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Differences in Capacity Requirements, Line Flows and System Operability under Alternative Deregulated Market Structures: Simulations Derived from Experimental Trials

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***Abstract* – How line flows, capacity requirements and system design might be altered under deregulated market structures is explored through simulations of experimentally-obtained loads and generator dispatches under alternative market structures, including a regulated base-case dispatch. Eight generators were located on the Power Web 30 bus simulated transmission network, and the 19 buyers were randomly allocated over thirty different trials to busses on the network. Line flows were estimated using a DC optimal power flow routine.**

Unambiguously, the sum of maximum flows over all lines is lower (by from one to ten percent) under a real-time pricing (RTP) regime, as compared to a simulation of the former regulated regime with fixed price (FP). Furthermore, a demand response program (DRP) is shown to perform nearly as well, resulting in lower maximum line flows in all but one of the allocations. RTP also restores line flow predictability close to operation under regulation.

***Index Terms* – Capacity Requirements, Demand Response, Deregulation, Line Flows, System Design.**

I. INTRODUCTION

WHAT are the effects of deregulation on line flows and the capacity needs of the electric system? How do market exchanges with speculative behavior alter the design parameters and operability of the system? How do these answers change with the natures of the market structure? In particular, how might active demand-side participation alter the conclusions?

As an example, in previous experimental analyses of the widely used single-sided electricity markets, the resulting simulated line flows are linearly proportional to system load when the dispatch that minimizes total system cost is based upon the actual cost of generation (e.g. perfectly regulated or perfectly competitive markets). But when that least-cost dispatch is based upon offers from deregulated suppliers who can speculate, that physical relationship breaks down and is highly erratic (See Thomas [3]). Thus it is interesting to explore the physical line flows that might be inferred from recent experiments on full two-sided markets with active demand-side participation. While a primary concern about electricity markets has been to reduce price spikes and to improve competitiveness and overall economic efficiency, it is important to understand how variations in market design that are intended to achieve those economic goals also affect the physical characteristics of the system and might result in different design parameters and different levels of investment in facilities.

Recent experiments were conducted to test the efficiency of two alternative forms of active demand-side participation in full two-sided electricity markets (See Adilov, et.al. [1]). As a base case for comparison, the typical utility pricing mechanism was tested where buyers pay a pre-determined fixed price (FP) in all periods. In the second treatment, buyers were alerted prior to consumption periods when supply shortages were anticipated. In those periods, customers were given the opportunity of reducing their consumption below their normal benchmark purchases in similar periods, and by doing so they were able to earn a pre-specified credit per kWh for each unit of electricity less than their benchmark that they chose to buy. This treatment is analogous to the NYISO's Emergency Demand Response (DRP) program. All electricity actually purchased under this DRP scheme was priced at the same fixed price used in the base case, but total customer payments were reduced by any DRP credits earned. The third treatment was a simple real time pricing (RTP) scheme where price forecasts were announced for the next day and night periods, and based upon those forecasts, buyers decided how much electricity to purchase. However, buyers paid the actual market-clearing price in each period for their purchases, and that price usually differed slightly from the forecasted price.

In each of these experiments, suppliers were free to engage in whatever offering behavior they liked, short of collusion with their competitors. One purpose of these experiments was to understand the extent to which electricity markets might become more self-regulating, economically, were widespread customer participation to become prevalent. Based on the supply and demand allocations from these previous

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experiments, the physical effects, implications for design capacities and the extent to which electricity flows become more predictable as the customers achieve greater involvement are examined.

II. Description of Prior Experimental Trials

A. Buyer Problem

Each buyer was assigned a simple two-step discrete demand function with separate valuations for day and for night usage, as shown in Figure 1. In fact, these individual demand relationships are decomposed from an aggregate demand function that has a retail price elasticity of demand, at the mean price, of –.3, Faruqui and George [2]. Nineteen different buyers were included in each experiment, each with different assigned valuations. The aggregate demand function, ranging from very low prices to the reservation price, was given the inverted S-shape suggested by Schulze's work (reported by Woo, et. al. [4]) on consumer value loss for interruptible service.

Each customer's valuation differs between day and night, and there is an additional "substitutable" block of energy that customers can choose to buy in either period (unused substitutable energy cannot, however, be carried over to the next day/night pair of periods). Typically, substitutable electricity purchases are valued less than the regular purchases in each of these periods. Furthermore, these induced valuations are increased substantially in pre-specified periods called "Heat-Waves" to reflect the added value of electricity in extreme climatic conditions. The buyer's problem then is to maximize the spread between their assigned valuation for each quantity of electricity they buy, and the price they have to pay for it. Thus if all consumers behave optimally in these experiments, the total system load should be grouped around four distinct levels, representing combinations of normal, heat wave, day and night periods.

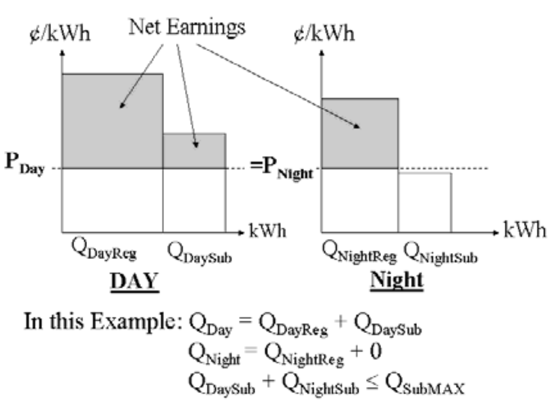

Figure 1. Illustration of Buyer's Problem

B. Seller's Problem

Each of the six active suppliers was assigned three different generating units with different constant incremental production costs (20 MW @ \$22/MW, 15 MW @ \$50/MW and 20 MW @ \$ 61/ MW). In addition there was a fixed cost associated with each supplier's total capacity that was paid regardless of the supplier's level of activity (\$20 per market period per generating unit, or \$60 per supplier). The supplier is free to offer as much or little capacity into the market, up to the total capacity limit on their generation, as they wish, and they can specify a different price for each of the three different blocks of power. Offers may be made at prices lower or higher than the incremental production cost. The discretionary cost each supplier can incur is associated with whether or not and how much capacity they offer into the market. Each MW offered bears an opportunity cost of \$5.00, regardless of having been selected to generate. This opportunity cost represents the commitment of resources and/or cost of foregone maintenance that is associated with planning to have those units available, as reflected in making an offer. The seller's problem is illustrated in Figure 2, and since the market in each period clears at the highest offer needed to meet the market demand, all suppliers with offered prices at or below that level are paid the identical last (highest) accepted offer. Each seller earns a profit in each period equal to the market price times the quantity they sell, minus the incremental cost of generating the electricity they sell, minus the \$5.00 opportunity cost times all of the energy they offer into the market, minus their fixed costs.

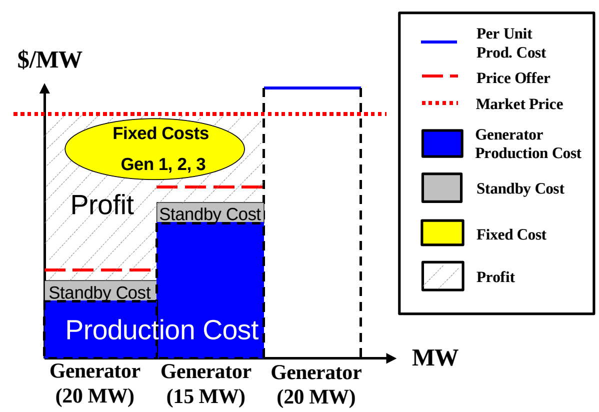

Figure 2. Illustration of Seller's Problem

C. Market Structure and Calibrations

In these two-sided markets, 19 buyers and 8 sellers were included. Six suppliers were represented by humans; the seventh seller was the only generator subject to random outages, and its behavior was simulated numerically so that none of the six active participants would feel that their earnings were biased by a random phenomenon. The eighth supplier was a high-priced external source that was used only when internal supplies were not sufficient to clear the market. A computer-simulated agent with a single 30MW block of low-cost \$20/ MW generation represented the outage unit and was always offered at \$25/MW (including the \$5/MW opportunity cost of making offers).

Each of the buyers was assigned a different set of valuations for the energy they could purchase, and for approximately 80 percent of the buyers, those values were set very high, but realistically, based upon previous empirical work (see Woo et. al. [4]). Therefore, the optimal quantity purchases did not change for the majority of buyers unless the market-clearing prices reached levels many multiples higher than normally anticipated. Given the popular sentiment that "most' buyers are not interested in altering their electricity consumption or participating in demand side programs, this assignment of values reflects that assertion.

Three demand-side treatments were tested, FP as the base-line, DRP and RTP. Each treatment was run over the identical eleven day-night pairs (22 periods, total) with the same sequence of combinations of normal periods, heat-waves and unit-outages. DRP was triggered by any predicted retail price that exceeded $.106/kWh ($106/MWh wholesale price) so that speculative behavior on the part of suppliers might also initiate this program. The average market demand in these experiments was designed to be approximately 200 MW (lower at night, higher during the day and in heat waves), and 330 MW of active supply was available, plus the 30 MW provided by the numerically-simulated base-load unit, when not subject to a random outage. The wholesale market was cleared at, and all accepted suppliers were paid, the uniform price of the highest (last) accepted offer. Demand was always met, despite withholding, because of the availability of purchases from external sources, about which all participants knew.

D. Market Sequence

Each market period began with the auctioneer (ISO/RTO) providing fair load forecasts (quantities) for the upcoming two (day-night pair) periods. All buyers and sellers were told before each day-night pair whether the upcoming period had normal or heat-wave conditions, and whether or not a unit outage had occurred. Next the suppliers submitted their price-quantity offers for both of the day-night periods. Then, either price forecasts or firm prices and/or anticipated market conditions were given to the buyers. Under FP, the retail price was always set at $.085/kWh, which included a $.04/kWh wires charge, regardless of wholesale market conditions. Under the DRP treatment, the same fixed price of $.085/kWh was charged for all purchases, but when DRP was announced to be in effect, a $.079/kWh credit for purchases below each buyer's announced benchmark consumption level was provided. Under the RTP treatment, a fair forecast of market clearing prices for the next day-night pair was announced, based upon market conditions and the suppliers' offers. The buyers then made their quantity purchases, suppliers were committed and the market clearing wholesale prices were declared. In the case of RTP, buyers were told the actual price they were assessed for their purchases in each of the previous day-night periods, which however didn't vary more than twenty percent from the forecast prices for those periods. Finally, each seller was told their earnings, and each buyer was apprised of the net value of their purchases, including DRP credits where applicable. The process was then repeated for the next day-night pair until all eleven pairs were completed.

III. Summary of Experimental Results for Two-Sided Markets

These experiments were repeated for two different groups of participants, and the resulting total market efficiencies are summarized in Table 1 for the DRP and RTP treatments as a percentage of the wholesale revenues under the FP treatment. As a benchmark, the theoretical socially optimal levels of efficiency are also presented, and the combined data indicate that it is possible obtain a 6.75 % overall gain in efficiency, compared to a FP system without regulatory controls on suppliers. Experiments on both DRP and RTP also provide welfare gains to consumers, but in the case of DRP the offsetting loss to suppliers is so great that there is a net welfare loss; whereas with RTP, a combined gain of 2.02% is obtained. In general, the large price spikes generated under the FP system are muted by the RTP and DRP treatments, as shown elsewhere (see Adilov, et. al. [1]).

Table 1. Two-Sided Experimental Results: Overall Efficiency for Combined Trials

1. Deviations as % of FP Revenues without Regulation:

	% Added Consumer Value	% Changes Supplier Profit	Combined Change
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):

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

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

Most of the substantive differences in the quantities purchased between the different pricing schemes are statistically significant. As shown in Table 1, buyers consume less electricity in all periods under DRP, as compared to FP; whereas, under RTP customers buy more electricity at night and less during the day than under FP. Furthermore, the last column emphasizes the overall conservation effect of DRP since it results in a statistically significant reduction in purchases both during the day and at night, as compared to RTP. Unfortunately, there is too much conservation under DRP, as highlighted by the quantity comparisons between both DRP and RTP with the socially optimal level of consumption where RTP comes the closest.

In a poll that was conducted for both groups of subjects that participated in this experiment, there was a reversal of stated preferences from selecting DRP to preferring RTP as experience was gained with both regimes. The first group switched from 74% preferring DRP initially to 64% preferring

RTP afterward, a statistically significant reversal. The second group's reversal was less appreciable, moving from only 53% preferring DRP ahead of time to 68% preferring RTP after having tried both. However the final fraction that preferred RTP was similar in both groups.

IV. Implications for Flows on Individual Lines

The market-clearing supply by each generator and the usage by each customer were assigned to specific nodes on the Power Web simulated thirty bus electrical network shown in Figure 3. The locations of generators remained fixed, but since the flows on individual lines differ depending on the demand characteristics at each bus, and the assigned valuations for electricity purchases varies widely among different participants, fifteen different randomly selected spatial allocations of the buyers were made for each of the two different sets of participants in the experimental trials. Since each trial was comprised of twenty two time periods (eleven day-night pairs), the period with the maximum line flow was selected as the surrogate for required installed capacity for each 22-period trial. In every case, the line flows were computed using an optimal power flow procedure to minimize the total cost of meeting the demand, and these maximum line flows are tabulated in Table 2 by market treatment and customer assignment.

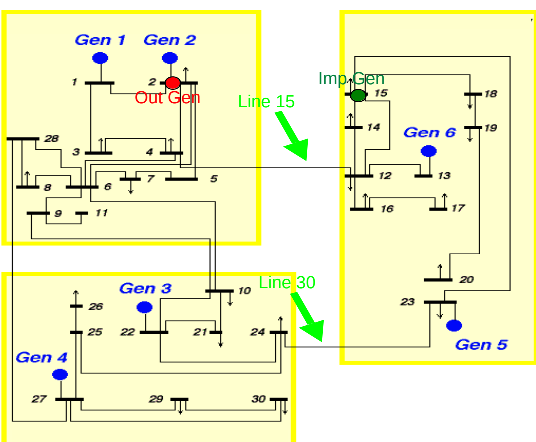

Figure 3. Power Web Simulated Electricity Network with Monitored Lines

In addition to the three market-based treatments (FP, DRP, and RTP), the line flows were computed for the socially optimal conditions (cost-based offers and optimal purchases by buyers), and the former regulatory regime was simulated under fixed-price purchases by buyers. In this simulation of regulation, the actual purchases by each customer under the FP market regime were used, but the supplies were replaced by a least-cost, cost-based allocation.

What is important to notice in Table 2 is that for each of the 30 trials (think: different power systems) the sum of maximum flows across all lines under RTP is smaller than for the regulated regime. This fact is highlighted in Table 3 that tabulates the pair-wise differences in this sum of maximum line flows. Under every system configuration, the difference between the sum of maximum line flows (SumMax) under regulation with FP and under markets with RTP is positive! Furthermore, Table 2 notes that across all system configurations, the SumMax for RTP averages 6.4 percent less than for the regulated regime, which is suggestive that on average less line capacity might be required under markets, if they are two-sided with active customer response.

The concern that deregulated markets could lead to larger facilities is given some support by comparing SumMax for regulation with that for markets using FP. Table 3 shows that for most system configurations, SumMax is larger for market-based systems with FP than for regulated systems with the same FP signals to buyers, and Table 2 shows the difference averages .7 percent greater flows for the market-based system. Recall, however, that the market regime simulated here has no price caps or restrictions on capacity withholding, so suppliers are free to speculate wildly under the market regime; whereas the regulated regime is simulated with cost-based supplies throughout.

Table 3 shows that the DRP demand-side mechanism is also effective (together with RTP) in moderating speculative behavior by suppliers, since for every customer configuration the difference in SumMax between FP and DRP is positive (as it also is for FP-RTP), and SumMax for DRP is also smaller than for the regulated regime in all but one of the thirty configurations. In fact, on average across all configurations, DRP results in an 8.7 percent smaller SumMax than for a regulated regime, suggesting how effective active demand side participation might be in moderating peak line flows, and in the long run in reducing investment in facilities.

The maximum system loads are also tabulated for each of these market regimes in Table 2, where RTP is shown to result in a 7.6 percent reduction in peak load, as compared with the regulated regime under FP (peak loads under regulation might also be lower if RTP were inaugurated under regulation, but that scenario cannot be fairly simulated with the available experimental data).

Finally, note that the maximum flows are also computed for socially optimal power exchanges, and Table 2 indicates on average across all 30 system configurations, the RTP market system comes closest to this ideal, both in terms of the sum of maximum line flows across each system, and in terms of peak loads. In fact, t-tests were conducted on the pair-wise differences in SumMax across all combinations of regimes (where SumMax for each configuration is considered an observation) and only two pairs fail this statistical test at the 5 percent level: SO-DRP (p-value =.068), and SO-RTP (p-value=.8589)! Thus, the line flows under markets with RTP are not statistically significantly different from the socially optimum values; whereas, the SumMaxs under regulation with FP are significantly different than the socially optimal levels.

Table 2. Implied Line Capacity Requirements by Market Treatment

Sum Across All Lines in the System of Maximum Absolute Value in Flow (MW) Across 22 Time Periods for Each of 39 Lines						
	Cust. Assign.	FP	DRP	RTP	REG	SO
	1	664.80	560.99	590.33	656.06	621.46
	2	625.30	523.57	556.81	646.40	589.43
	3	687.68	584.00	615.52	661.88	616.30
	4	669.84	577.63	613.15	657.65	643.01
	5	682.46	574.93	618.28	673.33	644.46
	6	645.02	530.29	583.16	646.32	594.72
	7	620.49	521.31	573.27	625.28	600.36
Exp. 1	8	661.69	572.62	586.55	643.12	605.68
	9	624.88	524.04	566.08	617.55	586.28
	10	662.79	577.74	614.59	661.49	632.25
	11	617.29	514.46	560.23	619.51	571.72
	12	619.83	510.09	555.33	622.05	576.04
	13	602.35	496.91	539.33	595.80	545.88
	14	649.96	544.03	593.63	664.15	617.82
	15	665.65	558.00	586.89	658.31	625.94
	16	669.55	655.07	639.06	672.47	621.46
	17	644.77	622.91	606.81	644.18	589.43
	18	672.01	661.25	641.77	670.58	616.30
	19	686.86	665.37	666.54	674.47	643.01
	20	688.91	669.67	667.04	692.73	644.46
	21	646.06	626.59	609.96	631.76	594.72
	22	643.49	620.06	621.16	627.98	600.36
Exp. 2	23	661.86	647.94	626.81	655.65	605.68
	24	618.99	605.09	604.91	614.99	586.28
	25	666.58	645.91	654.53	660.31	632.25
	26	611.27	590.69	592.25	622.62	571.72
	27	643.54	621.25	595.74	620.51	576.04
	28	597.19	566.99	555.16	583.75	545.88
	29	663.03	643.50	641.67	665.27	617.82
	30	673.05	649.26	644.29	668.43	625.94
Average Trials 1-15 (Exp. 1)		646.67	544.71	583.54	643.26	604.76
Average Trials 16-30 (Exp. 2)		652.48	632.77	624.51	647.05	604.76
Average All Trials 1-30		649.57	588.74	604.03	645.15	604.76
% Difference from REG		0.7%	-8.7%	-6.4%	0.0%	-6.3%
Summary of System Loads (MW):						
Experiment 1 (trials 1 to 15)						
Mean System Load		176.92	152.77	169.75	176.92	176.14
Max System Load		271.50	212.00	237.00	271.50	252.00
Experiment 2 (trials 16 to 30)						
Mean System Load		180.24	164.34	175.11	180.24	176.14
Max System Load		275.00	275.00	254.01	275.00	252.00
Combined Experiments						
Mean System Load		178.58	158.56	172.43	178.58	176.14
Max System Load		275.00	275.00	254.01	275.00	252.00
% Difference from REG		0.0%	0.0%	-7.6%	0.0%	-8.4%

Table 3. Difference in Weighted Average of Max Absolute Line Flow (MW) by Market Treatment Pairs

Cust. Assign.	FP - DRP	FP - RTP	DRP - RTP	REG - FP	REG - DRP	REG - RTP	SO - REG	SO - FP	SO - DRP	SO - RTP
1	103.80	74.47	(29.34)	(8.74)	95.07	65.73	(34.60)	(43.34)	60.47	31.13
2	101.73	68.49	(33.24)	21.10	122.83	89.59	(56.98)	(35.88)	65.85	32.62
3	103.68	72.16	(31.51)	(25.80)	77.88	46.36	(45.58)	(71.38)	32.30	0.78
4	92.21	56.69	(35.52)	(12.19)	80.02	44.50	(14.63)	(26.83)	65.38	29.86
5	107.53	64.18	(43.35)	(9.13)	98.40	55.05	(28.87)	(38.00)	69.53	26.18
6	114.73	61.86	(52.87)	1.29	116.03	63.15	(51.60)	(50.31)	64.43	11.55
7	99.19	47.22	(51.96)	4.78	103.97	52.00	(24.92)	(20.14)	79.05	27.08
8	89.06	75.13	(13.93)	(18.57)	70.50	56.57	(37.44)	(56.01)	33.05	19.12
9	100.84	58.79	(42.05)	(7.32)	93.52	51.47	(31.27)	(38.60)	62.25	20.20
10	85.06	48.20	(36.86)	(1.30)	83.75	46.89	(29.24)	(30.54)	54.51	17.65
11	102.83	57.06	(45.77)	2.22	105.05	59.28	(47.79)	(45.56)	57.26	11.50
12	109.74	64.51	(45.24)	2.22	111.96	66.72	(46.01)	(43.79)	65.95	20.72
13	105.45	63.03	(42.42)	(6.55)	98.89	56.47	(49.92)	(56.48)	48.97	6.55
14	105.93	56.33	(49.60)	14.19	120.12	70.52	(46.33)	(32.14)	73.79	24.19
15	107.65	78.76	(28.89)	(7.34)	100.31	71.42	(32.36)	(39.71)	67.94	39.06
16	14.49	30.49	16.01	2.92	17.40	33.41	(51.01)	(48.10)	(33.61)	(17.60)
17	21.86	37.97	16.10	(0.59)	21.27	37.38	(54.76)	(55.35)	(33.48)	(17.38)
18	10.76	30.24	19.48	(1.43)	9.33	28.80	(54.28)	(55.71)	(44.95)	(25.47)
19	21.49	20.31	(1.17)	(12.39)	9.09	7.92	(31.46)	(43.85)	(22.36)	(23.53)
20	19.24	21.87	2.63	3.83	23.07	25.70	(48.27)	(44.45)	(25.21)	(22.58)
21	19.48	36.11	16.63	(14.31)	5.17	21.80	(37.04)	(51.35)	(31.87)	(15.24)
22	23.43	22.33	(1.10)	(15.51)	7.92	6.82	(27.62)	(43.13)	(19.70)	(20.80)
23	13.91	35.05	21.13	(6.21)	7.71	28.84	(49.97)	(56.18)	(42.27)	(21.13)
24	13.90	14.07	0.18	(3.99)	9.91	10.08	(28.71)	(32.70)	(18.80)	(18.63)
25	20.68	12.06	(8.62)	(6.27)	14.41	5.79	(28.07)	(34.34)	(13.66)	(22.28)
26	20.58	19.02	(1.56)	11.35	31.93	30.37	(50.90)	(39.54)	(18.97)	(20.52)
27	22.29	47.80	25.51	(23.03)	(0.74)	24.77	(44.47)	(67.50)	(45.21)	(19.70)
28	30.20	42.03	11.83	(13.44)	16.76	28.59	(37.87)	(51.31)	(21.11)	(9.28)
29	19.53	21.36	1.83	2.24	21.77	23.60	(47.45)	(45.21)	(25.67)	(23.85)
30	23.79	28.76	4.97	(4.62)	19.17	24.14	(42.49)	(47.11)	(23.32)	(18.35)
Avg. Difference	60.84	45.55	(15.29)	(4.42)	56.41	41.12	(40.40)	(44.82)	16.02	0.73
Paired T-Stat	7.87	12.24	(3.22)	(2.32)	6.93	10.33	(20.48)	(21.58)	1.90	0.18
P-Value	0.0000	0.0000	0.0032	0.0274	0.0000	0.0000	0.0000	0.0000	0.0679	0.8589

Table 4. Statistical Relation Between Line Flows and System Load

			Results with Active Participants		
	Social Optimum	(Reg. Regime) Fixed Price with Regulated Sellers	Fixed Price	Demand Reduction Program	Real Time Pricing
Regression Results for Tie Line 15					
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
Regression Results for Tie Line 30					
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					

V. Line Flow Predictability

One indication of the facility with which the system might be operated under various market regimes is suggested by the relationship between overall system load, and the flows on any individual lines.

In a preliminary analysis using the line flows derived from the PowerWeb 30 bus electrical transmission network shown in Figure 3, two lines were selected to illustrate the possibilities. The location of all generators, including the import generator that cleared the market when insufficient internal supplies were offered, is shown, but the flows for only one of the thirty random allocations of buyers to busses is used in this illustration.

Two of the lines were selected (line 15 with the greatest variability and the more typical line 30), and a statistical test was performed on the correlation between system load and line flows on those links for the different exchange regimes. These regression results are summarized in Table 4. Because of the location of the generators and specific buyers, there is actually a negative correlation between system load and the flow on line 15 (due to changes in the optimal system dispatch), but that negative relationship exists under all five regimes. What is different is the magnitude and the degree of statistical significance of that relationship. The relationships are nearly identical under the socially-optimal, previously regulated and RTP regimes; the association is weakest under the FP market case, but improves somewhat under DRP.

In the case of a more typical transmission link like line 30 where there is a positive relationship between system load and line flow in all five cases, once again the socially optimal and former regulated regimes yield almost identical results. Here, the relationship is much weaker under the FP market regime, compared to regulation, becomes almost identical in magnitude but not in statistical significance under DRP, and becomes even stronger under RTP, although still not as significant statistically. Thus operators of electrical systems may also find value in the widespread implementation of demand side participation in market exchanges if it strengthens the predictability of flows on any particular line.

VI. Conclusions

Using experimental results derived from a previous economic analysis of the efficiency and effectiveness of alternative market regimes with eight suppliers and nineteen buyers, the supply and demand quantities for each buyer and seller were allocated to the thirty bus Power Web simulated transmission network. Thus likely line flows were computed using an optimal power flow routine, and these flows were used to illustrate and compare the consequences on system capacity needs and on the operability of regulated and alternative market-based systems.

As an example for a single random allocation of buyers to particular locations, the predictability of electricity flows on several transmission lines was explored as a function of overall system load for three two-sided market regimes and under a simulation of the former cost-based regulatory regime. That relationship deteriorates substantially under the FP market regime, is partly re-established under DRP, and under RTP once again resembles the predictability that was previously available to system operators under regulated power pool exchanges. Thus, achieving far greater active customer participation in these electricity markets may ease the task of the system operators, as well as reduce the extent of required market power surveillance, as was emphasized in previous economic analyses (See Adilov, et.al. [1]).

But these line flow analyses suggest even greater possible economic benefits from introducing active demand-side participation: they may reduce both line and generator capacity requirements. To minimize the probability that the line flow results are a coincidence of an arbitrary assignment of customers to locations on Power Web, thirty random assignments were made. The differences in maximum line flows and in peak generation capacity were compared, pair-wise, across the three different market regimes, with a simulated cost-based regulated regime using FP, and with the socially optimal regime. On average across all 30 customer allocations, the RTP-market regime came closest to the socially optimal results, and its sum of maximum flows over all lines was 6.4% less than for the average of regulated regimes. Furthermore, the peak load for generation was 7.6% lower under RTP than for the simulated peak load under regulation. Taken together with earlier economic inferences showing that active demand participation in market-based systems leads to greater economic efficiency and smaller price spikes (as well as a majority of experimental participants preferring RTP, having tried it), these simulations of experimental results suggest the merit of performing further detailed analyses for specific operating systems.

VII. References

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