrix, $\boldsymbol{W}$. The diagonal elements represent the sensitivity of the LMP at bus i to load changes at bus i, while the off-diagonal entries represent the sensitivity of the LMP at bus i with respect to load changes at any bus j. For this test case, LMPs tend to be more sensitive to load changes at Bus 4.

$$\boldsymbol{W} = \frac{\partial \boldsymbol{\lambda_i}}{\partial \boldsymbol{P_j}} = \begin{bmatrix} 2.16 & 0.10 & 0.49 & 3.85 & 1.61 & 0.64 \\ 0.10 & 0.10 & 0.10 & 0.11 & 0.11 & 0.11 \\ 0.49 & 0.10 & 0.84 & 1.02 & 0.41 & 0.64 \\ 3.85 & 0.11 & 1.02 & 9.01 & 3.27 & 1.33 \\ 1.61 & 0.11 & 0.41 & 3.27 & 2.12 & 0.70 \\ 0.64 & 0.11 & 0.64 & 1.33 & 0.70 & 0.85 \end{bmatrix}$$

Based on this sensitivity matrix and using Equation (3.20), we then calculate how much of the cost of load reductions should be allocated to each individual bus using Equation (3.23). Note that costs are only allocated to load buses (Bus 4, Bus 5, and Bus 6).

Table 3-5 gives the allocation factors and the allocated costs. Results of the load-based method are also presented in Table 3-5 for comparison.

Table 3-5. Comparison of Sensitivity-Based and Load-Based Cost Allocation

Bus	Sensitivity-Based		Load-Based	
	Allocation Factor (%)	Allocated Cost ($)	Allocation Factor (%)	Allocated Cost ($)
4	62.33	20.89	35.40	11.84
5	26.57	8.89	33.92	11.35
6	11.10	3.71	30.68	10.26

Since the load is almost evenly distributed between each of the three load buses, the load-based method allocates cost almost equally. In contrast, the sensitivity-based method accounts for the fact that Bus 4 has a greater impact on LMPs, experiences the largest LMP reduction and is therefore, allocated costs proportionally to that sensitivity.

3.8.3 Allocate nodal DR cost to market buyer level (LSE-level)

Once the total DR cost has been allocated to each of the load busses, we then divide the cost allocated to each node among the market buyers at this node. This LSE-level cost allocation depends upon the load share of each LSE, as well as each LSE's share of the DR provided. These values are given in Table 3-6.

Table 3-6. LSE-Level Cost Allocation Factors and Cost Allocation Determinants

Bus Number	*LSE Number*	*Load Share ×100 (%)*	*DR Share ×100 (%)*	$F^{C}_{i,m}$ *×100 (%)*
4	1	1.0	1.0	1.0
5	1	0.51	0.29	0.61
	2	0.49	0.71	0.39
6	1	0.41	0.16	0.46
	2	0.13	0.54	0.07
	3	0.46	0.30	0.47

Since there is only one LSE at Bus 4, it accounts for 100% of the load and 100% of the load reductions. Thus, this LSE is allocated 100% of the DR cost assigned to Bus 1.

Bus 5 has two LSEs that have a roughly equal share of the load. However, LSE 2 provides a significantly larger proportion (71%) of the DR. Therefore, LSE 2 is allocated a smaller fraction of the cost. This provides an incentive to LSE 1 to encourage its customers to participate in demand response programs, and rewards LSE 2 for its above average contribution.

Bus 6 has three LSEs, two fairly large, and one fairly small. However, the smaller one (LSE 2) provides over half of the demand response. This LSE therefore is allocated a cost that reflects its size, and contribution. Although LSE 3 provides twice as much DR as LSE 1, they both have similar cost allocation factors. This is in part due to LSE 3 being slightly larger and the fact that both are penalized for providing less than their "fair share" of DR. Table 3-7 summarizes the complete cost allocation process.

Table 3-7. Summary of Complete Cost Allocation Process

Step 1	Step 2:		Step 3	
Total Cost ($)	Allocated Cost (nodal-level)		Allocated Cost (LSE-level)	
33.13	Bus	C_i ($)	LSE #	$C_{i,m}$ ($)
	4	20.86	1	20.86
	5	8.89	1	5.46
			2	3.43
	6	3.71	1	1.70
			2	0.25
			3	1.76

3.8.4 Fairness Index

In order to assess the fairness of the proposed method, we calculate two OPFs (with and without demand response) to calculate exactly how much each nodal price is reduced and hence how much each node benefits. Table 3-8 shows the change in nodal prices. λ_{i,wo_D} is the LMP before load reduction and λ_{i,w_D} is the LMP after load reductions. Although each of the load buses have similar load reductions, the price reductions, vary significantly. Bus 4 enjoys a larger price reduction than Bus 6. This is why the sensitivity-based allocation method assigns a larger portion of the cost to Bus 4 (62.3%) than Bus 6 (11.1%).

Table 3-8. Summary of Price Reductions Due to Load Reductions

Bus	λ_{i,w_D} (\$/MWh)	λ_{i,wo_D} (\$/MWh)	D_i (MWh)
4	9.73	9.91	1.2
5	9.87	9.94	1.15
6	9.71	9.75	1.04

Table 3-9. Comparison of Fairness Index, K

	Sensitivity-Based			Load-Based		
Bus	Benefit ($)	Allocated Cost ($)	Ben/Cost Ratio	Benefit ($)	Allocated Cost ($)	Ben/Cost Ratio
4	21.28	20.86	1.02	21.28	11.84	1.80
5	8.94	8.89	1.01	8.94	11.35	0.79
6	3.68	3.71	0.99	3.68	10.26	0.36
Fairness Index, K		2.1×10^{-4}			0.5449	

Once the actual change in LMP is determined, we then calculate the benefit of each node using Eq. (3.22) and the benefit to cost ratio. Using these benefit to cost ratios, we can then determine the fairness of the cost allocation method using Eq. (3.21).

Table 3-9 gives these values for both the sensitivity-based and load-based allocation methods.

These results show that the sensitivity-based cost allocation method achieves almost identical cost benefit ratios for all three nodes. This is because the sensitivity matrix appropriately accounts for the fact that Bus 4 has a greater impact on LMP and also experiences the largest LMP reduction and is therefore, allocated costs proportionally to that sensitivity.

3.9 Results: Case 2 (Analysis of "Fairness")

Unlike load-based allocation methods, the proposed sensitivity-based method of Equation (3.20) depends on the location and magnitude of the load reductions. Thus, for a more complete analysis of fairness, we calculate the sensitivity-based allocation factors for several load reduction scenarios. In each scenario, the distribution of load reductions is randomly distributed between the three load buses. This process is repeated for increasing levels of load reduction (ranging from 1% to 7%). Figure 3-12 presents a comparison of the average fairness index for sensitivity-based and load-based allocation.

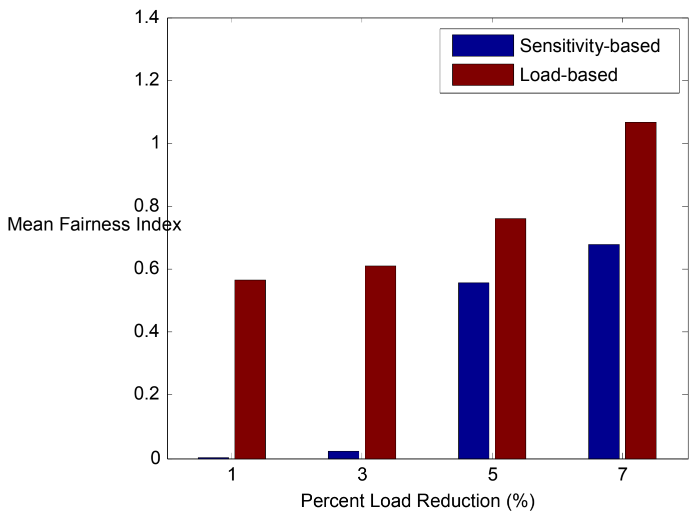

Figure 3-12. Comparison of mean fairness index for the sensitivity based and load based methods. For each level of load reduction (1%, 3%, 5%, and 7%)), the distribution of DR across the three load buses was randomly assigned 1000 times and the figure gives the average value of the fairness index.

For low levels of demand response (1-3% of total load), the sensitivity-based method has a fairness index very close to zero, indicating equal distribution of costs proportional to benefits. However, as DR penetration increases, the fairness index quickly grows larger. This is because binding constraints begin to change with increasing load reductions. This inevitably has an effect on the LMP sensitivities and the linearization underlying the method becomes less accurate. However, even at large load reductions, the sensitivity-based method is fairer than the load-based method.

3.10 Conclusion

Regardless of the price paid to demand response resources, those payments must ultimately be allocated. Because DR resources provide benefits that are enjoyed market-wide through reduced LMPs, it is not surprising that current cost allocation methods are based on each buyer's share of the total load. When there is no congestion in the network, all energy buyers benefit from price reductions proportionally to their share of the total load.

However, when there is congestion, energy buyers' benefits vary by location. Some ISOs have attempted to account for this price/benefit separation during times of congestion, while others have chosen not to consider the effect of congestion explicitly.

In an attempt to improve the fairness of cost allocation and also provide an incentive to LSEs to encourage demand response, we proposed a two-step cost allocation method. First, LMP sensitivities are used to approximate the effect of congestion on LMP reductions and allocate costs down to the nodal level. Next, a method that considers load share ratio as well as DR share ratio is used to allocate the cost of DR down to the LSE-level. Finally, we analyzed the fairness of the proposed method by measuring its ability to allocate costs in proportion to the benefits. We find that for all DR penetrations considered, the sensitivity-based method results in a lower (i.e. better) fairness index value than load-based allocation. This means that the sensitivity-based method is more effective at allocating costs in proportion to benefit.

Chapter 4. Valuing Demand Response in Retail Markets

In this chapter we consider compensation of DR at a local level, considering local distribution benefits. In Part I, we present a modified real time price signal that reflects both wholesale market conditions as well as overloading conditions in the distribution network In Part II, we present an incentive pricing model that also incorporates the local overloading conditions.

PART 1: DYNAMIC PRICING

4.1 Methodology

We propose a modified real time price that varies according to market conditions, local grid conditions as well as a customer chosen parameter reflecting a desired level of price risk. In this pricing scheme, customers are offered a choice of risk in the form of possible price range. From a single customer-selected parameter, a variety of dynamic prices can be formed representing all levels of price security, ranging from a flat rate to real-time pricing. The value of demand response depends upon market and grid conditions; thus, we propose the use of a retail rate based on indices that reflect these conditions. The customer's retail rate is then a function of these two indices as well as the desired level of price risk, B.

4.1.1 Market-based Grid Condition Index, $\boldsymbol{G_m}$

For the market condition index, we implement CAISO's proposed grid state index. This index takes the form of eleven possible values based on current wholesale market conditions, where each index represents a range of LMP prices, π (Price & Sanders, 2013).

Table 4-1 shows the range of market prices that are associated with each level of the CAISO grid state index. The average off-peak price, π^{off_peak}, is determined by calculating the average price during recent (past 30 days) off-peak hours, where off-peak hours are from 7pm to 7am. Similarly, the average "on-peak" price, π^{on_peak} is determined using recent on-peak (from 7am to 7pm) prices.

Table 4-1. CAISO Grid State Index (GSI), G_m

GSI	Lower Limit ($/MWh)	Upper Limit ($/MWh)
0	n/a	≤ -30
1	> -30	≤ 0
2	> 0	$\leq \pi^{off\_peak}$
3	$\geq \pi^{off\_peak}$	$\leq \pi^{on\_peak}$
4	$\geq \pi^{on\_peak}$	$\leq 1.1 * \pi^{on\_peak}$
5	$\geq 1.1 * \pi^{on\_peak}$	$\leq 1.33 * \pi^{on\_peak}$
6	$\geq 1.33 * \pi^{on\_peak}$	$\leq 1.67 * \pi^{on\_peak}$
7	$\geq 1.67 * \pi^{on\_peak}$	$\leq 2 * \pi^{on\_peak}$
8	$\geq 2 * \pi^{on\_peak}$	$\leq 3 * \pi^{on\_peak}$
9	$\geq 3 * \pi^{on\_peak}$	$\leq 10 * \pi^{on\_peak}$
10	$\geq 10 * \pi^{on\_peak}$	n/a

4.1.2 Local Network-based Grid Condition Index, G_n

In order to determine the need for local services, we propose the use of a "grid condition index" defined as the proximity of the network to its operational limits and/or desired operating point. For each potential benefit afforded by the DER, a grid condition index can be calculated. Here, we use a single index to represent the proximity of the system to network capacity. The grid index G_n is then defined as (4.1).

$$G_n^t = a^{\frac{P_{actual}^t}{P_{rated}^t}} \tag{4.1}$$

$$a = e^{\frac{\ln(G_{max})}{r}} \tag{4.2}$$

Where

$$r = \frac{emergency\ capacity\ rating\ (MW)}{normal\ capacity\ rating\ (MW)} \qquad (pu)$$

Here, P_{actual}^{t} is the total power delivered in a given region at time t, P_{rated}^{t} is the maximum deliverable power in this region based on its most limiting component. G_{max} is the maximum grid condition, which in our case has been defined as $G_{max} = 10$. The parameter r is the pu emergency rating, where the base is the normal rated network capacity P_{rated}^{t}. Like G_m, this index is calculated for each time period t, which here, we assume is in hours.

4.1.3 Combined Grid Condition Index, $\boldsymbol{G}$

The market condition index is broadcast publicly and is available to all parties, including end-use customers while the local grid index G_n, is computed locally and only known to the distribution network owner. Therefore, the distribution network owner (DNO) combines these two indices into a single index provided to the customer. If the DNO is not the retailer, then the retailer collects these two indices and combines them into one. Equation 4.3 shows the proposed combination of the two indices.

$$G = G_{max}(1 - r^{-(G_m+G_n)}) \tag{4.3}$$

Alternatively, in the case of the retailer and DNO being separate entities or if the DNO does not provide a local grid state index, the retailer may opt to simply use the market index alone to develop its retail rate. In such a case $G = G_m$. Both cases are compared in the results section.

4.1.4 $\boldsymbol{mRTP}$ Formulation

In Equation 4.4, we define the retail rate, $mRTP$, as a linear function of the grid state index G, where G is a function of the market and local network grid condition indices and B is the customer chosen range in price.

$$mRTP = B * G + R_{min} \tag{4.4}$$

$$B = \frac{R_{max} - R_{min}}{G_{max}} \tag{4.5}$$

The value R_{min} is the minimum price that a customer can pay (when $G = 0$) and must be determined by the energy service provider to ensure that revenue requirements are collected regardless of what value of risk the customers select. In other words, once the utility has determined the revenue required for a given rate planning period, the values of $R_{min}$for any given risk level, B, is determined as Equation 4.6. Since total revenue collected will be a function of customers' choice of risk level B, the utility will need to estimate the number of customers at each risk level. However, this information is often determined through pilot programs.

$$\min_{R_{min}} \left| \sum_{t=1}^{8760} (B * G^t + R_{min}) * Load^t - RR \right| \tag{4.6}$$

In (4.6), we assume a rate planning period of 1 year (8760 hours). The revenue requirements RR, for the entire year, consist of a debt service from large capital expenses, and operational costs (4.7). In order to ensure that financial obligations are met and new capital projects are funded, the debt service charge collected is increased by a factor β, also known as the debt service coverage (DSC) ratio. This number can vary typically from 1.5 to 2 and has an effect on the amount of cash available for capital investments as well as future interest rates on loans.

$$RR = Operating\ Expenses + (Debt\ Service) * \beta \tag{4.7}$$

4.2 Case Study

The typical period for rate planning is 1-3 years. Therefore, the proposed rate structure was calculated based on PJM's price and load data for the year of 2012 (PJM, 2012). Market based grid conditions were based on this PJM data.

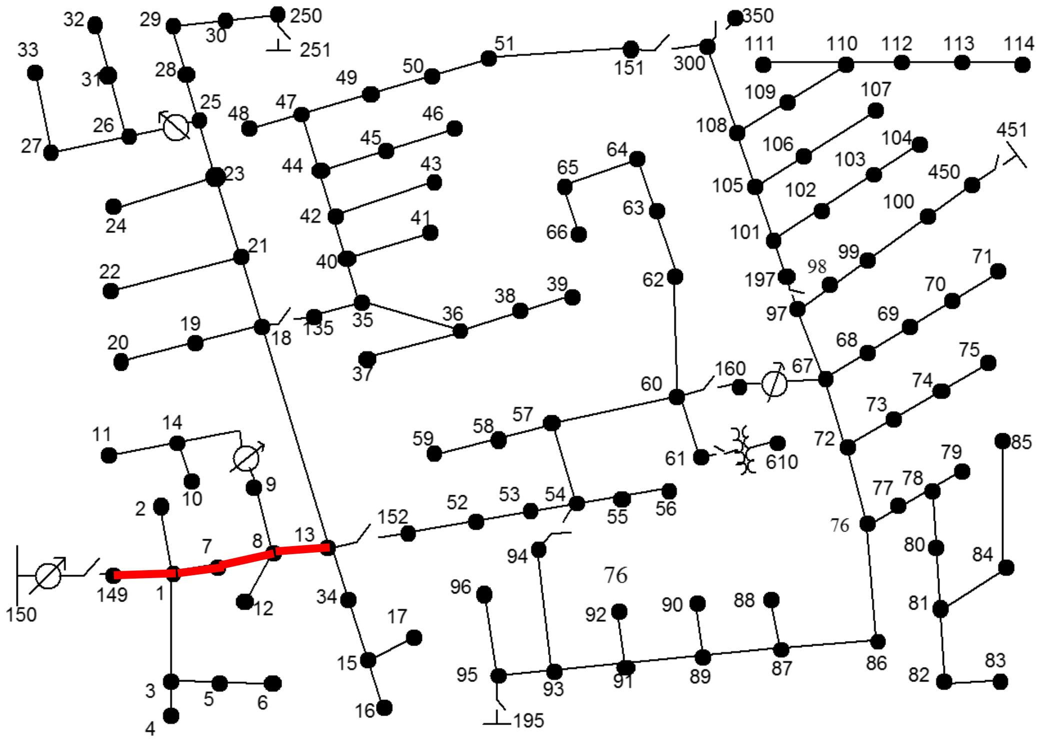

Figure 4-1. IEEE 123-Bus Test Feeder. Feeder sections highlighted in red are near capacity and benefit from load reductions during local peak usage.

For the local grid condition index, we used the IEEE 123 bus test feeder (Figure 4-1) and we assume that this single feeder represents one load serving entity that owns the distribution wires, meters and charges the customers, and also owns a small amount of generation sold in the wholesale market. For simplicity, we assume that all customers are on a single rate (residential rate). However, it is also possible to use the proposed method for a subset of the customers. All components in this feeder have emergency ratings 20% above their normal rating ($r = 1.2$).

Table 4-2 details assumed expenses and revenues based on Seattle City Light (Seattle City Light Financial Planning Unit, 2011). Additionally, we assume a tax rate of 5% and a DSC ratio of 1.8. Based on these assumptions, as well as the energy forecast for the year, the revenue requirements and average flat retail rate are calculated and shown in Table 4-2.

Table 4-2. Revenue Assumptions. (Dollars are in millions.)

Expenses		
Operational Expenses		
	Energy	$ 330.00
	Distribution	$ 70.00
	Customer Accounting	$ 30.00
	Administration	$ 63.00
	Rate Discounts	$ 7.00
Debt Service		
	Debt Service (DS)	$ 175.00
Capital Projects		
	Total Capital Expense	$ 237.00
Revenue		
Wholesale		
	Wholesale Sales	$ 100.00
Retail		
	Retail Revenue Requirements	$ 752.60
Rate:		
Total Load (MWH)		9,200,000
Average rate ($/MWH)		81.8

In order to observe the independent effect of the local grid condition on price, the load is somewhat uncorrelated to the market price (there is daily correlation, but not seasonal correlation), thus, G_m is somewhat uncorrelated to G_n. Figure 4-2 compares hourly load and market price over the entire year.

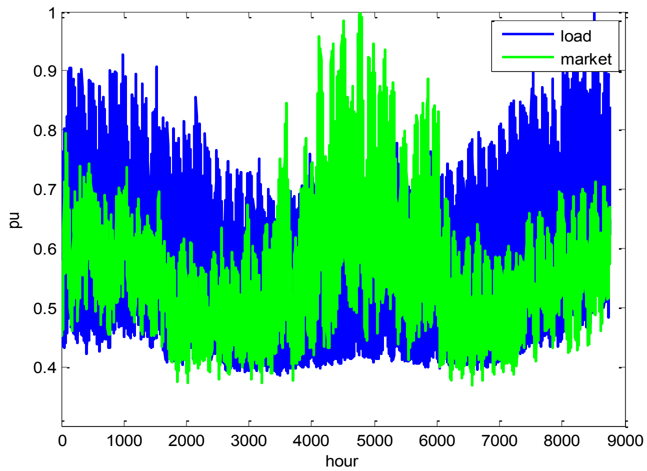

Figure 4-2. Comparison of normalized hourly load and market price over the entire test year.

Figure 4-3 is a close up view of Figure 4-2. In comparison, we can see that while the long term patterns are not very well correlated, the daily peak is at least partially correlated. Thus, we expect that on some days, the local grid conditions due to local load patterns will exacerbate the grid state due to market conditions, and on other days it will mitigate extreme grid state index values.

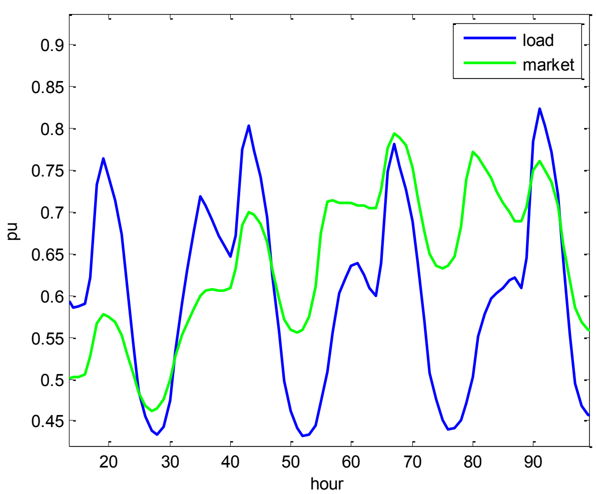

Figure 4-3. Comparison of normalized hourly load and market prices. (First 4 days of the test year)

The proposed rate design was tested on two cases: 1) using a market based only grid index and 2) using a market and local network based grid index.

- Case 1: Market-based only, $G = G_m$
- Case 2: Market/local network-based: $G = f(G_m, G_n)$

4.3 Results

4.3.1 Grid Condition Indices

The average on-peak wholesale energy price is $40.8/MWh and the average off-peak is $24.9/MWh. Based on these values, the market condition index G_m, for each hour of the test year is shown in Figure 4-4.

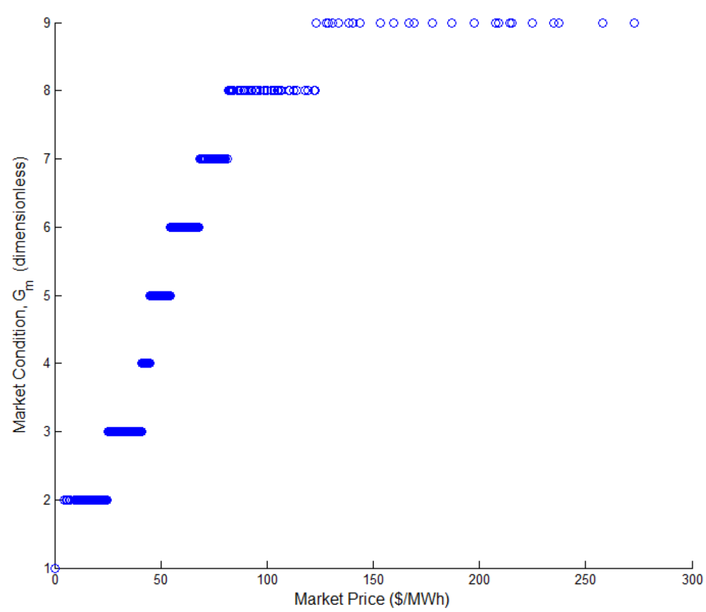

Figure 4-4. Market-Based Grid Condition Index vs. Wholesale Market Prices.

Figure 4-5 shows the network condition index for each hour of the year. From the figure, it is clear that there are only a few hours in the year when the local network is loaded past 100% the normal rating.

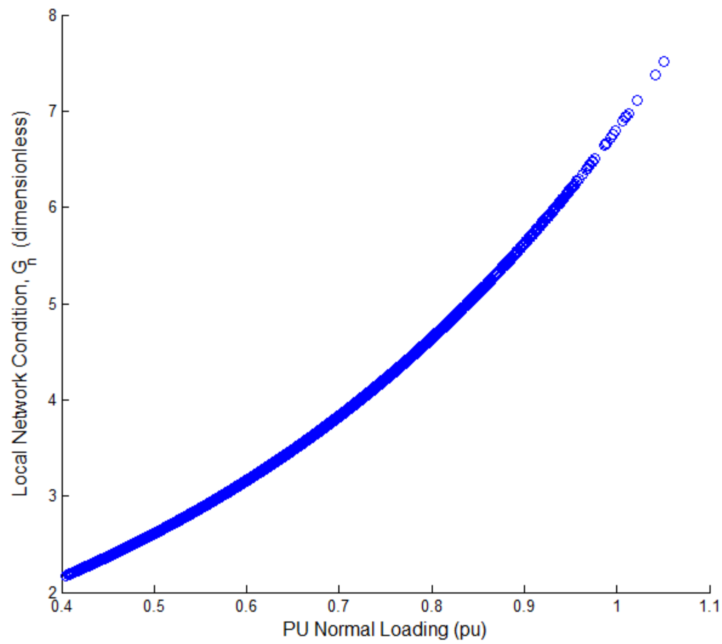

Figure 4-5. Network-Based Grid Condition Index vs. System Loading Level (as a percentage of max normal loading)

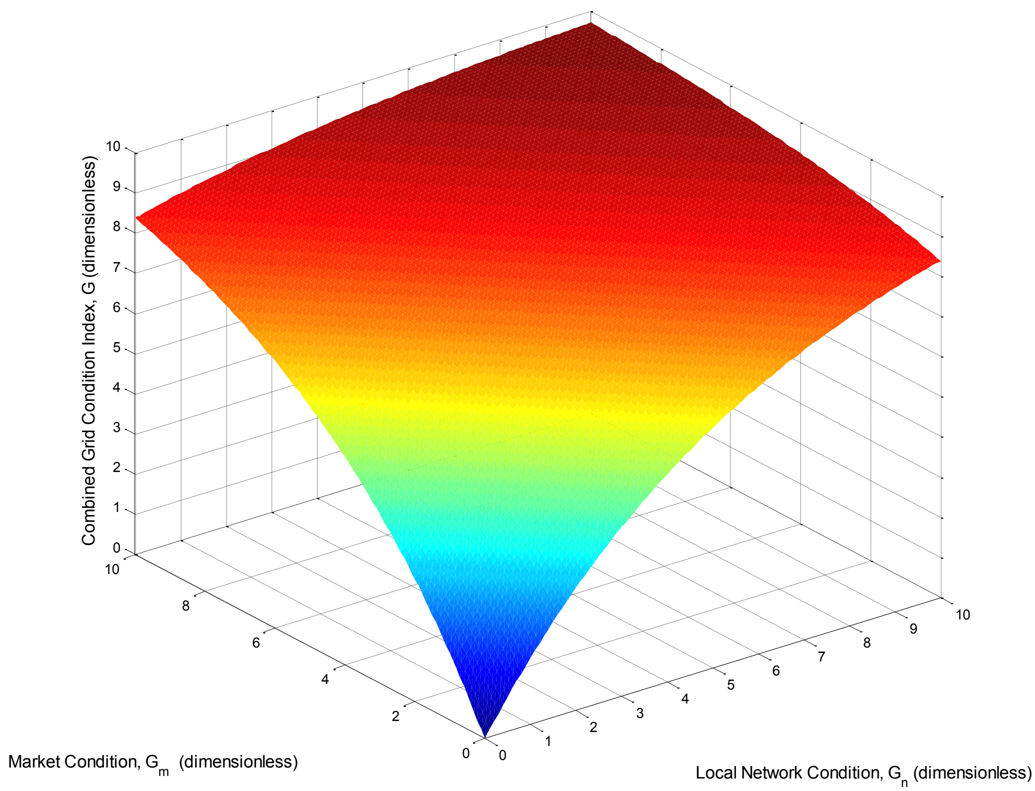

Figure 4-6. Combined Grid Condition Index vs. Market and Network Based Grid Condition Indices

Figure 4-6 shows the combined grid condition index as a function of the network and market indices. Since G_m and G_n both vary from 0 to 10 and G is a function of the sum of these two, the surface plot is symmetric.

4.3.2 Case 1: $\boldsymbol{G = G_m}$ (market grid condition only pricing)

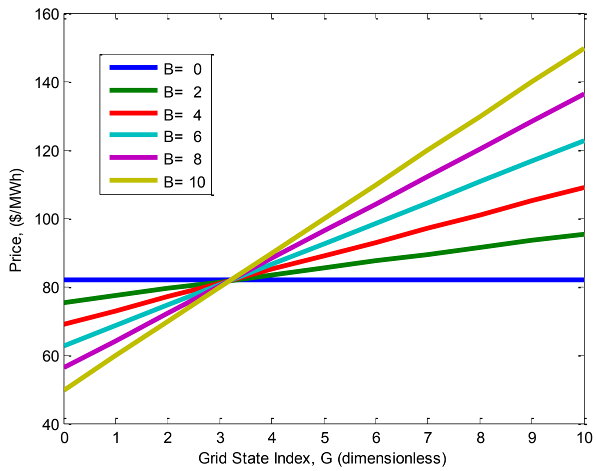

Figure 4-7: mRTP at various levels of price risk B.

Figure 4-7 shows the proposed retail rate for various selected values of B. Note that when $B = 0$, the customer opts to have zero price risk, and the retail rate is therefore flat and completely independent of the grid state index, $G = G_m$. Figure 4-8 shows the frequency of each grid state index value throughout the test year. From Figure 4-8, we see that for roughly 90% of the billing hours, the grid state index G_m, has a value of 3 or less. Thus, by increasing B, the customers risk prices spiking in up to 10% of billing hours and must choose a risk level based on their ability to react in time and with a proper magnitude of load reductions.

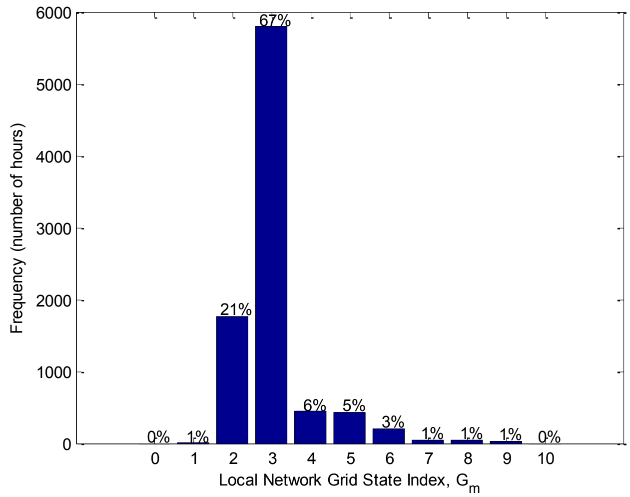

Figure 4-8. Distribution of grid state index, $\boldsymbol{G_m}$, throughout the year.

Figure 4-9 and Figure 4-10 compare existing time varying dynamic rates and the proposed grid state varying rate on two sample days. Figure 4-9 is a weekend day with low market prices and Figure 4-10 is a high market price day. In these figures, mRTP1 and mRTP10 are the $mRTP$ rates with $B = 1$ and $B = 10$, respectively. Here we see that the lower the customer-selected price risk, the more the price resembles a flat rate. Higher levels of price risk more closely resemble RTP, but with significantly less exposure to unexpected and extreme high prices.

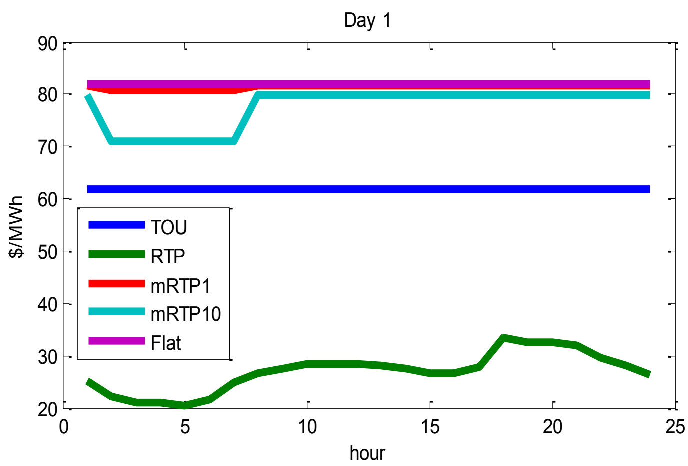

Figure 4-9. Comparison of proposed mRTP, RTP, TOU and flat rates. (Day 1 is a Saturday and the TOU rate used is flat during weekends.)

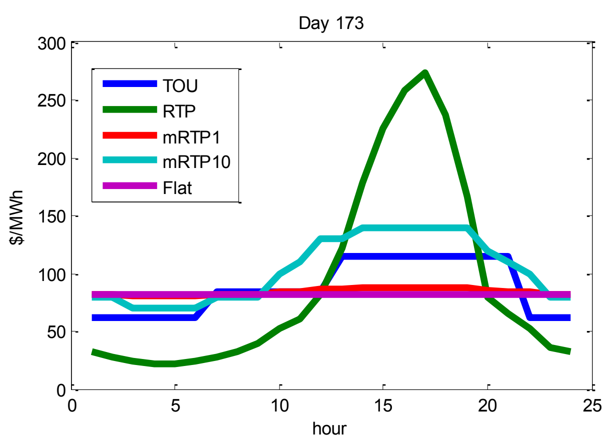

Figure 4-10. Comparison of proposed rate, RTP, TOU and flat rates. (Summer weekday)

A distinguishing feature of the mRTP is that while the range of possible prices is fixed, the day-to-day price structure depends upon the state of the grid, providing an appropriate economic signal for demand response resources.

4.3.3 Case 2: $\boldsymbol{G = f(G_m, G_n)}$

Figure 4-11 shows the proposed retail rate for various selected values of B, when the local network condition is used to modify the market based grid state index. In comparison to

Figure 4-7, we observe that the distribution of grid state values, G, changes and the mRTP equals the average (flat rate) at G=7.

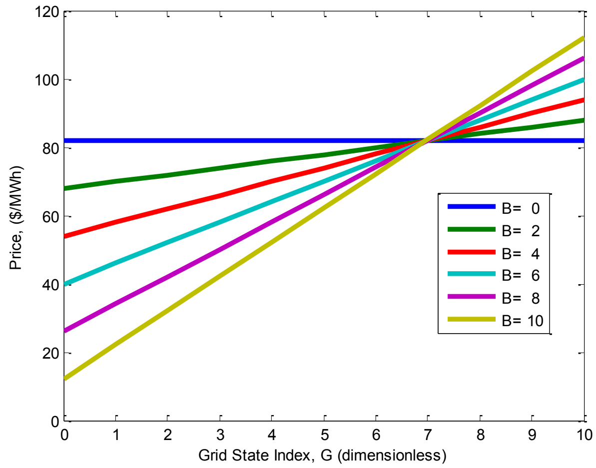

Figure 4-11. mRTP at various levels of price risk $\boldsymbol{B}$.

Figure 4-12 shows the frequency of values of G throughout the test year. In this case, just over 80% of the hours have a grid state index 7 or less. Since the flat rate price occurs at G=7, then customers who choose an mRTP would need to be able to modify their consumption during up to 20% of the time.

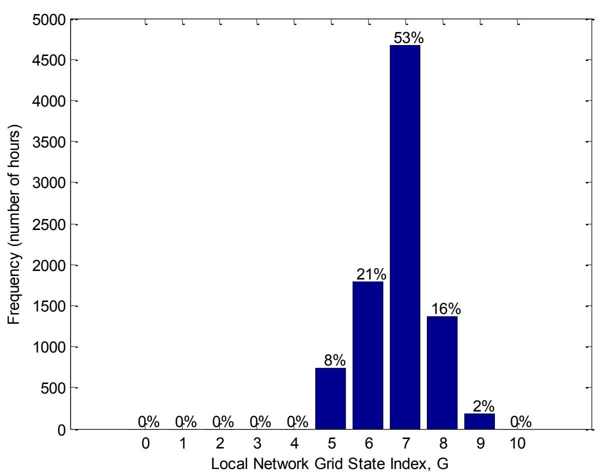

Figure 4-12. Distribution of grid state index, $\boldsymbol{G}$*, throughout the year*

Although the network based grid state index, G_n was not independently used (without G_m) to calculate the mRTP, Figure 4-13 shows the distribution of G_n for reference and to compare to the distribution in of G_m in Figure 4-8 and G in Figure 4-12.

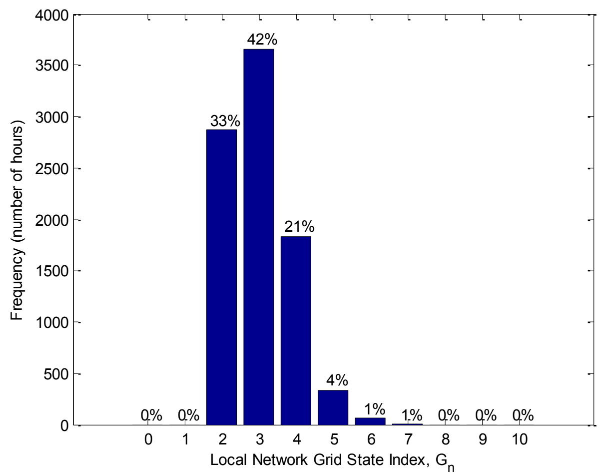

Figure 4-13. Distribution of grid state index $\boldsymbol{G_n}$, throughout the year

Figure 4-14 and Figure 4-15 compare the mRTP to TOU, RTP and flat rates on the same two sample days as in Figure 4-9 and Figure 4-10. One of the more obvious differences between the mRTP based on G_m and that based on G is that G_m values are discrete. Thus, the mRTP has a blocky shape in Figure 4-8 and Figure 4-9, while the continuity of G allows for a smoother mRTP.

We can also observe how local conditions have an effect on prices. From Figure 4-3, we see that during the first 24 hours (Day 1), the market prices are at a relative low, while local load is moderately high. Thus, in Figure 4-8 (Day 1), the G_m-based mRTP is low (even lower than the average flat rate) throughout the entire day. However, in Figure 4-14, when the local grid conditions are included, the mRTP rises above the flat rate, reflecting the additional stress on the local grid.

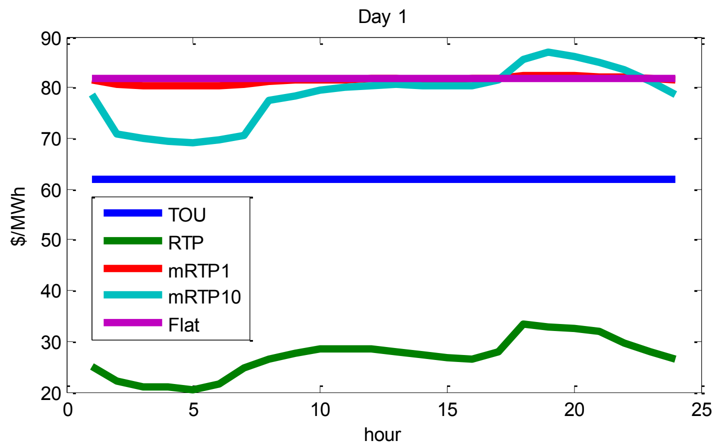

Figure 4-14. Comparison of proposed rate, RTP, TOU and flat rates. (Day 1 is a Saturday and the TOU rate used is flat during weekends.)

Another feature of the mRTP is that is that the price follows the real time wholesale price very well; but because customers choose their maximum acceptable price range, they are shielded from excessively high prices. This is illustrated in Figure 4-15. Although the RTP reaches just over 250 $/MWh, the mRTP barely reaches $100 $/MWh.

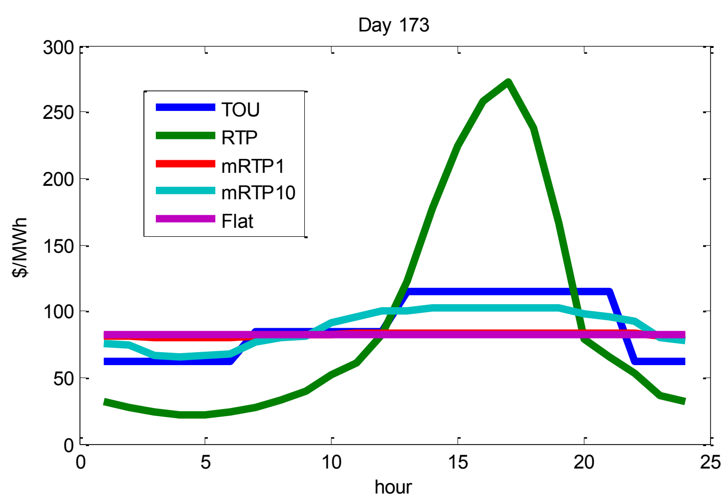

Figure 4-15. Comparison of proposed rate, RTP, TOU and flat rates. (Summer weekday)

4.3.4 Probability of Savings

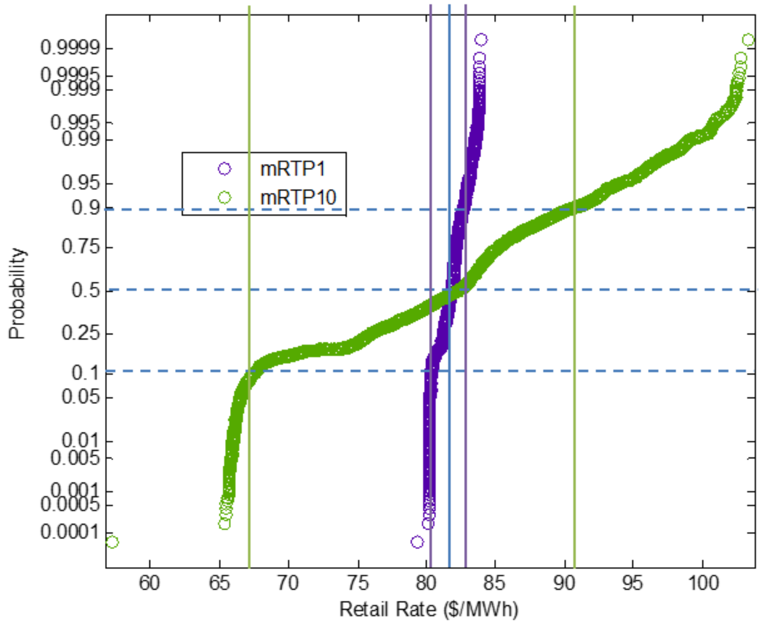

Figure 4-16. Probability plot for Case 2: $\boldsymbol{G} = \boldsymbol{f}(\boldsymbol{G_m}, \boldsymbol{G_n})$

Figure 4-16 and Figure 4-17 are probability plots for mRTP using G and G_m, respectively. In Figure 4-16, when a customer chooses the maximum level of risk (B=10), there is a 10% probability that the retail rate will be 67 $/MWh or less. This means that 10% of the time, the customer on mRTP10 gets a rate that is at least 17% cheaper than a flat rate price. However, there is also a 10% probability that the price will be at least 91 $/MWH, or in other words, at least 11% higher than a flat rate price.

A customer selecting a low level of risk will have far fewer opportunities to save from load reductions as well as lower off peak rates. From Figure 4-16, a customer on mRTP1 has a 10% probability of prices about 1.5% less than the flat rate and a 10% chance of prices being 1% above the flat rate. Although this low level of risk minimizes the amount of risk a customer has in high prices, it also minimizes opportunities to save.

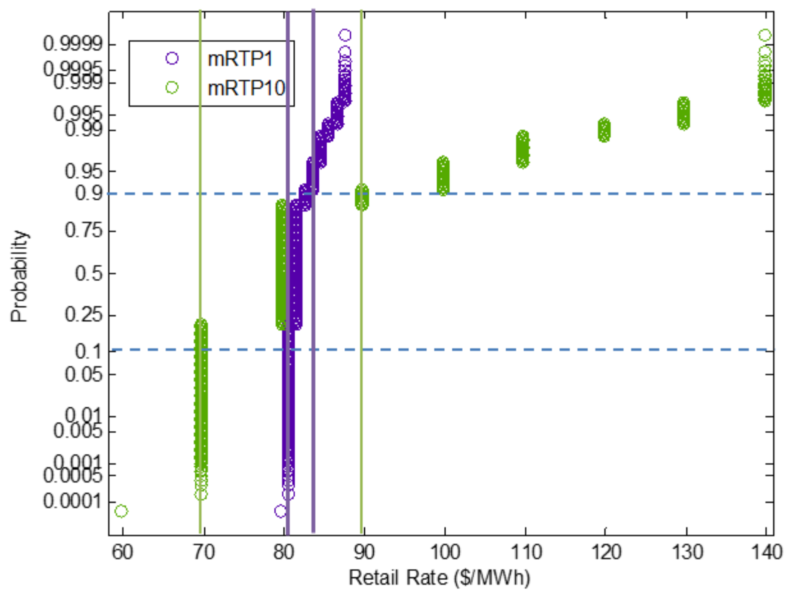

Figure 4-17. Probability plot for Case 1: $\boldsymbol{G} = \boldsymbol{f}(\boldsymbol{G_m})$

The same analysis can be done for the mRTP based only on G_m. In Figure 4-17, the discrete nature of the CAISO market based grid state index results in a discrete probability distribution. Again, a customer on mRTP10 has a larger spread of possible prices than a customer on mRTP1 and therefore a higher chance of larger bill savings. In Figure 4-17, there is a 10% chance that mRT10 is 70 $/MWh or less (at least 15% less than the flat rate). And, there is a 10% chance that mRTP10 is greater than 90 $/MWh (at least 10 % greater than the flat rate).

4.4 Conclusion

Retail rates are the first step in providing an incentive for demand response. Customers must have information not only about the current grid state, but also about what specific actions they can take to help manage the grid. Concurrent work explored how customers can react to the proposed pricing scheme and analyzes the resulting market, energy provider, and customer benefits (VanderKley & Negash, 2014).

Part II: Incentives

4.5 Proposed Incentive Scheme

If retail compensation is through incentive payments, then in this case, the LSE decides when short term DR payments are justified by a quantifiable long term benefit. We assume that the customer providing DR is on a flat retail rate. Here the main question is how much should the LSE or aggregator offer for DR? This incentive must be optimized according to the benefit that is gained by the LSE. Ultimately, in this type of pricing scheme, it is up to the LSE to determine what the benefit of DR is and set prices accordingly. Here, we define the benefit to the LSE as a reduction in economic loss when DR reduces the amount of energy the LSE sells to the consumer at a price less than the wholesale price.

When customers are on a flat retail rate, this rate represents an average cost not only across the residential class of customers but also across time. Therefore, there will be times where wholesale prices will fall below the flat rate and other times when they will rise above. The flat rate is set just high enough that the LSE can recover its approved revenue requirement. Because retail rates are regulated, and fixed for 1-3 years at a time, once the rate has been set, the LSE can increase its profit by targeting demand response specifically when wholesale prices rise above the local retail rate. Thus, the objective of the LSE is to minimize economic loss during peak price periods.

4.5.1 Formulation of Demand Response Incentive

We define the DR incentive, Equation (4.8), to be an exponential function of a grid state index. An exponential function is chosen in order to mimic large price spikes in the wholesale market at very high demand and therefore, provide a price signal that is more consistent with wholesale market energy price signals.

$$I = a^{b*G-c} \tag{4.8}$$

$$0 \leq G \leq 10$$

$$0 \leq b \leq 1$$

Here, a is a parameter chosen based on historical wholesale price data, b represents the portion of LSE's financial benefit due to load reductions that the LSE is willing to share with DR providers, G is the grid state index, and c is a parameter that is optimized in order to ensure the incentive provided does not exceed the benefit of load reductions. Equations (4.9 – 4.10) lead to the following optimization problem.

$$\min_{c} \; \left|\left(a^{b*G-c}\right) * D - b * R\right| \tag{4.9}$$

$$s.t. \quad R = (w^0 - r)D + B_l \tag{4.10}$$

Here, R is the LSE's total financial benefit of load reductions D; B_l is the local value of DR; r is the flat retail rate; and w^0 is the wholesale price without DR. Thus, the first term of the objective function is the incentive and the second term represents the share of the LSE's total benefit that is given to the DR provider. In other words, given an anticipated load reduction D, the LSE can predict its savings R, that result from the load reduction and the parameter c, is optimized such that the incentive does not exceed the benefit of the load reduction.

4.5.2 Comparison of Wholesale and Retail Compensation

We compare the costs and benefits of demand response compensation at the wholesale and retail levels and for various market participants. These costs and benefits are illustrated in

Figures 1 and 2 and the equations are tabulated in Table 1. Here, w^0 is the wholesale price without DR, w is the wholesale price after load reductions, D is the load reduction (demand response), B_l is the local value of DR (such as reduced losses), L is the load after load reductions, r is the flat retail rate, and I is the demand response incentive. These costs and benefits are analyzed from the perspective of the load serving entity (LSE), buyers in the wholesale market (BM) including energy exporters as well as LSEs, and demand response providers (DRP).

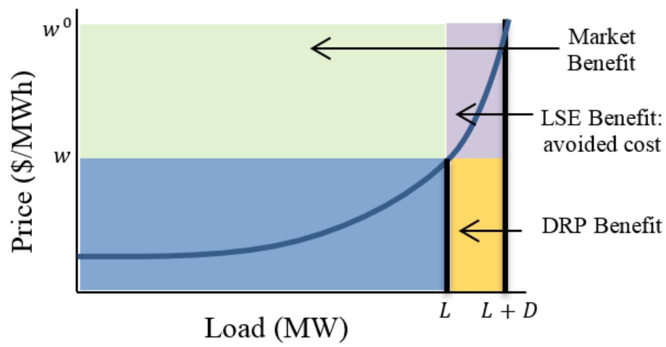

Figure 4-18. Benefits and Costs of DR in Wholesale Markets

In Figure 4-18, the green shaded region represents the market benefit of load reductions enjoyed by all the buyers. The blue shaded region is the revenue that the market collects. The yellow shaded region is the payment made to DRPs. Since the revenue collected is less than the amount needed to pay LMP to both conventional generators for load, L, as well to DRPs for the reduced load, D, the payment to the DRP is a cost that must be allocated to all buyers in the market. The purple shaded region is an LSE benefit in that it represents high priced energy that it was not required to purchase;

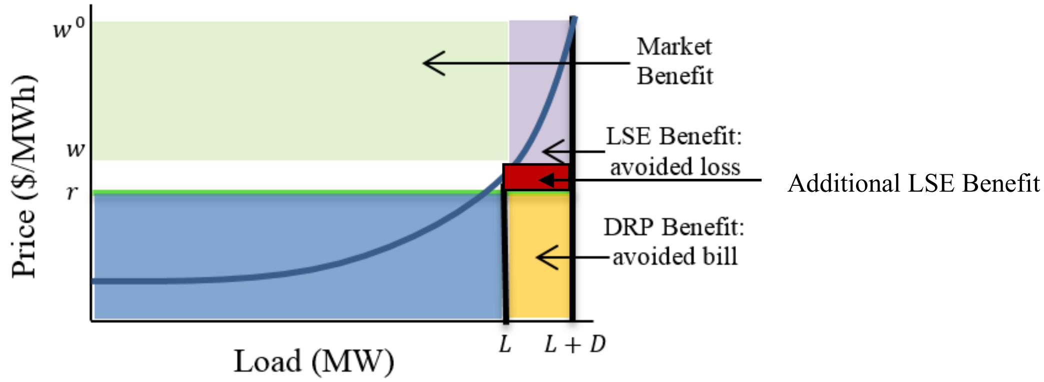

Figure 4-19. Benefits and costs of demand response at the retail level

Figure 4-19, looks at compensation at the retail level and as such we consider the role of the retail rate, r. In the figure, the retail rate is lower than the wholesale price even after load reductions. However, if load reduction is large enough, the wholesale price will fall below r. The important distinction to make between Figure 4-18 and Figure 4-19 is that when the retail rate is considered, there is an additional LSE benefit that the wholesale compensation scheme cannot extract. The red shaded area given by $(w - r) * D$ represents avoided economic loss from the LSE when wholesale prices are still higher than retail. This potential benefit is contained in the LSE benefit model when a retail side DR compensation scheme is used.

Table 4-3 breaks down and compares each market participant's benefit and cost, if any. Note, that at the wholesale level, payments to DR resources is allocated to LSEs, where each LSE pays a fraction f, of the total cost. The market participants (BM) represent all loads, including those providing DR. That is because when DR reduces wholesale prices, all consumers benefit. It is interesting to note that the economic benefit to buyers in the wholesale market is independent of whether compensation is at the wholesale or retail level. However, because wholesale markets do not consider the role of local retail rates, the benefits (and costs) for the LSE and DRP are heavily influenced by whether DR is compensated at the wholesale or retail level. Additionally, local value of demand response, B_l cannot be considered by a wholesale level compensation scheme.

Table 4-3. Comparison of benefits and costs of demand response compensation at the wholesale and retail levels, and from the perspective of various market participants

	Wholesale	*Retail (incentive)*
	Benefits	
LSE	$(w^0 - w)(D)$	$(1 - b)(w^0 - r)D + B_l$
BM	$(w^0 - w)L$	$(w^0 - w)L$
DRP	$w * D$	$I * D + r * D$
	Costs	
LSE	$(w * D) * f$	$I * D + r * D$
BM	$w * D$	---
DRP	---	---

In summary, at the wholesale level, all market participants benefit, and all market participants bear a cost. At the retail level, all market participants benefit and even the buyers in the wholesale market see identical benefits as in the case of wholesale DR compensation. However, LSEs can consider their local value of DR resources and provide additional incentives to reward these resources. As a result, only the LSE bears the cost of DR compensation. Finally, because the wholesale market does not consider the role of the retail rate, the DRP avoided bill cost, $r * D$, is not reflected in either the LSE cost, nor the DRP benefit.

4.6 Case Study

We analyzed the benefits and costs of DR compensation at the wholesale and retail level using load data from the PJM region for the year of 2011. Price data was simulated based on a PJM model for an averaged supply curve (PJM, 2011).

$$w = 2.584468^{0.000178*MW-18.14454} + 35.82109 \qquad (4.11)$$

In (4.11), MW, is the load, and all other constants are determined based on fitting to this exponential curve actual historical price/quantity pairs from generation offers. Based on this formulation, the incentive was calculated as (4.12):

$$I = 2.584468^{b*G-c} \qquad (4.12)$$

The value of c, was then optimized for every selected value of benefit sharing percentage, b. The retail rate, r, was determined by calculating the average wholesale cost of supplying the original load (before load reductions) over the entire year (4.13).

$$r = \frac{1}{8760}\sum_{h} w_h * (L_h + D_h), \qquad h = 1, 2, ..8760, \qquad (4.13)$$

4.6.1 Assumptions

For simplicity, we assume that there is only one load serving entity with many customers. When calculating the potential savings of demand response, we assume that all customers participate and reduce their loads when the GSI is higher than 4. This assumption affects the dollar value amount of LSE benefit, but is not necessary. It is likely that only a portion of the customers would participate, and it is a risk on the LSE to accurately forecast this participation such that the incentive isn't too high. In practice, small customers providing demand response must contract with a curtailment service provider, or aggregator, to offer their resources into the wholesale market. Here, we assume that the customer receives the entire LMP for load reductions, but in reality, the curtailment service provider takes a percentage.

4.7 Results

4.7.1 Proposed Incentive Structure

Using the simulated market price data, we first converted the price data to the GSI signal. Figure 4-20 shows the frequency of each GSI value (from 0-10) throughout the year. The GSI of level 4 and above represent times when prices are above average peak prices. In total, these represent less than 20% of the total hours in the year.

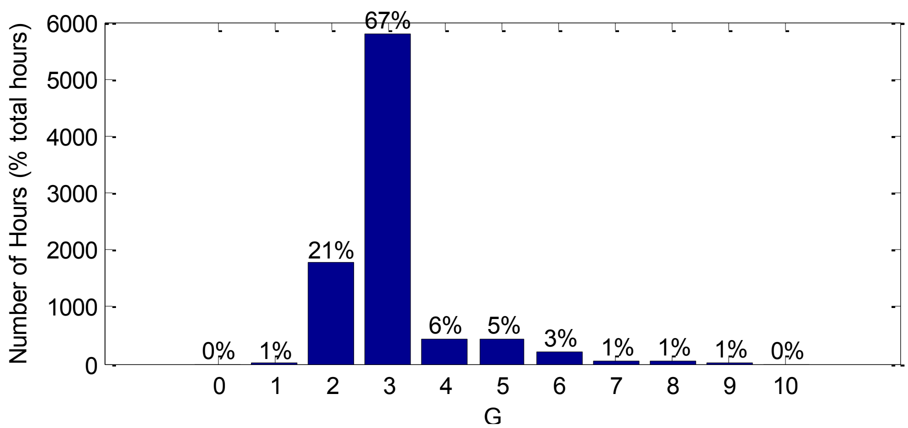

Figure 4-20. Distribution of GSI index

4.7.2 Retail Level DR Incentive (function of CAISO GSI, $\boldsymbol{G}$)

The resulting incentive (as a function of CAISO's proposed GSI), is presented in Figure 4-21. Because an exponential function was selected, incentives rise sharply for larger values of G. Incentives also rise more steeply for larger benefit sharing ratios, b.

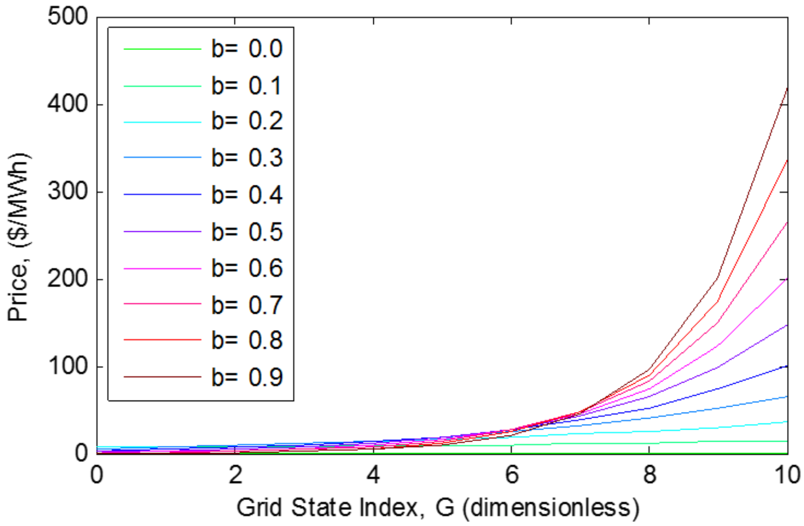

Figure 4-21. Incentive for DR as a function of the GSI

4.7.3 Benefit Comparison

As shown in Table 4-3, the benefit of demand response for buyers in the wholesale market, in terms of market price reductions, is independent of whether DR is compensated at the wholesale or retail level. Therefore, we will concentrate our comparison on LSE and DRP benefits.

In Figure 4-22, we observe that for small levels of demand response (≤6% peak load), the LSE benefit is larger with retail DR compensation. At 1% peak load reduction, this is true for even a benefit share of 90% for the DRP.

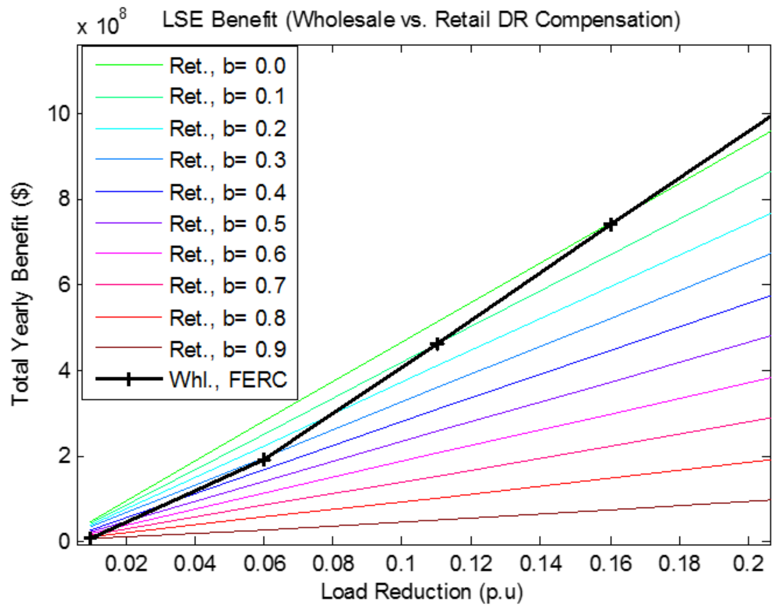

Figure 4-22. Comparison of LSE benefit when demand response is compensated at wholesale vs. retail for various levels of benefit sharing ratios, b. Note, "b" is the percentage of the total LSE benefit that is shared with the DRP in the form of the proposed incentive.

Figure 4-23 shows the benefit from the DRP's point of view. Here, for large benefit share ratios, the DRP always gains a higher benefit from the retail incentive. For low benefit ratios and at low levels of load reductions (<=6%), the DRP gains more by selling in the wholesale market. However, this is largely due to our including the DRP's bill reductions due to DR in the calculation of DRP benefit. From an economic point of view, this inclusion is valid. In fact, the benefit of bill savings for the customer is the same, regardless of whether DR is sold at wholesale or retail. However, realistically, some customers might not view savings as "payment". Therefore, in order to have a more realistic comparison of wholesale vs. retail compensation from a customer point of view, we also considered the DRP benefit without including bill reductions (Figure 4-24). In such a case, if the load reduction is small, or if the benefit share ratio is too small, the DRP is better off selling in the wholesale market. However, for moderate load reductions (>6%), and high benefit share ratios (>60%), the DRP is better off selling at the retail level. But at moderate to high load reductions, wholesale prices fall below the retail rate, and the LSE benefit at the retail side diminishes.

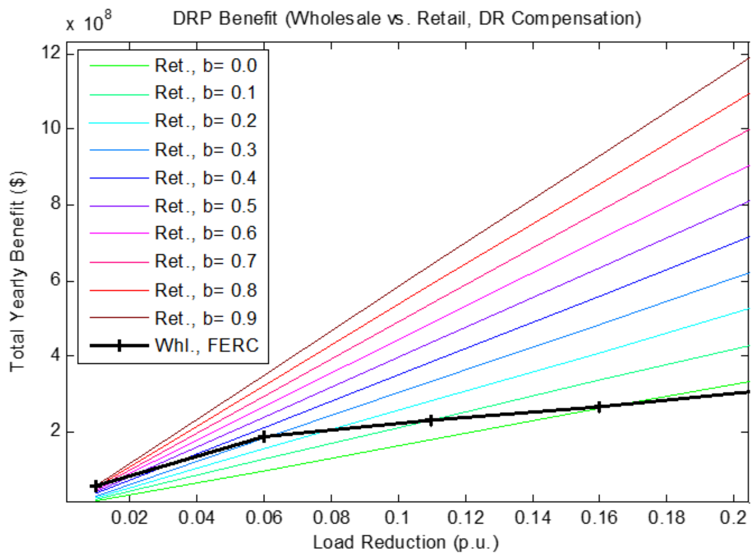

Figure 4-23. Comparison of DRP benefit when demand response is compensated at wholesale vs. retail (for various levels of benefit sharing ratios, b).

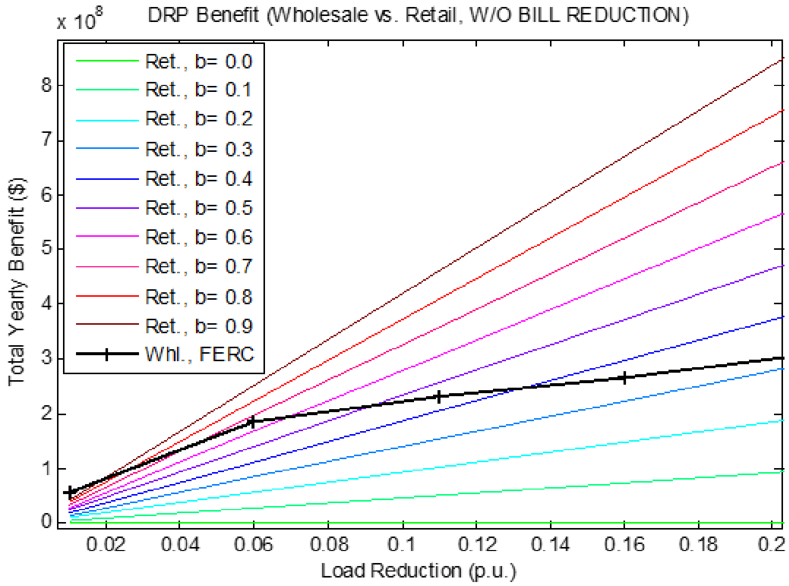

Figure 4-24. Comparison of DRP benefit (not including bill savings) when DR is compensated at wholesale vs. retail (for various levels of ratios, b).

It is worth pointing out again, that we assumed no local benefits, $B_l = 0$. If local benefits, such as loss reduction, investment deferral, or other benefits, are included in the total LSE benefit due to DR, then the LSE as well as the DRP have an opportunity to both do better off on the retail side.

4.8 Conclusion

We presented a retail level DR compensation scheme based on the newly proposed CAISO grid state index. This index is intended to serve as a signal to customers and can be modified by load serving entities to produce dynamic rates or incentives for voluntary demand response. We compared this method to the current method of compensating DR in competitive wholesale energy markets. We find that when DR penetration is high, DRP are better off selling at the local retail level if LSEs are willing to share at least 60% of their economic benefits. At low DR penetrations (less than 15%), the wholesale market provides

DRP a larger payment. The main benefit of compensating at the retail level is that a more complete picture of each participant's benefits and costs can be analyzed and modeled. Because demand response is a local resource, providing local benefits, aggregation of these resources to the wholesale level strips them of an opportunity to be compensated for local added value. Because market prices depend on load level, and are independent of whether DR is compensated at retail, all buyers in the wholesale market benefit from price reductions due to DR. Future research could quantify the minimum local benefit, B_l, that ensures both the DRP as well as the LSE are better off with retail compensation.

Chapter 5. Valuing Distributed Solar through Value of Solar Tariffs

Part 1 of this chapter addresses methodologies to calculate the value of solar. We first compare the value of solar for a local Washington State utility (Snohomish Public Utility District) using two existing methodologies: The Clean Power Research (CPR) methodology used by the State of Minnesota and a modified version of the Pacific Northwest Utilities Conference Committee (PNUCC) methodology. After comparing existing methods, we propose a new value of solar methodology that unlike existing methods reflects societal value of solar and is directly linked to retail rates.

Part 2 of this chapter proposes a methodology to combine value of solar tariff and retail rate design to minimize cost shifting, maximize PV owner's benefits, and minimize economic loss for the utility.

5.1 Minnesota VOST Methodology

Minnesota's VOS methodology, as required by state law, accounts for distributed PV value in terms of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value (Minnesota Department of Commerce, Division of Energy Resources, 2014). Specifically, these benefits are categorized into the following categories:

1) Avoided Fuel Costs
2) Avoided Plant O & M Variable Costs
3) Avoided Plant O & M Fixed Costs
4) Avoided Generation Capacity Costs
5) Avoided Reserve Capacity Costs
6) Avoided Transmission Capacity Costs
7) Avoided Distribution Capacity Costs
8) Avoided Environmental Costs

Of the above eight value components, the first two are energy related and variable in nature. The next 4 are capacity related and fixed in nature. As such, the calculation of these components requires a given capacity related factor be assigned to the distributed solar value. This factor is called the effective load carrying capacity (ELCC) and reflects the <u>average</u> output of the PV panel during peak hours. The seventh benefit is also capacity related, but it is a more localized benefit that depends on the extent to which PV is able to reduce peak load on the distribution network. For this benefit, a second type of capacity factor called the peak load reduction factor (PLR) is used. Note, a system of PV panels can potentially have a nonzero ELCC and zero PLC.

Losses are accounted for in all of the 8 value components using 3 different loss savings factors:

1) **Energy Loss Savings Factor**: Represents the annual avoided energy losses and is calculated as the ratio of annual avoided energy with losses included and without losses included.

2) **ELCC Loss Savings Factor**: Represents the increased capacity factor that is achieved when losses are reduced and is calculated as the ratio of ELCC when losses are considered and ELCC when losses are not considered.

3) **PLR Loss Savings Factor**: Represents the increased reduction in peak load that is achieved when losses are reduced and is calculated as the ratio of PLR when losses are considered and PLR when losses are not considered.

Once the value of each of the various components, VOS_i, has been determined, the load match factors and loss savings factors are included to determine the final levelized value of solar using Equation 5.1. Detailed definitions and descriptions of the parameters and variables in Equation 5.1 are given in Appendix 3.

$$VOS = \sum_{i}^{numComponents} VOS_i * LoadMatchFactor_i * (1 + LossSavingsFactor_i) \tag{5.1}$$

Where,

$$LoadMatchFactor_i = \begin{cases} PLR_{withoutlosses} & for\ dist\ capacity\ component, or\ i = 7 \\ ELCC_{withoutlosses} & for\ other\ capacity\ components, or\ i = 4, 5,6 \\ 1 & for\ energy\ dependent\ components, or\ i = 1,2,3,8 \end{cases}$$

$$LossSavingsFactor_i = \begin{cases} LossSavings_{PLR} & for\ dist\ capacity\ component, or\ i = 7 \\ LossSavings_{ELCC} & for\ other\ capacity\ components, or\ i = 4,5,6 \\ LossSavings_{Energy} & for\ energy\ dependent\ components, or\ i = 1,2,3,8 \end{cases}$$

5.1.1 Results: CPR Method (Minnesota)

This methodology was tested using Snohomish Public Utility District (SnoPUD) as a case study. Appendix 5 provides a description of the economic, network and PV characteristics assumption made. Based on these assumptions, the value of solar to SnoPUD according to the Minnesota (CPR) method is given in Table 5-1. From the analysis, it is observed that the largest value components are avoided fuel costs (energy cost) and avoided environmental costs. However, it is important to stress that this methodology assumes that in all hours that solar produces, the marginal fuel is natural gas. This, of course, is not true for utilities in the Pacific Northwest, where the marginal resource is often hydro. By assuming natural gas as the marginal resource, we are essentially creating value where potentially, none exists. This means that the avoided environmental costs as well as the avoided fuel costs are overvalued in Table 5-1 and some regionally appropriate adjustments must be made.

Table 5-1. Value of Solar Tariff Components

Value of Solar Tariff Components:	Economic Value of (VOS_i)	Load Match (no losses)	Loss Savings Factor	Distributed PV Value
	($/kWh)			($/kWh)
Avoided Envr. Cost	$0.026	1	7.50%	**$0.027**
Avoided Dist. Cap. Cost	$0.007	0	0.00%	**$0.000**
Avoided Trans. Cap Cost	$0.016	0.0047	7.50%	**$0.000**
Avoided Reserve Cap Cost	$0.007	0.0047	7.50%	**$0.000**
Avoided Gen Cap Cost	$0.047	0.0047	7.50%	**$0.000**
Avoided Plant O&M - Variable	$0.009	1	7.50%	**$0.009**
Avoided Plant O & M - fixed	$0.014	0.0047	7.50%	**$0.000**
Avoided Fuel Cost	$0.055	1	7.50%	**$0.059**
Total	$0.180			**$0.096**

This methodology also assumes a natural gas plant for any new generation capacity deferred by solar. However, because SnoPUD has made a commitment to meet load growth through energy efficiency and renewable resources, this assumption in fact undervalues solar since the renewable resources are more expensive than a new gas plant. Figure 5-1 illustrates the new value of solar components assuming a combination of renewables as the generation capacity deferred. The result in Figure 5-1 is also based on the modified assumption that solar avoids natural gas as a marginal fuel only 20% of the time it generates and the remaining hours, it offsets hydro purchases. In this case, the economic value of the avoided generation capacity increased significantly, however, since the load match factor is nearly zero (ELCC=0.0047), the generation capacity component is still relatively small. Additionally, we also note that the value of avoided fuel cost is slightly reduced while avoided environmental costs and variable plant costs are drastically reduced. This is because the 80% of "fuel cost" is replaced with hydro power cost, but 80% of the variable plant and environmental costs cannot be avoided because they do not apply to hydro power.

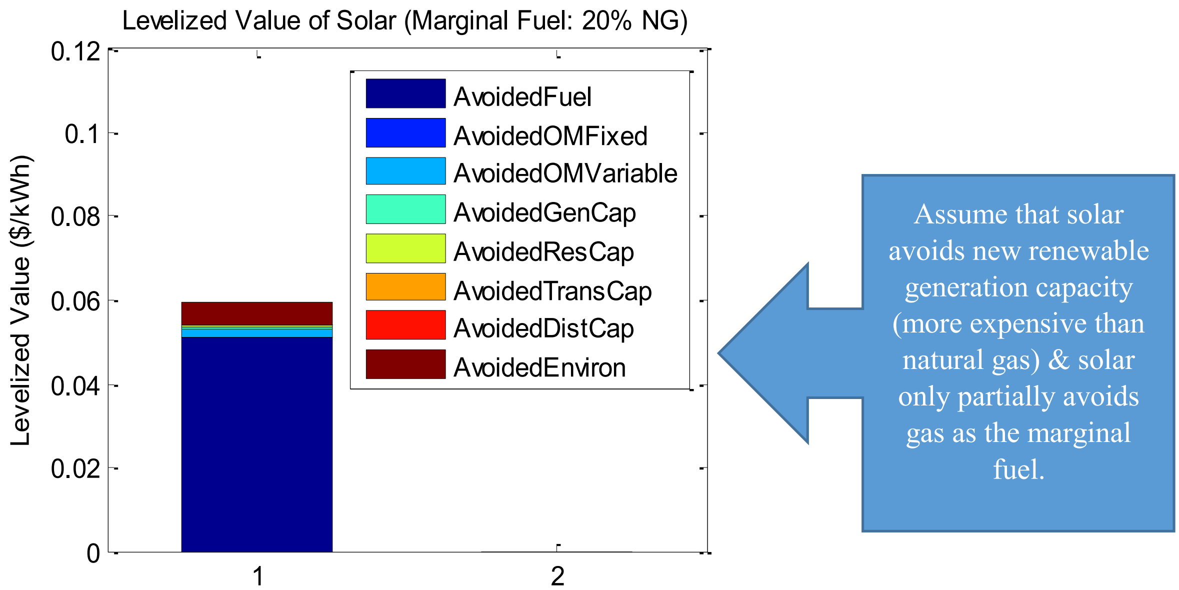

Figure 5-1. Value of Solar when generation capacity is met by renewables and when natural gas is avoided 20% of the time

5.2 "Modified" PNUCC VOST Methodology (Net Value)

Like Minnesota, PNUCC considers the value of energy and its delivery, generation and transmission capacity as well as line losses. However, one of the main difference between the two is that the PNUCC methodology bases the environmental value of solar on policy while Minnesota bases this value on detailed analysis of the social cost of carbon. Furthermore, while the Minnesota method does recognize that PV integration costs are a factor, the methodology assumes that those costs are negligible. In contrast, the PNUCC method explicitly considers integration costs. Thus, the distributed PV net value components are categorized as follows:

1. Avoided Energy Value
2. Energy Hedge Value *
3. Avoided Line Losses Value

4. Avoided Generation Capacity Value *
5. Avoided Transmission Capacity Value *
6. Reduced RPS Need Value
7. Potential REC Sales Value **
8. PV Integration Cost

The first three value components are energy related benefits; components 4 and 5 are capacity related (and therefore require a capacity factor); components 6 and 7 are based on environmental factors and the last component is a cost, and reduces the ultimate value of solar. It is worth pointing out here that we have made several modifications and additions to these components to better reflect the potential value of solar in general as well as specifically for SnoPUD. These modified (*) and added (**) value components are marked with asterisks. These modifications/additions are further explained in Appendix 4. Finally, PNUCC calculates the value of solar for a single year as opposed to a 25 year levelized value approach. To better compare the Minnesota and PNUCC methods, we used economic assumptions from the Minnesota method to perform a 25-year levelized value of solar to SnoPUD.

Capacity factors are directly incorporated into the value components' calculations and the losses explicitly modeled as a separate energy savings; therefore, once the individual components, VOS_i^{PNUCC}, have been calculated, the value of solar is simply the sum of each of the individual value components as given in Equation 5.2. A detailed description of the components and their formulations are given in Appendix 4.

$$VOS^{PNUCC} = \sum_{i=1}^{8} VOS_i^{PNUCC} \tag{5.2}$$

5.2.1 Results: Modified PNUCC Method

For consistency, the VOST results using the modified PNUCC method are based on the same economic, network and PV characteristics assumptions used in the Minnesota method. Table 5-2 presents the value of solar under various policy scenarios. Case 1 assumes SnoPUD meets its RPS requirement using compliance method 1 (4% retail revenue requirements, or RRR). Case 2 assumes SnoPUD meets RPS requirement using compliance method 2 (percentage of load met by renewables in each year). Case 3 assumes that in addition to meeting RPS requirements according to compliance method 1, SnoPUD is able to sell the solar RECs at a price ranging from $1/REC to $3/REC. Finally, case 4 is the same as case 3, except the REC is sold at a price ranging from $15/REC to $50/REC.

Again, the largest value components are energy and environmental components. Because the capacity factor of solar in Washington State is low, there is not much of a capacity value of solar. However, the environmental benefit is high. This is because environmental value in this methodology is not a function of avoided cost of carbon. The environmental value is actually rooted in the RPS policy itself.

Table 5-2. Value of Solar: (each case assumes a different environmental benefit calculation)

Value Component	Case 1	Case 2	Case 3	Case 4
	RPSValue1 (RRR)	**RPSValue2 (RPS)**	**Low REC Value $1-$3**	**High REC Value $15-$50**
Energy	$0.0452	$0.0452	$0.0452	$0.0452
Hedge	$0.0027	$0.0027	$0.0027	$0.0027
Loss	$0.0034	$0.0034	$0.0034	$0.0034
RPS	**$0.0055**	**$0.0121**	**$0.0055**	**$0.0055**
REC	$0.0000	$0.0000	**$0.0012**	**$0.0414**
G. Cap.	$0.0002	$0.0002	$0.0002	$0.0002
T. Cap.	$0.0024	$0.0024	$0.0024	$0.0024
Int. Cost	-$0.0005	-$0.0005	-$0.0005	-$0.0005
VOS	**$0.0590**	**$0.0655**	**$0.0616**	**$0.1004**

Figure 5-2 and Figure 5-3 illustrate how current policy design as well as SnoPUD decisions have an impact on the value of solar. In Figure 5-2, the value of solar is $0.0616/kWh and reflects the current low market price for solar RECs as well as SnoPUD's decision to meet RPS requirements through compliance method 1 (4% retail revenue requirements). In Figure 5-3 the value of solar is $0.1004/kWh and is based on SnoPUD meeting RPS requirements through compliance method 2 and REC sales starting at $15 and increasing to a high of $50 (a highly unlikely scenario without the influence of policy).

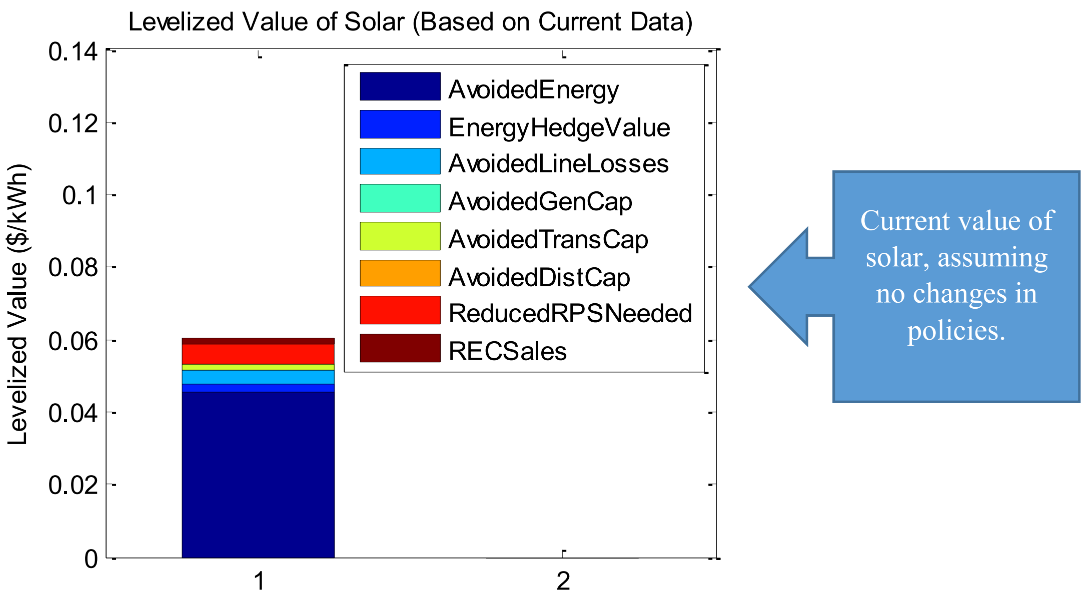

Figure 5-2. Value of solar with current data (without new policies)

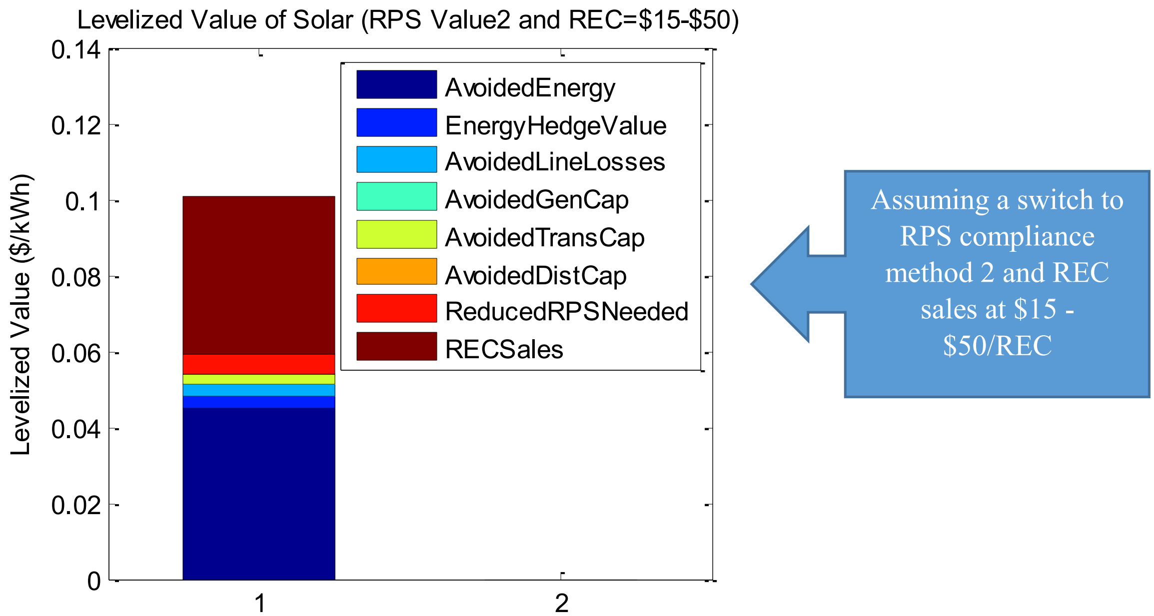

Figure 5-3. Value of solar using RPS compliance method 1 (% Load) and REC value of $15-$50[8]

5.3 Proposed VOST Methodology: Weighted Retail Rate (WRR) VOST

We propose that the value of solar be linked to the proportion of each of the utility's various cost components. Each of these cost components would be weighted by a factor that represents the efficacy of distributed solar to reduce those costs. An additional "externality" rate would then be added to the weighted retail rate as follows:

$$VOS = (a * R * w_1 \quad + \quad b * R * w_2 \quad + \quad c * R * w_3) \quad + \quad v \tag{5.3}$$

Where:

$R = retail\ rate$ ($/kWh)

$a = energy\ cost\ ratio$ (pu)

$b = demand\ cost\ ratio$ (pu)

$c = customer\ cost\ ratio$ (pu)

[8] A REC value of $50 is assumed as a mean estimate. RECs range from $1 to several hundred depending upon a number of factors including supply, demand, and alternative compliance payment (ACP) rates. Ideally, the ACP would be equal to the total value of solar so SREC market prices would rationally settle at the environmental value of solar (total value minus the market value of energy and capacity).

$v = externality\ rate$ ($/kWh)

$w_1 = energy\ weight$ (pu)

$w_2 = demand\ weight$ (pu)

$w_3 = customer\ weight$ (pu)

The externality rate, v, is the added cost that the utility incurs to fulfil RPS requirements. In other words, it is the incremental cost of procuring renewable energy resources. This cost can be determined from the cost of RECs, or by calculating the incremental cost of renewable energy (the difference between the cost of conventional energy and renewable energy), or by any other RPS compliance method.

5.3.1 Cost Component Weights

This simplified methodology ties the VOS to the energy, demand and customer charge components of a utility's cost of service analysis for residential customers. Thus, a, b, and c (Equations 5.4 to 5.6) represent the percentage of the retail rate that recovers energy, demand, and customer costs, respectively. Since solar avoids these cost components to various degrees, we define three weights to represent the extent to which solar can avoid these various cost components.

$$a = \frac{EnergyCosts}{TotalCosts} \tag{5.4}$$

$$b = \frac{DemnadCosts}{TotalCosts} \tag{5.5}$$

$$c = \frac{CustomerCosts}{TotalCosts} \tag{5.6}$$

5.3.2 PV Contribution Weights

Energy costs vary in time and by season. Thus, the energy weight factor is ratio of average energy prices during expected solar producing hours to average energy prices throughout the year. As a proxy, we use Forecast Mid-Columbia prices for 2015.

$$w_1 = \frac{\frac{1}{P}\sum_p^P MarketPrice_p}{\frac{1}{T}\sum_t^T MarketPrice_t}, \qquad P \in [1 \ldots 8760] \tag{5.7}$$

$$P = Numer\ of\ PV\ generation\ producing\ hours$$

$$T = 8760\ (number\ of\ non\ leap\ year\ hours\qquad)$$

Alternatively, if we consider the seasonal value of solar (to match SnoPUD's seasonal retail rates), we would perform a similar calculation as above twice: once for summer months (April-September) and once for winter months (October-March).

$$w_1^s = \frac{\frac{1}{S}\sum_s^S MarketPrice_s}{\frac{1}{T}\sum_t^T MarketPrice_t}, \qquad s \in [1 \ldots 2160] \cup [6553 \ldots 8760] \tag{5.8}$$

$$w_1^w = \frac{\frac{1}{W}\sum_w^W MarketPrice_w}{\frac{1}{T}\sum_t^T MarketPrice_t}, \qquad s \in [2161 \ldots 6552] \tag{5.9}$$

$$S = Number\ of\ PV\ generation\ producing\ hours\ in\ the\ summer$$

$$W = Number\ of\ PV\ generation\ producing\ hours\ in\ the\ winter$$

Table 5-3. Energy weights based on 2015 Mid-C Price forecast and assumed PV Fleet shape

	Yearly Method	*Seasonal Method*
w_1	1.06	--
w_1^s	--	0.62
w_1^w	--	1.12

Table 5-3 lists the PV weights calculated based on 2015 Mid-C price forecasts and the assumed PV fleet shape. These results indicate that the overall value of energy produced by solar is 6% higher than the average price of energy throughout the year. This is intuitive since solar produces during the day, which, on average is more expensive than energy during the night. However, when we decompose this result by seasons, the value of energy produced by solar is 38% less than the value of energy produced by other sources during the winter. This is due to the winter peaking characteristic of the region. Market prices peak in the winter when PV panels are not producing. However, in the summer, days are longer and PV can produce energy during the higher priced hours. Thus the energy weight for PV during the summer is 1.12, meaning its value is 12% higher than the average summer energy price.

Demand costs include the portion of generation, O & M, and capital costs that are generally fixed and do not vary with consumption. These costs are therefore strongly affected by both the ability of solar to produce at capacity as well as the ability of solar to produce during peak times. These two factors are both dependent upon the sun. Thus, the demand weight is a capacity factor defined as the average normalized PV output throughout the year (Equation 5.10). Using the assumed PV fleet shape (See Appendix 5), the capacity factor w_2, for SnoPUD is approximately equal to 0.11.

$$w_2 = \frac{1}{T}\sum_{t}^{T} PVFleetShape_t \tag{5.10}$$

Customer costs are assumed to be fixed and therefore unrelated to either customer load or solar output. Thus, the customer cost weight is zero.

$$w_3 = 0 \tag{5.11}$$

5.3.3 Results: WRR VOST

Based on the proportion of energy, demand and customer costs in 2013[9], the VOS based on the WWR methodology is presented in Table 5-4 as the "base case". The table makes clear which components of the WWR VOST are dependent upon policy, market, or PV characteristics. We assume that the environmental value is based on reduced RPS needs (See Tables 24 and 25 in Appendix 4). Comparing the retail rate R, and the value of solar VOS, PV owners would be better off with traditional net energy metering unless the environmental value of solar v, increases (Case 1), the price of energy during solar generation producing hours increases (Case 2), or the proportion of energy costs a, exceeds 80% (Case 3). For Case 1, one way in which v can increase is through utility-administered, state production incentives. If local policy-makers perceive a justifiable societal value in solar, v, will increase above the amount that the utility pays.

Table 5-4. Alternative VOS Methodology: For the year 2014, assuming environmental benefit is from Reduced RPS needs (Base Case, Case 1 & Case 3: $1/REC. Case 2: 4%RRR).

	R ($/kWh)	v ($/kWh)	a (%)	b (%)	c (%)	w_1 (%)	w_2 (%)	w_3 (%)	VOS ($/kWh)
Base Case	$0.092	$0.0033	0.52	0.35	0.13	1.06	0.11	0	$0.057
Case 1	$0.092	$0.057	0.52	0.35	0.13	1.06	0.11	0	$0.111
Case 2	$0.092	$0.0033	0.52	0.35	0.13	1.70	0.11	0	$0.087
Case 3	$0.092	$0.0033	0.80	0.10	0.10	1.06	0.11	0	$0.087

Policy Market Environment PV Characteristics

Figure 5-4 presents a breakdown of SnoPUD's current energy only retail rate according to its various cost components. The resulting WRR VOST is presented in Figure 5-5. Here, the

[9] Cost proportions taken from SnoPUD 2013 Cost of Service Analysis (COSA).

environmental cost component of the retail rate[10] is based on compliance method 1 (4% RRR). The WRR method makes obvious that the value of solar can never be greater than (or even equal to) the retail rate (as is assumed with NEM) unless distributed solar is able to reduce utility costs at a rate greater than the average cost to serve (marginal value of solar energy>average value of utility energy). This happens when the characteristics of PV align well with the energy market environment, for example, if energy market prices are much higher during hours when solar is abundant. Alternatively, various policies can create value as well, either artificially (through strategic RPS design), or analytically (by pricing externalities).

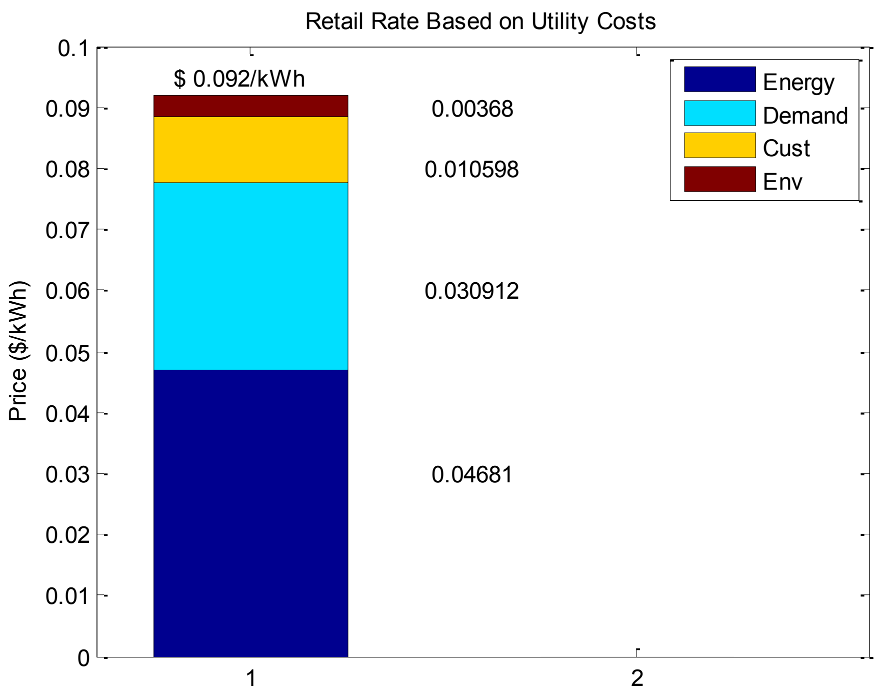

Figure 5-4. Current retail rate ($/kWh) separated according to SnoPUD 2013 costs (COSA).

[10] The environmental price component was determined by taking the difference between the average price paid for renewables ($74/MWh in Table 25) and the average price paid for BPA's Block product ($32/MWh, SnoPUD 2014 Budget) multiplied by the current renewable penetration (7%).

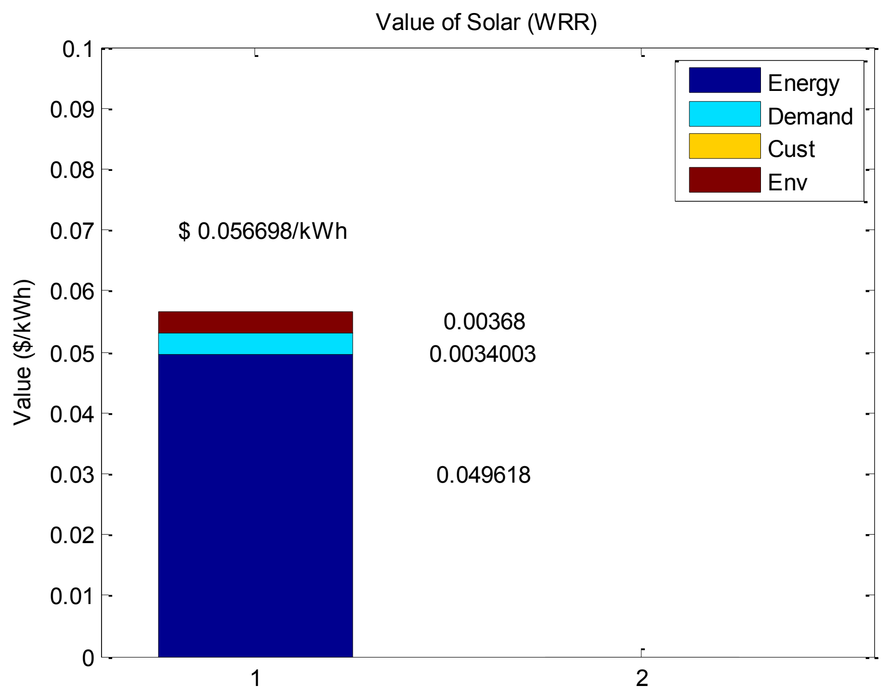

Figure 5-5. Value of solar based on WRR method.

Part II: Combined VOST and Retail Rate Design

5.4 Proposed Combined VOST and Rate Design

The WRR VOST proposed in Chapter 5.3 combines characteristics of current VOST and NEM practices in that PV customers are compensated according to their retail rates, but only to the extent that solar is a value. Here, we propose that retail rate structure and design be co-optimized with the WRR VOST methodology. This requires that the energy, capacity, fixed, and environmental or policy dependent costs borne by the utility be transparently disaggregated and reflected in customer rates as energy, capacity, fixed and environmental rate components (with different charges). Ideally, this would mean that retail rates would be non-linear, with both variable and fixed charges that reflect actual utility costs (e.g. $/kWh rate for energy related costs, $/kW rate for demand related costs, $/customer charge for customer related costs)[11]. PV customers partially net meter according to various predetermined weights that reflect the ability of PV to reduce various utility costs. Because these weights can be greater or less than one, there is potential for the value of solar tariff to be greater than or less than the retail rate depending upon market conditions, locational PV characteristics as well as policy design. Figure 5-6 illustrates the proposed rate making process. This process optimizes the proportion of fixed and variable components given the utility's cost to serve, local PV characteristics as well as practical constraints of ratemaking, such as fairness, efficiency, and both rate and revenue stability (Bonbright, et al., 1988). Any costs related to externality pricing or energy policy

[11] We acknowledge that in practice, it is often neither technically feasible nor even socially desirable to have significant fixed charges and completely decoupled rates. Insufficient metering infrastructure typically makes demand charges for residential customers impossible and high fixed costs potentially discourage conservation. Thus a modified version of this proposed retail rate is largely volumetric, but various rate components each reflect (to some degree) the actual component-wise utility costs. We describe this alternative formulation in Appendix 6.

constraints are explicitly considered as well. Once the proportion of fixed and variable retail rate components is optimized, the final retail rate and WRR VOST is determined.

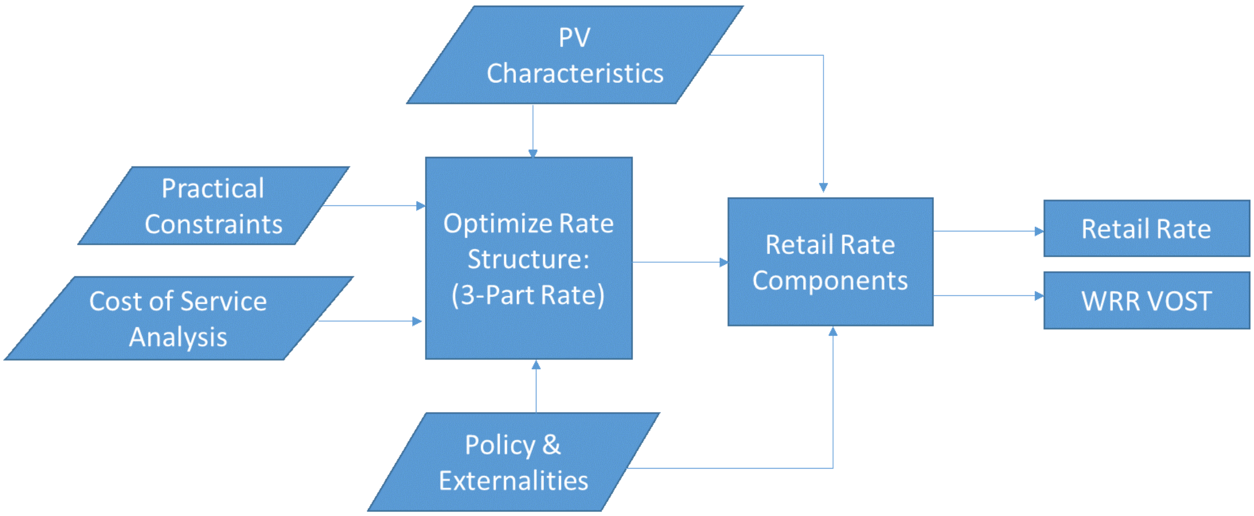

Figure 5-6. Co-optimized retail rate and WRR VOST design process

5.4.1 Three-Part Retail Rate

Given an expected cost to serve the residential class of customers as well as an expected amount of residential energy sales, the typical way of determining an averaged, energy only residential retail rate r, is as follows:

$$r = \frac{RR}{L}, \ \left(\frac{\$}{kWh}\right) \tag{5.16}$$

Here, RR is the total required revenue needed to serve the residential class of customers and L is the total expected energy sales. Unlike Equation 5.16, the proposed cost reflective retail rate is not averaged. This three-part retail rate attempts to recover variable costs through variable charges, and fixed costs through fixed charges. Here, we classify energy costs as variable and demand and customer costs as fixed. However, because residential customers do not always have advanced metering needed to measure demand, an alternative (and possibly more practical) method that assumes a variable charge for the demand component is presented in Appendix 6. Equations (5.17)-(5.19) show the proposed three-part residential rate. Here x_1, x_2 and x_3 are decision variables in an optimization problem defined later in Section 5.4.4., and represent the proportions of the total revenue that recover the utility's energy, demand and customer costs, respectively. K is the annual peak load and N_{cust} is the total number of residential customers.

$$r_{eng} = x_1 * \frac{RR}{L}, \qquad \left(\frac{\$}{kWh}\right) \tag{5.17}$$

$$r_{dmd} = x_2 * \frac{RR}{K}, \qquad \left(\frac{\$}{kW}\right) \tag{5.18}$$

$$r_{cust} = x_3 * \frac{RR}{N_{cust}}, \qquad \left(\frac{\$}{Customer}\right) \tag{5.19}$$

5.4.2 Weighted Retail Rate VOST

As previously described in Section 5.3, the value of solar is linked to the proportion of each of the utility's various cost components. Each of these cost components is weighted by a factor that represents the efficacy of distributed solar to reduce those costs. An optional "externality" rate v, is added on top of the weighted retail rate as follows (Equation 5.20) to account for any policy enforced incentives.

$$VOST = r_{eng}w_1 + r_{dmd}w_2 + r_{cust}w_3 + v \tag{5.20}$$

Where

$$v = x_4 * RR$$

Here r_{eng}, r_{dmd}, and r_{cust} are the utility's energy, demand and customer cost components of the retail rate, respectively; w_1, w_2 and w_3 are the PV owner's energy, demand and customer cost weights that allow for weighted retail rate value of solar tariff; and v, is defined as a percentage x_4, of total required revenues. By defining v as a percentage of revenue requirements, the financial impact of policy is capped.

5.4.3 PV Contribution Weights

We define the energy weight factor w_1 as the ratio of average energy prices during expected solar producing hours P, to average energy prices throughout the year as given previously in Equation 5.7. The demand weight w_2, and customer weight, w_3, are given in Equation 5.10 and Equation 5.11, respectively. It should be noted here that if PV integration costs are included, w_3 can potentially be a negative number. However, we neglect PV integration costs.

5.4.4 Utility Cost Components: Cost Recovery Weights, **x**

This methodology ties the VOST to the energy, demand and customer charge components of a utility's cost of service analysis for residential customers. The parameters, a, b, and c (Equations 5.4, 5.5 and 5.6) represent the percentage of the retail rate that must recover the utility's energy, demand, and customer costs, respectively.

While it is possible for these weights to be determined strictly based on a cost of service analysis (i.e. $x_1 = a,\ x_2 = b,\ x_3 = c$), a rate based on these components can lead to potentially sharp bill increases for customers with low consumption levels. We therefore propose that these values be optimized such that, among other constraints, rate shock is minimized. The optimized incentive and cost recovery weights $\boldsymbol{x}$, are determined as follows:

$$\min_{x} \ \left|P_{pv} w_1 (x_1 - a)\right| + \left|P_{pk} w_2 (x_2 - b)\right| + \left|P_{cust} w_3 (x_3 - c)\right| + x_4 \tag{5.12}$$

s.t.

$$x_1 + x_2 + x_3 = 1 \tag{5.13}$$

$$\left|\frac{L_i}{L}(x_1 + x_2 - 1) + \frac{x_3 N_{cust,i}}{N_{cust}}\right| \le \frac{\delta L_i}{L} \tag{5.14}$$

$$w_1 * P_{pv} * (x_1 - a) + w_2 * P_{pk} * (x_2 - b) + w_3 * P_{cust} * (x_3 - c) + x_4 \ge \gamma - a * \left(P_{re} - P_{pv}\right) \tag{5.15}$$

Here, $\boldsymbol{x} = [x_1 \;\; x_2 \;\; x_3 \;\; x_4]^T$, P_{pv} is the percent PV energy penetration, P_{pk} is the percent PV capacity (nameplate), P_{cust} is the percentage of customers with PV, w_1, w_3 and w_3 are PV characteristic dependent weights described in Section 5.4.3, L_i is the total annual load of the i^{th} group of customers with similar monthly bills, L is the total annual load of all customers, $N_{cust,i}$ is the number of customers in the i^{th} group, and N_{cust} is the total number of customers, P_{re} is the renewable energy penetration, and γ is the percentage of revenue dedicated to the incremental cost of acquiring renewables.

Derivation of the proposed optimization formulation:

Objective function:

In the above formulation, the objective function (Equation 5.12) minimizes utility revenue loss α , defined as the difference between PV payments ρ_{pv}, and the utility's avoided costs μ, due to PV. Equation (5.12) is derived from the following:

$$\rho_{pv} = x_1 * \frac{RR}{L} w_1 \; * P_{pv} * L \;\; + \;\; x_2 * \frac{RR}{K} w_2 * P_{pk} * K \; + \; x_3 * \frac{RR}{N_{cust}} w_3 * P_{cust} * N_{cust} \;\; + x_4 RR$$

$$\mu = a * \frac{RR}{L} w_1 \; * P_{pv} * L \quad + \quad b * \frac{RR}{K} w_2 * P_{pk} * K \quad + \quad c * \frac{RR}{N_{cust}} w_3 * P_{cust} * N_{cust}$$

$$\alpha = \; \mu - \rho_{pv}$$

$$\begin{aligned} &= a * \frac{RR}{L} w_1 \; * P_{pv} * L \quad + \quad b * \frac{RR}{K} w_2 * P_{pk} * K \quad + \quad c * \frac{RR}{N_{cust}} w_3 * P_{cust} * N_{cust} \\ &\qquad - \left[x_1 * \frac{RR}{L} w_1 \; * P_{pv} * L \;\; + \;\; x_2 * \frac{RR}{K} w_2 * P_{pk} * K \; + \; x_3 * \frac{RR}{N_{cust}} w_3 * P_{cust} * N_{cust} \right. \\ &\qquad \left. + \, x_4 RR \; \right] \end{aligned}$$

If we let $\alpha = \; 0$, then

$$0 = a * \frac{RR}{L} w_1 \; * P_{pv} * L \quad + \quad b * \frac{RR}{K} w_2 * P_{pk} * K \quad + \quad c * \frac{RR}{N_{cust}} w_3 * P_{cust} * N_{cust}$$

$$- \Big[x_1 * \frac{RR}{L} w_1 \; * P_{pv} * L \quad + \quad x_2 * \frac{RR}{K} w_2 * P_{pk} * K \; + \; x_3 * \frac{RR}{N_{cust}} w_3 * P_{cust} * N_{cust}$$

$$+ x_4 RR \; \Big]$$

After simplification (division by RR, cancelling L, K and N_{cust}), this becomes

$$0 = a * w_1 * P_{pv} + b * w_2 \; * P_{pk} + c * w_3 * P_{cust}$$

$$- \left[x_1 * w_1 * P_{pv} + x_2 * w_2 * P_{pk} \, x_3 * w_3 * P_{cust} + x_4 \right]$$

Arranging like terms, we arrive at the following:

$$\boxed{0 = P_{pv} w_1 (x_1 - a) \; + \; P_{pk} w_2 (x_2 - b) \; + \; P_{cust} w_3 (x_3 - c) \; + x_4}$$

We note, that the utility's avoided costs are a function of the actual cost components a, b, and c, while the PV payments are a function of the corresponding optimized rate component weights x_1, $x_{2,}$ and x_3. Because this objective function contains the difference between each of the actual and optimized cost components, by taking the absolute value of each of the three terms in 5.12, the objective not only minimizes utility revenue loss, but also enforces a more cost reflective retail rate.

Revenue neutrality constraint:

Constraint (5.13) ensures revenue neutrality. This means that revenue collected under the original energy only rate RR_1, and the revenue collected under the proposed 3-part rate RR_3, are equal. This constraint is derived from the following:

$$RR_1 = r * L \; = \; \frac{RR}{L} * L \; = \; RR$$

$$RR_3 = r_{eng} * L + r_{dmd} * L + r_{cust} * N_{cust}$$

$$= x_1 \frac{RR}{L} L + x_2 * \frac{RR}{K} * K + x_3 * \frac{RR}{N_{cust}} * N_{cust} = x_1 RR + x_2 * RR + x_3 * RR$$

Setting $RR_1 = RR_3$, then

$$RR = x_1 RR + x_2 * RR + x_3 * RR$$

Or,

$$\boxed{1 = x_1 + x_2 + x_3}$$

Customer impact constraint:

Constraint (5.14) limits the change in customer bills (defined as the difference between B_1, bills under the original energy only rate, and B_3, bills under the proposed 3-part rate) to a fixed percentage δ, of their usual bills. Because low-use customers will experience relatively larger bill increases, we first separate the residential class of customers into subclasses i, according to typical monthly usage then apply customer bill impact constraint to each individual subclass of customers. Constraint 5.14 is thus derived as follows, where L_i is the average load of customers in subclass i, K_i is the average peak demand of customers in subclass i, $B_{1,i}$ is the average bill for customers in subclass i under energy only rate, $B_{2,i}$ is the average bill for customers in subclass i under the proposed 3-part rate, and $N_{cust,i}$ is the number of customers in subclass i:

$$B_{1,i} = r * L_i = \frac{RR}{L} * L_i$$

$$B_{2,i} = r_{eng} * L_i + r_{dmd} * K_i + r_{cust} * N_{cust}$$

$$= x_1 \frac{RR}{L} L_i + x_2 * \frac{RR}{K} * K_i + x_3 * \frac{RR}{N_{cust}} * N_{cust,i}$$

Setting $B_{2,i} \leq (1+\delta) * B_{1,i}$

$$x_1 \frac{RR}{L} L_i \;+\; x_2 * \frac{RR}{K} * K_i \;+\; x_3 * \frac{RR}{N_{cust}} * N_{cust,i} \leq (1+\delta) \frac{RR}{L} * L_i$$

Dividing by RR and grouping like terms, we arrive at the following:

$$\boxed{\left| \frac{L_i}{L}(x_1 - 1) \;+ \frac{K_i}{K} x_2 + \frac{N_{cust,i}}{N_{cust}} x_3 \right| \leq \frac{\delta L_i}{L}}$$

Policy-based constraint (revenue impact cap):

Constraint (5.15) enforces minimum PV payments guaranteed through renewable energy policy (i.e. renewable energy credit (REC) sales, estimated social cost of carbon displaced, or other externality price). Here, we assume that the policy constraint (5.15) enforces a minimum percentage of the utility's revenue requirement be spent on incremental renewable energy purchases (Secretary of State of the State of Washington, 2006). This means that the sum of incremental PV payments and incremental payments to other renewables must be greater than or equal to a percentage γ, of the total revenue requirement. Incremental payments IC, are defined as the average difference between payments for renewables and payments for conventional energy resources. Payments for renewables consist of two components: payments for centralized renewable resources ρ_{re}, and payments for distributed resources ρ_{pv}. Payments for conventional resources also consists of two components: payments for conventional (non-renewable) resources ρ_c, and avoided cost of distributed resources μ.

Given,

$$\rho_{pv} = x_1 * RR * w_1 * P_{pv} \quad + \quad x_2 * RR * w_2 * P_{pk} \quad + \quad x_3 * RR * P_{cust} * w_3 \quad + x_4 * RR$$

$\rho_c = a * RR * (P_{re} - P_{pv})$

$\rho_{re} = \varphi * \rho_c$

$\mu = a * RR * w_1 * P_{pv} \quad + \quad b * RR * w_2 * P_{pk} \quad + \quad c * RR * P_{cust} * w_3$

Constraint 5.15 is then derived as follows:

$IC \geq \gamma RR$

Or

$$\gamma RR \leq \rho_{pv} + \rho_{re} - \mu - \rho_c$$

$$\leq (x_1 * RR * w_1 * P_{pv} + x_2 * RR * w_2 * P_{pk} + x_3 * RR * P_{cust} * w_3 + x_4 * RR) + (\varphi * \rho_c)$$

$$- (a * RR * w_1 * P_{pv} + b * RR * w_2 * P_{pk} + c * RR * P_{cust} * w_3)$$

$$- (a * RR * (P_{re} - P_{pv}))$$

Dividing by RR

$$\gamma \leq (x_1 * w_1 * P_{pv} + x_2 * w_2 * P_{pk} + x_3 * P_{cust} * w_3 + x_4) + (\varphi * \rho_c)$$

$$- (a * w_1 * P_{pv} + b * w_2 * P_{pk} + c * P_{cust} * w_3)$$

$$- (a * (P_{re} - P_{pv}))$$

Simplifying and combining like terms we arrive at the following:

$$\boxed{\gamma - a * \left(P_{re} - P_{pv}\right) \leq w_1 * P_{pv} * (x_1 - a) + w_2 * P_{pk} * (x_2 - b) + w_3 * P_{cust} * (x_3 - c) + x_4}$$

5.4.5 Case Study

We tested the proposed rate structure and corresponding WRR VOST on a prototypical medium sized utility located in Washington State. We assume the utility has 100,000 residential customers with a distribution of customer annual consumption divided into 9 bins according to typical load share (and thus, typical bill size) as shown in Table 5-5. The majority of customers (bins 4-6) have monthly bills between $100 and $140.

Table 5-5. Distribution of Customer Consumption

Bin, i	*Customers*	*Load Share*	*Typical Bill*
#	(%)	(%)	($)
1	0.02	0.008	50.17
2	1.47	0.7	59.72
3	13	8.25	79.59
4	22	20	114
5	21	20	119.4
6	27	29	134.7
7	11	15	171
8	4.5	7	195.1
9	0.01	0.04	501.7

Table 5-6. Utility Cost Components and Bill Determinants

Assumption	*Annual Quantity*
Utility Cost Components	
Energy	$20,000,000
Demand	$15,000,000
Customer	$3,000,000
Policy (incremental RE cost)	$1,520,000
Required Revenue	$39,520,000
Energy Sales (MWh)	300,000
Base Case	
PV Penetration (%)	0.10%
Total RE Penetration (%)	3.8%
Sensitivity Case	
PV Penetration (%)	0.25%
Other RE Penetration (%)	0.4-15%

Like many states, Washington has a renewable energy portfolio standard. Washington utilities with more than 25,000 customers must meet a least 15% of their loads with non-hydro renewables by 2020 (Secretary of State of the State of Washington, 2006). Alternatively, the utility can achieve RPS compliance by spending at least 4% of its retail revenue requirements on the incremental cost of renewables. For the policy constraint of this problem, we assume that the utility chooses the latter option.

The optimal retail rate components were determined based on utility costs listed in Table 5-6. PV payments, utility revenue erosion, and customer impact were all assessed.

Next, we calculated the PV payments ρ_{pv}, the percent utility revenue erosion (lost revenue) $\alpha_{\%}$, and the impact on customers in the i[th] bin $\beta_{i,\%}$, as Equations 5.21 to 5.23. In equation 5.22, γ is the percentage of the revenue requirement spent on the incremental cost of renewables (for this case, $\gamma = 4\%$).

$$\rho_{pv} = x_1 * RR * w_1 * P_{pv} \quad + \quad x_2 * RR * w_2 * P_{pk} \quad + \quad x_3 * RR * P_{cust} * w_3 \quad + x_4 * RR \qquad (5.21)$$

$$\alpha_{\%} = \frac{\left[\rho_{pv} - \left(w_1 a \frac{RR}{L} + w_2 b \frac{RR}{K} + w_3 c \frac{RR}{N_{cust}}\right)\right]}{RR} * 100 \qquad (5.22)$$

$$\beta_{i,\%} = \frac{\left[(r - r_{eng})L_i - r_{dmd}K_i - r_{cust}N_{cust,i}\right]}{rL_i} * 100 \qquad (5.23)$$

Since we neglected w_3, PV payments are only a function of the value of solar tariff and the total PV output. In Equation (5.23), the customer impact is calculated as the change in customer bills from an energy only rate r, to the proposed optimized three-part rate.

5.5 Results

5.5.1 PV Weights

The energy weight, w_1 was calculated based on price variations at the Mid-Columbia pricing hub and was determined to be 1.06, meaning that PV produces power at times when market prices are about 6% more expensive than average. Using the PVWatts calculator (NREL, 2014) simulated PV data for Seattle, WA, the demand weight, w_2, was determined to be 0.11. As stated in the previous section, w_3 was assumed to be zero.

5.5.2 Base Case: 0.10% PV Penetration, 3.8% RE Penetration

For the base case scenario, we consider the 2012 renewable energy (RE) penetration of non-hydro renewables in Washington State (3.8%) and 0.10% PV penetration (Bonlender, 2012). Table 5-7 presents the results of the optimized rate component weights under the base case scenario. Because the RE penetration is low, the policy constraint requiring a minimum investment in the incremental cost of RE results in a rate that is heavily energy weighted. This is because the energy weight, w_1 provides the highest contribution to the VOST value. In Table 5-7, x_4 is 0.0205, meaning that the total value of externality payments v, is 2.05% of the utility's required revenue. In other words, the cost of the policy-based constraint is 2.05% of the required revenue. This cost must be allocated to ratepayers (i.e. NEM), society (i.e. state production incentives, rebates), the utility (lost revenue) or a combination of the three.

Table 5-7. Optimization Results

Actual Rate Proportion	*p.u.*	*Optimized Rate Proportion*	*p.u.*
$\boldsymbol{a}$	0.53	x_1	0.5632
$\boldsymbol{b}$	0.39	x_2	0.4100
$\boldsymbol{c}$	0.08	x_3	0.0269
--	--	x_4	0.0205

Table 5-8 shows the resulting VOST, 3-part rate and policy-based PV incentive. Because the selected policy does not specify how the externality (policy-based) payment v, should be distributed, we present it in Table 5-8 as a fixed value ($/kW-yr) and as a variable value

($/kWh) for comparison. In this case, the variable incentive is $1.73/kWh, far exceeding what is possible with NEM. This means that for small penetrations of RE, NEM actually undervalues solar and, without additional incentive payments, is potentially inconsistent with the RPS policy compliance method used in this analysis.

Table 5-8. Comparison of Retail Rates, VOST, PV Payments, and Utility Lost Revenue under a 1-Part Rate (net metered) and 3-Part Rate (partially net metered)

	1-Part Rate	*3-Part Rate*
Retail Rate		
Energy ($/kWh)	$0.084	$0.048
Demand ($/kW)		$12.980
Customer ($/Cust.)		$3.368
WRR VOST		
Energy ($/kWh)	N/A	$0.051
Demand ($/kW)	N/A	$1.428
Customer ($/Cust)	N/A	$0.000
Externality ($/kW-yr)	N/A	$1,667.00
($/kWh)		$1.73
Avoided Costs ($/yr)	$21,842	21,842
PV Payments ($)	$38,000	$23,351
Utility Lost Revenue (%)	0.0425	0.004

Table 5-9 shows the percent change in bills after customers switch to the 3-part retail rate. In this case, the binding constraint is the policy constraint and no class of customers approaches the 10% limit on bill increases. The next section looks at how the retail rate components and policy-enforced incentive change with increasing penetration of distributed PV as well as increasing RE penetration in general.

Table 5-9. Percent change in customer bills under new 3-part rate

Bin #	Customer (%)	1-Part Rate Bills ($)	3-Part Rate Bills ($)	% Change in Bill (%)
1	0.02	$ 50.17	$ 52.19	4.03
2	1.47	$ 59.72	$ 61.48	2.96
3	13	$ 79.59	$ 80.82	1.55
4	22	$ 114.00	$ 114.30	0.27
5	21	$ 119.40	$ 119.60	0.13
6	27	$ 134.70	$ 134.50	-0.19
7	11	$ 171.00	$ 169.80	-0.72
8	4.5	$ 195.10	$ 193.20	-0.96
9	0.01	$ 501.70	$ 491.50	-2.01

5.5.3 Sensitivity: RE Penetration

Figure 5-7 presents the optimized rate component weights for increasing penetrations of RE. This effectively represents the sensitivity of the rate structure to the RPS goals. We observe that the optimal retail rate is slightly more energy weighted for RE penetrations less than 8%. This is due to the policy constraint enforcing a minimum payment to renewables, both conventional and distributed. However, as RE penetration increases beyond 8%, the utility meets the policy constraint with centralized resources and the retail rate adjusts accordingly.

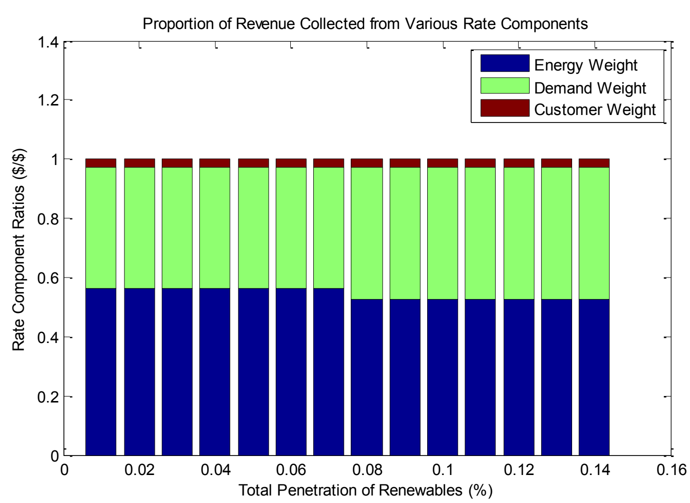

Figure 5-7. Optimization Results at Increasing RE Penetration Rates

Figure 5-8 illustrates the utility's lost revenue due to PV payments as a function of RE penetration. Because we have separated the policy-based value and neglected how that cost is allocated for now, the WRR VOST with a 3-part rate has negligible impact on utility revenue while traditional net metering with a 1-part, energy only rate causes immediate revenue erosion.

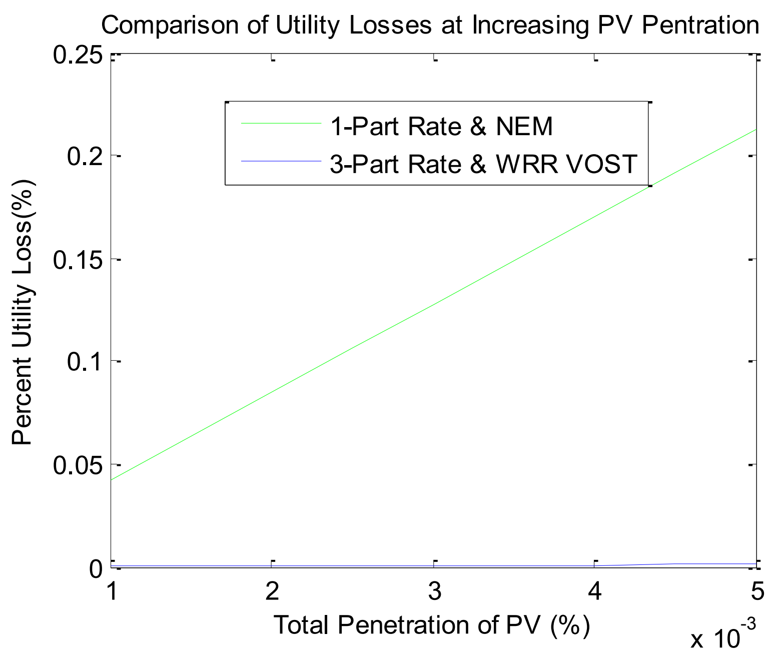

Figure 5-8. Comparison of Utility Lost Revenue at Increasing RE Penetration (PV Penetration Fixed at 0.25%)

The policy-based value of PV is presented in Figure 5-9 as a production credit incentive. For very low penetrations of RE and PV, this value is extremely high (almost 100 times the price of electricity!). However, as RE penetration increases or as PV penetration increases this incentive price drops very quickly[12].

[12] As a side comparison, the RE penetration for SnoPUD in 2014 was 7% and PV penetration was .2%. The current production incentive in Washington State is $0.54/kWh. Under the proposed method this incentive would be $0.28/kWh.

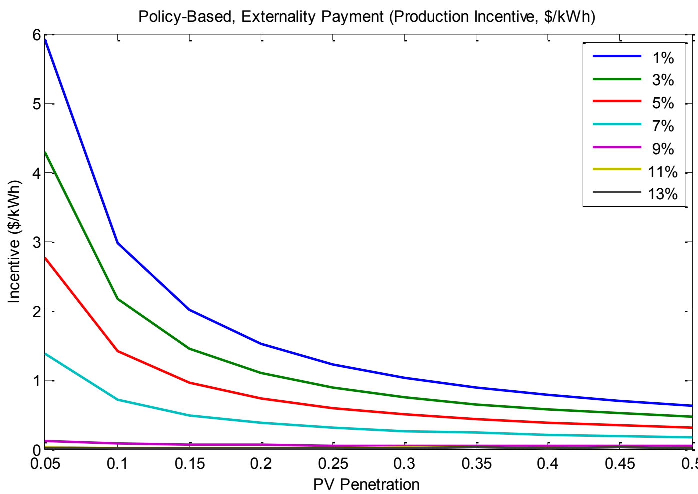

Figure 5-9. Policy-based value of PV as a function of PV penetration (0.05% - 0.5%) and RE Penetration (1% - 13%): variable incentive, or production credit ($/kWh)

5.6 Conclusion

The development of mechanisms to fairly and correctly price customer consumption as well as production will eventually become necessary, if not critical. Thus, the value of solar, and related value of solar tariff design, is a topic that will inevitably need to be addressed by every state. Here, we present a 3-part retail rate and corresponding weighted retail rate value of solar tariff to address the issue of poor rate design and NEM cost shifting.

Chapter 6. Conclusion, Contributions and Future Work

Integrating distributed energy resources, including DR and DSG, will unfortunately incur costs for at least the foreseeable future. This is because a) demand response is not an energy resource directly bought by end-use customers; it is a resource used to reduce market prices and therefore reduce market revenue, and b) energy from distributed solar generation is more expensive than conventional generation and the increased cost must be borne by the society that draws value from the unique properties of DSG. Successful valuation approaches must therefore address the issue of how those costs are incurred (i.e. DER prices) as well as fair cost allocation (allocation proportional to benefits). Restructuring current rate design represents possibly the simplest and most efficient means to express both the value of the grid and the value of DERs in a single price. However, so long as retail rates represent average (and not marginal) value of resources, there will need to be a separate mechanism to quantify the marginal value of DERs and to price them accordingly. We propose that this valuation methodology consider network models, RE models, economic or market models as well as policy impact models.

The technical, economic, and societal benefits of distributed energy resources have been extensively explored and defined. To some extent, the literature on quantifying the economic value of various benefits is vast and leads to equally widely varying conclusions. Less explored, however, has been the role of policy in quantifying the economic value of various non-traditional benefits that, unlike energy and capacity, are not readily monetized. This work provides contributions to methodologies that quantify the economic value of societal and environmental benefits of DERs as well as contributions to the development of value-based DER pricing mechanisms. In terms of the value of DR in wholesale markets, we have proposed:

1) A Fair and efficient cost allocation methodology for DR in wholesale energy markets (for case when DR changes LMP and necessitates cost allocation)
2) A demand response supply curve (to set DR price level when DR <u>is not allowed</u> to change LMP and cost allocation is therefore not required)

As for DR at the retail level, we have proposed the following value-based mechanisms:

1) A Utility Risk and DR Value-Based Incentive: for the case when customers are on flat energy only retail rates.
2) A Customer Risk and DR Value-Based Dynamic Pricing: for the case when customers are not on flat, energy only retail rates.

Finally, in terms of the value of DSG, we have proposed the following:

a. A New Value of Solar Tariff: A VOST based on a combination of NEM properties as well as emerging VOST design.
b. A Combined Retail Rate and VOST that explicitly models policy-driven value and is optimized to maximize prosumer benefits, minimize cost shifting to non-participating customers, and minimize utilities economic losses.

The practice and policy of valuing distributed energy resources as conventional centralized resources inevitably either undercompensates or overcompensates DERs and is fast becoming unsustainable. Our hope is that this work provides a foundation for valuing DERs which promotes and facilitates optimal integration through a thorough analysis that considers local technical constraints as well as policy and rate design influences.

Building on this foundation, future work could expand the breadth of technical and policy influences on DER value. With regard to DR pricing, we have proposed a dynamic price that is a function of a local grid condition index based on network loading. However, this price could also be a function of additional grid conditions. For example, voltage issues are also of great concern in distribution networks, in particular under a high rooftop solar penetration scenario. Thus, the mRTP developed in Chapter 4 could be expanded to include an additional grid state index G_v, to represent proximity to voltage violations, in addition to G_n, which represents proximity to overload conditions. With regard to the proposed co-optimized retail rate and value of solar tariff, although the retail rate consists of multiple components, we have still assumed a flat rate for these rate components. Future work could explore how the proposed WRR VOST methodology works with dynamic pricing, in particular, the mRTP proposed in Chapter 4. Furthermore, while the only policy constraint considered in this work was a price cap constraint, a number of different policies or combination of policies could also be implemented.

Finally, while we have considered the effect of DERs on utility revenue under various proposed DER pricing schemes, we have not considered how alternative utility business models might also allow for DER integration. One such alternative model currently subject to debate is the concept of utility owned PV sited on customer rooftops. This is a fairly new concept and state policies are only recently beginning to address it. Although a limited number of states have explicit legislation regarding utility owned DERs, the policies differ wildly and range from completely barring utilities from owning DERs (New York), to allowing utilities to own DERs but not to recover the investment cost through rates (South Carolina), to perhaps the most controversial, allowing utilities to own customer sited DERs and also to recover the investment cost and rate of return on that investment from the rate base (Arizona).

There are a number of possible paths in the pursuit of DER integration. Whether this issue is tackled from a DER pricing point of view or from a utility business model point of view, it is important that the value of DERs to the grid as well as the value of the grid to DER customers both be fully and fairly represented.

Appendix 1: OPF Formulation

The OPF solution is calculated using MATPOWER software. The standard OPF equations have the following form:

$$\min_{x} F(x) = \sum_{i=1}^{n_g} f_P^i(p_g^i) + f_Q^i(q_g^i)$$

Subject to

$$H(x) = 0$$

$$G(x) \leq 0$$

$$x_{min} \leq x \leq x_{max}$$

$$x = \begin{bmatrix} \theta \\ V_m \\ P_g \\ Q_g \end{bmatrix}$$

The objective function, F, is the sum of individual generator real power cost functions f_P^i and reactive power cost functions f_Q^i, for, $i = 1 \dots n_g$, and n_g = number of generators.

The equality constraints, H, are the set of nonlinear real and reactive power balance equations H_P and H_Q, respectively, where $i = 1 \dots n_b$ and n_b = number of buses.

$$H = \begin{cases} H_P(\theta, V_m, P_g) = P^i(\theta, V_m) + P_d^i - P_g^i \\ H_Q(\theta, V_m, P_g) = Q^i(\theta, V_m) + Q_d^i - Q_g^i \end{cases}$$

The inequality constraints, G, consist of apparent power flow limits for the from F_f, and to F_t, ends of each line.

$$G = \begin{cases} g_f = |F_f(\theta, V_m)| - F_{max} \\ g_t = |F_t(\theta, V_m)| - F_{max} \end{cases}$$

The optimization vector x contains vectors for voltage angles ϑ, voltage magnitudesV_m, and the generators' real and reactive power outputs P_g and Q_g, repectively.

Appendix 2 (6-Bus System Parameters)

Branch data

Bus (From)	*Bus (To)*	*R (pu)*	*X (pu)*	*B (pu)*	*Rating (MVA)*
1	2	0.10	0.20	0.04	36
1	4	0.05	0.20	0.04	72
1	5	0.08	0.30	0.06	63.6
2	3	0.05	0.25	0.06	36
2	4	0.05	0.10	0.02	91.2
2	5	0.10	0.30	0.04	42
2	6	0.07	0.20	0.05	72
3	5	0.12	0.26	0.05	36
3	6	0.02	0.10	0.02	84
4	5	0.20	0.40	0.08	18
5	6	0.10	0.30	0.06	14.4

Bus Data

Bus	*P (MW)*	*Q (MVA)*	V_{max} *(pu)*	V_{min} *(pu)*
1	0	0	1.1	0.9
2	0	0	1.1	0.9
3	0	0	1.1	0.9
4	120	80	1.1	0.9
5	115	82	1.1	0.9
6	140	66	1.1	0.9

Generator Data

Bus	*Pmax (MW)*	*Pmin (MW)*	*Qmax (MVAR)*	*Qmin (MVAR)*	C_2 *($/MW)²*	C_1 *($/MW)*
1	132.5	112.5	150	-150	0.0005	8.5
2	165	140	150	-150	0.0005	9.0
3	80	60	150	-150	0.0005	9.5

Appendix 3: Minnesota VOST Components

Load Match Factors: ELCC and PLC

ELCC: As previously mentioned, this method requires the calculation of two different capacity factors: ELCC and PLR. ELCC is calculated as the average production of the marginal PV resource during peak hours.

$$ELCC = \frac{\sum_{PeakMonths}\sum_{PeakHours} PVFleetShape_{month,hour}}{TotalPeakHours}, \quad (\%)$$

where,

$$PVFleetShape_{hour} = \frac{PVFleetProduction_{hour}}{PVRating}, \qquad \left(\frac{KWh}{KW - AC}\right)$$

$$PVRating \ = InstalledPVRating * InverterEfficiency * LossFactor, \qquad (kW - AC)$$

PLR: The PLR factor is a measure of the overall system peak that is reduced by PV. For this value to be nonzero, the system peak must occur during the day, when there is potential solar output.

Avoided Cost Components

In order to calculate the value of solar rate, the avoided cost of each value component is individually calculated. After all components have been determined, they are weighed according to the appropriate load match factor and added value of loss reduction is applied. The final value of solar is then the weighted sum of each of the individual components.

Avoided Fuel:

This methodology considers the avoided fuel costs when fuel is purchased at long-term contract prices. Because the price is fixed over a long period of time, the implied value is both that of energy as well as the avoided volatility in market prices. The avoided market volatility, or hedging value, is captured by discounting the VOS price at the risk-free discount rate tied to US treasury yields. The fixed price in each contract year is based on average monthly NYMEX futures quotes[13]. These prices are provided for a period of 12 years after which gas prices of the 12th year are escalated at the assumed general escalation rate. In order to calculate the costs from fuel prices, the solar weighed heat rate is required. This requires hourly heat rates for the actual plant on the margin.

$$VOS_1 = \frac{\sum_{year=0}^{24} RiskFreeDiscountFactor_{year} PVProduction_{year} BurnerFuelPrice_{year} SolarWeighedHeatRate_{year}}{\sum_{year=0}^{24} PVProduction_{year} RiskFreeDiscountFactor_{year}}$$

Where,

[13] These quotes can be found at the CME Group's Natural Gas (Henry Hub) Physical Futures Quotes website: www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

$$RiskFreeDiscountFactor_{year} = \frac{1}{(1+r)^{year}}$$

$$PVProduction_{year} = \sum_{hour=1}^{8760} PVFleetShape_{hour} * (1-p)^{year}$$

$$SolarWeighedHeatRate_{year} = \frac{\sum_{hour=1}^{8760} HeatRate_{hour} * PVFleetShape_{hour}}{\sum_{hour=1}^{8790} PVFleetShape_{hour}} * (1+h)^{year}$$

$$BurnerFuelPrice_{year} = \begin{cases} NGPrice_{year} + FuelPriceOverhead * (1+g)^{year}, & year = 0 \dots 11 \\ NGPrice_{11} * (1+g)^{year}, & year = 12 \dots 24 \end{cases}$$

Avoided Plant O&M - Variable:

Variable O & M are based on actual data (if the utility owns generation plants). Otherwise, the U.S. Energy Information Administration reports estimated costs (U.S. Energy Information Administration, 2013).

$$VOS_2 = \frac{\sum_{year=0}^{24} DiscountFactor_{year} PVProduction_{year} * O\&MVariableCost_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

Where,

$$DiscountFactor_{year} = \frac{1}{(1+d)^{year}}$$

$$O\&MVariableCost_{year} = O\&MVariableCost_0 * (1+v)^{year}$$

Avoided Plant O&M - Fixed:

Similarly, fixed O & M costs are based on actual data (if the utility owns generation plants). Otherwise, estimates are substituted.

$$VOS_3 = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * O\&MFixedCost_{year} * \frac{PVCapacity_{year}}{UtilityCapacity_{year}}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

Where,

$$PVCapacity_{year} = (1-p)^{year}$$

$$UtilityCapacity_{year} = (1+h)^{year}$$

$$O\&MFixedCost_{year} = F_0(1-f)^{year}$$

Avoided Generation Capacity:

It is assumed that PV capacity displaces capacity of a natural gas generator, either CT or CCGT. So the cost is calculated as an average of these two technologies, interpolated by their respective heat rates. These heat rates and capital costs must be known or estimated. This averaged generation capacity cost is weighted with the ratio of annual PV capacity to utility capacity. This is because PV capacity decreases as a function of the PV degradation rate. But since utility capacity also degrades with time, this ratio adjusts the PV capacity factor upwards (increasing PV capacity value slightly).

$$VOS_4 = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * CapacityCost_{year} * \frac{PVCapacity_{year}}{UtilityCapacity_{year}}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

Where,

$$CapacityCost_{year} = C_{g(1\ or\ 2)} * \frac{d}{1-(1+d)^{25}}$$

$$C_{g1} = \frac{C_w + C_h + C_b}{3}$$

$$C_{g2} = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) * \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}}$$

Avoided Reserve Capacity:

In general, many studies have listed additional reserve needs as a cost to integrate PV and compensate for potentially high forecast errors (Argonne National Laboratory, 2014). However, this methodology assumes that PV reduces the capital cost of generation to meet planning margins and ensure reliability. As such, this component is calculated in the same way as the generation capacity component is calculated, and is equal to the generation capacity value multiplied times the reserve margin.

$$VOS_5 = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * CapacityCost_{year} * \frac{PVCapacity_{year}}{UtilityCapacity_{year}}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}} * ReserveMargin$$

Avoided Transmission Capacity:

Transmission capacity value is similar to that of generation capacity; however, it is assumed that the transmission level capacity does not degrade (Annual Transmission Capacity=1). Transmission capacity costs are based on the previous 5 years' transmission network cost.

$$VOS_6 = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * TransCapacityCost_{year} * \frac{PVCapacity_{year}}{1}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

Where,

$$TransCapacityCost_{year} = \frac{\sum_{PastYear=-5}^{-1} NetworkCost_{PastYear}}{5}$$

Avoided Distribution Capacity:

Essentially, the distribution capacity value is based on the difference in utility costs when conventional planning is used and when a deferred plan is used. In a deferred cost plan, it is assumed that any new capacity required in a given year can be delayed by PV for an entire year[14]. Thus, in each year, the deferred plan will result in lower costs than the conventional plan and the difference is the value of distribution capacity.

$$VOS_7 = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * DistCapacityCost_{year} * \frac{PVCapacity_{year}}{1}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

Where,

$$DistCapacityCost_{year} = \frac{(ConventionalPlanCost - DeferredPlanCost) * d}{1 - (1+d)^{year}}$$

$$ConventionalPlanCost = \sum_{year=0}^{24} DistCapitalCost * NewDistCapaciy_{year} * DiscountFactor_{year}$$

$$NewDistCapaciy_{year} = PeakLoad * PeakLoadGrowthRate(1 + PeakLoadGrowthRate)^{year}$$

$$DeferredPlanCost = \sum_{year=1}^{25} DistCapacityCost * DeferredDistCapacity_{year} * DiscountFactor_{year}$$

$$DeferredDistCapacity_{year} = \begin{cases} 0\ , & year = 0 \\ NewDistCapacity_{year-1}\ , & year \neq 0 \end{cases}$$

Avoided Environmental Costs

Environmental externalities are based solely on the EPA estimated social cost of carbon and any available State estimates for non-carbon pollutants. The sum of these costs are collectively represented below as yearly "EnvironCost".

$$VOS_8 = \frac{\sum_{year=0}^{24} EnvironDiscountFactor_{year} EnvironCost_{year} * SolarWeighedHeatRate_{year} * PVProduction_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

Where,

$$EnvironDiscountFactor_{year} = \frac{1}{(1 + EnvironDiscountRate)^{year}}$$

[14] Note that in each year, the deferred distribution capacity is equal to the new capacity required in the year prior.

Appendix 4: Modified PNUCC VOST Components

Modifications

The following modification were made to the PNUCC methodology:

***Energy Hedge Value**

For PNUCC, the energy hedge value is assumed to range from $0-$2.00 per MWh and is based on the energy efficiency hedge value from Avista's 2013 IRP. For this report, we use SnoPUD's winter planning standard methodology which estimates the value at risk due to various contingencies, including market price volatility.

***Transmission Capacity Value**

PNUCC defines capacity value as being derived from PV's ability to defer building of new transmission lines. As such, this means that a non-zero transmission capacity value is contingent upon the existence of transmission congestion and this value was not assessed in its latest analysis (October 2014). For our purposes, we will assume that the capacity value is based on PV's ability to generate locally and reduce costs for BPA transmission.

****REC Sales**

This value component was added as an alternative to using reduced RPS needs to represent PV's environmental externalities. Although we do consider reduced RPS need as a value, we must also consider the case when SnoPUD takes title of customer's RECs.

Avoided Energy Value

The value of energy reductions in this methodology is based on 2015 Mid-Columbia price forecasts. This price serves as a proxy for the value of fuel as well as fixed and variable plant operation and maintenance costs.

$$VOS_1^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * \left(\sum_{hour=1}^{8760} MidColumbiaPriceForecast_{year,hour} * PVFleetShape_{year,hour}\right)}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$MidColumbiaPriceForecast_{year,hour} = 2015MidColumbiaPriceForecast_{hour} * (1+g)^{year}$$

$$PVFleetShape_{year,hour} = PVFleetShape * (1-p)^{year}$$

Energy Hedge Value

The energy hedge value is calculated based on SnoPUD's Winter Planning Standard methodology. This practice calls for SnoPUD to enter the winter peak month of December with an on-peak energy length in order to mitigate exposure to uncertainty in various contingencies, including, but not limited to, severe cold weather, loss of a PUD resource and spot market price volatility. The value of this hedging practice is calculated by taking the standard deviation of December on-peak prices around the historic mean December Mid-Columbia on-peak market price. The calculated standard deviation is used as a percentage and multiplied by the forecasted December on peak prices to determine the value at risk of market exposure[15].

However, since it has been shown that the largest PV contribution does not occur in the winter, for PV we calculate the standard deviation (**in $/MWh**) of the Mid-Columbia hourly forecast prices for the entire year. This standard deviation is converted to a percentage and multiplied by the average forecasted price to determine the energy hedge value over the entire year.

$$VOS_2^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * \sum_{hour=1}^{8760}\left(EnergyHedgePrice_{year,hour} * PVFleetShape_{year,hour}\right)}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$EnergyHedgePrice_{year,hour} = \frac{stdev\left(MidColumbiaPriceForecast_{year}\right)}{100} * MidColumbiaPriceForecast_{year\ hour}$$

Avoided Line Losses

Line losses are valued at the energy price times the percentage reduction in losses. Here, we have assumed a 7.5% transmission and distribution line loss reduction.

$$VOS_3^{PNUCC} = 0.075 * VOS_1^{PNUCC}$$

Reduced RPS Need

There are three RPS compliance methods in Washington. SnoPUD currently meets its RPS requirements by investing a minimum of 4% of its total retail revenue requirement on the incremental cost of renewable resources (excluding hydro). Alternatively, a second compliance method sets a target of 9% renewables by 2015 and 15% by 2020.

Method 1:

For the first compliance method (4% RRR), the value of RPS need reduction is based on the difference between retail revenue requirements with and without PV, given a particular energy penetration of PV.

$$RPSValue_{1,year} = \frac{\left(RRR_{1,year} - RRR_{2,year}\right)}{PVProduction_{year}}, \qquad \left(\frac{\$}{MWh}\right)$$

$$RRR_{1,year} = \left(RRR_{1,0}\right) * (1+g)^{year} \qquad (\$)$$

[15] SnoPUD 2013 IRP – Appendix F: Winter Planning Standard

$$RRR_{2,year} = (RRR_{1,year}) * \left(1 - \frac{PVProduction_{year}}{RetailEnergy * (1 + .001)^{year}}\right), \quad (\$)$$

Table 0-1. Example of compliance method 1 calculation

Compliance Method 1	2014 Retail Revenue Requirement $\boldsymbol{RRR_{1,0}}$ (\$)	2014 Retail Revenue Requirement $\boldsymbol{RRR_{2,0}}$ (\$)	RPS Value (\$/MWh)	***RRR Need***	***PV Production (MWh)***	***VOS***
Year=0	\$555,232,503	\$555,232,417	\$84.547	*4%*	*1.018*	*.00338*

Then finally, the VOS component is calculated using the percentage of the retail revenue requirement needed to meet the RPS standard in each particular year. The levelized approach is as follows:

$$VOS_4^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * RRRInvestmentNeed_{year} * RPSValue_{1,year} * PVProduction_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$RRRInvestmentNeed_{year} = \{0.04, \ (\%) \quad for\ year = [0 \dots 24]$$

Table 0-1 lists the annual levelized reduced RPS need value of solar using this compliance method.

<u>Method 2:</u>

Alternatively, for the second compliance method, the RPS value is based on the price for procuring renewable energy resources. In this case, we assume that these resources are purchased, not owned. The prices are based on the average projected 2014 renewable energy purchase costs from the SnoPUD 2014 budget. Then, the RPS value is calculated as follows:

$$RPSValue_{2,year} = \frac{TotalPurchasedRenewableEnergyCost}{TotalRenewableEnergyMWhsPurchased} * \frac{(1+g)^{year}}{(1+h)^{year}}$$

Here, the VOS component is calculated by considering the RPS need in each particular year.

Table 0-2. Value of Reduced RPS Need (\$/MWh)

Compliance Method 2	2014 Total RE Purchases (MWh)	2014 Payments (\$)	RPS Value (\$/MWh)	RPS Need	***PV Production (MWh)***	VOS Price (\$/kWh)
Year = 0	553,287	\$40,471,507	73.147	9%	1.018	0.00646

$$VOS_4^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * RPSNeed_{year} * RPSValue_{2,year} * PVProduction_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$RPSNeed_{year,method1} = \begin{cases} 0.09, & (\%) \quad for\ year = [0 \dots 5] \\ 0.15, & (\%) \quad for\ year = [6 \dots 24] \end{cases}$$

Table 0-2 lists the annual levelized reduced RPS need component of the value of solar using the second compliance method.

REC Sales

The value of REC sales depends first and foremost on whether or not the utilities are allowed to take title of the REC. Since the function of RECs is to separate the renewable quality from the electricity quality of the resource, utilities that own RECs must choose whether to value the environmental component of PV according to its contribution to the utility's RPS requirements or as a sale to meet the requirements of another load serving entity. However, it may be possible to count the value the RPS need reduction as well as that of the REC sale simultaneously.

Another factor seriously impacting the value of REC sales is the existence of state or regional REC or SREC markets. States with undersupplied SREC markets that allow for out-of-state sales and have high alternative compliance payments (ACP) would obviously serve to increase the environmental value component of solar. In a special report from Platts, the volatility and irrational behavior of SREC markets is explained in detail. Here, it is only important to note that this value is very much policy dependent and time constrained. As a result, prices in SREC markets can vary anywhere from $1/MWh to several hundred dollars per MWh.

Although local utilities can fulfil RPS requirements through REC purchases, Washington State does not currently have a REC market. In SnoPUD's 2010 IRP, REC prices are forecast through 2022 for various scenarios, producing a range of REC prices (Figure 0-1).

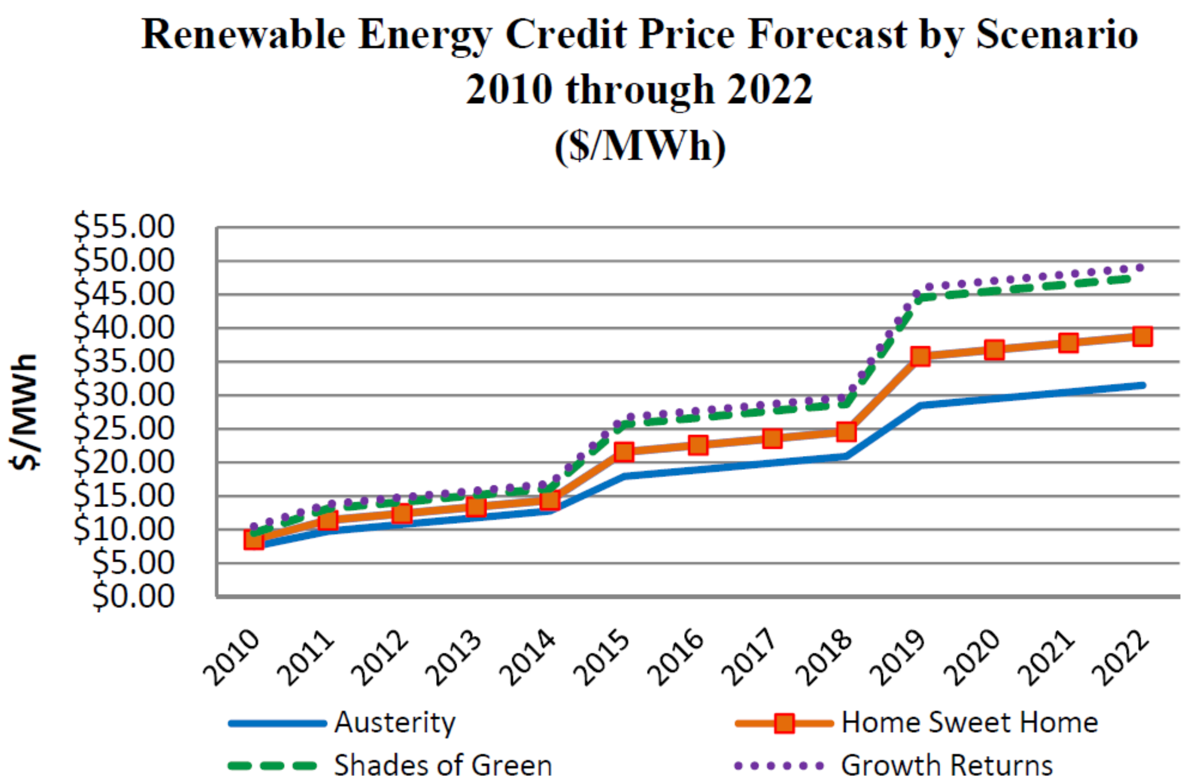

Figure 0-1. REC Price Forecast (Source: SnoPUD 2010 IRP)

Without clear, long term policy, the utility is exposed to risk if a high REC price is assumed, and if too low a value is assumed, then solar is undervalued. However, based on current market conditions and speculations about policy, market observers believe that REC prices in the Western region will be low (Platts, 2012). In light of this, we have assumed an SREC price on the low end of the spectrum ($1.00-$3.00/REC). For comparison, we also consider the case of high REC prices ($15-$50) provided in the SnoPUD 2010 IRP[16].

$$VOS_5^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * RECPrice_{year} * PVProduction_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$RECPrice_{year} = AverageRECPrice * (1+g)^{year} \qquad \left(\frac{\$}{MWh}\right)$$

Avoided Generation Capacity Value

The PNUCC methodology accounts for generation capacity in one of two ways: a) value of capacity sold (an uncommon scenario) and b) value of the net cost of a new generation plant (the total cost of the plant after marketable attributes such as energy and ancillary services have been accounted for). It should be noted, that for a winter peaking utility, PV typically

[16] The IRP does not provide REC forecast prices beyond 2022. For this analysis, REC prices beyond 2022 are assumed to stay fixed at $50.

adds no generation capacity value. However, assuming that capacity can be sold (at any time bilaterally, or during auction periods), then the generation capacity value depends upon market or bilateral capacity prices.

We assume that generation capacity can be sold any day of the year (SellingDays=365) and the generation capacity is therefore calculated as follows:

$$VOS_6^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * CapacityPrice_{year} * SellingDays * CapacityFactor * PVCapacity_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$CapacityPrice_{year} = CapacityPrice_{2014} * (1+g)^{year}$$

Avoided Transmission Capacity

The avoided transmission capacity cost was based on the average BPA point to point transmission rate for the past two rate cases (approximately a 5-year price average).

$$VOS_7^{PNUCC} = \frac{\sum_{year=0}^{24} DiscountFactor_{year} * TransCapacityCost * CapacityFactor * PVCapacity_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$TransCapacityCost_{year} = \frac{1}{2} * \sum_{year} BPANetworkCost_{year}, \quad year = \{2010, 2014\}$$

PV Integration Cost

This method takes into consideration integration costs and therefore calculates the net value of PV. Although it is often assumed that these integration costs are negligible, a recent PV integration study from Idaho Power estimated these costs for increasing penetrations of PV (Idaho Power, 2014). Cost estimates used were in agreement with other recent integration studies carried out at various national labs (Mills, et al., 2014). Since the penetration of PV is not likely to exceed 100MW, the value of $0.40/MWh was used.

Table 0-3. Integration Costs for Increasing PV Capacities (2014 dollars), Source: Idaho Power

	0-100 (MW)	*0-300 (MW)*	*0-500 (MW)*	*0-700 (MW)*
Integration Cost	$0.40/MWh	$1.20/MWh	$1.80/MWh	$2.50/MWh

$$VOS_8^{PNUCC} = (\mathbf{-1}) * \frac{\sum_{year=0}^{24} DiscountFactor_{year} * IntegrationCost_{year} * PVProduction_{year}}{\sum_{year=0}^{24} PVProduction_{year} DiscountFactor_{year}}$$

$$IntegrationCost_{year} = 0.40 * (1+g)^{year}$$

Appendix 5: Value of Solar Tariff Utility Case Study Assumptions: SnoPUD

Data Sources:

Load Data: Hourly, overall total system load data for 2012 and 2013 were used in the analysis, including calculation of the peak load reduction factor and new distribution capacity requirements.

PV Data: Hourly PV data was simulated using PV Watts[17] assuming weather patterns for the Seattle area and a variety of random PV orientations. The raw output data was then normalized to produce a "PV Fleet Shape" in accordance with the Minnesota VOST method as follows:

$$PVFleetShape_{hour} = \frac{PVFleetProduction_{hour}}{PVRating}, \qquad \left(\frac{KWh}{KW - AC}\right)$$

Where,

$$PVRating = InstalledPVRating * InverterEfficiency * LossFactor, \qquad (kW - AC)$$

SnoPUD currently has 3MW of distributed PV installed and the inverter efficiency was assumed to be 0.95 and the loss factor assumed to be 0.85. Using this definition, the sum of the PV Fleet Shape represents the annual energy output for a marginal PV system rated at 1 kW-AC (during the first year before any PV degradation effects).

$$FirstYearEnergyProduction = \sum_{hour=1}^{8760} PVFleetShape_{hour}, \qquad (kWh)$$

Environmental Costs Data: Environmental costs were based on the EPA estimated social cost of carbon and a 3% discount rate. Since Washington does not have an externalities cost established for other pollutants, no other costs were used (unlike the case in Minnesota). Figure 0-1 below lists the EPA social cost of carbon in $/MMBtu (assuming a 3% discount rate).

[17] PV Watts is a solar output simulator developed by the National Renewable Energy Lab (NREL): http://pvwatts.nrel.gov/pvwatts.php

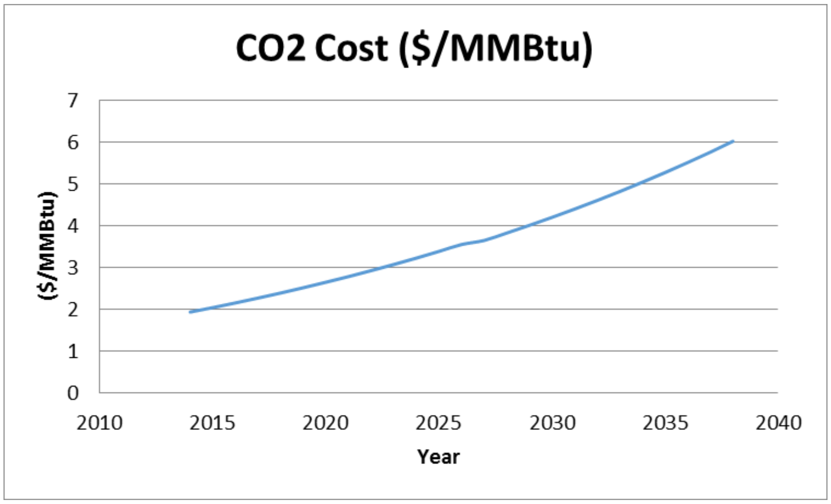

Figure 0-1. EPA Estimated Social Cost of Carbon (3% real discount rate)

Transmission Related Cost Data: Network charges were determined from BPA's Network Integration and Point to Point rates found in the 2014 and 2010 "Transmission, Ancillary Service and Control Area Service Rate Schedules" (BPA, 2013) (BPA, 2009). Table 0-1 below summarizes these transmission costs.

Table 0-1. Transmission related capacity costs

Year	Point to Point Rate ($/kW-mo)	Network Integration ($/kW-mo)
2014	$1.298	$1.741
2010	$1.479	$1.665
Average	**$1.388**	**$1.703**

New Generation Cost Data: When calculating the value of avoided generation capacity, many Value of Solar studies assume that distributed PV displaces natural gas generation, either CT, CCGT or some combination thereof. In general this assumption is correct, as the marginal generator in many locations is a natural gas resource. In the Pacific Northwest region, the marginal resource is both hydro and gas (FERC, 2015). We therefore assume, initially, that PV displaces or defers a new gas plant. The costs associated with new generation is derived from EIA generation capital costs estimates and heat rate values (EIA, 2013). Table 0-2 below contains cost and heat rate data needed in to carry out the value of solar study. Estimated operational and maintenance costs are listed in Table 0-3.

Table 0-2. Gas Plant Capital Costs and Heat Rates

Advanced CT (peaking)			
	Installed cost	676	$/kW
	Heat rate	9750	BTU/kWh
Advanced CC (intermediate peaking)			
	Installed cost	1023	$/kW
	Heat rate	6430	BTU/kWh

Table 0-3. Variable and Fixed Operational and Maintenance Costs

	Fixed Cost ($/kW)	*Variable Cost ($/kWh)*
Advanced CT	$7.04	$0.010375
Advanced CC	$15.37	$0.00327
Average	$11.205	$0.00682

It is important to note that SnoPUD has a commitment to pursuing only clean, renewable generation. Thus, it is more correct to assume that PV displaces a combination of other renewable resources. According to the 2013 SnoPUD IRP, when calculating avoided costs, the average capital cost of small hydro, wind and biomass is used (SnoPUD, 2013). A separate calculation of the value of solar was performed using this more realistic, albeit more expensive, alternative. Table 0-4 contains the cost parameters from the 2013 SnoPUD IRP. For this alternative method, the generation capacity is no longer a function of heat rate and the Minnesota methodology is slightly modified. The capital cost of generation is calculated as follows:

$$CapacityCost_g = \frac{DebtService_g + FixedO\&M_g + Variable\ O\&M_g}{CapacityFactor_g * PlantSize_g * AvailableHours_g}, \quad g = 1,2,3$$

$$CapacityCost = \frac{\sum_{g=1}^{3} CapacityCost_g}{3}$$

Where the available hours for generation (not including leap years) is approximately the following:

$$AvailableHours_g \cong 8760 * GenerationLife_g$$

Table 0-4. Cost and other parameters to calculate avoided generation capacity cost (from SnoPUD 2013 IRP)

Power Generation		Input Data	Units
Wind			
	Capital Cost	2376	$/kW
	Plant Size (CF = .35)	100	MW
	Capacity Factor	0.35	MW
	Inflation rate	2.5	%
	Debt Service Rate	5	%
	Fixed O&M Cost	45	$/kW
	Variable O &M Cost	0.0023	$/kWh
	Generation Life	20	years
Small Hydro			
	Capital Cost	4516	$/kW
	Plant Size (CF = .40)	5.85	MW
	Capacity Factor	0.4	
	Inflation rate	2.5	%
	Debt Service Rate	5	%
	Fixed O&M Cost	89	$/kW
	Variable O &M Cost	---	$/kWh
	Generation Life	50	years
Biomass			
	Capital Cost	3225	$/kW
	Plant Size (CF = .8)	13.2	MW
	Capacity Factor	0.8	
	Inflation rate	2.5	%
	Debt Service Rate	5	%
	Fixed O&M Cost	219	$/kW
	Variable O &M Cost	0.8	$/kWh
	Generation Life	20	years

Fuel Cost Data

Avoided fuel cost is based on the NYMEX futures quotes[18]. These quotes, shown in Table 0-5, are prices at the Henry Hub. For comparison, the forecast natural gas prices according to NW Council's 7th power plan are also given in Table 0-5 (Northwest Power and Conservation Council, 2013).

[18] http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

Table 0-5. Henry Hub Natural Gas Prices. NYMEX Futures and NW Council Forecast Prices

Year	Price (NYMEX)	Price (NW Council)	Unit
2014	$3.93	$4.04	$ per MMBtu
2015	$4.12	$4.20	$ per MMBtu
2016	$4.25	$4.34	$ per MMBtu
2017	$4.36	$4.47	$ per MMBtu
2018	$4.50	$4.56	$ per MMBtu
2019	$4.73	$4.65	$ per MMBtu
2020	$5.01	$4.74	$ per MMBtu
2021	$5.33	$4.83	$ per MMBtu
2022	$5.67	$4.93	$ per MMBtu
2023	$6.02	$5.03	$ per MMBtu
2024	$6.39	$5.13	$ per MMBtu
2025	$6.77	$5.23	$ per MMBtu

Economic Assumptions

Table 0-6 lists the various discount and degradation rates required to calculate the 25-year levelized value of solar.

Table 0-6. Economic Assumptions

Parameter	Symbol	Value (assumption)	Unit
Risk Free Discount Rate	r	See Fig.9	%
Discount Rate (WACC)	d	0.05	%
General Escalation Rate	g	0.025	%
PV Degradation Rate	p	0.005	%
Heat Rate Degradation Rate	h	0.001	%
O & M Variable Cost esc. Rate	v	0.025	%
O & M Fixed Cost esc. Rate	f	0.025	%
Environmental Discount Rate	--	0.03	%

The risk free discount rate was based on fitting a curve to 1, 2, 3, 5, 7, 10, 20 and 30 year maturity of US Treasury Yields. Figure 0-2 below shows the regression and equation producing the risk free discount rate r, in each year x.

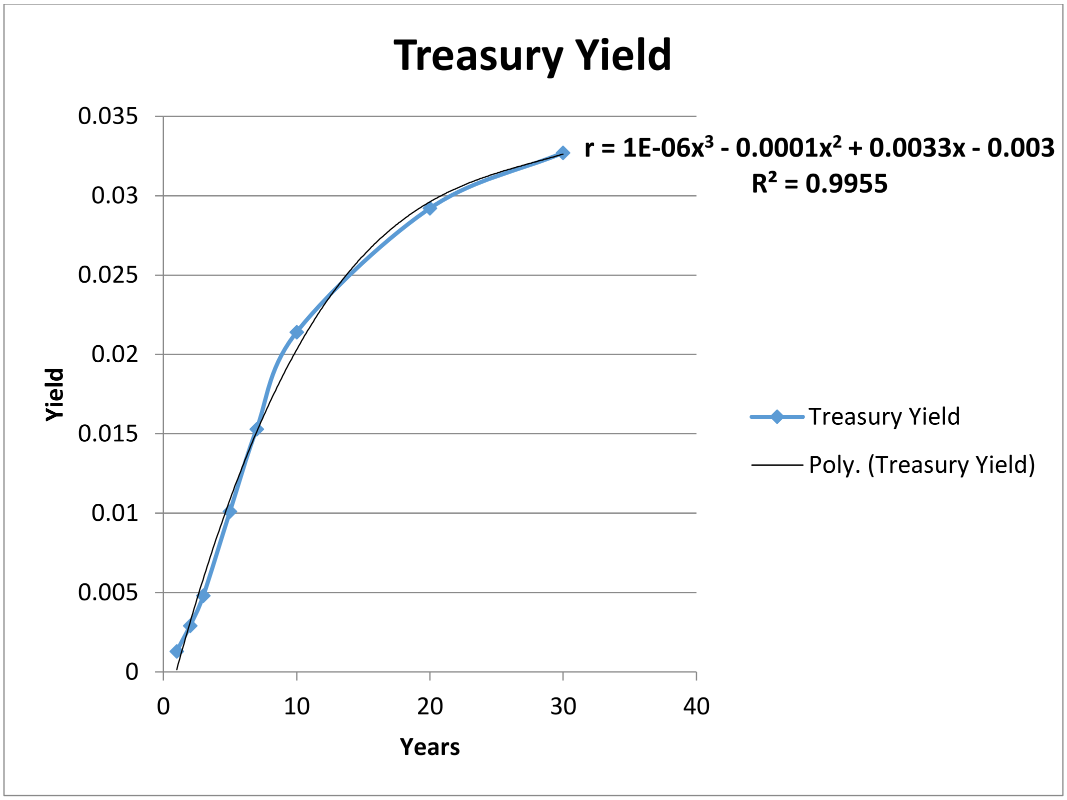

Figure 0-2. Risk-free discount rate curve from treasury yields

Appendix 6: Modified Version of Retail Rate (volumetric rate)

Three-Part Retail Rate

$$r = \frac{RR}{L}, \quad \left(\frac{\$}{kWh}\right) \tag{5.16}$$

$$r_{eng} = x_1 * \frac{RR}{L}, \qquad \left(\frac{\$}{kWh}\right) \tag{5.17}$$

$$r_{dmd} = x_2 * \frac{RR}{L}, \qquad \left(\frac{\$}{kWh}\right) \tag{5.18}$$

$$r_{cust} = x_3 * \frac{RR}{N_{cust}}, \qquad \left(\frac{\$}{Customer}\right) \tag{5.19}$$

Weighted Retail Rate VOST

$$VOST = r_{eng}w_1 \; + \; r_{dmd}w_2 \; + \; r_{cust}w_3 \; + v \tag{5.20}$$

Utility Cost Components: Cost Recovery Weights, x

$$\min_x \; \left|P_{pv}[w_1(x_1 - a) + w_2(x_2 - b)] + P_{cust}w_3(x_3 - c)\right| \quad + x_4 \tag{5.12}$$

s.t.

$$x_1 + x_2 + x_3 = 1 \tag{5.13}$$

$$\left|\frac{L_i}{L}(x_1 + x_2 - 1) + \frac{x_3 N_{cust,i}}{N_{cust}}\right| \le \frac{\delta L_i}{L} \tag{5.14}$$

$$-[(x_1 * w_1 \; + \; x_2 * w_2 \;) * P_{pv} \; + \; x_3 * w_3 * P_{cust}] * \left(1 + \frac{P_{re}}{P_{pv}}\right) + x_4 + \; a * P_{re} \le \gamma \tag{5.15}$$

Derivation of the modified version of proposed optimization formulation:

Objective:

$$\rho_{pv} = \left(x_1 * \frac{RR}{L}w_1 \; + \; x_2 * \frac{RR}{L}w_2 \;\right) * P_{pv} * L \; + \; x_3 * \frac{RR * P_{cust} * N_{cust}}{N_{cust}}w_3 \quad + x_4 RR$$

$$\mu = \left(a * \frac{RR}{L}w_1 \; + \; b * \frac{RR}{L}w_2 \;\right) * P_{pv} * L \; + \; c * \frac{RR * P_{cust} * N_{cust}}{N_{cust}}w_3$$

$$\alpha = \; \mu - \rho_{pv}$$

$$= \left(a * \frac{RR}{L} w_1 + b * \frac{RR}{L} w_2 \right) * P_{pv} * L + c * \frac{RR * P_{cust} * N_{cust}}{N_{cust}} w_3 - \left[\left(x_1 * \frac{RR}{L} w_1 + x_2 * \frac{RR}{L} w_2 \right) * P_{pv} * L + x_3 * \frac{RR * P_{cust} * N_{cust}}{N_{cust}} w_3 + x_4 RR\right]$$

If we let $\alpha = 0$, then

$$0 = \left(a * \frac{RR}{L} w_1 + b * \frac{RR}{L} w_2 \right) * P_{pv} * L + c * \frac{RR * P_{cust} * N_{cust}}{N_{cust}} w_3 - \left[\left(x_1 * \frac{RR}{L} w_1 + x_2 * \frac{RR}{L} w_2 \right) * P_{pv} * L + x_3 * \frac{RR * P_{cust} * N_{cust}}{N_{cust}} w_3 + x_4 RR \right]$$

After simplification (division by RR, cancelling L, and cancelling N_{cust}), this becomes

$$0 = (a * w_1 + b * w_2) * P_{pv} + c * w_3 * P_{cust} - \left[(x_1 * w_1 + x_2 * w_2) * P_{pv} + x_3 * w_3 * P_{cust} + x_4\right]$$

Arranging like terms, we arrive at the following:

$$\boxed{0 = P_{pv}[w_1(x_1 - a) + w_2(x_2 - b)] + P_{cust} w_3(x_3 - c) + x_4}$$

Constraint (5.13)

$$RR_1 = r * L = \frac{RR}{L} * L = RR$$

$$RR_3 = r_{eng} * L + r_{dmd} * L + r_{cust} * N_{cust}$$

$$= x_1 \frac{RR}{L} L + x_2 * \frac{RR}{L} * L + x_3 * \frac{RR}{N_{cust}} * N_{cust} = x_1 RR + x_2 * RR + x_3 * RR$$

Setting $RR_1 = RR_1$, then

$$RR = x_1 RR + x_2 * RR + x_3 * RR$$

Or,

$$\boxed{1 = x_1 + x_2 + x_3}$$

Constraint (5.14)

$$B_{1,i} = r * L_i = \frac{RR}{L} * L_i$$

$$B_{2,i} = r_{eng} * L_i + r_{dmd} * L_i + r_{cust} * N_{cust}$$

$$= x_1 \frac{RR}{L} L_i + x_2 * \frac{RR}{L} * L_i + x_3 * \frac{RR}{N_{cust}} * N_{cust,i}$$

Setting $B_{2,i} \leq (1 + \delta) * B_{1,i}$

$$x_1 \frac{RR}{L} L_i \; + \; x_2 * \frac{RR}{L} * L_i \; + \; x_3 * \frac{RR}{N_{cust}} * N_{cust,i} \leq (1+\delta) \frac{RR}{L} * L_i$$

Dividing by RR and grouping like terms, we arrive at the following:

$$\boxed{\left| \frac{L_i}{L}(x_1 + x_2 - 1) + \frac{x_3 N_{cust,i}}{N_{cust}} \right| \leq \frac{\delta L_i}{L}}$$

Constraint (5.15)

$$\rho_{pv} = x_1 * RR * w_1 * P_{pv} \quad + \quad x_2 * RR * w_2 * P_{pv} \quad + \quad x_3 * RR * P_{cust} * w_3 \quad + x_4 * RR$$

$$\rho_c = a * RR * (P_{re} - P_{pv})$$

$$\rho_{re} = \varphi * \rho_c$$

$$\mu = a * RR * w_1 * P_{pv} \quad + \quad b * RR * w_2 * P_{pv} \quad + \quad c * RR * P_{cust} * w_3$$

Constraint 5.15 is then derived as follows:

$$IC \geq \gamma RR$$

Or

$$\gamma RR \leq \rho_{pv} + \rho_{re} - \mu - \rho_c$$

$$\begin{aligned} &\leq (x_1 * RR * w_1 * P_{pv} \; + \; x_2 * RR * w_2 * P_{pv} \quad + \quad x_3 * RR * P_{cust} * w_3 \quad + x_4 * RR) \; + \; (\varphi * \rho_c) \\ &\qquad - \; (a * RR * w_1 * P_{pv} \; + \; b * RR * w_2 * P_{pv} + \quad c * RR * P_{cust} * w_3) \\ &\qquad - (a * RR * (P_{re} - P_{pv})) \end{aligned}$$

Dividing by RR

$$\begin{aligned} \gamma \; &\leq (x_1 * w_1 * P_{pv} \; + \; x_2 * w_2 * P_{pv} \quad + \quad x_3 * P_{cust} * w_3 \quad + x_4) \; + \; (\varphi * \rho_c) \\ &\qquad - \; (a * w_1 * P_{pv} \; + \; b * w_2 * P_{pv} + \quad c * P_{cust} * w_3) \\ &\qquad - (a * (P_{re} - P_{pv})) \end{aligned}$$

Simplifying and combining like terms we arrive at the following:

$$\boxed{\gamma - a * \left(P_{re} - P_{pv}\right) \leq w_1 * P_{pv} * (x_1 - a) + w_2 * P_{pv} * (x_2 - b) + w_3 * P_{cust} * (x_3 - c) + x_4}$$

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