



Structuring Electricity Markets for Demand Responsiveness: Experiments on Efficiency and Operational Consequences



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Project Team

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Why Demand Responsiveness?

1. Get Customers into the Game
2. Mitigate Supplier Market Power
3. Efficient Use of Resources
(Including the Environment)
4. Affect System Operation

Questions:

1. Why Has Utility Promotion been so Tepid?
2. Why Haven't Marketers Jumped In?
3. What Type of Demand-Side Market Structure
 - a. Is the Most Efficient?
 - b. Is Understood and Effectively Used by Consumers
 - c. Might be Selected by Customers, Given a Choice?
4. Effect on Line Flow Predictability?

Why Laboratory Experiments?

1. Theory Not Up to the Task
2. To Avoid Social Cost of Experiments of the Whole (e.g. California)
3. Low Cost Alternative for Winnowing Out Alternatives
4. Reveals Human Cognitive Processes (Learning & Lags)
5. Value as Educational Tool

**But to be Effective,
___ Participants Must be Paid!**

Demand-Side Behavioral Representation

1. **Start with Final Demand:** We Need to Understand Behavior of End-Use Customer Before We Represent Marketing Agents
2. Disaggregate **Observed Market Demand** Characteristics to Representative Individual Buyers
3. Develop “Induced Valuation” Relationships for Individuals
4. **Customer’s Problem:**
Select Electricity Consumption in Each Period to Maximize Total Value – Total Expenditure
5. Compensate Subjects in Proportion to Net Benefits (as computed in 4)

Average Demand Curve

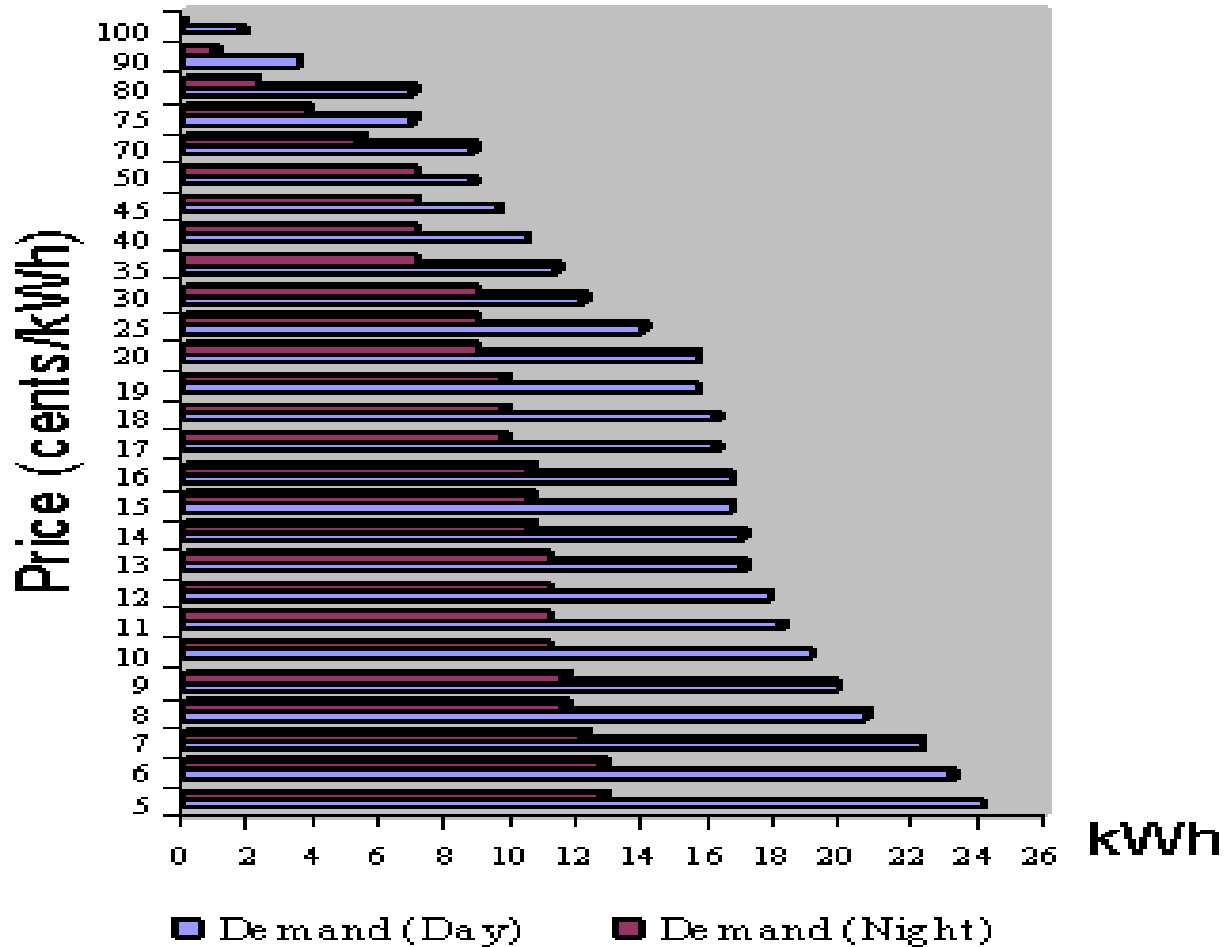
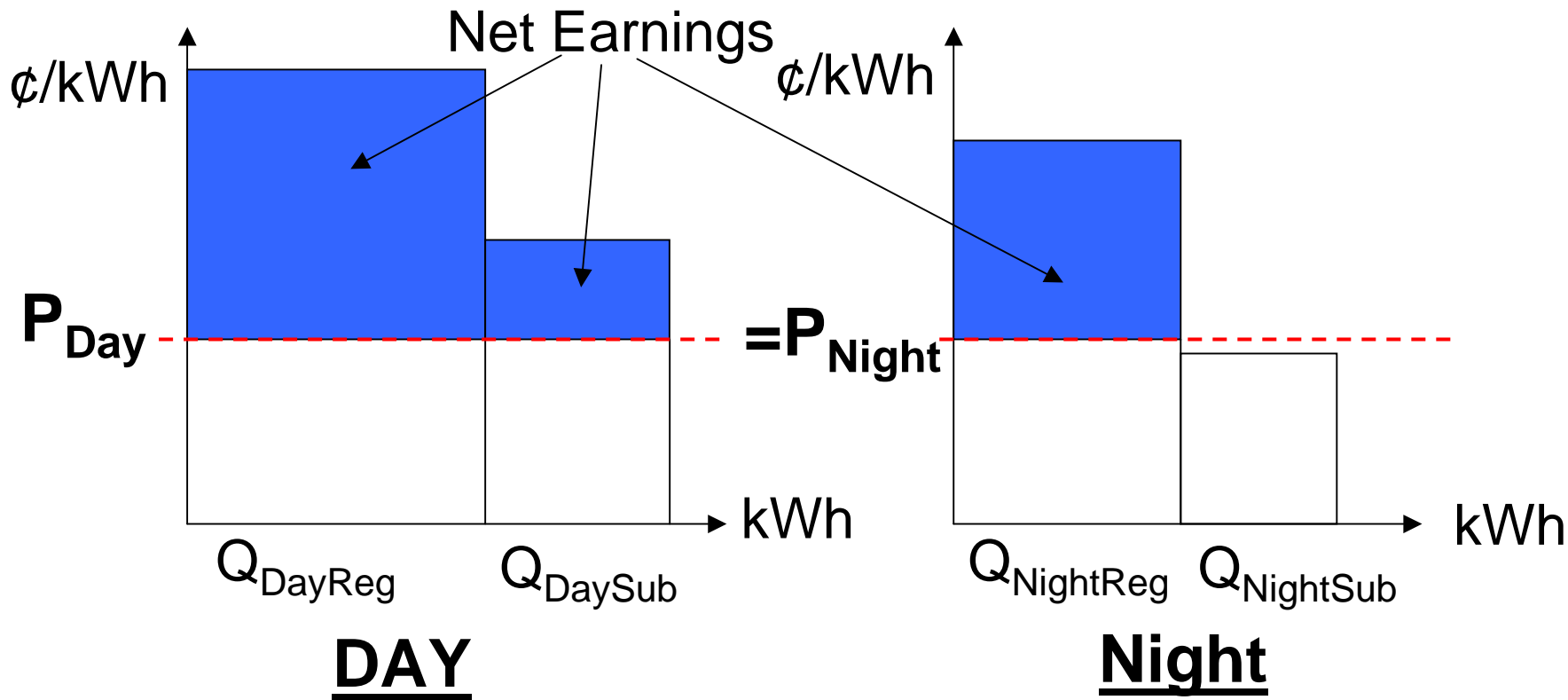


Illustration of Buyer's Problem (with Constant Price)



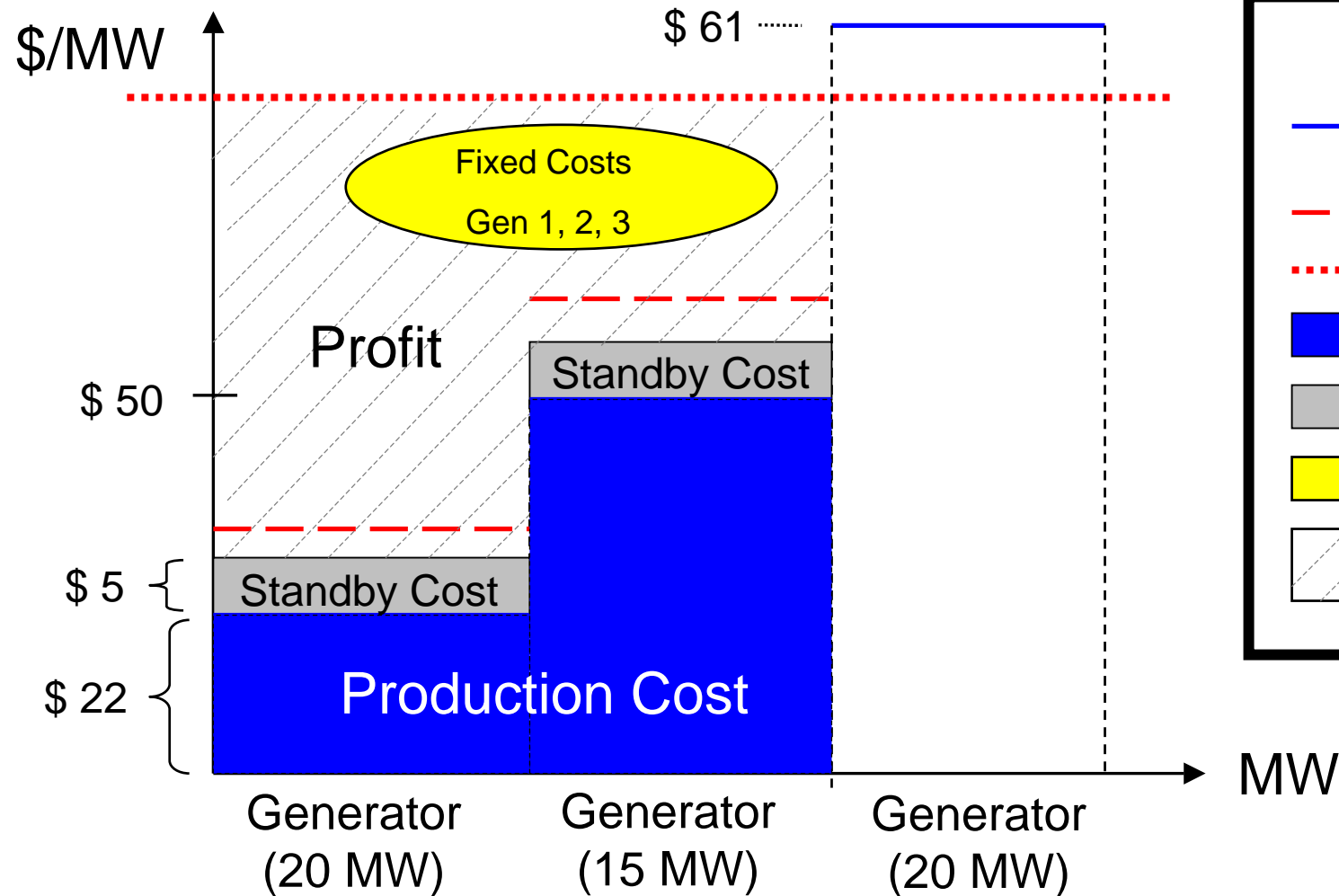
In this Example:

$$Q_{Day} = Q_{DayReg} + Q_{DaySub}$$

$$Q_{Night} = Q_{NightReg} + 0$$

$$Q_{DaySub} + Q_{NightSub} \leq Q_{SubMAX}$$

Illustration of Seller's Problem



Key

- Per Unit Prod. Cost
- - - Price Offer
- ⋯ Market Price
- Generator Production Cost
- Standby Cost
- Fixed Cost
- Profit

Conceptual Framework for Efficient Market Structures

1. Reliability Provided through Networks Has Public Good Aspects:

Market Cannot Solve Completely!

2. Efficient Customer Response Requires Both:
 - Real Time Pricing of Energy (**RTP**)
 - Demand Reduction Program (**DRP**) to Represent Cost Offset for Generation Reserves

Demand Side Scenarios

FP (Fixed Price) – Pre-announced, Constant Identical Prices in All Periods (the Baseline) – Quantity Bids

DRP (Demand Response Program) – FP with Preset Savings in Pre-announced Periods for Purchases Below Benchmark – Quantity Bids

RTP (Real Time Pricing) – Forecast Day/Night Prices – Quantity Bids – Customers Pay Actual Market Clearing Price

Note: RTP with buyers specifying a maximum price (limit orders) was piloted, but was no more effective

Experimental Design for Three Treatments over 11 Day/Night Pairs

Treatments: **FP** (Baseline); **DRP** (Specified/kWh Credit); **RTP** (Forecast Prices, Q-Bids, Pay Mkt. Price)

<u>Characteristics of Day/Night Pairs:</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>	<u>10</u>	<u>11</u>
	N	S	H	N	N	N	H+S	H+S	N	S	H

N=Normal; H=Heat Wave; S=Random Supply Shortage

Preference Poll, “What Do You Prefer: DRP or RTP?”

After FP

After DRP

After RTP → Determines Selection of Additional “High Stakes” Runs on Pairs 1 to 4

Two Separate Identical Trials Were Conducted – with Different Participants

Experiments Conducted


1. Single-Sided Market

- 3 Active Demand Treatments
- Predetermined Cost-Based, Hockey-Stick Shaped Offers with Random Outages
- Two Repeats with 21 Professional Students, Total
- May Reflect Active Demand Side in Market with Supplier Regulations (Full Demand-Side with current NYISO markets)

2. Two-Sided Markets

- 3 Active Demand Treatments
- Active Suppliers without Regulations
- Two Repeats, Each with 7 Suppliers (6 Experienced Grad. Students + 1 Agent) and 19 Buyers (Undergrad. & Grad. Students + Agents)

Buyer's Computer Screen



Name: [test] Test User [Logout](#)

Session: [2] Example Session

Representing: [34] Buyer 1

Period
FP-1

SYSTEM DATA	Day	Night
Market Condition	Normal	Normal
Fixed Price (¢/kWh)	8.5¢	8.5¢


BUYER DATA	Day	Night
Regular Energy Value (¢/kWh)	15.0¢	13.0¢
Regular Max Energy Quantity (kWh)	7000	5000
Substitutable Energy Value (¢/kWh)	11.0¢	7.0¢
Substitutable Max Quantity (kWh)	2000	

MY BIDS	Day	Night
Energy Quantity Bid (kWh)	<input type="text" value="9000"/>	<input type="text" value="5000"/>
<input type="button" value="Submit"/>		
Regular (kWh)	<input type="text" value="7000"/>	<input type="text" value="5000"/>
Substitutable (kWh)	<input type="text" value="2000"/>	<input type="text" value="0"/>

EARNINGS	Day	Night
Benefits from Energy Consumption	<input type="text" value="\$ 1270"/>	<input type="text" value="\$ 650"/>
Cost of Energy Purchased	<input type="text" value="\$ 765"/>	<input type="text" value="\$ 425"/>
Energy Earnings	<input type="text" value="\$ 505"/>	<input type="text" value="\$ 225"/>

Gray background indicates computed values.

Seller's Computer Screen



Name: [test] Test User [Logout](#)

Session: [2] Example Session1

Representing: [29] Seller 3

Period
FP-1

SYSTEM DATA	Day	Night
Market Condition	Normal	Normal
Forecast Load (MW)	196.0	118.0

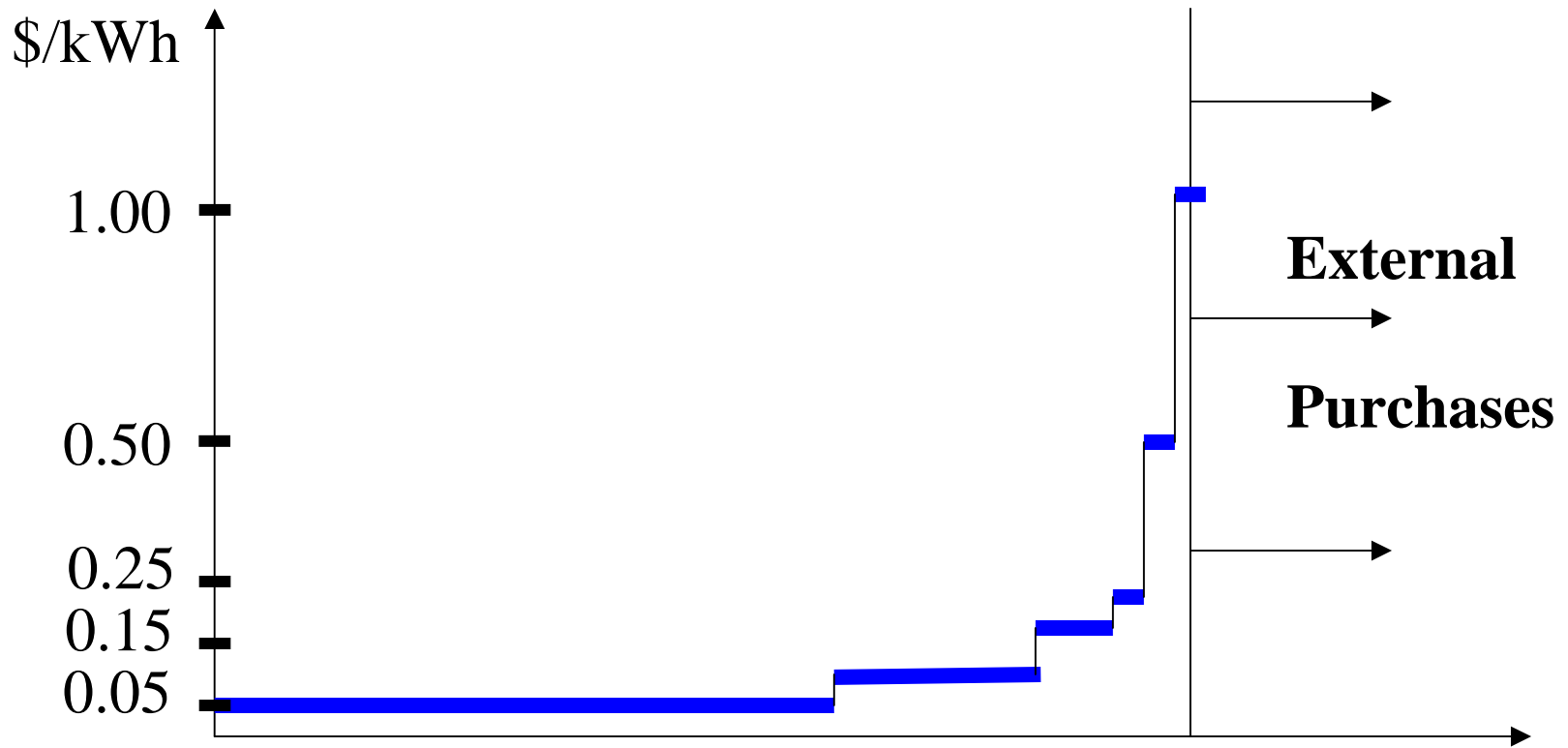
GENERATOR DATA	Day			Night		
	Gen 7	Gen 8	Gen 9	Gen 7	Gen 8	Gen 9
Max Capacity (MW)	20.0	15.0	20.0	20.0	15.0	20.0
Per-Unit Production Cost (\$/MW)	\$22.00	\$50.00	\$61.00	\$22.00	\$50.00	\$61.00
Standby Cost (\$/MW)	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00	\$5.00
Fixed Cost (\$)	\$20.00	\$20.00	\$20.00	\$20.00	\$20.00	\$20.00

MY OFFERS	Day			Night		
	Gen 7	Gen 8	Gen 9	Gen 7	Gen 8	Gen 9
Capacity Offer (MW)	<input type="text" value="20"/>	<input type="text" value="15"/>	<input type="text"/>	<input type="text" value="20"/>	<input type="text" value="15"/>	<input type="text"/>
Price Offer (\$/MW)	<input type="text" value="22"/>	<input type="text" value="100"/>	<input type="text"/>	<input type="text" value="22"/>	<input type="text" value="100"/>	<input type="text"/>

Note: Initial offers are set at your previous offer levels.

Submit

Illustration of Seller's Stack for Single-Sided Market



Experimental Results

- Which Market Structure is **Most Efficient**
(As % of Theoretical Maximum)?

	<u>Active Demand/Preset Cost-Based Supply with Random Shift</u>	<u>Full Two-Sided Market</u>
RTP	99.6%	99.4%
DRP	96.9%	98.7%
FP	98.7%	99.1%

- What **Rate Change** is Required After Runs to Balance the Budget?

	<u>Active Demand/Preset Cost-Based Supply with Random Shift</u>		<u>Full Two-Sided Market</u>	
	<u>First Group</u>	<u>Second Group</u>	<u>First Group</u>	<u>Second Group</u>
RTP	--	--	--	--
DRP	- 2.42 ¢/kWh	- 3.27 ¢/kWh	+ 2.1 ¢/kWh	+ 0.8 ¢/kWh
FP	- 0.68 ¢/kWh	- 3.26 ¢/kWh	+ 1.5 ¢/kWh	+ 1.5 ¢/kWh

Experimental Results:

Two-Sided Experiments: Details on Overall Efficiency for Combined Trials

1. Deviations Re-Stated as % of FP Revenues without Regulation:

	<u>% Added Consumer Value</u>	<u>% Changes Supplier Profit</u>	<u>Combined Change</u>
RTP	9.02	-6.99	2.02%
DRP	13.86	-17.52	-3.67%
Social Optimum (as comparison)	29.32	-22.57	6.75%

2. Statistically Valid Differences in Behavior from FP Results (@ .95 level):

	<u>RTP vs. FP</u>		<u>DRP vs. FP</u>	
	<u>Consumers</u>	<u>Sellers*</u>	<u>Consumers</u>	<u>Sellers*</u>
Value/Profit	+	—	+ ?	—
<u>Quantities Bought/Sold:</u>				
Days	—	— ?	—	—
Nights	+	+ ?	—	+ ?

*Note: With fewer sellers, statistical significance is harder to attain.

Single-Sided Market: Paired t-tests on Weighted Individual Consumer Surplus Differences, Active Demand-Side/Preset Cost-Based Supply.

Period Pairs	FP - OPT		DRP - OPT		RTP - OPT		FP - DRP		FP - RTP		DRP - RTP		Conditions
	sign	significance	sign	significance	sign	significance	sign	significance	sign	significance	sign	significance	
1&2	-	100.00%	-	100.00%	+	27.20%	-	63.49%	-	100.00%	-	100.00%	N
3&4	+	70.13%	+	96.65%	+	90.58%	-	96.30%	-	45.95%	+	96.65%	S, DRP
5&6	-	100.00%	-	99.30%	+	100.00%	+	67.09%	-	100.00%	-	99.30%	H
7&8	-	100.00%	-	100.00%	+	100.00%	0	0.00%	-	100.00%	-	100.00%	N
9&10	-	100.00%	-	100.00%	+	100.00%	-	68.99%	-	100.00%	-	100.00%	N
11&12	-	100.00%	-	100.00%	+	100.00%	+	67.07%	-	100.00%	-	100.00%	N
13&14	+	100.00%	+	99.70%	+	100.00%	-	91.86%	+	99.99%	+	99.70%	H+S, DRP
15&16	+	100.00%	+	99.69%	+	54.05%	-	91.55%	+	99.99%	+	99.69%	H+S, DRP
17&18	-	100.00%	-	100.00%	+	100.00%	-	67.07%	-	100.00%	-	100.00%	N
19&20	+	86.89%	+	96.63%	+	99.95%	-	95.63%	+	29.62%	+	96.63%	S, DRP
21&22	-	100.00%	-	100.00%	+	100.00%	-	67.07%	-	100.00%	-	100.00%	H

(N=Normal, H=Heat Wave, S=Generator Outage, DRP=In Effect)

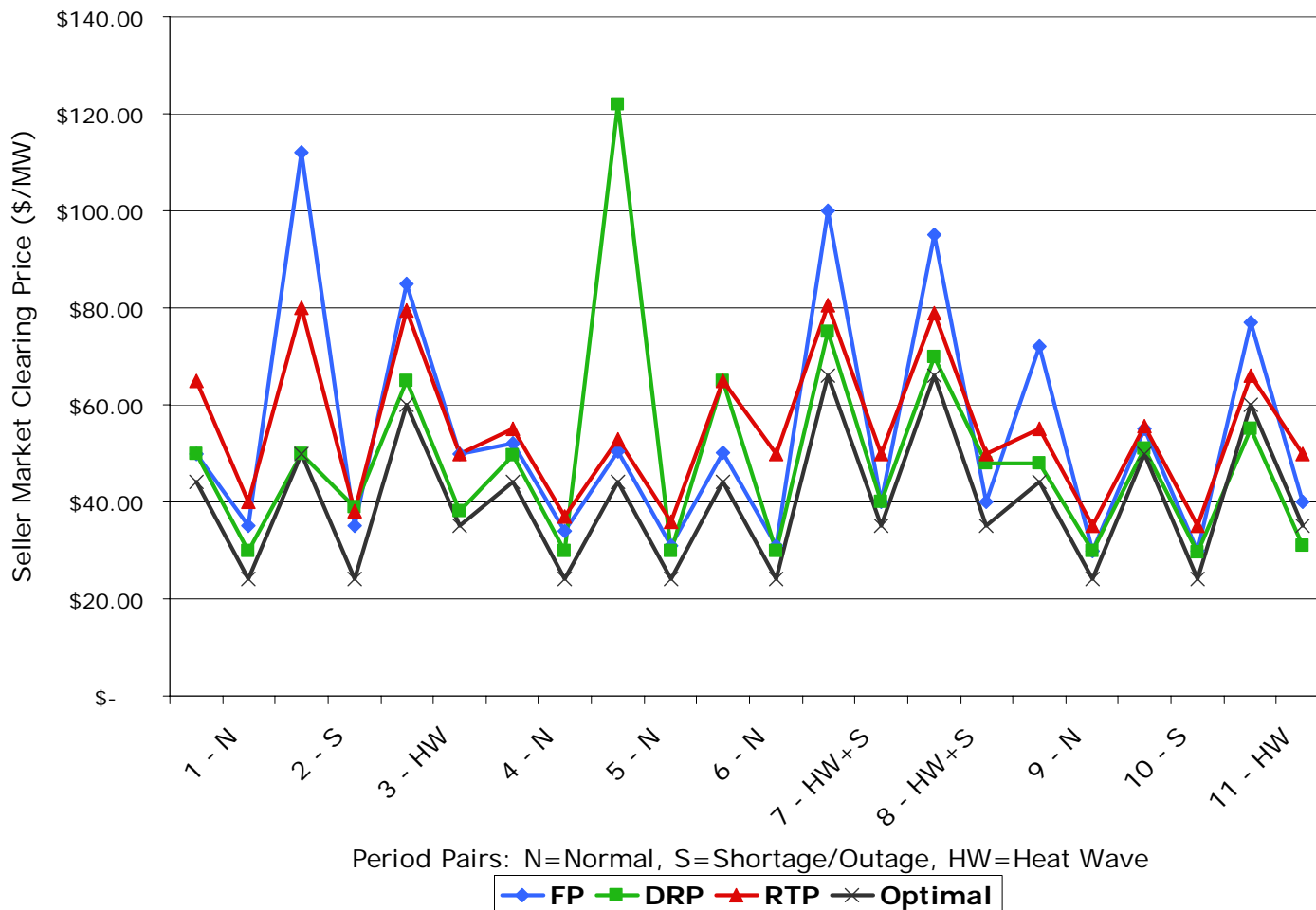
Two-Sided Markets: Statistical Analysis Using Paired t-tests of Differences in Surplus Between Treatments (Pooled Data)

Buyer Surplus (29 Buyers, Balanced Budget)						
<i>A) Surplus Adjusted on per Customer Basis</i>						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
P-Value	0.000	0.025	0.000	0.047	0.128	0.084
Sign	(+)	(+)	(+)	(-)	(-)	(+)
<i>B) Surplus Adjusted on Quantity Purchased Basis</i>						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
P-Value	0.000	0.188	0.000	0.054	0.048	0.216
Sign	(+)	(+)	(+)	(-)	(-)	(+)
Seller Surplus (12 Sellers)						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
P-Value	0.000	0.086	0.049	0.000	0.003	0.003
Sign	(-)	(+)	(-)	(+)	(+)	(-)
<i>P-Values Associated with t-test Performed on Pooled Data for Participants in Experiments 1 and 2</i>						

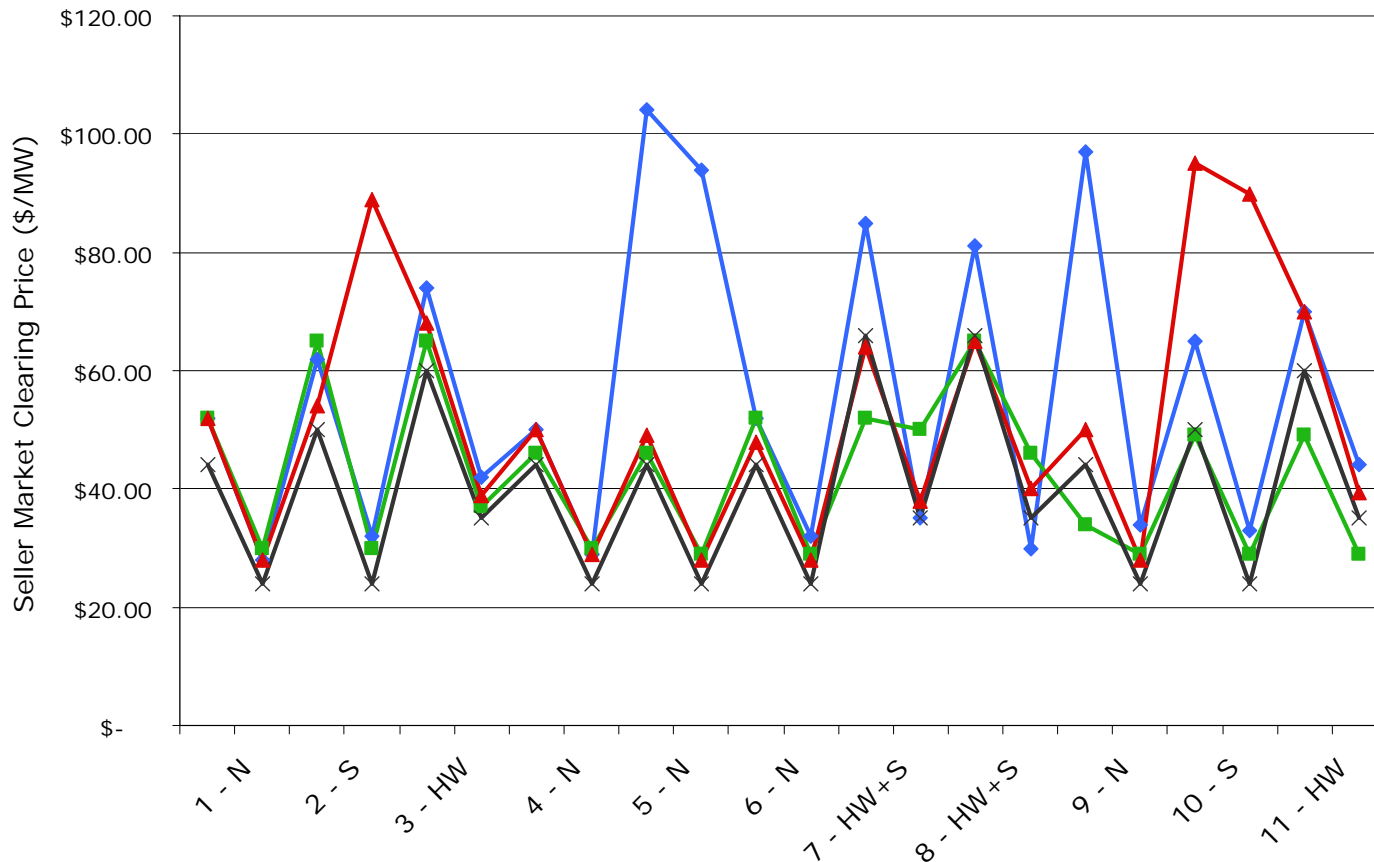
Two-Sided Markets: Statistical Analysis Using Paired t-tests of Differences in Quantities Between Treatments (Pooled Data)

Buyer Quantities (29 Buyers)						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
Normal Day	0.234 (-)	0.001 (+)	0.017 (+)	0.000 (+)	0.013 (+)	0.009 (-)
Normal Night	0.036 (+)	0.001 (+)	0.641 (+)	0.017 (+)	0.039 (-)	0.000 (-)
Heat Wave Day	0.008 (-)	0.000 (+)	0.267 (+)	0.000 (+)	0.004 (+)	0.000 (-)
Heat Wave Night	0.165 (+)	0.046 (+)	0.665 (+)	0.180 (+)	0.160 (-)	0.043 (-)
Combined Day	0.029 (-)	0.000 (+)	0.051 (+)	0.000 (+)	0.005 (+)	0.001 (-)
Combined Night	0.016 (+)	0.002 (+)	0.535 (+)	0.048 (+)	0.033 (-)	0.001 (-)
Seller Quantities (12 Sellers)						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
Normal Day	0.989 (-)	0.087 (+)	0.575 (+)	0.007 (+)	0.356 (+)	0.180 (-)
Normal Night	0.799 (+)	0.462 (+)	0.984 (+)	0.401 (+)	0.555 (-)	0.237 (-)
Heat Wave Day	0.281 (-)	0.025 (+)	0.782 (+)	0.001 (+)	0.021 (+)	0.100 (-)
Heat Wave Night	0.726 (+)	0.352 (+)	0.992 (+)	0.635 (+)	0.663 (-)	0.525 (-)
Combined Day	0.519 (-)	0.023 (+)	0.669 (+)	0.002 (+)	0.051 (+)	0.111 (-)
Combined Night	0.768 (+)	0.384 (+)	0.987 (+)	0.436 (+)	0.350 (-)	0.221 (-)
P-Values Associated with t-test Performed on Pooled Data for Participants in Experiments 1 and 2						

Prices: Two-Sided Market (Group 1)



Prices: Two-Sided Market (Group 2)

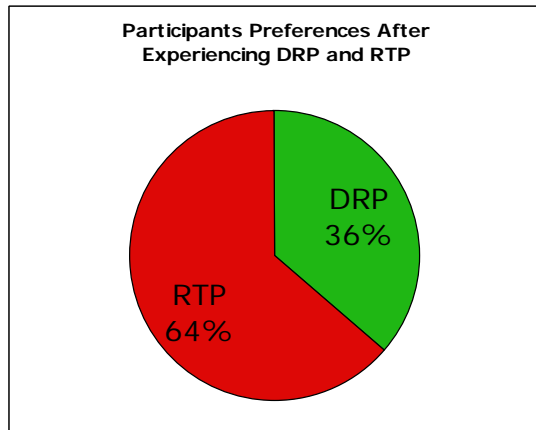
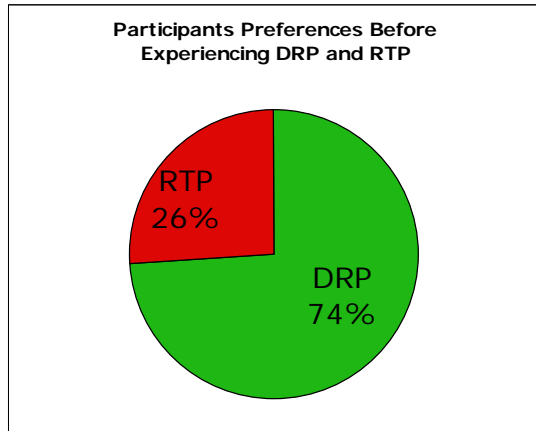


Period Pairs: N=Normal, S=Shortage/Outage, HW=Heat Wave

FP DRP RTP Optimal

Experimental Results: Participant Preferences in Two-Sided Markets

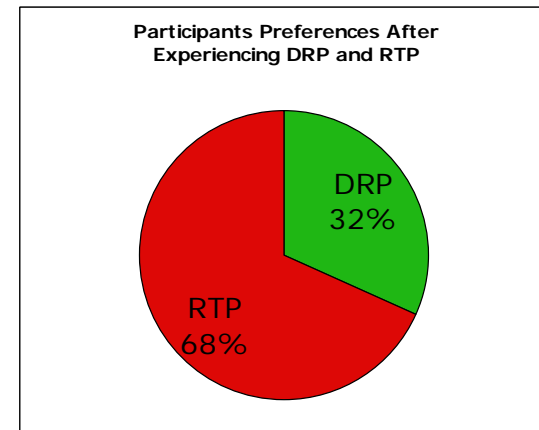
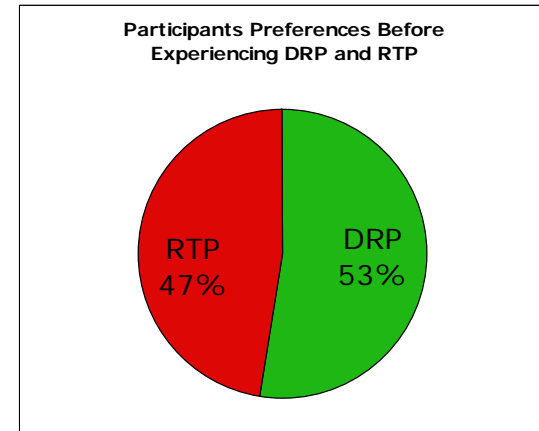
Experiment 1:



Before

After

Experiment 2:



Two-Sided Markets: Participant Expression of Preferences (DRP vs. RTP) After Each Trial

	Group 1		Group 2		Combined	
	DRP	RTP	<i>Raw Vote (%)</i>		DRP	RTP
	DRP	RTP	DRP	RTP	DRP	RTP
1. After FP						
Buyers	17 (100%)	0 (0%)	7 (54%)	6 (46%)	24 (80%)	6 (20%)
Sellers	0 (0%)	6 (100%)	3 (50%)	3 (50%)	3 (25%)	9 (75%)
Combined	17 (74%)	6 (26%)	10 (53%)	9 (47%)	27 (64%)	15 (36%)
2. After DRP						
Buyers	5 (29%)	12 (71%)	6 (46%)	7 (54%)	11 (37%)	19 (63%)
Sellers	1 (17%)	5 (83%)	0 (0%)	6 (100%)	1 (8%)	11 (92%)
Combined	6 (26%)	17 (74%)	6 (32%)	13 (68%)	12 (29%)	30 (71%)
3. After DRP						
Buyers	8 (50%)	8 (50%)	6 (46%)	7 (54%)	14 (48%)	15 (52%)
Sellers	0 (0%)	6 (100%)	0 (0%)	6 (100%)	0 (0%)	12 (100%)
Combined	8 (36%)	14 (64%)	6 (32%)	13 (68%)	14 (34%)	27 (66%)

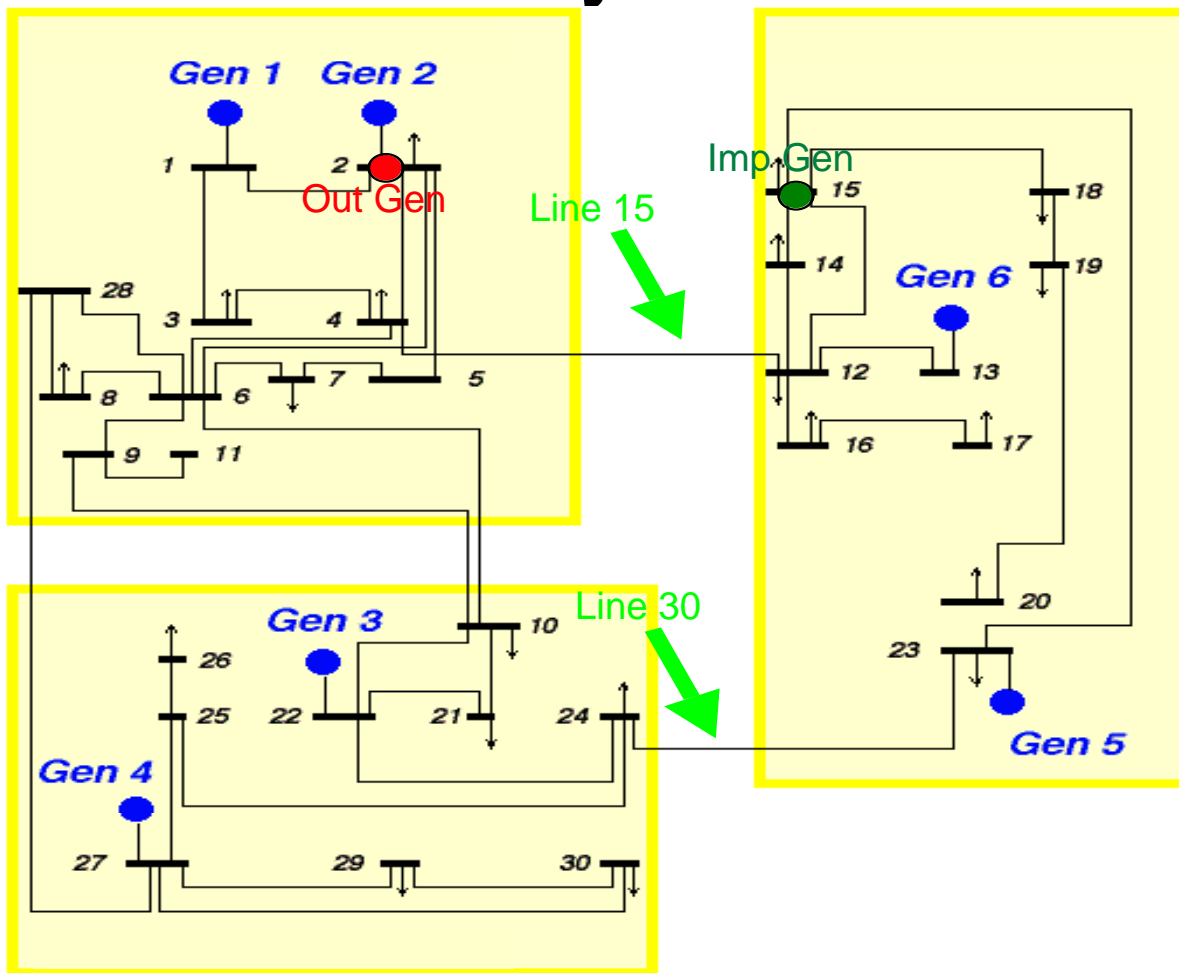
Note: P-value for differences in preferences between stages 1 and 3 by binomial proportions test:

Group 1: P-value = 0.0113

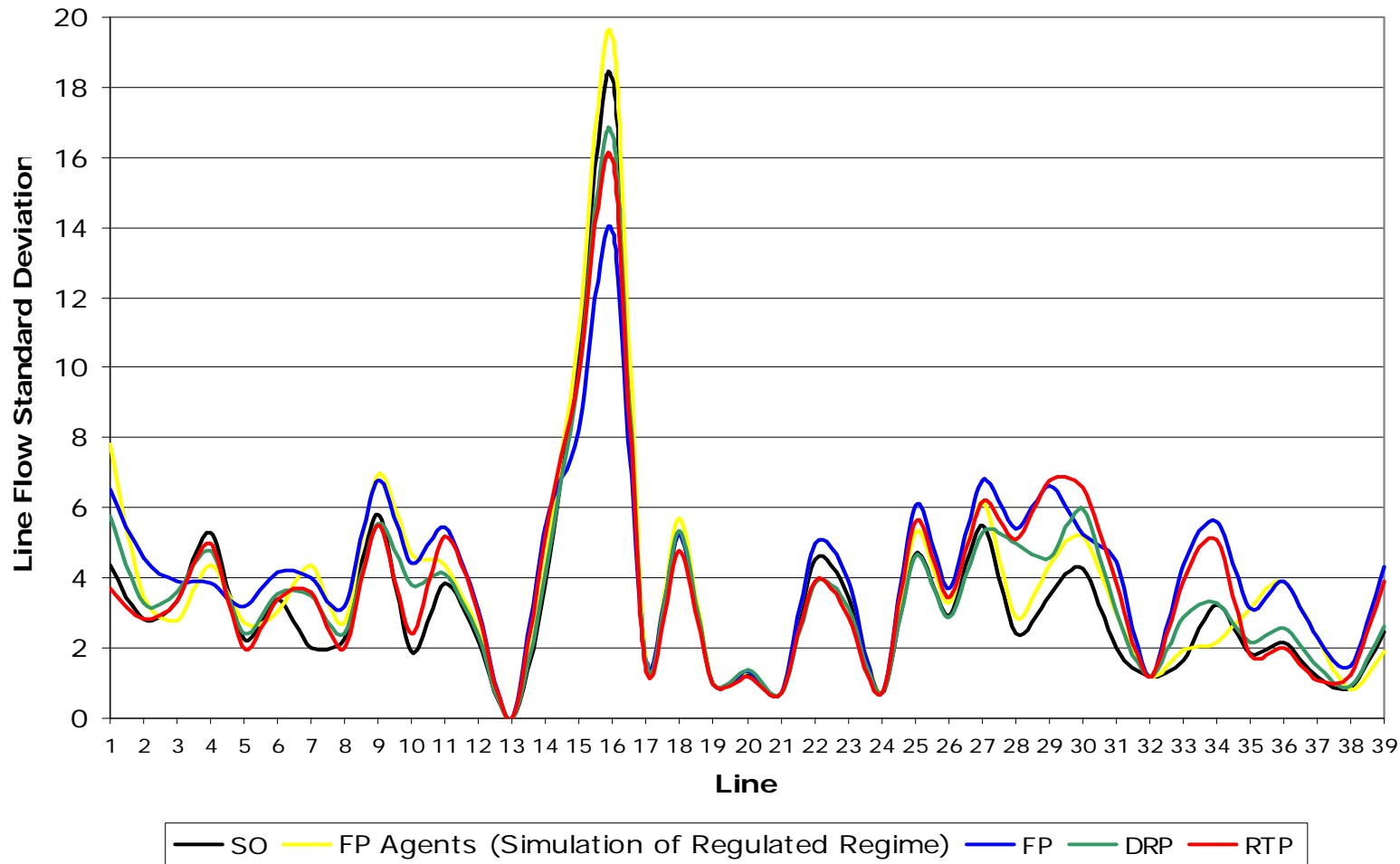
Group 2: P-value = 0.1890

Combined: P-value = 0.0060

Schematic of Underlying Electricity Network



Standard Deviation in Line Flows



Relationship Between Line Flows and System Load

	Social Optimum	(Reg. Regime) Fixed Price with Regulated Sellers	Results with Active Participants		
			Fixed Price	Demand Reduction Program	Real Time Pricing
<i>Regression Results for Tie Line 15</i>					
Intercept	40.1779	39.1761	17.9780	29.9462	33.0568
Std Err	3.0375	2.1514	3.1385	3.8662	3.5013
Slope Coefficient	(0.1982)	(0.1901)	(0.1025)	(0.1789)	(0.1909)
Std Err	0.0167	0.0116	0.0168	0.0236	0.0197
R-Squared	0.7701	0.8657	0.4695	0.5777	0.6906
F-Statistic	140.6651	270.7614	37.1714	57.4517	93.7394
P-value	0.0000	0.0000	0.0000	0.0000	0.0000
<i>Regression Results for Tie Line 30</i>					
Intercept	(17.5262)	(18.5527)	(9.1573)	(13.9666)	(17.5818)
Std Err	1.5631	1.7259	2.4566	3.0202	3.1587
Slope Coefficient	0.0751	0.0753	0.0437	0.0802	0.1024
Std Err	0.0086	0.0093	0.0132	0.0184	0.0178
R-Squared	0.6449	0.6111	0.2079	0.3104	0.4409
F-Statistic	76.2617	66.0048	11.0260	18.9069	33.1193
P-value	0.0000	0.0000	0.0019	0.0001	0.0000
Note: The following linear regression equation was estimated with OLS.					
Line Power Flow = Bo + B1 x System Load					
N = 44 for all regressions					

Results

(and Their Significance)

1. Customers Can Perform Efficiently in Electricity Markets, if Given the Chance
2. Markets Perform More Efficiently with Customer Participation, with Less Need for Regulation
3. Real Time Pricing Performs Better than Pre-announced Demand Response Programs in Most Cases
4. Customers Prefer DRP before Trying RTP, but Switch Their Preferences after Experiencing RTP
5. Line Flows May be More Predictable with Demand Response