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1 National Renewable Energy Laboratory
2 Advanced Research Projects Agency-Energy (ARPA-E)

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Preface

The price sensitivity of demand and the ability to shift some loads to lower price times have long been appreciated as economically efficient options for balancing power system generation and load at all timescales. Recently, interest in such demand-side resources has been building in anticipation of supply curves that could resemble hockey sticks: a long handle comprising variable renewable and other low marginal cost generation, followed by a near-vertical stick of low-capacity-factor, high-marginal-cost resources maintained to serve the last 10% of load. Under such conditions, accurately presenting the value and flexibility of electricity consumption to grid operators and planners might be the only way to clearly distinguish between the low-capacity factor resources that are and are not needed to achieve socially preferred outcomes.

To improve economic efficiency and in anticipation of low-carbon grids, wholesale electricity markets have developed a wide range of demand participation mechanisms. Despite these efforts, participation in the energy markets remains low (although also challenging to quantify), and observers have cataloged a wide range of demand-side participation barriers.

This project hypothesizes that two key wholesale energy market reforms could help unlock demand-side participation and produce better societal outcomes—first, greater reliance on welfare-maximizing energy markets with demand-side value of consumption bids that are cleared and settled by market operators as demand-side purchases of electricity (i.e., as buyers in the market). This model simplifies demand-side participation, metrology, and compensation, in part by eliminating payments for curtailment relative to a baseline—which is a common form of demand response compensation. Second, flexible demands must be able to bid in operational parameters analogously to generators. This latter reform is widely recognized, e.g., in Federal Energy Regulatory Commission (FERC) Order 2222 and in some demand response participation models. However, it has not yet been fully realized in part because the most critical operational parameters to capture are energy limits, which have not yet been satisfactorily incorporated into all industry-standard dispatch software programs even for storage resources.

This report is part of a series exploring these ideas from multiple perspectives and with increasing levels of sophistication. This first report focuses on bid-in price-sensitive load. A companion report will discuss the impacts of different load-shifting mechanisms. The authors are indebted to the entire project team (Table P-1) for regular discussion of these topics among ourselves and with various stakeholders.

Table P-1. Bid-In Demand-Side Data and Scenarios (Bid-DS) Project Team

Name	Organization	Name	Organization
Richard O'Neill	ARPA-E	Michael Baldea	
Elaine Hale		Ross Baldick	UT Austin
Tarek Elgindy		Xin Tang	
Nongchao Guo	NREL	Chris Knittel	MIT
Colin McMillan		Benjamin Krebs	
Bryan Palmintier		Udi Helman	Helman Analytics, Inc.

Acknowledgments

The authors would like to thank our team members (Tarek Elgindy, Colin McMillan, Bryan Palmintier (NREL), Michael Baldea, Ross Baldick, Xin Tang (UT Austin), Chris Knittel, Benjamin Krebs (MIT), and Udi Helman (Helman Analytics, Inc.)) for fruitful discussions and Sourabh Dalvi for assistance with the RTS-GMLC system as represented in Sienna—both of which were invaluable for defining and embarking on the research described in this report. The first draft of this report was greatly improved by feedback we received from reviewers Rebecca Ciez (Purdue University), Udi Helman (Helman Analytics, Inc.), Debra Lew (ESIG), Jill Powers (CAISO), Henry Yoshimura (ISO-NE), and Yonghong Chen and Luke Lavin (NREL). Thank you for your thorough readings and honest assessments. We are also indebted to Emily Horvath for technical editing and to Adarsh Nagarajan and Jaquelin Cochran (NREL) for a final round of review comments.

List of Acronyms

ARPA-E	Advanced Research Projects Agency-Energy
BPSL	bid-in price-sensitive load
CAISO	California ISO
CC	combined-cycle
CT	combustion turbine
DR	demand response
ESIG	Energy Systems Integration Group
FPIL	fixed price-insensitive load
FPSL	fixed price-sensitive load
GWh	gigawatt-hours
ISO	independent system operator
ISO-NE	ISO New England
LMP	locational marginal price
LP	linear program
MIP	mixed-integer program
MIT	Massachusetts Institute of Technology
MM	million
MWh	megawatt-hours
NREL	National Renewable Energy Laboratory
PCM	production cost model
PTDF	power transfer distribution factor
PV	photovoltaics
PRD	price responsive demand
RTO	Regional Transmission Organization
RTP	real-time price
RTS-GMLC	Reliability Test System – Grid Modernization Lab Consortium
ST	steam turbine
TWh	terawatt-hours
UT	University of Texas

Executive Summary

Bulk power systems operations, in both simulation and practice, are often built on the principle of minimizing production costs, which assumes to first order that demand is fixed and that the only degrees of freedom for balancing generation and load are supply-side unit commitment and dispatch decisions. The purpose of this report is to interrogate the value of welfare-maximizing markets that not only physically balance demand and supply but also ensure that market outcomes provide consumer value by directly maximizing welfare, defined as the value of consumption minus production costs.

In cost-minimizing markets, demand is assumed inelastic—i.e., insensitive to price—and is always served, no matter the cost. If the inelasticity assumption is inaccurate, in such markets it is possible for some loads to be asked to pay a price for their consumption that exceeds its value; e.g., an industrial facility might be required to pay more for electricity than what the product made with that electricity is worth. This uneconomic outcome does not occur in welfare-maximizing markets only if all electricity consumers bid in their value of consumption.

Wholesale electricity markets today generally do allow demand-side bids for consumption and maximize welfare in the day-ahead markets, but the preponderance of submitted bids are for fixed demand—i.e., demand forecast profiles that are inelastic and unpriced. It is outside the scope of this report to evaluate the levels of participation in different markets or to attempt to judge whether the splits between inelastic and elastic load therein are reasonable, but we do note the widely held sentiment that demand-side participation is "too low."

It is in the spirit of wanting to understand the gap between that sentiment and actual participation that this report analyzes the impact of large, price-sensitive electricity consumers bidding their value of consumption directly into welfare-maximizing energy markets using day-ahead unit commitment simulations of the Reliability Test System – Grid Modernization Lab Consortium (RTS-GMLC) test system (Barrows et al. 2019). Importantly, in addition to the system-level impacts addressed by numerous papers on demand-side participation, we analyze the financial impacts on bidding participants, other electricity consumers, and suppliers because those are the incentives or disincentives for demand-side participation. It is outside the scope of this report to analyze the impact of demand-side bids on the combined operations of capacity and energy markets, but we note this as an important area for future work given the potentially large impact demand bidding could have on capacity market formulations and outcomes.

The authors represent price sensitivity and market participation stylistically, using three participation models: fixed price-insensitive load (FPIL), fixed price-sensitive load (FPSL), and bid-in price-sensitive load (BPSL). The participation models all assume that the true demand curve for a given hour is the RTS-GMLC load for that hour partitioned into five equal blocks valued at $1,000/MWh, $500/MWh, $100/MWh, $50/MWh, and $10/MWh, respectively. However, the models assume three different types of electricity consumer (Figure ES-1).

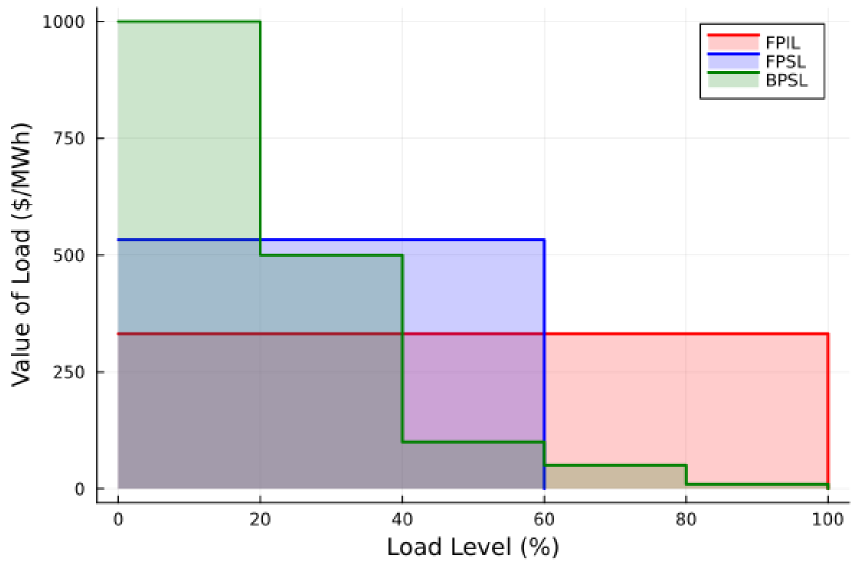

Figure ES-1. The three load participation models compared in this report

The FPIL model posits a consumer who thinks of all their potential load as "important-enough," with an average value of $332/MWh (the average value of the five blocks under BPSL) that is well above average energy prices. Thus, under this model, demand is fixed at the upper bound of the load time series, with an assigned value of $332/MWh. By construct, the red-shaded area is the same size as the green-shaded area in Figure ES-1.

The FPSL model posits a consumer who is aware of their demand curve but not actively participating in the market. This consumer consumes only the first three blocks of electricity—that is, 60% of the load time series—because those are the blocks above the average energy price such an entity might see on their electricity bill. This model's consumption has an average value of $533/MWh, which is equal to the average value of the first three blocks under BPSL; that is, the blue-shaded area is the same size as the first three blocks of green-shaded area (up to the 60% load level) in Figure ES-1.

In the BPSL model, the full demand curve is bid directly into the market. Because of these additional degrees of freedom, which include both the FPIL and FPSL dispatch levels as feasible outcomes, removing an FPIL or FPSL load from the market and replacing it with a BPSL load will always increase the total welfare—that is, any reductions in consumption value will always be offset by an even larger reduction in production cost. Production costs can also go up but only if the value of consumption increases even more.

This report compares the BPSL model to both FPIL and FPSL under several conditions.

Throughout the report, we analyze market outcomes under two social-cost-of-carbon assumptions: $0/metric ton CO_2 and $50/metric ton CO_2. In the RTS-GMLC system, if there is no carbon price, coal units are often dispatched, sometimes set market prices, and contribute to higher average emission rates. On the other hand, with a $50/metric ton CO_2 price, the system largely foregoes coal generation and relies more heavily on its natural gas fleet to complement nuclear, wind, and solar resources. This results in a near halving of emissions, a near doubling of production costs, and a reduction in total welfare (considering only this system and with no specific disposition of the carbon cost revenues) of about 4%.

The report also progressively analyzes increasing levels of BPSL participation.

An initial examination of "one load, one day," in which one load is modeled as FPIL, FPSL, and BPSL and we analyze single-day hourly pricing as well as welfare and net surplus outcomes, establishes some key properties of BPSL compared to FPIL and FPSL. In brief:

- Because FPIL fixes the load time series at 100%, comparing BPSL to FPIL only shows the cost savings of reducing load when costs are high. In particular, the value of consumption is always going to be lower in BPSL than in FPIL and will always be offset by even greater reductions in production costs.
- On the other hand, because FPSL fixes the load time series at 60%, comparing BPSL to FPSL shows both the cost savings of reducing load when costs are high *and* the benefit of increased electricity consumption when costs are low.
- Although it is always the case that participating, price-responsive consumers (i.e., BPSL) will never be asked to pay more than their consumption is worth, there is no guarantee that they will actually benefit in terms of increased net consumer surplus compared to either of our fixed load reference points (i.e., FPIL, FPSL). This also holds true for all other market participants, i.e., nonparticipating consumers and suppliers can see net surplus increases or decreases when fixed loads are replaced with bid-in demand.

We derive our key findings from annual simulation results, which more realistically describe how real-world market participants might experience and evaluate the impacts of increased demand-side bidding. We explore the full range of BPSL participation, from 0% to 100%, largely using the FPIL model as a reference, and compare BPSL to FPSL at the one-load and all-load levels. Our analysis relies on the metrics listed in Table ES-1.

Table ES-1. Key Metrics Glossary

Metric	Definition
Total Welfare	Total surplus of the power system. This is numerically equal to the sum of Total Value of Load minus Total Production Cost or the sum of Net Producer Surplus, Net Consumer Surplus, and Congestion Rents.
Total Value of Load	Total value of load served by the power system, taken as the sum of each load block served (in MWh) times its value (in $/MWh).
Total Production Cost	Total variable and fixed costs to operate the system (includes carbon costs if there are any).
Total Producer Revenue	Total revenues producers earn from selling energy in wholesale markets. This includes energy sold at locational marginal prices (LMPs) and may include uplift payments.
Net Producer Surplus	Total Producer Revenue minus Total Production Cost.
Total Load Payment	Total costs consumers incur for purchasing energy from wholesale markets. This includes energy bought at LMPs and may include uplift payments.
Net Consumer Surplus	Total Value of Load minus Total Load Payment.
Congestion Rents	Total Load Payment minus Total Producer Revenue.
Uplift Payments	Uplift payments considered here include make-whole payments, which are payments made to generators if their LMP revenues do not cover their costs (variable costs plus commitment costs). This is evaluated for individual generators on a 24-hour horizon.

Key Findings

Increased demand bidding always increases total welfare, but percentage changes in total welfare and value of load tend to be small compared to percentage changes in production costs.

As described previously, mathematically the BPSL model can only increase total welfare compared to the same load participating as FPIL or FPSL. However, the percentage changes in welfare are relatively modest: at most 0.87% without a carbon price and 2.96% with one for 100% BPSL compared to 100% FPIL. This is because the total value of load ($12,500 million under FPIL) is approximately two orders of magnitude larger than the production costs ($501 million without a carbon price and $972 million with one under FPIL), and most of the total welfare is the portion of the total value of load that is returned to consumers as net consumer surplus (84%–97% across all three load models at 100% participation and with and without a carbon price). In comparing BPSL to both FPIL and FPSL at 100% participation, total welfare and total value of load never change more than ±3.5%, but production costs change by up to ±62%.

This does not, however, mean that the impact of BPSL is small. The absolute increases in total welfare in going from 100% FPIL to 100% BPSL are $104 million and $340 million for the scenarios without and with a carbon price, respectively. That is, the changes in total welfare, which net out decreases in total value of load with decreases in production cost, are of the same order of magnitude as the changes in total production costs, which for this system are in the hundreds of millions of dollars per year (Figure ES-2).

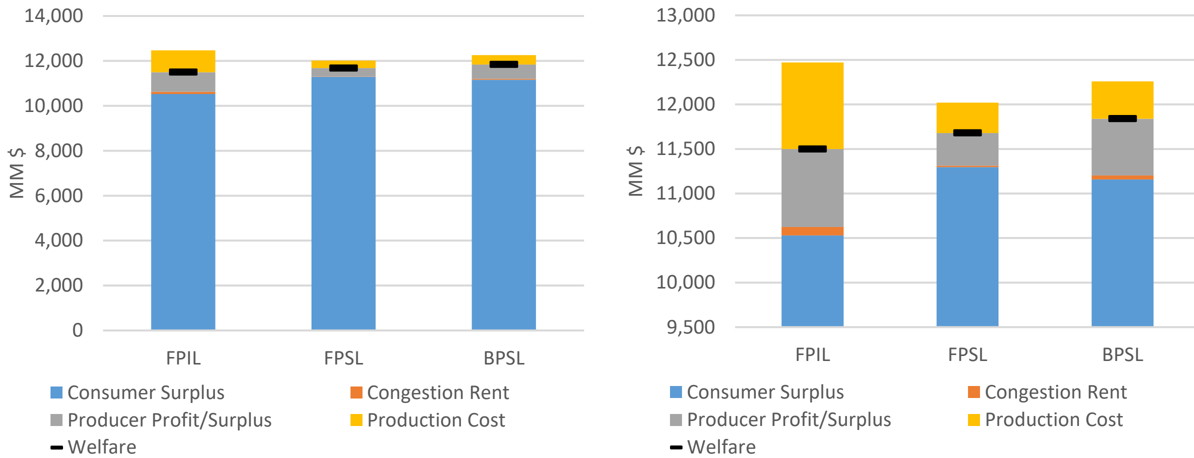

Figure ES-2. Surplus breakdown across all-load, one-year scenarios with \$50/metric ton social cost of CO_2.

The figure on the left plots the y-axis starting from \$0 to visually show that net consumer surplus is orders of magnitude larger than production costs and net producer surplus. The figure on the right plots the y-axis starting from \$9,500 million to enable comparison across scenarios and to show that congestion rents are orders of magnitude smaller than production costs and net producer surplus.

Although demand bidding always increases total welfare, the impacts on specific participants—i.e., net consumer surplus for both participating and nonparticipating loads, net producer surplus, and congestion rents—do not follow any predictable trends.

The decomposition of total welfare into net consumer surplus, net producer surplus, and congestion rents is the outcome of the marginal pricing process, which guarantees that no market participant is harmed on the margin from moment to moment (i.e., no consumer pays more than their marginal value of consumption and no supplier is paid less than their marginal cost of production at any one time) but provides no assurances regarding longer timescales. Furthermore, almost all the time a specific participant will not be setting the marginal price (this is what it means to have a competitive market), which means that almost all the time when one's generator is dispatched or one's load is served, one is accumulating a net surplus. Certainly, higher-value loads and lower-cost generation resources will tend to accumulate larger net surpluses, but how those surpluses change in response to market changes is highly system- and situation-dependent.

In addition to being mathematically true, we observe this capriciousness across our scenarios. For example, compared to FPSL, all loads bidding into the market generally increases LMPs because of higher consumption, which increases net producer surplus both with and without a carbon price—but the net consumer surplus outcomes depend on the balance between increased value of load and increased load payments, which tips one way or the other depending on circumstance (Table ES-2, FPSL results). When there is no carbon price, increased value of load (\$373 million) is greater than the increased load payments (\$318 million), yielding a net consumer surplus gain. However, when there is carbon price, the increased value of load (\$240 million) is less than the increased load payments (\$379 million), resulting in a net consumer surplus loss. As another example, BPSL impacts the relative magnitude of producer surplus changes for variable generation (VG) and non-VG resources, but which types of producers benefit most or experience fewer losses depends on the hours when price changes are induced (i.e., high-VG hours or high-fossil hours) and the directionality of the price changes.

Table ES-2. Summary Impact of BPSL on Consumer and Producer Surplus

Load Scenario	BPSL vs.	Social Cost of Carbon $/Metric Ton CO_2	Total Net Consumer Surplus Change MM $	%	VG Net Producer Surplus Change MM $	%	Total Net Producer Surplus Change MM $	%
All Load (100%)	FPIL	0	140	1.22%	-13.3	-6.65%	-36.4	-9.04%
		50	629	5.97%	-59.6	-15.2%	-238	-27.2%
	FPSL	0	55.0	0.473%	99.6	115%	185	102%
		50	-139	-1.23%	164	96.8%	271	74.0%

Increased demand bidding might increase the size of wholesale energy markets relative to wholesale capacity markets and other out-of-market payments.

Some independent system operators (ISOs) and regional transmission organizations (RTOs) run a centralized capacity market to address the revenue adequacy issues of peaking resources (i.e., the "missing money" problem). Although this report does not directly study capacity markets, the authors observe that demand bidding into the wholesale energy market at prices below the administratively set value of lost load does not need to be included in capacity markets, in which case the bidders also should not have to pay for capacity and should not be paid for reducing their consumption under emergency conditions, because that demand will not be dispatched to consume power at prices above its bid-in value. The PJM price responsive demand (PRD) model is a real-world implementation of this principle, albeit without direct bidding into the energy market.

More tenuously, we observe significant increases in supplier surplus when comparing the all-load BPSL to FPSL scenarios—which can be attributed to increases in both load and average LMP in our simulations—and note that increased supplier surplus should reduce the "missing money" problems addressed by capacity and other markets like those for renewable energy credits. For an outcome like this to hold under other (e.g., real-world) conditions, BPSL would have to increase the amount of low-value load served and set strictly positive prices when they would otherwise be zero or negative, more so than it reduces the amount of load served and the prices set at high-price times.

Increased demand bidding lowers emissions compared to the FPIL model in our annual simulations but can increase emissions for single days compared to FPIL and often increases emissions compared to FPSL because emissions largely track load levels, even when the system is subject to a carbon price.

Lower load levels lead to reductions both because of the absolute decrease in consumption, and because less load allows the system to choose higher proportions of lower-emission resources, which tend to also have lower marginal costs compared to higher-emission resources. That is, reductions in load levels are often accompanied by reductions in average emission rates and vice versa.

Including a carbon price in dispatch decisions does tend to mute the correlation between load levels and average emission rates when flexibility is added to the system. For example, comparing our One-Load, One-Year BPSL and FPSL scenarios with a carbon price, emissions decrease in spite of a net increase in load served because the average emissions rate decrease of 0.001 metric ton CO_2/MWh applied to the FPSL scenario load (37.0 TWh) is about 30% larger than the emissions induced by the additional 134 GWh of load under BPSL at 0.200 metric tons CO_2/MWh. However, emissions increase 26.6% in the All-Load, One-Year BPSL scenario compared to the All-Load, One-Year FPSL scenario with a carbon price based on a 25.5% increase in load and a 0.8% increase in the average emission rate.

The overall carbon emissions of impacts of BPSL are highly system-dependent. Although we sometimes observed emissions increases for BPSL compared to FPSL, compared to the FPIL model, All-Load BPSL reduced carbon emissions by 39% and 58% without and with a carbon price, respectively. Unsurprisingly, we always observed carbon emissions reductions whenever we added a $50/metric ton CO_2 social cost of carbon to any specific scenario, typically around 50%, but up to 64%—which we observed across the All-Load FPIL, FPSL, and BPSL scenarios.

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1 Introduction

Demand response (DR) can provide a wide range of benefits, including cost savings from avoided energy and ancillary services costs, avoided generation, transmission and distribution capacity costs, and increased reliability in power systems planning and operations (U.S. Department of Energy 2006; O'Connell et al. 2014; Hledik and Faruqui 2015). Among various DR mechanisms, having load directly bid into wholesale electricity markets is considered one of the most efficient practices (Wellinghoff and Morenoff 2007; Faruqui et al. 2010; Liu, Holzer, and Ferris 2015; O'Neill, Lew, and Ela 2023). Although the day-ahead wholesale electricity markets in the United States accept economic demand bids, not many loads submit nonfixed (price-sensitive) bids on a regular basis, and most real-time markets do not allow such bids. To understand the gap between the perceived benefits of demand bidding and the lack of demand bidding participants and capabilities, it is important to not only quantify system-level benefits but to also examine the financial impacts on demand bidders, other electricity consumers, and suppliers.

Although the social welfare benefits of increased demand participation are generally accepted on principle, there are few quantitative demonstrations available in the literature. Liu et al. (2015) list five categories of demand: fixed demand, elastic demand, adjustable demand, shiftable demand, and arbitrage. They provide a behavioral model for each demand type and describe how these demands fit into the central dispatch model. Using a representative day of the PJM system, the authors show that demand participation of all types increases social welfare compared to fixed demand. The paper also discusses the potential implications of network integration and unit commitment but does not provide simulation results under these more complicated situations. Newell and Felder (2007) use a commercial production cost model (PCM) to quantify the potential benefits of DR in PJM. They simulate the impact of DR by curtailing 3% of load during high-price times in selected regions. The authors find energy price reductions of 5%–8% on average, which translates to potential benefits of $65–$203 million per year to uncurtailed load in the entire PJM system. They also estimate the financial benefits to curtailed load based on simplified assumptions regarding the value of load, which amount to $9–$26 million per year. However, because the value of load is not directly formulated into market bids, in their simulations DR resources are not able to set prices, which may result in different pricing outcomes than observed in our study. Borenstein (2005) models the demand side with constant elasticity and considers costs associated with the long-run equilibrium of generation capacity. The author finds significant efficiency gains from real-time pricing (RTP).

In this report, we explore several scenarios designed to advance understanding about how more load participating in wholesale markets as bid-in demand could impact system-level, customer-level, and supplier-level outcomes. For simplicity, we focus on a wholesale energy market and on load with a demand curve that resembles what we might expect for a large industrial load for which electricity is a key input. This study therefore represents one of several possible bounding cases. A companion report (Guo, Hale, and O'Neill Forthcoming) explores similar questions for another bounding case—that of large, highly valuable commercial loads whose primary form of flexibility is shifting when they consume a portion of their electricity demand.

In this report, we analyze scenarios formed by choosing one of three load participation models, specifying the amount of bid-in load, and specifying the cost assigned to carbon emissions. Two of the participation models assume a fixed load profile, that is, an inelastic load forecast that the power system must dispatch generation resources to meet. The third participation model is bid-in demand—that is, load directly bids in their actual demand curve in the form of load quantity and value of consumption pairs.

This report is structured as follows: Section 2 introduces the three load participation models simulated in this analysis. Section 3 describes the Reliability Test System – Grid Modernization Lab Consortium (RTS-GMLC) test system. Sections 4 through 6 present detailed simulation results for different load participation levels and amounts of simulated time. Section 7 discusses the implications of the analysis and concludes.

2 Value of Load and Participation Models

We formulate three load participation models to compare the impact of bid-in demand on power system economics and emissions. The participation models all assume that the true demand curve is that shown under “Bid-in price-sensitive load (BPSL)” in Table 1 and illustrated as the BPSL, green line of Figure 1. However, the models assume three different types of electricity consumers.

Table 1. Value of Fixed (FPIL and FPSL) and Dispatchable (BPSL) Load by Participation Model

		Fixed price-insensitive load (FPIL)	
Block	*% of Fixed Load*	*Value ($/MWh)*	*Comment*
1	100	332	Fixed load
		Fixed price-sensitive load (FPSL)	
Block	*% of Fixed Load*	*Value ($/MWh)*	*Comment*
1	60	533	Fixed load
		Bid-in price-sensitive load (BPSL)	
Block	*% of Fixed Load*	*Value ($/MWh)*	*Comment*
1	20	1,000	Reduced in an emergency, that is, when the price goes above $1,000/MWh
2	20	500	Reduced when system is stressed, that is, when the price goes above $500/MWh
3	20	100	High-value consumption, served most of the time
4	20	50	Flexible consumption
5	20	10	Low-value consumption

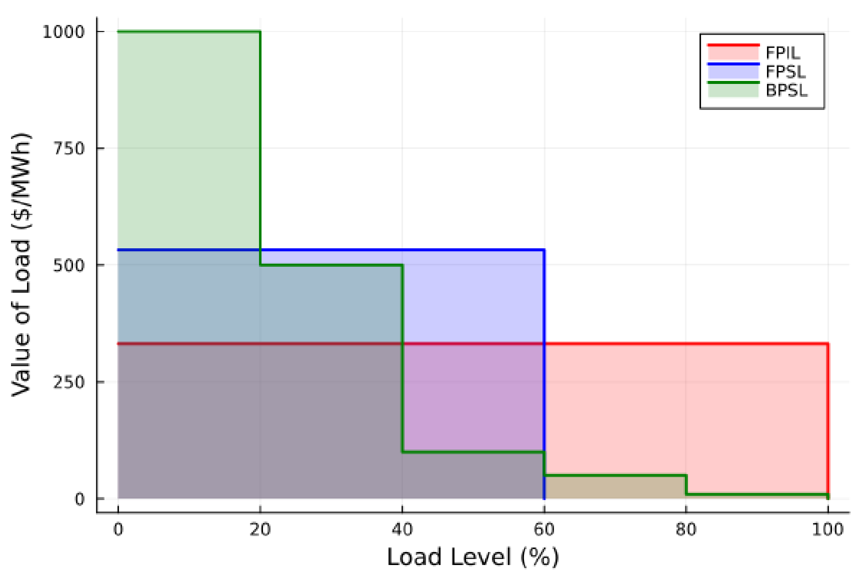

Figure 1. Illustrative example of three load participation models

The FPIL model posits a consumer who thinks of all their potential load as "important enough," with an average value of $332/MWh that is well above the average energy price of approximately $59/MWh.[1] The average value of this consumer's demand is computed by averaging the values listed under BPSL in Table 1 because each block is the same size and we are assuming that all demand will be fulfilled. Thus, demand is fixed at the upper bound of the load time series, with an assigned value of $332/MWh. By construct, the red-shaded area (FPIL) is of the same size as the green-shaded area (BPSL) in Figure 1.

The FPSL model posits a consumer who is aware of their demand curve but not actively participating in the market to determine when to stop consuming. This consumer consumes electricity with value only above the average energy price of about $59/MWh. Thus, only 60% of the total demand is actually consumed, which we represent as 60% of the load time series with an assigned value of $533/MWh (the average value of BPSL Blocks 1–3). In addition, the blue-shaded area (FPSL) is of the same size as the first three blocks of green-shaded area (area under the BPSL curve up to 60% of load level) in Figure 1.

In the BPSL model, the full demand curve is bid directly into the market. This is implemented in RTS-GMLC by partitioning each time period's load into five equally sized blocks, with the blocks' values being $1,000/MWh, $500/MWh, $100/MWh, $50/MWh, and $10/MWh, respectively.

Table 1 also shows the value of load for these models. By construction, the total value of BPSL consumption would be the same as the value of FPIL consumption if market clearing prices were always below $10/MWh, because all the bid-in load would clear the market and load would be 100% of the input load time series—as is assumed for the FPIL consumers. Also by construction, the total value of BPSL consumption would be the same as the value of FPSL consumption if market clearing prices always fell between $50/MWh and $100/MWh, because 60% of bid-in load would clear the market in each hour—as is assumed for FPSL consumers.

Thus, comparing BPSL to FPIL shows the cost savings of reducing load only when costs are high. The value of consumption is always going to be lower in BPSL than in FPIL; the flexible consumer benefits from lower energy costs but also forfeits some value of consumption. The cost reduction benefits will also be shared with other consumers to the extent that the flexible consumer's actions reduce prices systemwide.

On the other hand, comparing BPSL to FPSL shows both the cost savings of reducing load when costs are high *and* the benefit of increased electricity consumption when costs are low. In this case, the flexible consumer could end up consuming more electricity and having lower overall costs.

[1] In 2020, the U.S. annual average retail electricity price was about $105.9/MWh, of which 56% is attributable to the cost of generating electricity (U.S. EIA 2021). Thus, we estimate an average energy price of 105.9 × 56% = $59/MWh.

3 RTS-GMLC Test System

We evaluate the demand bidding scenarios using the Institute of Electrical and Electronics Engineers (IEEE) Reliability Test System, a standardized power system model that was originally developed in 1979 to test and compare results from different power system reliability evaluation methodologies (Albrecht et al. 1979). The Grid Modernization Laboratory Consortium update to the IEEE Reliability Test System (RTS-GMLC) is a 2019 update to the 1979 model to reflect a generation mix more representative of modern power systems. Compared to previous updates, RTS-GMLC removed several oil, coal, and nuclear steam turbine units, relocated hydro units, and added natural gas combustion turbines (CTs), natural gas combined-cycle (CC) units, wind, solar photovoltaics, concentrating solar power, and battery energy storage. The update also assigned the test system to a geographic location in the southwestern United States and provided spatiotemporally consistent wind, solar, and load time series data for both day-ahead (hourly resolution) and real-time (5-minute resolution) dispatch models for a full year. Figure 2 illustrates the generation facilities and network of RTS-GMLC, with unit type indicated by disc color and capacity indicated by disc size. CO_2 emission rates of fossil resources range from 118 lb/MMBtu for natural gas to 210 lb/MMBtu for coal. For more information on RTS-GMLC, see Barrows et al. (2019).

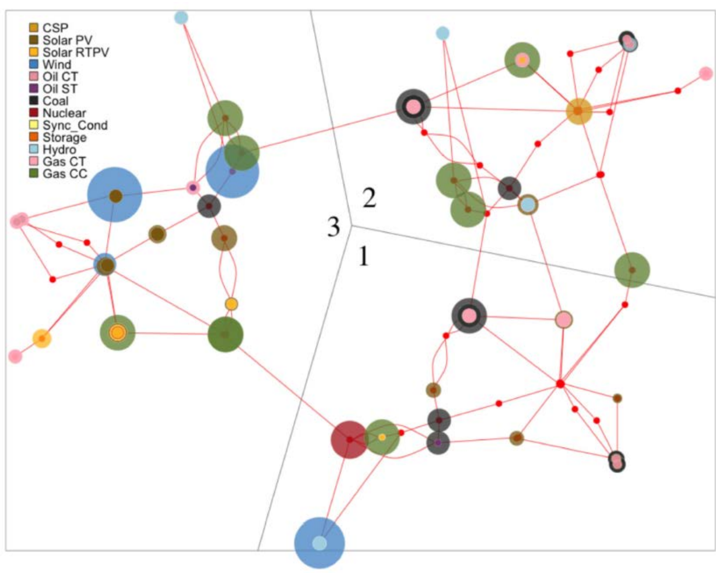

Figure 2. RTS-GMLC generation and network

In this report, we examine day-ahead unit commitment and economic dispatch results for a select day and for the entire simulation year using RTS-GMLC represented in Sienna.[2] The objective of the simulations is to maximize total welfare, which is defined as the total value of load served minus total production costs. We model basic unit commitment constraints for thermal units to capture the relationships between binary startup, shutdown, and commitment variables. Therefore, the optimization problem is a mixed-integer program (MIP). We model transmission constraints using direct current (DC) power flow, which assumes that reactive power and voltage limits will be satisfied in actual operations. After solving the MIP, binary variables are fixed, and

[2] https://www.nrel.gov/analysis/sienna.html

the problem is solved again as a linear program (LP) to calculate the dual variables. We use the Xpress solver for both the MIP and LP problems, with relative MIP gap equal to 1.0E-4 and run on high-performance compute nodes with 18 processors (36 cores) and 96 GB of memory. We calculate locational marginal prices (LMPs) with the formula (assuming no transmission losses) (Fu and Li 2006):

$$LMP_i = \lambda + \sum_k \mu_k^+ T_{i,k} + \sum_k \mu_k^- T_{i,k},$$

where λ is the dual variable of the supply-demand balance constraint of the system, μ_k^+ and μ_k^- are the dual variables of transmission upper and lower bound constraints, respectively, and $T_{i,k}$ is the power transfer distribution factor (PTDF) of Bus i on Line k (Wood, Wollenberg, and Sheblé 2013). Note that our simulations assume competitive markets where generators offer their true cost and BPSL loads bid their true value. Therefore, strategic bidding behaviors are not considered.

We apply the three participation models to one or more load nodes in the RTS-GMLC system and run single-day (January 1, 2020) and whole-year simulations. When we apply the models to a single node, we use Bus 215 ("Barton"). As described in Table 2, Bus 215 has a higher-than-average amount of load and is co-located with significant generation resources. Table 2 also characterizes the overall size of the RTS-GMLC system. For example, it has 51 load buses and its peak load is 8.2 GW. There are adequate generation resources to meet load in our simulations; thus, we do not enable slack variables in supply-demand balance constraints. Similar to day-ahead unit commitment procedures in real systems, our day-ahead simulations have a 24-hour simulation horizon and hourly resolution. All nonparticipating load is always modeled using the FPIL construct (100% of the load time series is served with a value of $332/MWh).

Table 2. Summary of Price-Sensitive Consumer Bus and System Load

Bus	Noncoincident Peak Load (MW)	Generation		Marginal Cost Range ($/MWh)
		Type	Capacity (MW)	
215 ("Barton")	317	Gas CT	55	[25.92, 32.73]
		Gas CT	55	[25.92, 32.73]
		Hydro	50	0.0
		Hydro	50	0.0
		Hydro	50	0.0
		PV	125.1	0.0
RTS-GMLC System				
System Peak Load (MW)	8,192 (2020-08-26T14:00)			
System Noncoincident Peak Load (MW)	8,550			
Number of Load Buses	51			
Average Noncoincident Peak Load Per Bus (MW)	168			

Because of varying load levels and variable generation (VG) availability, the supply and demand curves of the system are different in every hour of the year. In this study, the presence or absence of a carbon price and the amount of BPSL (or FPSL) in a given scenario also significantly impact the system supply and demand curves, respectively. Figure 3 previews what follows by providing a few example supply and demand curves. These curves are illustrative only. In addition to varying from hour to hour and from scenario to scenario, the RTS-GMLC supply curves like those shown here do not by themselves determine simulated market clearing prices and producer revenues. Transmission constraints and unit commitment decisions—the latter via startup and no-load costs—also impact the dual variables in the LMP equation and thus the market clearing prices. Uplift payments are also sometimes required in this nonconvex market to ensure that all generation costs are covered by market revenues.

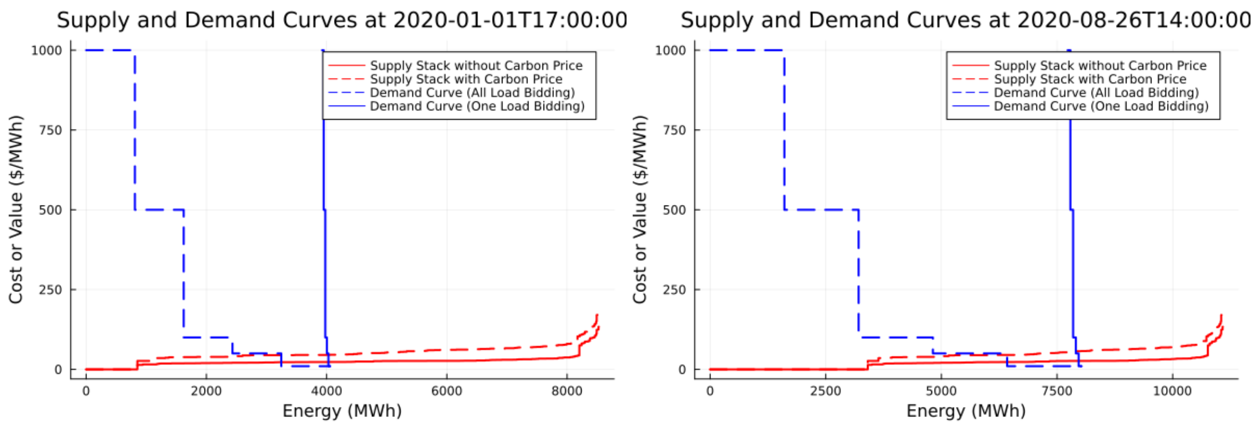

Figure 3. Supply and demand curve examples.

Both examples show BPSL demand curves for One Load (Bus 215) and All Load and supply curves with and without a carbon price: (left) January 1 at 5 pm, (right) peak day, August 26, at 2 pm. The intersections of these demand curves are insufficient to determine market clearing prices, which are also influenced by transmission constraints and unit commitment decisions, but are indicative of system-level energy price lower bounds.

This analysis focuses on market outcomes under varying levels of BPSL. Table 3 defines the key metrics used in this analysis; Figure 4 illustrates the relationship between these metrics.

Table 3. Key Metrics Glossary

Metric	Definition
Total Welfare	Total surplus of the power system. This is numerically equal to the sum of Total Value of Load minus Total Production Cost or the sum of Net Producer Surplus, Net Consumer Surplus, and Congestion Rents.
Total Value of Load	Total value of load served by the power system, taken as the sum of each load block served (in MWh) times its value (in $/MWh).
Total Production Cost	Total variable and fixed costs to operate the system (includes carbon costs if there are any).
Total Producer Revenue	Total revenues producers earn from selling energy in wholesale markets. This includes energy sold at locational marginal prices (LMPs) and may include uplift payments.
Net Producer Surplus	Total Producer Revenue minus Total Production Cost.
Total Load Payment	Total costs consumers incur for purchasing energy from wholesale markets. This includes energy bought at LMPs and may include uplift payments.
Net Consumer Surplus	Total Value of Load minus Total Load Payment.
Congestion Rents	Total Load Payment minus Total Producer Revenue.
Uplift Payments	Uplift payments considered here include make-whole payments, which are payments made to generators if their LMP revenues do not cover their costs (variable costs plus commitment costs). This is evaluated for individual generators on a 24-hour horizon.

Specifically, welfare maximization guarantees that the total value of load served is greater than production costs, because otherwise both generation and load would be set to zero. We can then visualize total welfare as the value of load minus production costs, which is shown in Figure 4 as the value of load being the total height of all the stacked bars, the production costs being the yellow bar, and the total welfare being the height of all the stacked bars excepting the (yellow) production costs (and indicated by the black line). However, we can further articulate how the total welfare is apportioned to the market participants by observing that load payments are also smaller than the value of load and can be partitioned into—as shown in Figure 4—(1) production costs (yellow bar), (2) net producer surplus (gray bar), and (3) congestion rents (red bar) and then noting that total welfare is equal to the sum of the net producer surplus (gray bar), congestion rents (red bar), and net consumer surplus (blue bar).

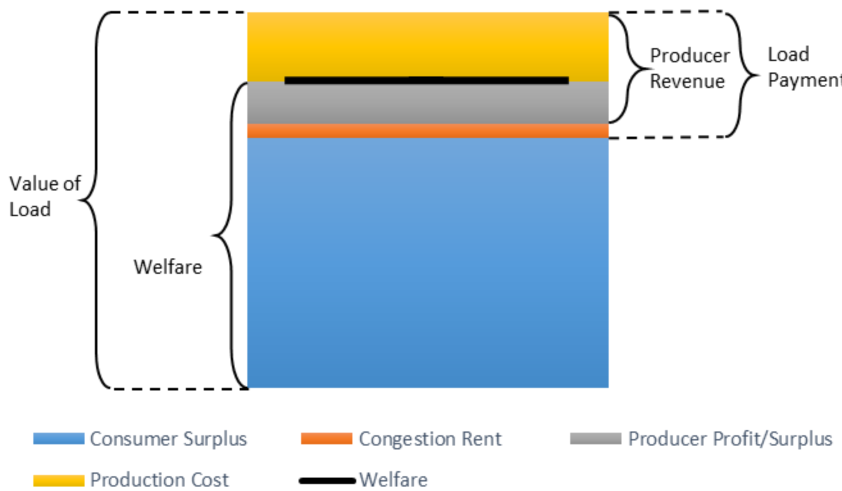

Figure 4. The value of load is equal to production costs plus total welfare, and total welfare is the sum of net consumer surplus, net supplier surplus, and congestion rents

Determining how increasing quantities of BPSL (or FPSL) changes the total welfare compared to FPIL and how it is distributed to market participants in the RTS-GMLC system requires simulation to account for time-varying load and resource availability as well as unit commitment and transmission congestion costs. However, we can develop an intuition for the results we will see in subsequent sections using a stylized, convex, one-period market without unit commitment and with linear demand and supply curves. The resulting Econ 101-style graph shown in Figure 5 is labeled to align conceptually with the participation models studied in this report. Specifically, the linear, downward sloping demand curve is identified with the BPSL model, and we compare the outcome of clearing that demand curve against the supply curve (Q_{BPSL}) to two fixed load quantities: $Q_{FPIL} > Q_{BPSL}$ and $Q_{FPSL} < Q_{BPSL}$.[3]

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[3] Note that although in the simulation results that follow it is always true that $Q_{FPIL} \geq Q_{BPSL}$, the amount of load cleared by BPSL can be less than, equal to, or greater than the fixed quantity of FPSL load. Thus, the simulation outcomes for BPSL compared to FPSL will be a blend of the stylistic results for both BPSL – FPSL and BPSL – FPIL, in addition to being impacted by the nonconvexities of LMP pricing with unit commitment.

Table 4 shows the values of the Table 3 metrics for the stylistic BPSL, FPIL, and FPSL load quantities in terms of the areas labeled with letters in Figure 5. It further shows how the metrics compare between BPSL and FPIL (BPSL – FPIL column) and BPSL and FPSL (BPSL – FPSL column). Taking BPSL as an example, this stylistic market clears at the intersection of the supply and demand curves, resulting in cleared quantity Q_{BPSL} and cleared price P_{BPSL}. The value of load is the area under the demand curve up to the vertical line at Q_{BPSL}, i.e., A+B+C+D+E+F+G+H. The production cost is the area under the supply curve up to the vertical line at Q_{BPSL}, i.e., G+H. Producer revenues and load payments are the area of the rectangle equal to C+D+F+G+H. Net producer surplus is the difference between producer revenue and production cost, i.e., C+D+F. Net consumer surplus is the difference between the value of load and load payment, i.e., A+B+E. Total welfare is the sum of net producer and net consumer surplus, i.e., A+B+C+D+E+F. Under FPIL and FPSL, loads are fixed at levels Q_{FPIL} and Q_{FPSL}, and prices are set by the supply curve at P_{FPIL} and P_{FPSL}, respectively. All metrics of interest under these two scenarios are calculated similarly as described above for BPSL. The results are summarized in Table 4. There are several directional conclusions we can draw under this perfectly convex, one-period market:

- BPSL always achieves the largest total welfare.
- Compared to fixed load scenarios where load is *greater than* the optimal dispatch level set by BPSL, BPSL always decreases the value of load served, production costs, producer revenues (load payments), and net producer surplus and always increases net consumer surplus.
- Compared to fixed load scenarios where load is *less than* the optimal dispatch level set by BPSL, BPSL always increases the value of load served, production costs, producer revenues (load payments), and net producer surplus. However, the change in net consumer surplus can be either positive or negative—the outcome depends on the relative sizes of Areas C and E.

The results that follow are not as simple as this stylistic illustration, and it is also informative to observe the magnitude of the changes induced by BPSL in a realistic test system. Nonetheless, in the end the last two bullets are a reasonable summary of what we observe directionally for the All-Load scenarios (i.e., all RTS-GMLC load modeled as FPIL, FPSL, or BPSL) with and without a carbon price.

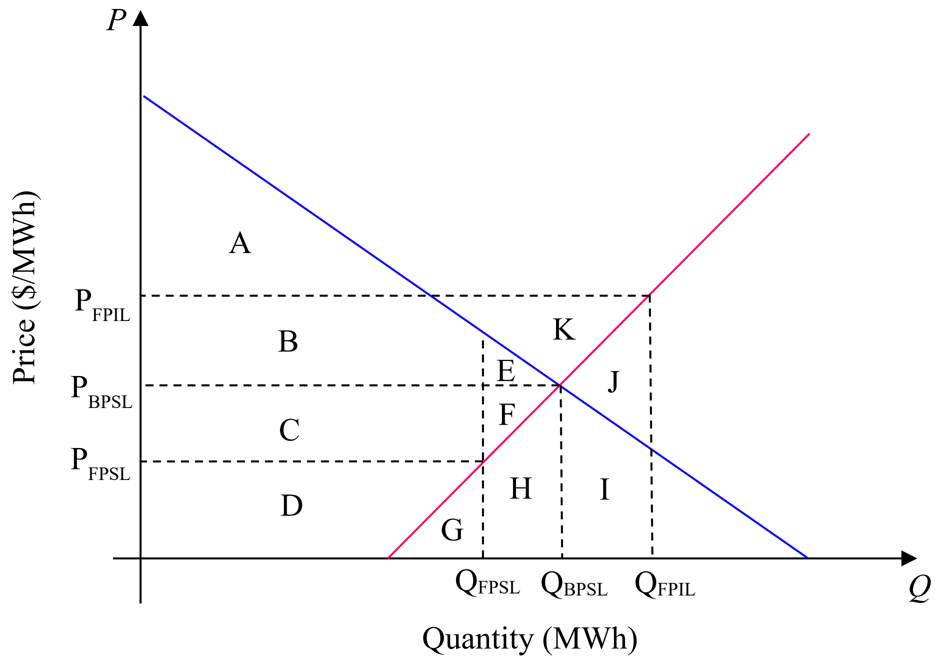

Figure 5. Graph demonstrating market clearing and associated value components assuming a perfectly convex market, a linear BPSL demand curve (blue line), and a linear supply curve (red line).

For illustrative purposes, we depict a fixed load quantity greater than Q_{BPSL} as Q_{FPIL} and a fixed load quantity less than Q_{BPSL} as Q_{FPSL}. However, although in our simulations Q_{FPIL} is always greater than Q_{BPSL}, Q_{FPSL} can be less than, equal to, or greater than Q_{BPSL}.

Table 4. Stylistic Comparison of Total Welfare and Other Metrics in a Perfectly Convex Market with Linear Supply and Demand Curves.

The letters in the table refer to the areas labeled in Figure 5, which have monetary units (e.g., $).

	FPIL	FPSL	BPSL	BPSL-FPIL	BPSL-FPSL
Total Welfare	A+B+C+D+E+F-J	A+B+C+D	A+B+C+D+E+F	J	E+F
Total Value of Load	A+B+C+D+E+F+G+H+I	A+B+C+D+G	A+B+C+D+E+F+G+H	-I	E+F+H
Production Cost	G+H+I+J	G	G+H	-I-J	H
Producer Revenue (Load Payment)	B+C+D+E+F+G+H+I+J+K	D+G	C+D+F+G+H	-B-E-I-J-K	C+F+H
Net Producer Surplus	B+C+D+E+F+K	D	C+D+F	-B-E-K	C+F
Net Consumer Surplus	A-J-K	A+B+C	A+B+E	B+E+J+K	E-C

4 Participation Model Demonstration (One-Load Node, One Day)

To evaluate the three participation models, we begin with one price-sensitive “large consumer” and the impact of this consumer’s actions on a single day’s results at the system level, including effects on suppliers and all other inelastic consumers. Other loads in the RTS-GMLC are assigned the FPIL load model with inelastic load valued at \$332/MWh. The load at Bus 215 (“Barton”) is assigned to be the price-sensitive consumer. We apply all participation load models in turn to this node to construct three scenarios.

Table 5 compares the BPSL participation model to FPIL and FPSL when there is no carbon price. As expected, BPSL has the highest total welfare of the three scenarios. BPSL results in less load served than the FPIL model (100% of load valued at \$332/MWh) because the independent system operator (ISO) dispatches the BPSL consumer down when the incremental cost of generation exceeds the incremental value of consumption, and this reduces the total value of served load by \$6,820. This reduction in the value of load served is completely borne by the price-sensitive large consumer. Production costs are \$17,700 less in the BPSL scenario than in the FPIL scenario, producing a net welfare gain of \$10,900 once the value of the 547 MWh of load that is no longer being served is subtracted. Even though the participating consumer pays 6.14% less for electricity (\$3,690 less), their value of consumption is also reduced by 0.638% under BPSL (\$6,820 less) compared to FPIL. Therefore, their net consumer surplus decreases by 0.310% (\$3,120 less). This shows that, depending on the pricing outcomes, BPSL participants can have worse outcomes than they would have had under FPIL in some instances, even though their more active participation always increases total system welfare. Total load payments, as well as producer revenue and surplus, are higher under BPSL compared to FPIL because of higher LMPs induced by bid-in load (average LMP increases by \$4.23/MWh or 23.5% under BPSL compared to FPIL).

Table 5. Summary Results for One-Day-One-Load (without carbon price)

Uplift payments are included in all revenue, payment, and net surplus metrics.

		Change BPSL – FPIL	Change BPSL – FPSL	Change % (BPSL - FPIL) / FPIL	Change % (BPSL - FPSL) / FPSL
Total Welfare (Thousand $)		10.9	21.9	0.0364%	0.0735%
Total Value of Load (Thousand $)		-6.82	31.8	-0.0221%	0.103%
Production Cost (Thousand $)[4]	Fixed	-3.32	-0.237	-1.16%	-0.0839%
	Variable	-14.4	10.1	-1.86%	1.35%
	Total	-17.7	9.9	-1.67%	0.957%
Producer Revenue (Thousand $)	Total	289	368	15.5%	20.6%
Net Producer Surplus (Thousand $)	VG	66.3	105	11.2%	18.8%
	Non-VG	240	253	112%	126%
	Total	307	358	37.9%	47.3%
Load Payment (Thousand $)	Total	289	368	15.5%	20.6%
Net Consumer Surplus (Thousand $)	Total	-296	-336	-1.02%	-1.15%
Congestion Rents (Thousand $)		0	0	0%	0%
Uplift Payments (Thousand $)		-107	-117	-100%	-100%
Load Served (MWh)	Participant	-547	740	-17.0%	38.3%
Value of Load (Thousand $)	Participant	-6.82	31.8	-0.638%	3.09%
Load Payment (Thousand $)	Participant	-3.69	21.7	-6.14%	62.4%
Net Consumer Surplus (Thousand $)	Participant	-3.12	10.1	-0.310%	1.01%
Total Emissions	CO_2 (metric ton)	-966	375	-2.54%	1.02%
Total Load Served (MWh)		-547	740	-0.588%	0.806%
Average Emissions	CO_2 (metric ton/ MWh)	-0.00803	0.000862	-1.97%	0.216%
LMP ($/MWh)	Min	0	0	N/A	N/A
	Max	63.9	63.9	177%	177%
	Average	4.23	4.92	23.5%	28.4%
	Std. Dev.	8.27	7.78	71.3%	64.4%

[4] Fixed costs comprise those production costs that do not change with output level, such as start-up, shut-down, and commitment costs; variable costs are those that do change with output level, such as fuel and variable O&M costs. Thus, in this analysis, fuel and variable O&M costs incurred when a unit is committed at minimum or maximum generation level are categorized as variable costs.

Even though bid-in demand is guaranteed to achieve maximum total welfare, its impact on LMPs is more complicated because LMPs are the incremental costs of serving an increment of load. Figure 6 shows the LMP profiles induced by the three scenarios. Taking Hour 5 as an example, its LMPs are $0/MWh under FPIL and $10/MWh under BPSL. Under FPIL, a coal unit (201_STEAM_3) is committed at its minimum generation of 30 MW, pushing wind resources to the margin of the supply curve (wind is dispatched at 1,986 MWh of its 1,999 MWh of availability), which sets the LMP to $0/MWh. On the other hand, under BPSL, the dispatch algorithm does not commit the coal unit and makes full use of the available wind resources. It also dispatches less bid-in load (17.4 MWh less compared to the 122 MWh fixed load in FPIL), which sets the LMP at the lowest bid block of $10/MWh. Another more dramatic example is Hour 17, where the LMP under FPIL is $36.1/MWh but increases to $100/MWh under BPSL. Under FPIL, the same coal unit (201_STEAM_3) is committed at its maximum capacity of 76.0 MW. A natural gas unit (221_CC_1) dispatched at 333 MWh is the marginal unit and sets the LMP at $36.1/MWh. Under BPSL, the coal unit is not committed, and the gas unit is dispatched at its maximum capacity of 355 MW. In addition, bid-in load is dispatched down to 78.4 MWh compared to the 132.8 MWh FPIL fixed load, which sets the LMP at the mid-load bid block of $100.00/MWh.

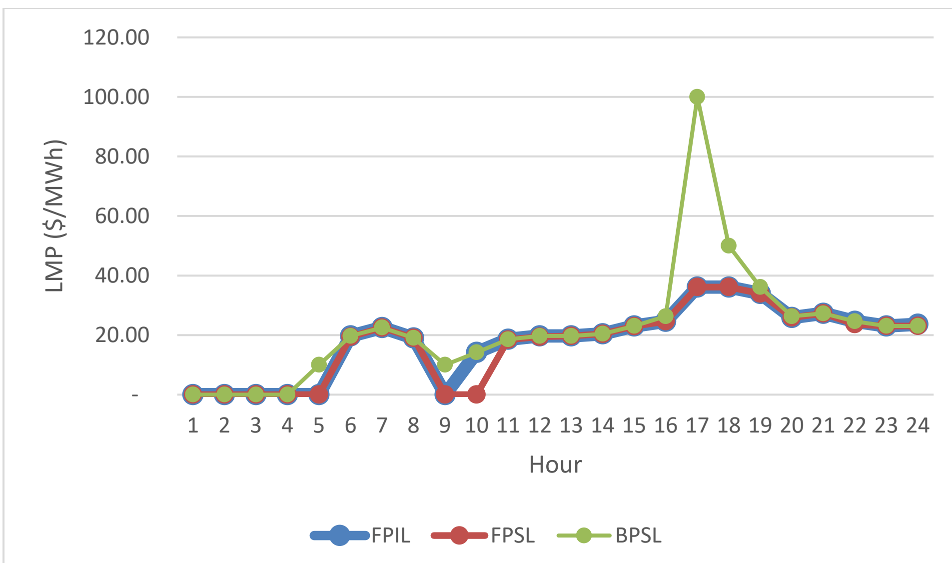

Figure 6. LMP at Bus 215 (without carbon price)

Table 6 summarizes the dispatch differences during these 2 hours. Also note that because BPSL increases LMP at an hour with abundant fossil generation (Figure 7, Hour 17), increased producer surplus is much higher for non-VG resources (112%) compared to VG resources (11%).

Table 6. Dispatch Differences Under FPIL and BPSL at Hour 5 (top) and Hour 17 (bottom) (without carbon price)

* denotes the marginal resources that set the LMPs at that hour

Hour 5 (MWh)	FPIL	BPSL
201_STEAM_3	30.0	0
Wind	1,986*	1,999
Bid-in Demand (Dispatch Down)	-	17.4*
Sum	2,016	2,016

Hour 17 (MWh)	FPIL	BPSL
201_STEAM_3	76.0	-
221_CC_1	333*	355
Bid-in Demand (Dispatch Down)	-	54.4*
Sum	409	409

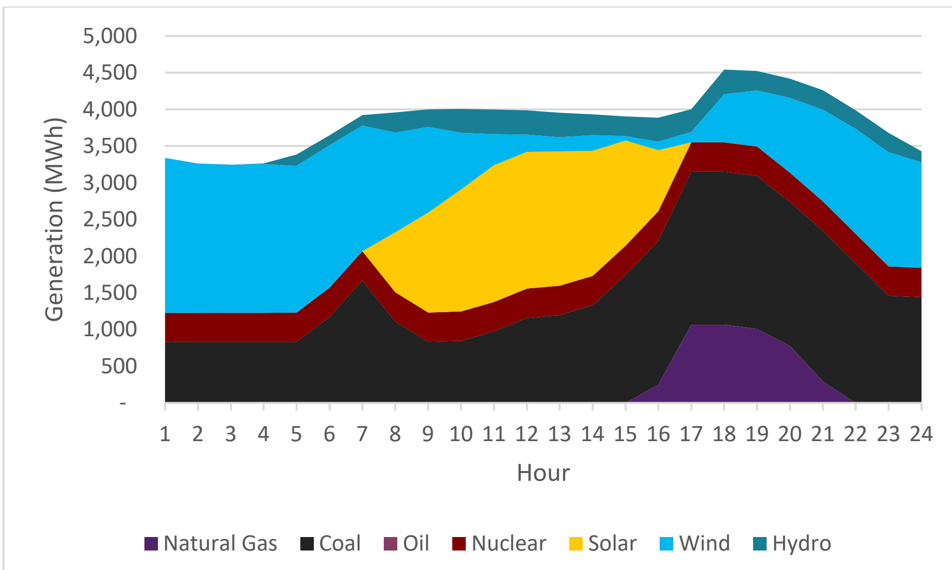

Figure 7. Generation by type under BPSL without a carbon price. FPIL results are visually nearly identical, with abundant fossil generation in Hour 17.

As described in Section 3, total welfare can be partitioned into three parts: net producer surplus, net consumer surplus, and congestion rents. It is important to observe that even though total welfare always increases under BPSL, its individual components do not follow consistent trends. In particular, welfare increases can be accompanied by shifts in the trade-off between net producer surplus and net consumer surplus because producers' revenues are consumers' costs and the welfare-maximizing objective function nets out these quantities. For example, we see in Table 5 that switching from FPIL to BPSL increases net producer surplus by $306,000, mostly at the expense of lowered net consumer surplus ($296,000 less) but also by increasing the total welfare by $10,900. CO_2 emissions decrease under BPSL because of both a decrease in the average emissions rate (responsible for 77% of the total reduction) and a reduction in amount of load served (responsible for the other 24%).

Compared to FPSL (60% of load valued at $533/MWh), on net BPSL serves more load (740 MWh) and provides more consumption value ($31,800) to the price-sensitive consumer. The BPSL participant pays $21,700 more to suppliers in return for this additional value compared to FPSL, but because the additional payment is less than the additional value, they also experience a net consumer surplus increase of $10,100. Systemwide, the impact of the price-sensitive consumer actively bidding in their demand (BPSL) versus reacting only to average system prices (FPSL) is to increase total welfare by $21,900, which breaks down into a $358,000 increase in net producer surplus and a $336,000 decrease in net consumer surplus (there are no congestion rents in this scenario). Load is 0.806% higher and emissions are 1.02% higher in BPSL than in FPSL.

Figure 8 shows the change in the participating load's hourly consumption under BPSL compared to FPIL (blue dots) and FPSL (red dots). Compared to FPIL, BPSL only reduces load, and it does so in 20 of the 24 hours. Of the 20 hours with load reductions, 16 forego 20% of load, corresponding to times when energy prices are above $10/MWh but below $50/MWh (Figure 6). Bid-in load sets the LMP in the remaining 4 hours, including at Hours 5 and 9, when the load is reduced by 14% and 2%, respectively, and the prices were set at $10/MWh; at Hour 18, when load is reduced by 23% and sets the LMP at $50/MWh; and at Hour 17, when load is reduced by 41% and sets the LMP at $100/MWh. Compared to FPSL, BPSL increases load in all hours except Hour 17, when it sets the LMP at $100/MWh. Of the 23 hours with load increases, load is increased by a third of FPSL levels when prices are between $10/MWh and $50/MWh and is further increased by an additional third of FPSL levels when prices are below $10/MWh. Load increases are not in exact increments of one-third of FPSL levels during the hours when BPSL sets prices, which again were Hours 5, 9, 17, and 18.

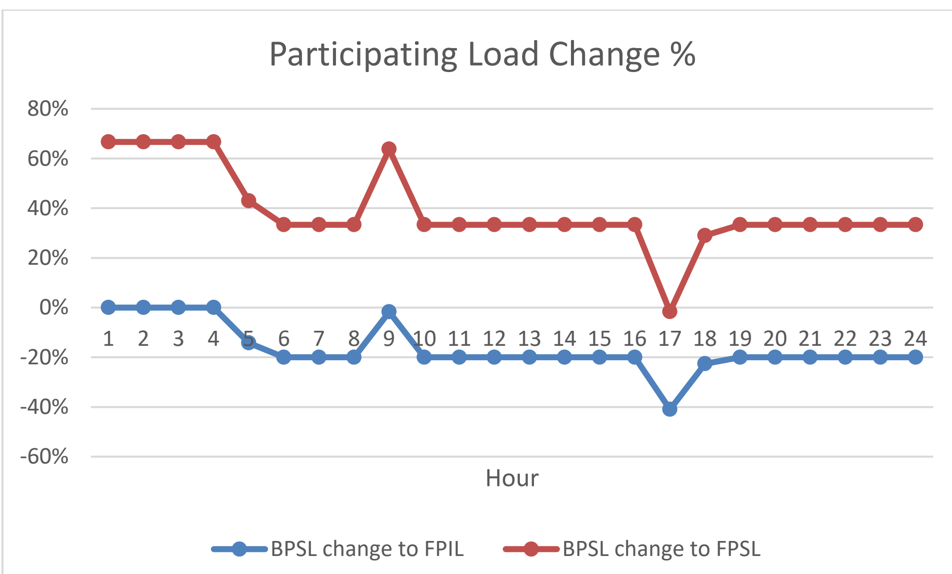

Figure 8. Participating load change (without carbon price).

BPSL sets the LMP in Hours 5, 9, 17, and 18 to $10/MWh, $10/MWh, $100/MWh, and $50/MWh, respectively.

Table 7 shows the results for the same day and same three participation models applied to Bus 215 but with a $50/metric ton social cost of CO_2 emissions added to the generation costs of all fossil fuel generators. Pricing emissions this way almost doubles total production costs and more than halves total CO_2 emissions in all three scenarios. The three load models compare similarly to one another as what we saw without a carbon price, except that the average LMPs are lower under BPSL compared to FPIL when there is a carbon price. (In all other comparisons, BPSL produced a higher average LMP for this particular day compared to either FPIL or FPSL.)

Figure 9 shows the price time series for all three scenarios with carbon price. In this case, the largest difference in LMPs again comes in Hour 17, but this time it is FPIL rather than BPSL that sets the highest price. The dispatch differences between FPIL and BPSL in this hour are shown in Table 8. Note that there are two marginal units in both cases. As seen in Table 9, if we increase the load in Hour 17 at Barton by a small amount (0.01 MWh), so that unit commitment decisions do not change, the LMPs will be equal to the increment in total production costs. For FPIL, this means increasing the outputs from 101_CT_2 by 0.00781 MWh and 107_CC_1 by 0.00219 MWh; for BPSL, the 0.01 MWh incremental load is supplied by a 0.00989 MWh output increase from 221_CC_1 and a 0.00011 MWh increase from 107_CC_1. BPSL therefore results in lower producers' revenue and surplus—and higher consumer surplus—compared to FPIL because the two CCs dispatched under BPSL have lower incremental costs than the one CT and one CC dispatched under FPIL. This difference in LMP outcome is decisive for the participant—unlike in the no-carbon-cost case, the participant's net consumer surplus increases in this scenario by $33,400 (or 3.58%) under BPSL compared to FPIL. This is because the decreased value of consumption ($14,100) is less than the reduced load payment ($47,500) under these conditions. The reduction in LMP under BPSL compared to FPIL also benefits nonparticipating consumers because the $22,900 increase in total welfare is partitioned into a $182,000 decrease in net producer surplus, a $22,500 decrease in congestion rents, and a $227,000 increase in net consumer surplus.

Table 7. Summary Results for One-Day One-Load (with $50/metric ton social cost of CO_2)

Uplift payments are included in revenue, payment, and net surplus metrics unless otherwise stated.

		Change BPSL – FPIL	Change BPSL – FPSL	Change % $\frac{\text{BPSL - FPIL}}{\text{FPIL}}$	Change % $\frac{\text{BPSL - FPSL}}{\text{FPSL}}$
Total Welfare ($)		22.9	11.7	0.0793%	0.0404%
Total Value of Load ($)		-14.1	24.5	-0.0456%	0.0794%
Production Cost ($)	Fixed	-1.65	1.01	-0.332%	0.206%
	Variable	-35.3	11.8	-2.26%	0.781%
	Total	-37.0	12.8	-1.80%	0.639%
Total Producer Revenue ($)	Without Uplift	-425	121	-11.1%	3.69%
	With Uplift	-219	90.2	-5.57%	2.49%
Net Producer Surplus ($)	VG	-98.9	61.5	-7.60%	5.39%
	Non-VG	-83.0	15.9	-14.6%	3.36%
	Total	-182	77.4	-9.72%	4.80%
Load Payment ($)	Total	-241	127	-6.02%	3.50%
Net Consumer Surplus ($)	Total	227	-103	0.845%	-0.377%
Congestion Rents ($)		-22.5	37.1	-29.3%	217%
Uplift Payments ($)		206	-30.9	205%	-9.16%
Load Served (MWh)	Participant	-695	592	-21.6%	30.7%
Value of Load ($)	Participant	-14.1	24.5	-1.32%	2.38%
Load Payment ($)	Participant	-47.5	17.5	-35.5%	25.3%
Net Consumer Surplus ($)	Participant	33.4	7.05	3.58%	0.733%
Total Emissions	CO_2 (metric ton)	-294	105	-1.82%	0.665%
Total Load Served (MWh)		-695	592	-0.747%	0.645%
Average Emissions	CO_2 (metric ton/MWh)	-0.00188	0.0000337	-1.08%	0.0197%
LMP ($/MWh)	Min	0	-14.4	0%	N/A
	Max	-88.6	0	-57.0%	0%
	Average	-4.28	1.67	-10.6%	4.86%
	Std. Dev.	-4.95	-1.67	-19.0%	-7.32%

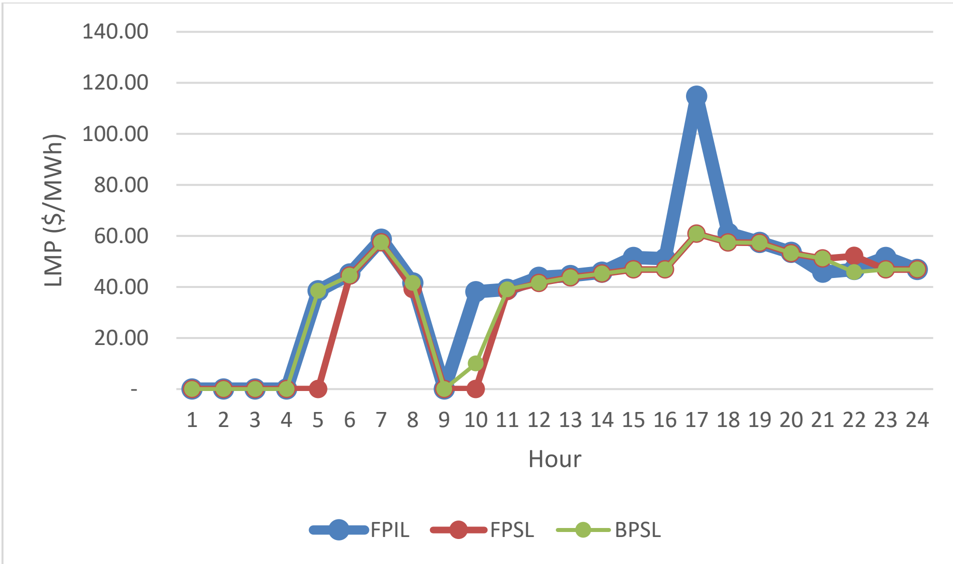

Figure 9. LMP at Bus 215 (with \$50/metric ton social cost of CO_2)

Table 8. Dispatch Differences Under FPIL and BPSL at Hour 17 (with \$50/metric ton social cost of CO_2)

(* denotes the marginal resources that set the LMPs at that hour)

Hour 17 (MWh)	FPIL	BPSL
101_CT_2	15.5*	-
107_CC_1	350*	345*
221_CC_1	355	322*
Bid-in Demand (Dispatch Down)	-	53.1
Sum	720	720

Table 9. Marginal Units Under FPIL (top) and BPSL (bottom) at Hour 17 (with \$50/metric ton social cost of CO_2); Responses to 0.01 MWh Increase in Load

FPIL	Generation Increment (MWh)	Marginal Cost ($/MWh)	Cost Increment ($)
101_CT_2	0.00781	132	1.03
107_CC_1	0.00219	51.5	0.113
Sum of Cost Increment ($/MWh)			**115**

BPSL	Generation Increment (MWh)	Marginal Cost ($/MWh)	Cost Increment ($)
221_CC_1	0.00989	61.0	0.603
107_CC_1	0.000113	51.5	0.00583
Sum of Cost Increment ($/MWh)			**60.9**

Figure 10 shows the generation dispatch of BPSL for the one-load one-day scenario with a \$50/metric ton social cost of CO_2. Compared to Figure 7, we see that no coal units have been committed and that natural gas has been substituted for all the coal generation in the no-carbon-cost scenario. Across the three scenarios, the combination of adding an emissions cost and the resulting dispatch changes increases the average LMP from \$18–22/MWh to \$34–40/MWh.

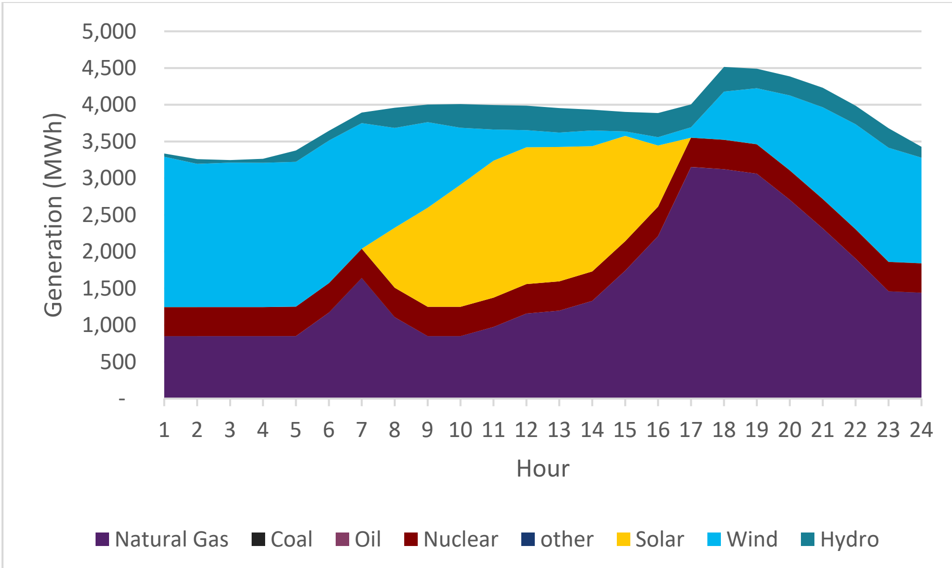

Figure 10. Generation by type under BPSL with \$50/metric ton social cost of CO_2. FPIL results are visually nearly identical.

Those LMP changes increase the number of hours in which BPSL dispatches to the same level as FPSL (or lower), from 1 hour in the no-carbon-cost case (Figure 8, Hour 17) to 6 hours (Hour 7 and Hours 17–21) in Figure 11. The number of hours in which BPSL reduces load compared to FPIL is similar to the no-carbon-cost scenario, at 19 (compared to 20) hours, but in this scenario BPSL spends less time at the -20% level (11 hours instead of 16) and happens to set the price less often, i.e., only in Hour 10 at the \$10/MWh level, with BPSL load 17% less than FPIL.

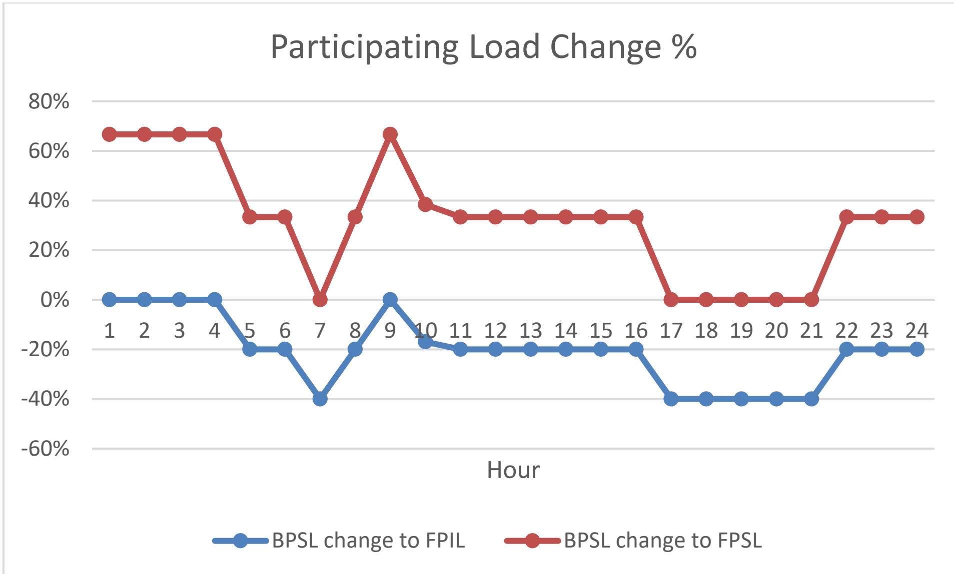

Figure 11. Participating load change (with $50/metric ton social cost of CO_2). BPSL sets the LMP to $10/MWh in Hour 10.

5 Marginal Impact of Participation Models (One-Load Node, One Year)

To make more general statements about the marginal impact of bid-in demand, we extend the one-day simulations described in Section 4 to a full year. This results in simulations with 3.6% of annual demand modeled as FPIL, FPSL, or BPSL and the remaining 96.4% of demand always modeled as FPIL. Table 10 and Table 11 show the summary results without carbon price and with $50/metric ton carbon price, respectively. For the RTS-GMLC test system, the annual marginal impact of bid-in demand can be summarized as follows:

- BPSL achieves the highest total welfare compared to either FPIL (0.04% higher without carbon price, 0.16% with carbon price) or FPSL (0.07% higher without carbon price, 0.04% with carbon price). However, this welfare gain is distributed disproportionately among producers and consumers: producers see a surplus increase of 5.75%–9.78% compared to FPIL and an increase of 7.70%–10.6% compared to FPSL whereas consumers record a reduction in surplus of about 0.3% compared to FPIL and 0.3%–0.6% compared to FPSL.
- Participant load experiences an increase in net surplus under BPSL compared to either FPIL (0.88% higher without carbon price, 4.25% with carbon price) or FPSL (1.59% higher without carbon price, 0.60% with carbon price). The net surplus gain of participant load under BPSL is because of reduced load payments being greater than reduced value of load compared to FPIL and increased value of load greater than increased load payments compared to FPSL.
- Average LMPs under BPSL are higher on an annual basis compared to either FPIL (4.97% higher without carbon price, 2.75% with carbon price) or FPSL (5.43% higher without carbon price, 3.81% with carbon price), which contributes to lower net consumer surplus overall.
- Without carbon pricing, total CO_2 emissions generally track the level of total load served, with BPSL recording 0.94% less CO_2 emissions compared to FPIL and 1.03% more compared to FPSL; with a carbon price, BPSL lowers total emissions compared to FPIL (3.46% lower) and FPSL (0.07% lower). Comparing BPSL to FPIL with a carbon price, there are emissions reductions attributable to both reduced load (about 5% of the emissions reductions) and a reduced average emissions rate (about 95% of the emissions reductions). Comparing BPSL to FPSL with a carbon price, emissions decrease despite a net increase in load served because the average emissions rate decrease of 0.001 metric tons CO_2/MWh applied to the FPSL scenario load (37,000 GWh) is about 30% larger than the emissions induced by the additional 134 GWh of load under BPSL at 0.200 metric tons CO_2/MWh.

Table 10. Summary Results for One-Year One-Load (without carbon price)

Uplift payments are included in revenue, payment, and net surplus metrics unless otherwise stated.

		Change BPSL – FPIL	Change BPSL – FPSL	Change % (BPSL - FPIL) / FPIL	Change % (BPSL - FPSL) / FPSL
Total Welfare (MM $)		5.30	8.49	0.0443%	0.0709%
Total Value of Load (MM $)		-3.73	12.5	-0.0299%	0.100%
Production Cost (MM $)	Fixed	-2.69	-0.779	-2.11%	-0.621%
	Variable	-6.35	4.79	-1.70%	1.32%
	Total	-9.04	4.01	-1.80%	0.821%
Producer Revenue (MM $)	Total	30.4	46.2	3.36%	5.20%
Net Producer Surplus (MM $)	VG	5.36	8.38	2.69%	4.27%
	Non-VG	34.0	33.8	16.7%	16.6%
	Total	39.4	42.2	9.78%	10.5%
Load Payment (MM $)	Total	31.2	47.9	3.37%	5.27%
Net Consumer Surplus (MM $)	Total	-35.0	-35.4	-0.303%	-0.307%
Congestion Rents (MM $)		0.861	1.75	3.86%	8.14%
Uplift Payments (MM $)		-7.20	-6.17	-41.6%	-37.9%
Load Served (GWh)	Participant	-254	287	-18.8%	35.3%
Value of Load (MM $)	Participant	-3.73	12.5	-0.832%	2.89%
Load Payment (MM $)	Participant	-7.39	5.93	-22.3%	29.9%
Net Consumer Surplus (MM $)	Participant	3.66	6.56	0.879%	1.59%
Total Emissions	CO_2 (MM metric tons)	-0.138	0.148	-0.943%	1.03%
Total Load Served (GWh)		-254	287	-0.677%	0.775%
Average Emissions	CO_2 (metric ton/MWh)	-0.00105	0.000987	-0.268%	0.254%
LMP ($/MWh)	Min	1.00	-4.72	2.54%	-14.0%
	Max	522	535	186%	200%
	Average	1.15	1.25	4.97%	5.43%
	Std. Dev.	4.98	4.67	28.7%	26.5%

Table 11. Summary Results for One-Year One-Load (with $50/metric ton social cost of CO_2)

Uplift payments are included in revenue, payment, and net surplus metrics unless otherwise stated.

		Change BPSL – FPIL	Change BPSL – FPSL	Change % $\frac{\text{BPSL - FPIL}}{\text{FPIL}}$	Change % $\frac{\text{BPSL - FPSL}}{\text{FPSL}}$
Total Welfare (MM $)		18.1	4.38	0.157%	0.0380%
Total Value of Load (MM $)		-12.3	3.91	-0.0988%	0.0314%
Production Cost (MM $)	Fixed	-9.90	-2.82	-4.14%	-1.22%
	Variable	-20.5	2.36	-2.80%	0.332%
	Total	-30.4	-0.465	-3.13%	-0.0493%
Producer Revenue (MM $)	Total	19.9	65.7	1.08%	3.65%
Net Producer Surplus (MM $)	VG	5.56	10.8	1.42%	2.78%
	Non-VG	44.7	55.4	9.28%	11.7%
	Total	50.3	66.1	5.75%	7.70%
Load Payment (MM $)	Total	21.2	72.0	1.09%	3.81%
Net Consumer Surplus (MM $)	Total	-33.5	-68.1	-0.318%	-0.644%
Congestion Rents (MM $)		1.32	6.29	1.40%	7.02%
Uplift Payments (MM $)		-2.87	-1.78	-14.3%	-9.39%
Load Served (GWh)	Participant	-407	134	-30.1%	16.5%
Value of Load (MM $)	Participant	-12.3	3.91	-2.74%	0.904%
Load Payment (MM $)	Participant	-28.3	1.56	-38.7%	3.60%
Net Consumer Surplus (MM $)	Participant	16.0	2.35	4.25%	0.604%
Total Emissions	CO_2 (MM metric tons)	-0.267	-0.00494	-3.46%	-0.0663%
Total Load Served (GWh)		-407	134	-1.08%	0.362%
Average Emissions	CO_2 (metric ton/MWh)	-0.00494	-0.000860	-2.40%	-0.427%
LMP ($/MWh)	Min	2.13	45.8	2.07%	31.2%
	Max	20.0	120	2.58%	17.8%
	Average	1.32	1.81	2.75%	3.81%
	Std. Dev.	8.90	9.09	26.2%	26.9%

6 Impact of Participation Models at Saturation (Up to All-Load Nodes, One Year)

To finish describing the impact of bid-in demand on the RTS-GMLC system, we first apply the three load models to all loads in the system.

Table 12 shows the results without carbon pricing. When all loads bid into the market under BPSL, we observe total welfare gains of 0.87% compared to FPIL and 2.13% compared to FPSL. Notably, total production costs are 36% less under BPSL than they are under FPIL. BPSL also reduces average LMPs by 1.5% compared to FPIL, reducing total load payments, producers' revenue, and producers' net surplus—which is a directionally different outcome than seen in the analogous one-load, one-year results. Although a reduction in average LMPs is not guaranteed in this case, it is also not unexpected because economic demand bids are provided by all loads and welfare under BPSL can increase compared to FPIL only by reducing production costs more than the total value of load. Regarding the amount of load served, BPSL serves only 31,100 GWh, which is 17.2% less than under FPIL, but the foregone load represents only 0.62% of the total value because it typically comes from the low-value blocks (e.g., \$10/MWh or \$50/MWh). Net consumer surplus increases by about 1% by overcoming this small loss of load value with a 23.5% reduction in total load payments. The corresponding decrease in net producer surplus is \$36.4 million or 9%. Net consumer surplus also increases under BPSL compared to FPSL (by 0.47%), but the mechanism is different. In this case, BPSL increases total load by about 38%, which results in a \$373 million (3.11%) higher value of load and an increase in load payments of \$318 million. From the consumer perspective, the net result is a \$55.0 million increase in net consumer surplus under BPSL compared to FPSL. It also happens that BPSL average LMPs are almost 45% higher than FPSL average LMPs; combined with the increased load levels, this increases producers' revenue and surplus—the latter by \$184 million or 102%.

Figure 12 shows how total value of load breaks down into production costs (yellow bar) and total welfare (black dash), and how total welfare breaks down into net producer surplus (gray bar), congestion rents (red bar), and net consumer surplus (blue bar). The two subplots show the same data, but on the left the values are plotted starting from \$0 and on the right the y-axis starts at \$11,000 million. On the left, we see that most all of the total value of load (total height of the bars) is returned to customers in the form of net consumer surplus (blue bar). Across the three scenarios, 92% to 97% of the value of load is eventually returned to consumers as their net surplus. The lowest proportion corresponds to the FPIL model, which we can see in the right figure has both the lowest net consumer surplus and the highest production costs and net producer surplus across all three participation scenarios. The highest proportion of load value returned to customers as surplus is achieved by the FPSL model, which has lower net consumer surplus but also much lower production costs and net producer surplus, than BPSL, whose proportion of load value returned to consumers as surplus falls in the middle of the three scenarios, at 94%. As mathematically required, BPSL has the highest total welfare and happens to also have the highest net consumer surplus across the three scenarios.

Table 12. Summary Results for One-Year All-Load (without carbon price)

Uplift payments are included in revenue, payment, and net surplus metrics unless otherwise stated.

		Change BPSL – FPIL	Change BPSL – FPSL	Change % (BPSL - FPIL) / FPIL	Change % (BPSL - FPSL) / FPSL
Total Welfare (MM $)		104	252	0.868%	2.13%
Total Value of Load (MM $)		-77.4	373	-0.620%	3.11%
Production Cost (MM $)	Fixed	-38.1	10.8	-29.9%	13.7%
	Variable	-143	111	-38.3%	93.0%
	Total	-181	122	-36.2%	61.5%
Producer Revenue (MM $)	Total	-218	306	-24.1%	80.7%
Net Producer Surplus (MM $)	VG	-13.3	99.6	-6.65%	115%
	Non-VG	-23.1	84.9	-11.4%	89.3%
	Total	-36.4	185	-9.04%	102%
Load Payment (MM $)	Total	-218	318	-23.5%	81.7%
Net Consumer Surplus (MM $)	Total	140	55.0	1.22%	0.473%
Congestion Rents (MM $)		-0.151	12.2	-0.677%	121%
Uplift Payments (MM $)		-14.8	-13.3	-85.8%	-84.4%
Total Emissions	CO_2 (MM metric tons)	-5.68	3.69	-38.8%	69.9%
Total Load Served (TWh)		-6.48	8.54	-17.3%	37.9%
Average Emissions	CO_2 (metric ton/MWh)	-0.101	0.0543	-26.0%	23.2%
LMP ($/MWh)	Min	24.1	6.09	61.0%	28.3%
	Max	-168	-66.2	-59.8%	-36.9%
	Average	-0.349	7.06	-1.50%	44.8%
	Std. Dev.	-2.58	-6.06	-14.9%	-29.1%

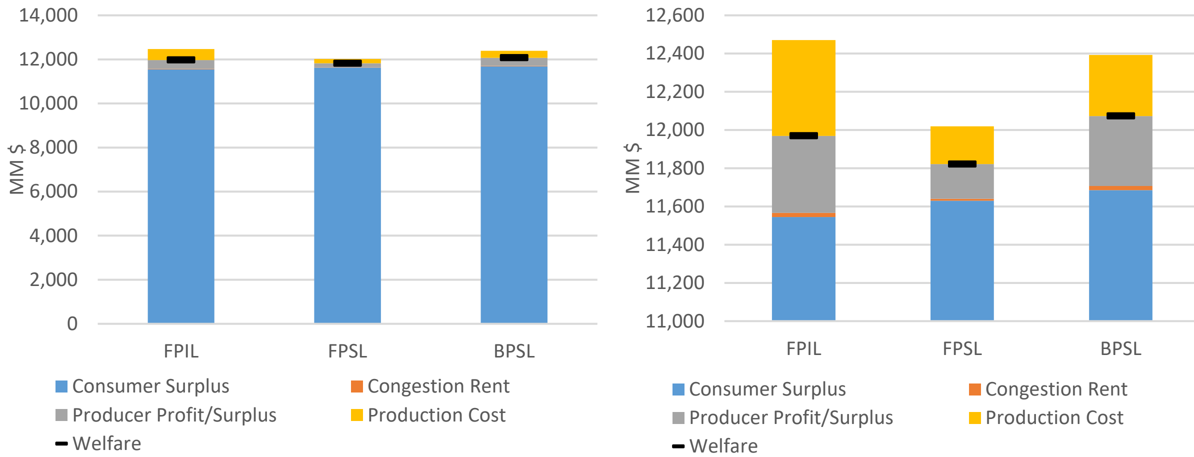

Figure 12. Surplus breakdown across All-Load, One-Year scenarios without carbon price.

The figure on the left plots the y-axis starting from $0 to visually show that net consumer surplus is orders of magnitude larger than production costs and net producer surplus. The figure on the right plots the y-axis starting from $11,000 million to enable comparison across scenarios and to show that congestion rents are orders of magnitude smaller than production costs and net producer surplus.

Table 13 summarizes the simulation results for All-Load, One-Year with a $50/metric ton CO_2 social cost of carbon applied to all emissions. In this case, the welfare gain under BPSL compared to FPIL and FPSL is 2.96% and 1.37%, respectively. Compared to FPIL, BPSL reduces production costs by 57% and reduces average LMPs by almost 15%. Combined with a 25% reduction in load served, the results are reductions in total load payments (43%) and producers' surplus (27%) as well as a 6% increase in net consumer surplus. On the other hand, BPSL increases total load by about 26% and increases average LMPs by almost 40% compared to FPSL, increasing total load payments (52%) and net producer surplus (74%) compared to that scenario. Net consumer surplus in this case decreases by 1.23% because the increased value of load ($240 million) is less than the increased load payments ($379 million).

Figure 13 shows the breakdown of the total value of load and the total welfare for the three All-Load, One-Year scenarios with a $50/metric ton CO_2 social cost of carbon. Similar to Figure 12, BPSL achieves the highest total welfare (black bar). Even though the total value of load (total height of the bars) under BPSL is larger than that under FPSL, the total load payment (sum of production cost [yellow], producer surplus [gray], and congestion rent [orange]) is much higher under BPSL than FPSL, resulting in BPSL having lower consumer surplus (blue) compared to FPSL. Also similar to Figure 12, most of the total value of load is returned to consumers as net surplus, but the proportions are lower with the carbon price applied: 84%, 94%, and 91% for FPIL, FPSL, and BPSL, respectively. This occurs because the carbon price increases production costs by 32% (BPSL) to 93% (FPIL) compared to the corresponding no-carbon-cost scenarios, and LMPs tend to increase accordingly. It was outside the scope of this study to consider where the emissions-associated revenues might eventually end up in the wider economy, but revenue recycling schemes could mitigate the impact to consumers. It is also worth noting that applying a $50/metric ton CO_2 cost in the dispatch algorithm effects large reductions in emissions for all three participation models: 47%, 52%, and 64%, respectively for FPIL, FPSL, and BPSL, primarily by replacing coal generation with gas generation but also by reducing the amount of load served under BPSL.

With both the marginal (3.7% of demand) and all demand bounding cases presented, we describe the transition from 0% to 100% of load participating as BPSL compared to the reference case of all other loads appearing in the market as FPIL.

Table 13. Summary Results for One-Year All-Load (with $50/metric ton social cost of CO_2)

Uplift payments are included in revenue, payment, and net surplus metrics unless otherwise stated.

		Change BPSL – FPIL	Change BPSL – FPSL	Change % (BPSL - FPIL) / FPIL	Change % (BPSL - FPSL) / FPSL
Total Welfare (MM $)		340	160	2.96%	1.37%
Total Value of Load (MM $)		-211	240	-1.69%	1.99%
Production Cost (MM $)	Fixed	-136	-22.7	-57.0%	-18.1%
	Variable	-415	102	-56.6%	47.6%
	Total	-551	79.7	-56.7%	23.4%
Producer Revenue (MM $)	Total	-789	351	-42.7%	49.6%
Net Producer Surplus (MM $)	VG	-59.6	164	-15.2%	96.8%
	Non-VG	-178	107	-37.0%	54.4%
	Total	-238	271	-27.2%	74.0%
Load Payment (MM $)	Total	-840	379	-43.3%	52.4%
Net Consumer Surplus (MM $)	Total	629	-139	5.97%	-1.23%
Congestion Rents (MM $)		-50.5	28.2	-53.4%	178%
Uplift Payments (MM $)		-14.0	-20.0	-70.1%	-77.0%
Total Emissions	CO_2 (MM metric tons)	-4.52	0.672	-58.5%	26.6%
Total Load Served (TWh)		-9.27	5.75	-24.7%	25.5%
Average Emissions	CO_2 (metric ton/MWh)	-0.09	0.00	-44.92%	0.83%
LMP ($/MWh)	Min	-0.0923	0.000927	-44.9%	0.826%
	Max	84.5	30.4	82.1%	62.3%
	Average	-618	-92.0	-79.7%	-36.9%
	Std. Dev.	-7.07	11.7	-14.8%	40.1%

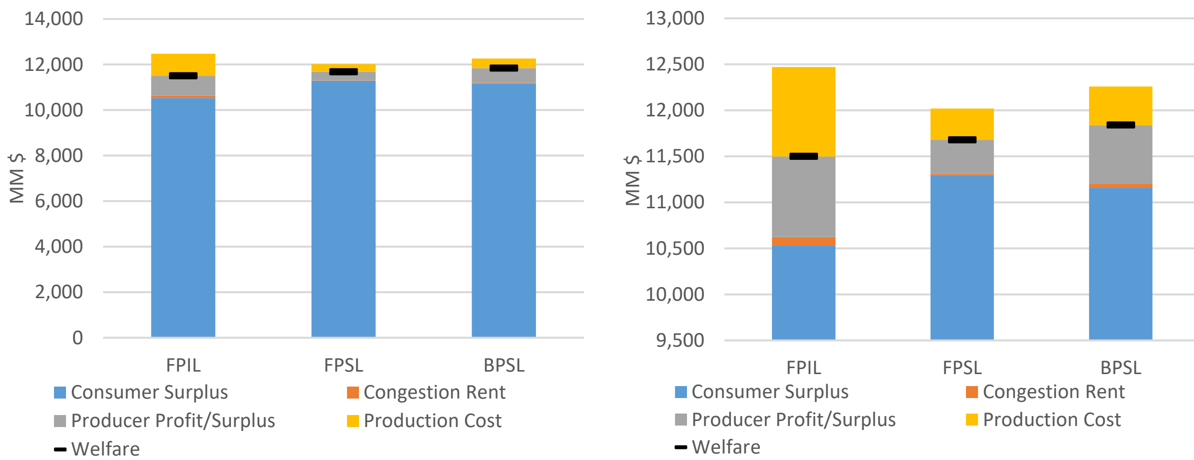

Figure 13. Surplus breakdown across All-Load, One-Year scenarios with $50/metric ton social cost of CO_2.

The figure on the left plots the y-axis starting from $0, to visually show that net consumer surplus is orders of magnitude larger than production costs and net producer surplus. The figure on the right plots the y-axis starting from $9,500 million to enable comparison across scenarios, and to show that congestion rents are orders of magnitude smaller than production costs and net producer surplus.

Figure 14 shows the change in total welfare as a percentage of total welfare under FPIL, and Figure 15 shows the change in total CO_2 emissions as a percentage of total CO_2 emissions under FPIL as the percentage of demand participating under the BPSL model increases from 0% to 100%. Regardless of carbon price, total welfare increases and total CO_2 emissions decrease with more bid-in load participation. However, the welfare increases and emissions decreases with increasing levels of BPSL are larger in the scenarios with a carbon price compared to those without one. This is likely attributable to the fact that under FPIL, although the total value of load is the same across the carbon price scenarios, the production costs are higher and the total welfare is lower when we impose a $50/metric ton social cost of CO_2. This provides more room for improvement under welfare-increasing participation models such as BPSL.

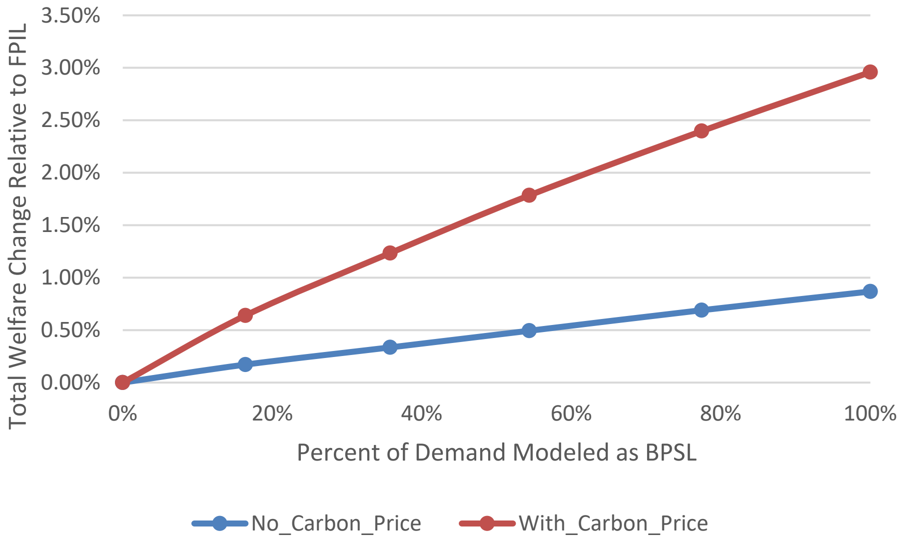

Figure 14. Total welfare change as bid-in load (BPSL) percentage increases relative to all demand participating as FPIL

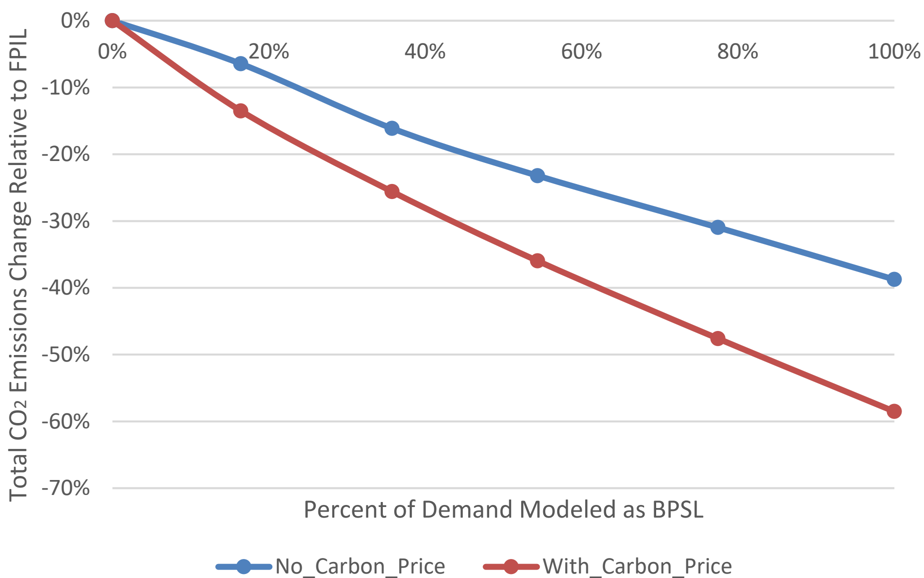

Figure 15. Total CO_2 emissions change as bid-in load (BPSL) percentage increases relative to all demand participating as FPIL

The amounts of change in Figure 14 and Figure 15 are striking. The percentage changes in welfare are relatively modest (at most 0.87% without a carbon price and 2.96% with one) because the total value of load ($12,500 million under FPIL) is about 2 orders of magnitude larger than the production costs ($501 million without a carbon price and $972 million with one under FPIL); however, the absolute increases in going from 100% FPIL to 100% BPSL are large—$104 million and $340 million for the scenarios without and with a carbon price, respectively. That is, the changes in total welfare, which net out decreases in total value of load with decreases in production cost, are of the same order of magnitude as the total production costs for this system, which are in the hundreds of millions of dollars.

The percentage changes in CO_2 emissions are even more striking in this system—almost 40% savings under BPSL compared to FPIL without a carbon price and almost 60% savings with one. As described throughout the report, this impact is because of both less load served and lower average emission rates under BPSL compared to FPIL. For the 100% BPSL cases, both with and without a carbon price, average emission rates decline by about 0.1 metric ton CO_2/MWh compared to FPIL; however, with a carbon price, costs and LMPs are generally higher—which results in less load served in that scenario compared to the no-carbon-price scenario. Those differences in amount of load served (reductions of up to 6,480 GWh without a carbon price and 9,270 GWh with a carbon price for BPSL compared to FPIL) are visible in Figure 16, which also shows the breakdown of annual generation by generation type. As expected in this system with about half low-carbon and low-marginal-cost generation and the balance comprising fossil generators with significant variable (i.e., fuel) costs, given the flexibility offered by BPSL, almost all foregone demand is low-value demand that would have been served by fossil generators.

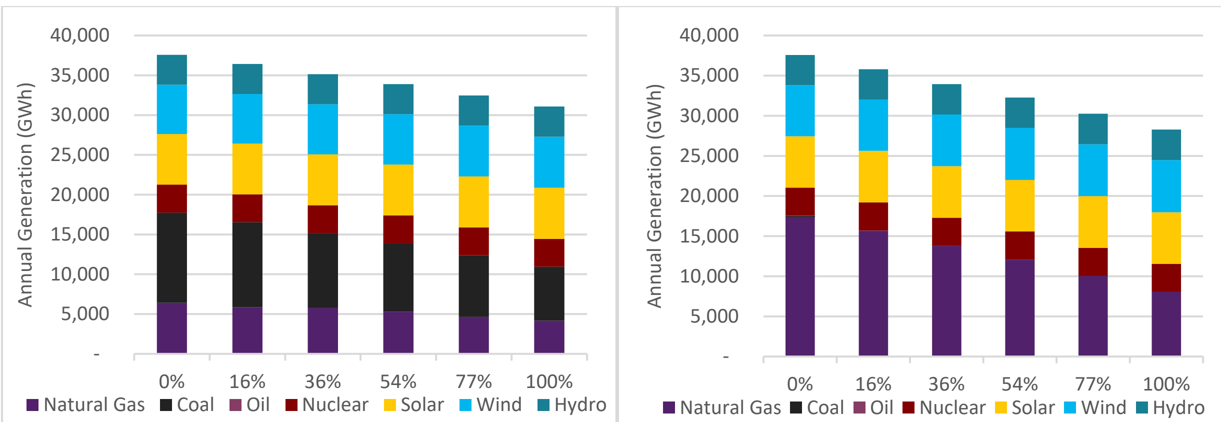

Figure 16. Annual generation by type with \$0 (left) and \$50 (right) per metric ton social cost of CO_2 as bid-in load percentage increases

Although not shown here, the comparison with 100% FPSL, which serves the least load and results in the fewest emissions across all three participation models both with and without a social cost of carbon, is different. Compared to those scenarios, 100% BPSL serves 38% and 26% more load and produces 70% and 27% more CO_2 emissions without and with a carbon price, respectively. Thus, the impact more bid-in demand would have on emissions appears to be highly dependent on how electricity customers currently relate to energy prices (do they conserve by avoiding low-value consumption as under FPSL, or do they count all their possible consumption as "valuable enough" as under FPIL), whether generator bid costs include the social (or other) cost of their carbon emissions, and system composition.

7 Discussion

As a final point of discussion, we revisit the statement made in the introduction: "to understand the gap between the perceived benefits of demand bidding and the lack of demand bidding participants, it is important to not only quantify system-level benefits but to also examine the financial impacts on demand bidders, other electricity consumers, and suppliers." Specifically, the previous section highlighted the system-level benefits of BPSL, i.e., increased welfare compared to both FPIL and FPSL, and decreased emissions compared to FPIL, but here we summarize and discuss the changes in net surplus induced by BPSL and observed across different market stakeholders at the incremental, One-Load (3.6% of demand) level, and the All-Load (100% of demand) level; versus both FPIL and FPSL; and with and without a $50/metric ton social cost of CO_2 emissions (Table 14).

The results shown in Table 14 reveal that the impacts of demand bidding on producer and consumer surplus do not follow consistent trends. When only 3.6% of demand is bid into the market, the participating load is better off in our simulations. However, because this bid-in load induces higher LMPs overall, total consumer surplus is reduced and total producer surplus is increased under BPSL compared to either FPIL or FPSL. When all loads bid into the market, prices are reduced compared to FPIL regardless of carbon pricing, which leads to higher net consumer surplus and lower net producer surplus. Compared to FPSL, all loads bidding into the market generally increases LMPs because of higher consumption. Even though this will increase net producer surplus, the net consumer surplus outcomes depend on the balance between increased value of load and increased load payments. When there is no carbon price, increased value of load ($373 million) is greater than the increased load payments ($318 million), yielding a net consumer surplus gain. However, when there is carbon price, the increased value of load ($240 million) is less than the increased load payments ($379 million), resulting in a net consumer surplus loss. We note that this observation is likely highly dependent on the system being evaluated—both its resource mix and overall load level—and should not be interpreted as a general conclusion. Lastly, BPSL also impacts the relative magnitude of producer surplus changes for VG and non-VG resources, but which types of producers benefit most or experience fewer losses depends on the hours when price changes are induced (i.e., high-VG hours or high-fossil hours) and the directionality of the price changes.

Although net surplus outcomes for particular classes of market participant are highly contingent on circumstance, we do note that if increased load bidding results in increased net producer surplus in wholesale energy markets, this should reduce the "missing money" problems addressed by capacity and other markets such as those for renewable energy credits—and a follow-on effect should be to reduce the size of those markets. For an outcome like this to hold under real-world conditions, BPSL must increase the amount of low-value load served and set strictly positive prices when they would otherwise be zero or negative, more so than it reduces the amount of load served and the prices set at high-price times. In our All-Load simulations, this was the outcome for BPSL compared to FPSL but not for BPSL compared to FPIL. Thus, what impact is dominant in the real world might depend on whether systems are relatively overbuilt (FPSL model, more $0/MWh and less high-price times) or underbuilt (FPIL model, fewer $0/MWh and more high-price times) compared to demand. Finally, we note that demand bid into energy markets below the administratively set value of lost load does not need to be included in capacity markets, in which case the bidders also should not have to pay for capacity and should not be paid for reducing load under emergency conditions, because that demand will not be dispatched to consume power at prices above its bid-in value. The PJM price responsive demand (PRD) model is a real-world implementation of this principle, albeit without direct bidding into the energy market (PJM Interconnection 2024). Like the PRD model, which requires automated and verifiable load reductions when prices exceed prespecified thresholds, loads avoiding capacity payments via energy bids would need to be monitored to ensure that they behave as expected during high-price times.

Table 14. Summary Impact of BPSL on Consumer and Producer Surplus

Load Scenario	BPSL vs.	Social Cost of Carbon $/Metric Ton CO_2	Participating Load Net Consumer Surplus Change MM $	%	Total Net Consumer Surplus Change MM $	%	VG Net Producer Surplus Change MM $	%	Total Net Producer Surplus Change MM $	%
One Load (3.6%)	FPIL	0	3.66	0.879%	-35.0	-0.303%	5.36	2.69%	39.4	9.78%
		50	16.0	4.25%	-33.5	-0.318%	5.56	1.42%	50.3	5.75%
	FPSL	0	6.56	1.59%	-35.4	-0.307%	8.38	4.27%	42.2	10.5%
		50	2.35	0.604%	-68.1	-0.644%	10.8	2.78%	66.1	7.70%
All Load (100%)	FPIL	0	N/A (All Load Participates)		140	1.22%	-13.3	-6.65%	-36.4	-9.04%
		50			629	5.97%	-59.6	-15.2%	-238	-27.2%
	FPSL	0			55.0	0.473%	99.6	115%	185	102%
		50			-139	-1.23%	164	96.8%	271	74.0%

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Appendix A. Optimal Power Flow Formulation

Demand response can be modeled either as a generator resource or as a load resource. Equations (1)–(3) and (4)–(6) show the basic economic dispatch formulation when modeling demand response as a generator resource and as a load resource, respectively. In both cases, $p_{j,b,t}$ is the amount of generator *j*'s block *b* generation that clears at time *t* in MWh, and $c_{j,b,t}$ is the cost of that block of generation in \$/MWh.

When we model demand response as a generator resource (Equations (1)–(3)), $d_{i,b,t}^{-}$ represents the amount of load *i*'s block *b curtailment* that clears at time *t* in MWh, $v_{i,b,t}$ is the cost of that block of curtailment in \$/MWh (which can also be interpreted as the value of load), and $\bar{d}_{i,b,t}$ is the baseline consumption of load *i*'s block *b* at time *t* in MWh, which we set equal to its upper bound. Equation (1) minimizes total costs, including the cost of curtailment. Equation (2) is the supply-demand balance constraint, which says that total generation plus the amount of curtailment must equal total baseline consumption at all times *t*. Equation (3) provides upper and lower bounds on the amount of load curtailment.

$$\min_{d_{i,b,t}^{-},p_{j,b,t}} \sum_{j,b,t} p_{j,b,t} \cdot c_{j,b,t} + \sum_{i,b,t} d_{i,b,t}^{-} \cdot v_{i,b,t} \tag{1}$$

Subject to:

$$\sum_{j,b} p_{j,b,t} + \sum_{i,b} d_{i,b,t}^{-} = \sum_{i,b} \bar{d}_{i,b,t}\, , \forall t \tag{2}$$

$$0 \le d_{i,b,t}^{-} \le \bar{d}_{i,b,t}, \forall i, b, t \tag{3}$$

When we model demand response as a load resource, $d_{i,b,t} = \bar{d}_{i,b,t} - d_{i,b,t}^{-}$ denotes the amount of load *i*'s block *b consumption* that clears at time *t* in MWh. Then if we substitute $d_{i,b,t}^{-} = \bar{d}_{i,b,t} - d_{i,b,t}$ in Equations (1)–(3), we get the following formulation:

$$\min_{d_{i,b,t},p_{j,b,t}} \sum_{j,b,t} p_{j,b,t} \cdot c_{j,b,t} - \sum_{i,b,t} d_{i,b,t} \cdot v_{i,b,t} \tag{4}$$

Subject to:

$$\sum_{j,b} p_{j,b,t} = \sum_{i,b} d_{i,b,t}\, , \forall t \tag{5}$$

$$0 \le d_{i,b,t} \le \bar{d}_{i,b,t}, \forall i, b, t \tag{6}$$

after we drop $\sum_{i,b,t} \bar{d}_{i,b,t} \cdot v_{i,b,t}$ from the objective function because it is a constant. Equation (4) thus minimizes total generation costs minus the total value of load, which is equivalent to maximizing total welfare. Equation (5) is the supply-demand balance constraint, which says that total generation must equal total cleared consumption at any time *t*. Equation (6) provides upper and lower bounds on the amount of demand cleared/load served. **This is the bid-in demand model discussed in this report, whose key advantages are that loads simply pay for their consumption and are not paid for curtailments relative to a baseline.**

However, we also just showed that the two formulations are mathematically equivalent. Therefore, the key differences of concern for this report relate to market settlement—are participating loads paid for curtailments relative to a baseline, or do they pay for the portion of their consumption that clears the market? To that end, we note that charging load locational marginal price (LMP) at the reference (maximum) consumption level ($\bar{d}_{i,b,t}$) and then paying loads for their curtailments ($d^{-}_{i,b,t}$) at the same LMP in formulation (1)–(3) is equivalent to charging cleared demand ($d_{i,b,t}$) the LMP in formulation (4)–(6). We have also observed that Equations (4)–(6) can be computationally less efficient than (1)–(3), which we surmise is because of the (large) net consumer surplus in (4) swamping all other values of interest (e.g., production costs) in the optimization problem, degrading the numerical efficacy of optimization solvers.

Appendix B. Detailed Results

This appendix provides more outputs for the simulations analyzed in the main text.

B.1 One-Load Node, One Day

Detailed results corresponding to the simulations analyzed in Section 4.

Table 15. Detailed Results for One-Day One-Load (without carbon price)

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Total Welfare ($)		29,844,901	29,833,834	29,855,764
Total Value of Load ($)		30,903,229	30,864,611	30,896,411
Production Cost ($)	Fixed	285,291	282,206	281,969
	Variable	773,038	748,571	758,677
	Total	1,058,328	1,030,777	1,040,646
VG Producer Revenue ($)	without Uplift	593,523	555,232	659,857
	with Uplift	593,523	555,232	659,857
Non-VG Producer Revenue ($)	without Uplift	1,165,629	1,114,703	1,495,082
	with Uplift	1,272,578	1,232,161	1,495,082
Total Producer Revenue ($)	without Uplift	1,759,152	1,669,935	2,154,939
	with Uplift	1,866,101	1,787,394	2,154,939
VG Net Producer Surplus ($)	without Uplift	593,523	555,232	659,857
	with Uplift	593,523	555,232	659,857
Non-VG Net Producer Surplus ($)	without Uplift	107,301	83,926	454,436
	with Uplift	214,250	201,384	454,436
Net Producer Surplus ($)	without Uplift	700,824	639,158	1,114,293
	with Uplift	807,773	756,617	1,114,293
Total Load Payment ($)	without Uplift	1,759,152	1,669,935	2,154,939
	with Uplift	1,866,101	1,787,394	2,154,939
Net Consumer Surplus ($)	without Uplift	29,144,077	29,194,675	28,741,472
	with Uplift	29,037,128	29,077,217	28,741,472
Congestion Rents ($)		0	0	0
Uplift Payments ($)		106,949	117,458	0
Participant Load Served (MWh)	Bus 215	3,218	1,931	2,671
Participant Value of Load ($)	Bus 215	1,068,443	1,029,824	1,061,624
Participant Load Payment ($)	Bus 215	60,205	34,792	56,511
Participant Net Consumer Surplus/Value ($)	Bus 215	1,008,238	995,033	1,005,114
Total Emissions	CO_2 (Metric Tons)	37,955	36,614	36,989
Total Load Served (MWh)		93,082	91,795	92,535
Average Emissions	CO_2 (Metric Tons/MWh)	0.408	0.399	0.400
LMP ($/MWh)	Min	0.00	0.00	0.00
	Max	36.12	36.12	100.00
	Average	18.01	17.32	22.24
	Standard Deviation	11.60	12.08	19.87

Table 16. Detailed Results for One-Day One-Load (with $50/metric ton social cost of CO_2)

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Total Welfare ($)		28,845,462	28,856,669	28,868,341
Total Value of Load ($)		30,903,229	30,864,611	30,889,122
Production Cost ($)	Fixed	495,492	492,833	493,846
	Variable	1,562,275	1,515,108	1,526,934
	Total	2,057,767	2,007,941	2,020,780
VG Producer Revenue ($)	without Uplift	1,300,723	1,140,366	1,201,871
	with Uplift	1,300,723	1,140,366	1,201,871
Non-VG Producer Revenue ($)	without Uplift	2,527,203	2,141,241	2,200,883
	with Uplift	2,627,817	2,479,176	2,507,868
Total Producer Revenue ($)	without Uplift	3,827,926	3,281,608	3,402,754
	with Uplift	3,928,540	3,619,543	3,709,740
VG Net Producer Surplus ($)	without Uplift	1,300,723	1,140,366	1,201,871
	with Uplift	1,300,723	1,140,366	1,201,871
Non-VG Net Producer Surplus ($)	without Uplift	469,436	133,300	180,102
	with Uplift	570,050	471,235	487,088
Net Producer Surplus ($)	without Uplift	1,770,159	1,273,666	1,381,974
	with Uplift	1,870,773	1,611,601	1,688,959
Total Load Payment ($)	without Uplift	3,904,580	3,298,702	3,456,910
	with Uplift	4,005,194	3,636,637	3,763,896
Net Consumer Surplus ($)	without Uplift	26,998,649	27,565,908	27,432,212
	with Uplift	26,898,035	27,227,974	27,125,226
Congestion Rents ($)		76,654	17,094	54,156
Uplift Payments ($)		100,614	337,935	306,986
Participant Load Served (MWh)	Bus 215	3,218	1,931	2,523
Participant Value of Load ($)	Bus 215	1,068,443	1,029,824	1,054,335
Participant Load Payment ($)	Bus 215	134,070	69,073	86,538
Participant Net Consumer Surplus/Value ($)	Bus 215	934,373	960,751	967,797
Total Emissions	CO_2 (Metric Tons)	16,145	15,746	15,851
Total Load Served (MWh)		93,082	91,795	92,387
Average Emissions	CO_2 (Metric Tons/MWh)	0.173	0.172	0.172
LMP ($/MWh)	Min	-14.38	0.00	-14.38
	Max	155.52	66.91	66.91
	Average	40.36	34.41	36.08
	Standard Deviation	26.07	22.79	21.12

B.2 One-Load Node, One Year

Table 17. Detailed Results for One-Year One-Load (without carbon price)

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Total Welfare (MM $)		11,969.38	11,966.20	11,974.69
Total Value of Load (MM $)		12,470.36	12,454.13	12,466.63
Production Cost (MM $)	Fixed	127.53	125.62	124.84
	Variable	373.44	362.31	367.10
	Total	500.98	487.93	491.94
VG Producer Revenue (MM $)	without Uplift	199.46	196.45	204.82
	with Uplift	199.46	196.45	204.82
Non-VG Producer Revenue (MM $)	without Uplift	686.86	675.08	719.06
	with Uplift	704.16	691.35	729.16
Total Producer Revenue (MM $)	without Uplift	886.32	871.52	923.88
	with Uplift	903.63	887.80	933.98
VG Net Producer Surplus (MM $)	without Uplift	199.46	196.45	204.82
	with Uplift	199.46	196.45	204.82
Non-VG Net Producer Surplus (MM $)	without Uplift	185.89	187.14	227.12
	with Uplift	203.19	203.42	237.22
Net Producer Surplus (MM $)	without Uplift	385.35	383.59	431.94
	with Uplift	402.65	399.86	442.04
Total Load Payment (MM $)	without Uplift	908.65	892.96	947.07
	with Uplift	925.95	909.24	957.17
Net Consumer Surplus (MM $)	without Uplift	11,561.71	11,561.17	11,519.56
	with Uplift	11,544.41	11,544.89	11,509.45
Congestion Rents (MM $)		22.33	21.44	23.19
Uplift Payments (MM $)		17.30	16.27	10.10
Participant Load Served (GWh)	Bus 215	1,352.39	811.44	1,098.25
Participant Value of Load (MM $)	Bus 215	448.99	432.77	445.26
Participant Load Payment (MM $)	Bus 215	33.17	19.85	25.78
Participant Net Consumer Surplus/Value (MM $)	Bus 215	415.82	412.91	419.48
Total Emissions	CO_2 (MM Metric Tons)	14.65	14.36	14.51
Total Load Served (GWh)		37,561.32	37,020.37	37,307.18

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Average Emissions	CO_2 (Metric Tons/MWh)	0.390	0.388	0.389
LMP ($/MWh)	Min	-39.49	-33.76	-38.49
	Max	281.09	267.66	802.84
	Average	23.18	23.08	24.34
	Standard Deviation	17.32	17.62	22.29

Table 18. Detailed Results for One-Year One-Load (with $50/metric ton social cost of CO_2)

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Total Welfare (MM $)		11,498.62	11,512.33	11,516.71
Total Value of Load (MM $)		12,470.36	12,454.13	12,458.04
Production Cost (MM $)	Fixed	239.32	232.24	229.42
	Variable	732.42	709.55	711.91
	Total	971.74	941.80	941.33
VG Producer Revenue (MM $)	without Uplift	392.60	387.39	398.17
	with Uplift	392.60	387.39	398.17
Non-VG Producer Revenue (MM $)	without Uplift	1,433.81	1,394.32	1,450.99
	with Uplift	1,453.81	1,413.23	1,468.13
Total Producer Revenue (MM $)	without Uplift	1,826.41	1,781.71	1,849.16
	with Uplift	1,846.41	1,800.62	1,866.29
VG Net Producer Surplus (MM $)	without Uplift	392.60	387.39	398.17
	with Uplift	392.60	387.39	398.17
Non-VG Net Producer Surplus (MM $)	without Uplift	462.07	452.52	509.66
	with Uplift	482.07	471.44	526.80
Net Producer Surplus (MM $)	without Uplift	854.67	839.91	907.83
	with Uplift	874.67	858.83	924.96
Total Load Payment (MM $)	without Uplift	1,921.02	1,871.35	1,945.09
	with Uplift	1,941.02	1,890.26	1,962.23
Net Consumer Surplus (MM $)	without Uplift	10,549.34	10,582.78	10,512.95
	with Uplift	10,529.34	10,563.87	10,495.81
Congestion Rents (MM $)		94.61	89.64	95.93
Uplift Payments (MM $)		20.00	18.91	17.14
Participant Load Served (GWh)	Bus 215	1,352.39	811.44	945.55
Participant Value of Load (MM $)	Bus 215	448.99	432.77	436.68
Participant Load Payment (MM $)	Bus 215	73.11	43.25	44.81
Participant Net Consumer Surplus/Value (MM $)	Bus 215	375.88	389.51	391.87
Total Emissions	CO_2 (MM Metric Tons)	7.72	7.45	7.45
Total Load Served (GWh)		37,561.32	37,020.37	37,154.49
Average Emissions	CO_2 (Metric Tons/MWh)	0.205	0.201	0.200

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
LMP ($/MWh)	Min	-102.93	-146.56	-100.80
	Max	775.47	675.48	795.50
	Average	47.91	47.42	49.23
	Standard Deviation	33.93	33.75	42.84

B.3 All-Load Node, One Year

Table 19. Detailed Results for One-Year All-Load (without carbon price)

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Total Welfare (MM $)		11,969.38	11,821.67	12,073.30
Total Value of Load (MM $)		12,470.36	12,019.62	12,392.99
Production Cost (MM $)	Fixed	127.53	78.65	89.46
	Variable	373.44	119.30	230.24
	Total	500.98	197.95	319.70
VG Producer Revenue (MM $)	without Uplift	199.46	86.60	186.19
	with Uplift	199.46	86.60	186.19
Non-VG Producer Revenue (MM $)	without Uplift	686.86	277.36	497.28
	with Uplift	704.16	293.08	499.74
Total Producer Revenue (MM $)	without Uplift	886.32	363.96	683.47
	with Uplift	903.63	379.68	685.93
VG Net Producer Surplus (MM $)	without Uplift	199.46	86.60	186.19
	with Uplift	199.46	86.60	186.19
Non-VG Net Producer Surplus (MM $)	without Uplift	185.89	79.41	177.58
	with Uplift	203.19	95.13	180.04
Net Producer Surplus (MM $)	without Uplift	385.35	166.01	363.78
	with Uplift	402.65	181.73	366.24
Total Load Payment (MM $)	without Uplift	908.65	373.98	705.65
	with Uplift	925.95	389.70	708.11
Net Consumer Surplus (MM $)	without Uplift	11,561.71	11,645.64	11,687.35
	with Uplift	11,544.41	11,629.93	11,684.89
Congestion Rents (MM $)		22.33	10.02	22.17
Uplift Payments (MM $)		17.30	15.72	2.46
Total Emissions	CO_2 (MM Metric Tons)	14.65	5.28	8.97
Total Load Served (GWh)		37,561.32	22,536.79	31,080.58
Average Emissions	CO_2 (Metric Tons/MWh)	0.390	0.234	0.289
LMP ($/MWh)	Min	-39.49	-21.47	-15.38
	Max	281.09	179.22	113.04
	Average	23.18	15.77	22.84
	Standard Deviation	17.32	20.80	14.73

Table 20. Detailed Results for One-Year All-Load (with \$50/metric ton social cost of CO_2)

		FPIL (Fixed at 100% Load)	FPSL (Fixed at 60% Load)	BPSL (Bid-in Load)
Total Welfare (MM \$)		11,498.62	11,678.80	11,838.81
Total Value of Load (MM \$)		12,470.36	12,019.62	12,259.38
Production Cost (MM \$)	Fixed	239.32	125.70	102.97
	Variable	732.42	215.12	317.61
	Total	971.74	340.82	420.57
VG Producer Revenue (MM \$)	without Uplift	392.60	169.25	333.02
	with Uplift	392.60	169.25	333.02
Non-VG Producer Revenue (MM \$)	without Uplift	1,433.81	511.57	718.32
	with Uplift	1,453.81	537.55	724.30
Total Producer Revenue (MM \$)	without Uplift	1,826.41	680.82	1,051.34
	with Uplift	1,846.41	706.81	1,057.32
VG Net Producer Surplus (MM \$)	without Uplift	392.60	169.25	333.02
	with Uplift	392.60	169.25	333.02
Non-VG Net Producer Surplus (MM \$)	without Uplift	462.07	170.74	297.75
	with Uplift	482.07	196.73	303.73
Net Producer Surplus (MM \$)	without Uplift	854.67	340.00	630.77
	with Uplift	874.67	365.99	636.74
Total Load Payment (MM \$)	without Uplift	1,921.02	696.68	1,095.40
	with Uplift	1,941.02	722.67	1,101.38
Net Consumer Surplus (MM \$)	without Uplift	10,549.34	11,322.94	11,163.98
	with Uplift	10,529.34	11,296.96	11,158.00
Congestion Rents (MM \$)		94.61	15.86	44.06
Uplift Payments (MM \$)		20.00	25.99	5.98
Total Emissions	CO_2 (MM Metric Tons)	7.72	2.53	3.20
Total Load Served (GWh)		37,561.32	22,536.79	28,288.08
Average Emissions	CO_2 (Metric Tons/MWh)	0.205	0.112	0.113
LMP (\$/MWh)	Min	-102.93	-48.82	-18.43
	Max	775.47	249.62	157.61
	Average	47.91	29.15	40.84
	Standard Deviation	33.93	34.74	25.28