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1. INTRODUCTION

In direct access competitive electricity markets, generators contract freely with customers to supply electricity according to the terms of contracts, which might for example stipulate price and quantity for periods of time. Actual delivery, however, is over a constrained transmission network controlled by a system operator who is responsible for, at least, the physical security of the system.

Many market restructuring proposals and implementation schemes, including the market structure mandated by the recent CPUC ruling (December 20, 1995), advocate an Independent System Operator (ISO) with various degrees of economic authority. In the UK system, for instance, the ISO (there the National Grid Company) operates a mandatory power pool and has the authority to schedule suppliers based on daily bids and set spot prices based on an optimal dispatch. In the Majority proposal of the CPUC ruling, the power pool (referred to as power exchange) is a separate entity but is managed in close coordination with the ISO which schedules transactions and manages congestion based on economic dispatch considerations. A general discussion advocating the generic POOLCO model which embodies many features of the UK system is given by Ruff (1994). A more recent article by Joskow (1996) advocates the Majority proposal in the CPUC ruling with some modifications based on a Memorandum of Understanding between Southern California Edison, its industrial customers and independent power suppliers in California. Hogan (1995) argues in favor of extending complete economic authority to the ISO, which would include administration of the exchange, scheduling, dispatch and price setting.

An important premise underlying the rationale for giving economic authority to the ISO is that the problem of scheduling electric supply resources is well understood but an efficient solution requires a central decision-maker to coordinate resource scheduling and operations. Many POOLCO proponents have even argued that in the absence of an economic motive for inefficient operation, the ISO is no more than "the keeper" of a computer program which will ensure efficient system operation, determine economically efficient price signals and manage congestion optimally. Indeed, the UK system has been

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*Concepts and methodologies presented in this paper do not necessarily represent PG&E's position on this subject. Furthermore, errors or omissions contained in this paper are the sole responsibility of the authors.

structured around an existing scheduling and dispatch algorithm (GOAL). Furthermore, the bidding protocol and compensation scheme in the UK has been designed to emulate the inputs that would be provided to the computer program in a centralized system by replacing the cost and constraints information with bid prices and dispatch restrictions. Shortcomings of the UK approach and the lessons to be learned have been the subject of many presentations and public discourse. Newbery (1995) highlights some of the defects in the UK system and analyzes their consequences with regard to market power. Lucas and Taylor (1995) discuss price distortions in the UK system that are attributed to the rule by which the pool allocates fixed costs of generators.

The purpose of this paper is to draw attention to important drawbacks of using a central scheduling and dispatch computer algorithm as a basis for organizing a competitive electricity market. In particular, we examine the effects of competition and decentralized ownership on resource scheduling, and show that centralized scheduling of multi-owned resources under imperfect information may face difficulties that do not arise when resources are centrally owned. As in many complex engineering economic systems, "the devil is in the details". Consequently, many of the impediments to the efficient operation of a system controlled through centralized coordination and economic authority are likely to result from the technical realities glossed over by the proponents of such an approach. State of the art scheduling and optimal dispatch algorithms contain inherent indeterminacies which provide broad latitude to the operator with potentially severe distributional implications.

Earlier work by Wu, Varaiya, Spiller and Oren (1995, 1996) has pointed out that any feasible power dispatch, optimal or not, will yield a corresponding market equilibrium with a corresponding set of locational spot prices. Discretionary enforcement of constraints by the operator so as to meet subjective security considerations could lead to different market equilibria and although such equilibria may not differ by much in terms of global criteria (e.g. total cost or social surplus) they may have strong distributional implications. While congestion management increases the operator's discretion the inherent latitude in near- optimal scheduling of power resources is present even in the absence of transmission constraints.

In order to illustrate the above phenomena we perform a simulation case study using a state-of-the-art Lagrangian relaxation-based unit commitment algorithm modified to simulate proposed second-price pool auction procedures. This algorithm is based on the Hydro-Thermal Optimization (HTO) program used in short-term resource scheduling at PG&E. We assume that a mandatory power pool sets both the prices paid to generators and generation schedules, and that the pool's objective is to minimize payments to generators, based on generator bids and a requirement that pricing be uniform (though possibly unbundled), subject to the same sorts of fixed demand and, possibly, reserve requirements previously observed by integrated utilities.

In the following sections we first describe the role of optimal unit commitment methods in the context of power pool auctions and sketch the underlying optimization problem. This is followed by a qualitative description of the Lagrangian relaxation approach underlying the HTO algorithm employed in our simulation study. We then present the results of a case study based on simulated unit commitment runs on a benchmark system and load, followed by general observations and conclusions.

2. CENTRAL UNIT COMMITMENT IN THE CONTEXT OF A POOL AUCTION

The pool auction procedure is generally assumed to be a unit commitment and economic dispatch based on bids rather than costs. Bids are treated as costs although actual payments to suppliers may be based on system marginal bids, in hopes of persuading resources to bid based on their true costs (and required profit margins) rather than on attempts to second-guess the market price or, worse, use their market power to directly distort the market price. When the auction procedure (as in, for example, the British day-ahead pool) allows resources to include operating characteristics such as startup costs, minimum up time, and minimum down time, these characteristics are in fact components of resource bids. The inclusion of these operating characteristics in the auction algorithm transforms the auction from an economic dispatch algorithm, which can in theory be performed independently in each half hour or hour of the period to be scheduled, into a unit commitment algorithm in which there are strong dependencies between decisions in successive hours.

The pool auction may be "first-price," in which case each bidder gets paid the price bid to supply electricity. Seen from the bidders' perspective, the "first-price" pool is somewhat similar to a system in which all sales are negotiated as bilateral transactions, assuming that the pool is prohibited from exercising its monopsony buying power for its own benefit. A "second-price" auction, in which all bidders are paid the same price for providing the same product (e.g., firm electricity supply in a given hour), is on the other hand quite different from a bilateral system in that the price bid and the price paid differ for most if not all bidders (in its pure form a second-price auction pays the lowest losing bid to all suppliers with lower winning bids). From the pool's perspective, the need to develop a single set of uniform prices to be paid to all bidders strongly influences the choice of auction algorithm.

An economic dispatch to match average production to expected demand in each period to be priced is an obvious candidate for an auction algorithm yielding uniform prices. In the absense of transmission congestion, dispatch costs are minimized when all resources operate as if in response to a single price for energy in each hour. Thus, all resources operating between their minimum and maximum levels should have equal marginal costs which constitute the system incremental cost (Resources whose maximum or minimum marginal costs are below or above the system incremental cost are pinned to their maximum or minimum output level, respectively, assuming they are constrained to be on.) When the transmission system is congested, however, the incremental costs corresponding to the optimal dispatch or the market clearing prices resulting from an auction will differ from one location to another. With or without congestion, the commitment which predicates the optimal dispatch phase strongly affects the market clearing prices resulting from the optimal dispatch in each half hour interval and the profits accrued to the various resources. Furthermore, as noted by Ring and Read (1996), these prices are suboptimal since they do not reflect the intertemporal costs and constraints that drive the unit commitment. As a consequence, the economic dispatch price does not guarantee the profitability of resources dispatched. "No-load" operating costs (operating costs at minimum operating point), startup costs, and sunk capital costs are obviously not considered by the dispatch unless they are somehow rolled in to resource marginal cost functions. In hopes of not distorting marginal cost signals too much, auction algorithms like the British system's ask for a separate capacity bid component, along with operational constraints. These components are then used within the algorithm itself to affect both the commitment and the dispatch. The heuristic modification of economic dispatch prices can ensure that the prices offered cover resource fixed costs, but not that these prices correctly incent the desired commitments. Due to the computational complexity of unit commitment optimization current practice is to ignore congestion effects in these computations and make allowances for possible congestion by overcommiting units at critcal locations (based on heuristic rules and past experience). Consequently, transmission congestion aggravates the distortion of market clearing prices by the unit commitment decisions.

3. LAGRANGIAN RELAXATION AND PRICE-BASED RESOURCE SCHEDULING

In a centrally operated system with perfect information, the unit commitment problem's objective is to minimize energy production costs over a specified time horizon (typically a week). The problem can be formulated as a mixed nonlinear integer program where the status of each resource at any particular time interval is characterized by its state (on or off and for how long) and output level. The objective function consists of the fuel costs and state transition costs (switching and ramping cost) while the constraints include meeting demand and spinning reserve requirements in each time interval as well as intertemporal limits on the output level of each resources including minimum down time, ramp up and ramp down constraints.

In the context of a power pool with centralized economically based unit commitment, the above formulation still represents the pool's resource scheduling problem (ignoring transmission constraints) but the cost components in the objective function are replaced by day ahead bids and the individual resource constraints are specified by the supplier as part of the bid in the form of dispatch restrictions. The demand and spinning reserve constraints are determined by the pool operator.

Lagrangian relaxation is a state of the art approach to solving the computationally challenging unit commitment problem for a practical number of resources (over 100). In contrast to heuristic approaches[1], unit commitment algorithms based on Lagrangian relaxation solve the optimal scheduling problem indirectly by solving a "dual" optimization problem, seeking a single set of prices that incent an optimal commitment of all resources. These algorithms have become popular because of their superior performance (in terms of achieving better schedules), modularity and extensibility in the representation of diverse resource operating constraints. Lagrangian relaxation algorithms for unit commitment operate as an internal multi-round auction, driving the resource commitment by posting "trial" vectors of prices for energy and spinning capacity in each time interval over the entire scheduling horizon. The individual resources are then scheduled in response to the posted prices so as to maximize each resource's profits over the entire scheduling horizon. The process is repeated (while adjusting the prices) until the demand and spinning reserve constraints are met. Because the entire price vector is computed simultaneously, these prices, (unlike prices based on optimal dispatch in a single time period) reflect intertemporal constraints as well as energy cost.

The simulation study reported in this paper employed a Lagrangian relaxation based unit commitment algorithm developed at Pacific Gas and Electric Company in its Hydro Thermal Optimization (HTO) package. The package includes detailed modeling of PG&E's interconnected hydro resources and its large pumped-storage plant (see Ferreira et al (1989)). Further extensions of that application accommodating ramping constraints are described by Svoboda et al. (1996)[2]. In this implementation, the prices corresponding to the demand and spinning reserves constraints are updated

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[1]The GOAL algorithm used in the UK system is based on a priority list heuristic. A new version, however, is being developed based on a Lagrangian relaxation approach.

[2]The use of Lagrangian relaxation to solve the resource scheduling problems was described nearly two decades ago by Muckstadt and Koenig (1977). It was further demonstrated by Bertsekas et al. (1983) that the quality of the solution yielded by Lagrangian relaxation actually improves with increases in the size of the scheduling problem, where size is measured in terms of the number of non-identical resources and the number of periods in the scheduling horizon.

The degree of detail in the system representation allowed by Lagrangian relaxation implies potentially very large input and output data sets in practical applications, but advances in computer memory and database technology have made such applications more feasible over the years since the technique was first proposed for the resource scheduling problem. Electricite de France developed several applications of the method which are described by Merlin and Sandrin (1982). Similar approaches and improvement are described by Zhuang (1988) and Guan et al. (1992).

based on the discrepancy in meeting these constraints[3]. A near-optimal solution to the Lagrangian dual problem represents a consistent set of prices and resource schedules incented by these prices. The "dual" optimum is a set of prices that comes closest (by the measure of total production costs) to yielding the optimal solution to the original scheduling problem.

The dual optimum and the optimal solution to the original scheduling problem are not identical: because of the discrete nature of the commitment decisions and constraints. The "duality gap" between dual and primal optima may be significant. A Lagrangian relaxation unit commitment algorithm must include a procedure for obtaining a feasible primal solution given the dual solution. The resulting schedules will in general be suboptimal even if based on the dual optimum (and in general, they are in fact based on a suboptimal dual solution). The structure of the unit commitment problem (near-degeneracy of the capacity and energy constraints) is such that the objective function has a "flat bottom" and consequently, there may be many near-optimal solutions to the problem. Thus, solutions which are equally good in total cost terms may yield very different schedules of individual resources which in turn vary significantly in terms of costs, profits, and commitments.

The problems inherent in Lagrangian relaxation are, by the above argument, inherent also in the use of uniform pricing combined with centralized commitment and dispatch in the scheduling of resources. Two equally efficient sets of price vectors may yield very different resource schedules and hence levels of profit for individual resources. And since unit commitment algorithms which recognize dynamic operating constraints, fix unit commitment before dispatching economically to the load forecast, the dispatch based prices in a particular time interval may exceed the bid prices of units that have been excluded by the unit commitment algorithm One might justify fixing schedules on grounds of system reliability, but not to the point of making a given resource's operations unprofitable.

4. CASE STUDY RESULTS

Our simulation study employs the Hydro Thermal Optimization (HTO) unit commitment algorithm developed at PG&E to schedule a benchmark system over a period of 168 hours. We make use of the CALECO system data developed by Marnay and Strauss (1990) as a benchmark system for the evaluation of chronological production costing simulation models. We have eliminated never-used resources from the resource set for simplicity of presentation. In the case study, peak load for the 168 hour period is 9749 MW, and minimum load is 4990 MW. Total load is 1178.861 GWH, giving a load factor of 74%. Figure 1 summarizes some significant unit characteristics for the resource set. The

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[3] In the optimization literature this approach is referred to as a subgradient method

operating cost for each resource is characterized in terms of a three segment piecewise linear cost curve with a fixed initial cost for "no load". The specific cost curve parameters for each of the resources are summarized in Table A in the appendix.

FIGURE 1:
Description of the CALECO System Used in Pool Simulations

Unit Name	Max Load	Min Load	Startup $	Min Up	Min Down	Fuel
Col-Stm	1000	250	100000	120	48	Coal
Stm1	750	50	15000	24	48	Gas
Stm5	330	50	15000	6	3	Gas
Stm6	330	50	15000	6	3	Gas
Stm7	340	85	15000	6	3	Gas
QF	1000	1000	N/A	N/A	N/A	QF
Pond Hydro	1500	1	0	1	1	Pond Hydro (Limited)
ROR Hydro	900	0	0	1	1	ROR Hydro
Nuke	2000	0	200000	1	1	Nuke
CTs	1000	0	0	1	1	Distillate
Econ01	500	0	0	1	1	Transaction at $17.5/MWH
Econ02	500	0	0	1	1	Transaction at $30/MWH

Load assumptions:

Maximum load = 9749 MW
Minimum load = 4990 MW
Total load = 1178861 MWH
Load factor = 74%
168 hours

In running HTO we assume perfect knowledge of the cost characteristics (i.e., the supply curve is the cost curve) and constraints of individual resources which are assumed to be independently owned. Such a scenario would represent an ideal bidding system providing perfect information to the ISO who needs to schedule the units in a pool based environment. Pond Hydro is scheduled by peak shaving, and thus is not included in the optimization.

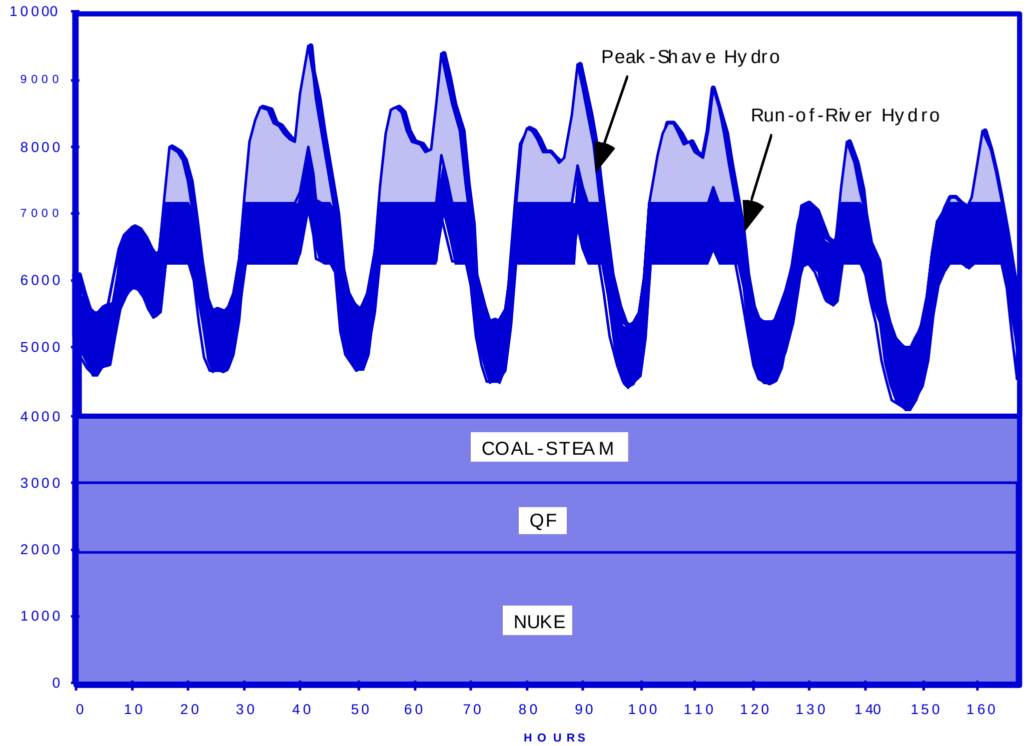
The QF[4] is scheduled manually as a base load unit at fixed cost (which may exceed the marginal system cost) hence it does not affect the optimization but is included for accounting purposes and for illustrating the opportunity cost of the fixed price QF contract. The Nuclear plants and the Run of River Hydro are also base-loaded manually. In addition, the Coal Steam plants were effectively base loaded by the algorithm in all the runs so for illustrative purposes they will also be treated as base-loaded plants.

The simulation was done by rerunning the unit commitment optimization a dozen times using the same benchmark load for 168 hours and the same resource data. The only difference between the runs were

[4]QF refers to a Qualified Facility (under PURPA) for independent power generation. Such facilities are contracted as "take or pay" fixed price resources.

slight variations in a user specifiable search parameter which caused the algorithm to find alternate optimal solutions. Figure 2 illustrates the benchmark load pattern used in the simulation and the segments of the load served by base loaded and hydro resources. Thus, the unit commitment algorithm had to schedule the remaining units so as to serve the net load, represented by the white area, at minimum cost.

FIGURE 2:
LOAD NET OF BASE LOADED RESOURCES AND HYDRO



For each run we computed the total system cost, the total payments to the resources and the aggregate profits (payments minus costs). The latter are based on the prices produced by the HTO algorithm. In order to capture the effect of distributed ownership in a centrally dispatched pool we also kept track, for each resource, of the resource specific costs (including energy and state transition, e.g. start-up and shutdown costs) and the profits as measured by the differences between revenues and operating costs. In the case of the QF resource we calculate the opportunity cost of the contract, i.e., the net efficiency losses due to nondispatchability. Since the total operating cost of the QF is fixed, the variation in the unit's opportunity cost are identical to the variation in the QF's profits had it been dispatched economically.

Table 1 contains a summary of total system cost, payments and aggregate resource profits for each simulation run. The bottom part of the table contains the corresponding distributional statistics. We note that the different simulation runs resulted in different near-optimal feasible schedules of roughly equal quality (in terms of total system costs). The variability in total system cost is under one tenth of one percent. However, the aggregate resource profits vary by up to six percent due to differences in the price vectors corresponding to the different solutions. Thus, while all the solutions are equally efficient they have different equity implications since the profit variability corresponds to welfare transfer between

TABLE 1:

SIMULATION RESULTS SUMMARY

	TOTALS (K$)		
Run	Cost	Payment	Profits
1	20,306.94	30,176.44	9,869.51
2	20,310.31	30,275.33	9,965.01
3	20,305.80	30,303.42	9,997.62
4	20,307.91	30,237.94	9,930.04
5	20,311.07	30,255.59	9,944.51
6	20,318.74	30,509.02	10,190.28
7	20,321.90	30,238.11	9,916.21
8	20,319.36	30,438.41	10,119.05
9	20,321.70	29,929.26	9,607.56
10	20,305.80	30,283.39	9,977.59
11	20,307.90	30,293.26	9,985.36
12	20,310.30	30,307.03	9,996.73
average	20,312.31	30,270.60	9,958.29
std	6.28	140.08	140.61
max	20,321.90	30,509.02	10,190.28
min	20,305.80	29,929.26	9,607.56
range	16.10	579.77	582.72
range/avg	0.08%	1.92%	5.85%
std/mean	0.03%	0.46%	1.41%

generators and consumers.

The variability among the alternate solutions is more significant with respect to the distribution of profits accrued to the individual resources. To illustrate this variability we selected out of the twelve runs five that span the outcome range. Figures 3 and 4 illustrate absolute and percentage variability in the profits of individual units. Variability is measured in terms of the deviation from the corresponding profits averaged over the relevant runs. Base loaded units are excluded, however; the QF unit is kept to illustrate the potential variability in that resource's profits, had it been dispatchable. Figure 3 also illustrates the absolute variability in total operating cost. However. the corresponding percentage variability in total cost is not displayed in Figure 4 since it is under one tenth of a percent. The aggregation by simulation run in Figure 4 shows that the near-optimal schedule may vary in different ways. In some runs the dispatchable resources are under utilized, thus shifting load to the base load units while in other runs load is shifted away from the base load units to the dispatchable resources. In yet other runs load is shifted among the dispatchable units.

The results demonstrate inherent instability and indeterminacies in the optimal schedule produced by a central unit commitment algorithm. As shown in Figures 3 and 4, alternative near-optimal schedules which are equally good from the perspective of social cost have significantly diverse implications on the profitability of individual resources. The results are particularly volatile for resources at the margin such as ECONO2 whose profitability can swing as much as 60%. Any of the schedules produced in our simulation could have been a plausible choice of an efficiency motivated ISO running the unit commitment program. Yet, any specific choice could benefit one resource to the detriment of another. It should also be noted that there is very little variability in the aggregate profits of the dispatchable resources, thus most of the profit variability observed in Table 1 is attributable to changes in payment to the base-loaded resources due to changes in the price vectors corresponding to the various solutions. Thus, in an integrated utility environment for which the central unit commitment program was designed, schedule indeterminacies would not have any adverse effects. Moreover, a unit commitment program like HTO would continue to serve as a useful decision tool to a multiple resource owner for internal scheduling of resources bid into the pool. It is the use of these programs as a central scheduling tools in a decentralized ownership environment that creates potential equity problems.

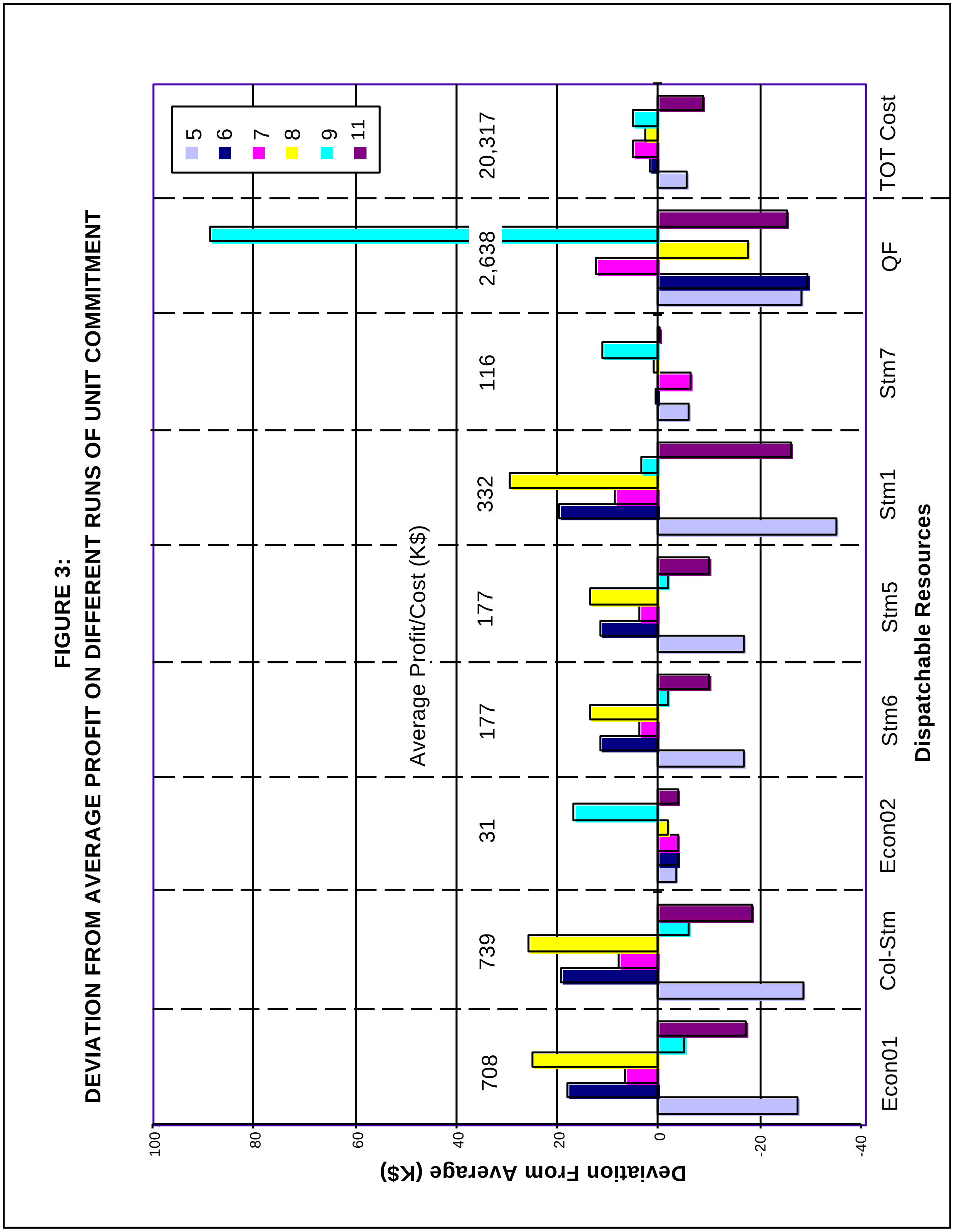


FIGURE 3:
DEVIATION FROM AVERAGE PROFIT ON DIFFERENT RUNS OF UNIT COMMITMENT

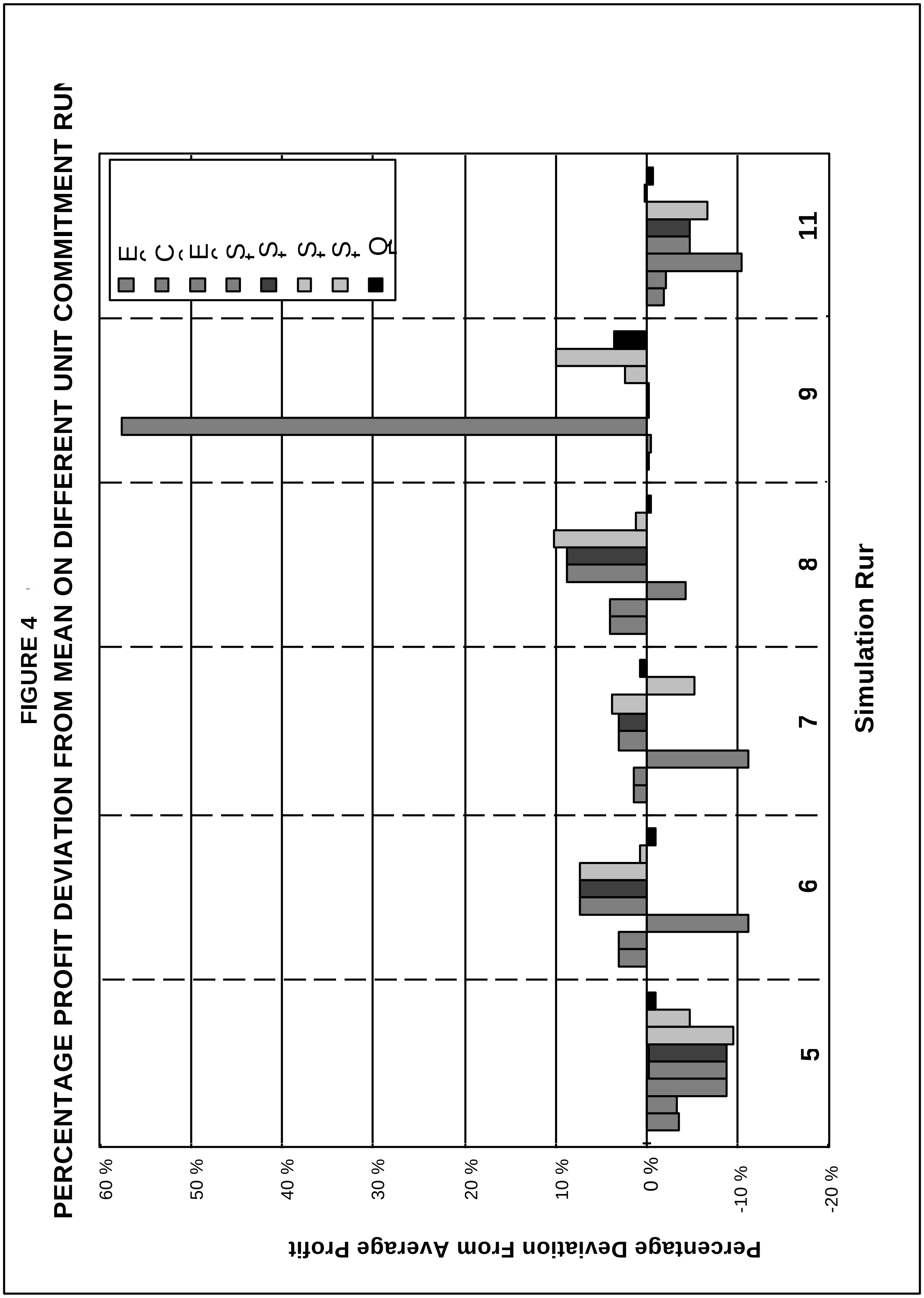


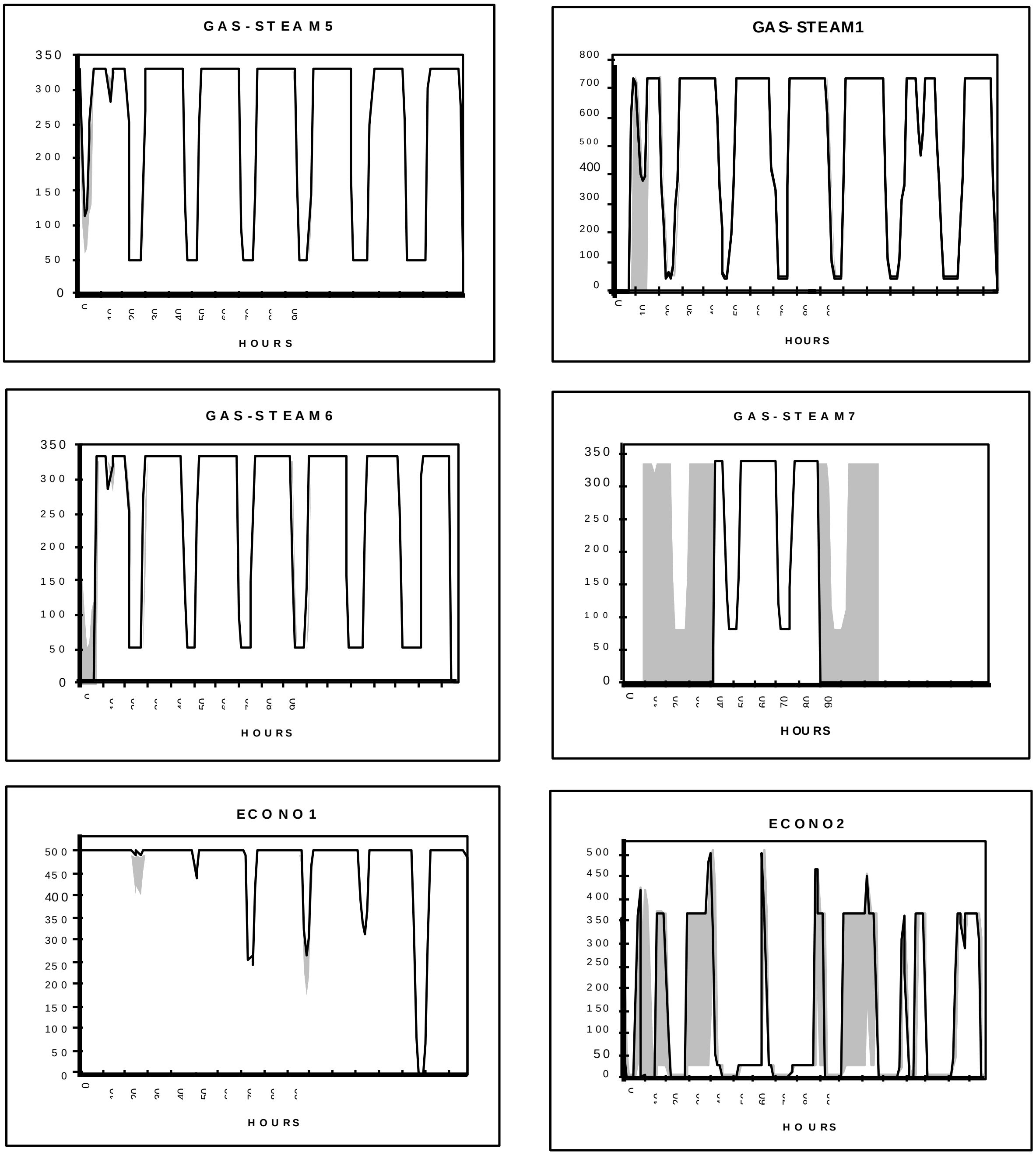
FIGURE 4
PERCENTAGE PROFIT DEVIATION FROM MEAN ON DIFFERENT UNIT COMMITMENT RUI

In order to illustrate in more detail the type of schedule indeterminacies that may result from unit commitment optimization we performed two additional simulation runs using the same data as before and produced the entire 168 hour schedules for each of the dispatchable resources. For convenience we identify the two run as Case A (also referred to as the base case) and Case B. Figure 5 illustrates a comparison of the two schedules for each of the resources. The solid line describes the schedules for the base case (A) while the gray area represents the deviation from the base case schedule obtained in Case B. We note that the main change from A to B is a reduction in the purchases of fixed price energy from the ECONO2 resource and an increase in the dispatch of GAS-STEAM7. There are also changes in the dispatch of the other three GAS-STEAM units in the first day of the scheduling horizon. While the later changes may seem insignificant, it should be noted that unit commitment algorithms are typically implemented in a "rolling horizon" where only the initial portion of the schedule is implemented before the program is rerun. In other words, the program is run repeatedly every few hours with updated information for the following 168 hours but the portion of the schedule used is only that corresponding to the time period till the next updated run. This approach makes the observed schedule changes in the initial period of our simulation runs quite significant.

Table 2 lists for each resource, the total revenue, cost and profits (aggregated over the 168 hours) for the base case as well as the corresponding changes between the two runs. Again we note the two schedules are equally good in the sense that the change in total system cost is about 0.02%. On the other hand, the total profits vary by nearly 1.5% representing a transfer of $150,000 between consumers and producers. More significant is the change in the distribution of cost and profits among the unit . These changes are illustrated in Figure 6 bellow which shows, for each resource, the percentage change in the costs and profits between the two simulation runs. As one would expect the marginal resources such as gas turbines and fixed price imports experience the highest profit volatility. For some of these resources the profit change from run to run exceeds 50%. For the CT the profit variation is even more radical (150%) changing from a net profit of $7,720 to a loss of nearly $10,000. While in absolute terms these amounts are insignificant the results suggest that a CT attempting to sell power to the pool as an independent power producer could be a risky enterprise.

FIGURE 5:

CHANGE IN RESOURCE SCHEDULES FOR TWO UNIT COMMITMENT RUNS



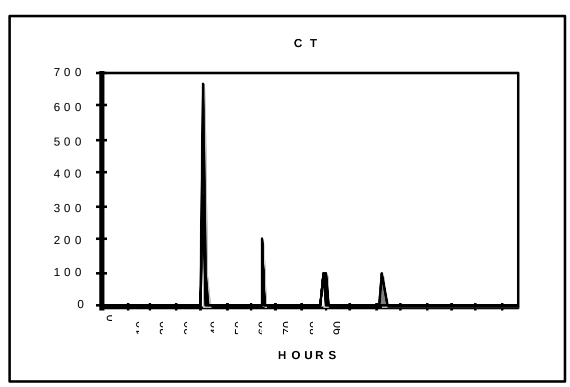
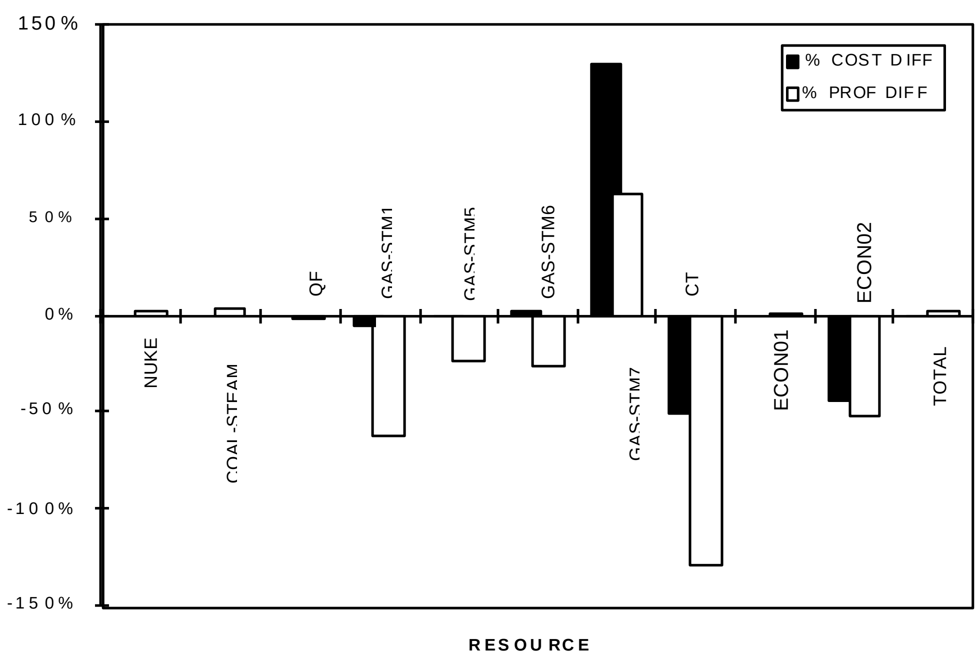


TABLE 2: COMPARISON OF TWO UNIT COMMITMENT RUNS (A and B)						
RESOURCE	REVENUE A	REV DIFF (B-A)	COST A	COST DIFF (B-A)	PROFIT A	PROF DIFF (B-A)
NUKE	$8,169,760	$74,720	$3,360,000	$0	$4,809,760	$74,720
COL-STEAM	$4,082,540	$36,986	$2,768,164	$0	$1,314,376	$36,986
QF	$4,084,880	$37,360	$6,720,000	$0	($2,635,120)	$37,360
GAS-STM1	$2,196,988	($150,170)	$2,136,433	($112,440)	$60,555	($37,730)
GAS-STM5	$1,069,147	($32,652)	$998,309	($15,849)	$70,838	($16,803)
GAS-STM6	$1,007,184	($1,116)	$936,325	$16,785	$70,859	($17,901)
GAS-STM7	$329,702	$417,142	$319,800	$410,911	$9,902	$6,231
CT	$61,483	($37,010)	$53,763	($27,072)	$7,720	($9,938)
ECON01	$1,941,980	($9,979)	$1,542,743	($12,616)	$399,237	$2,637
ECON02	$646,470	($290,616)	$579,576	($255,864)	$66,894	($34,752)
TOTAL	$35,842,434	$156,370	$25,543,277	$3,854	$10,299,157	$152,515

FIGURE 6: PERCENTAGE VARIATION IN COST AND PROFIT FOR TWO UNIT COMMITMENT RUNS



5. CONCLUSIONS

We have demonstrated both the volatility of "near optimal" scheduling outcomes for resources not base loaded, and the especially negative consequences of volatility for marginal resources (i.e., resources that frequently determine system marginal costs). Specifically, we have shown that variations in near optimal unit commitments that have negligible effect on total costs could have significant impact on the profitability of individual resources and on the transfer payments between consumers and suppliers . Consequently an ISO charged with making efficient central unit commitment decisions is in a delicate position of having to schedule resources equitably with no economic rationale to back the decision. These effects are inherent when attempting to optimize unit commitment from the perspective of a central operator, because of the near-degeneracy of the unit commitment problem and the presence of many near-optimal solutions.

The results, raise serious questions regarding the feasibility of proper mechanisms to oversee the efficiency and equity of a mandatory centrally committed and dispatched pool. We suggest that centralized scheduling by a mandatory power pool, using models appropriate for solving the integrated and regulated utility's scheduling problem, may be perceived by suppliers and consumers as unnecessarily volatile and even inequitable, and hence in the long run yield schedules that do not minimize costs. In particular, our results highlight potential pitfalls in central management of dispatch constraints specified by bidders.

The results of this paper support a more decentralized approach to unit commitment such as physical scheduling of self-nominated transactions or a simple auction with single prices and self-commitment. Proponents of the centralized dispatch may argue that self-commitment is a de facto option in an auction based system which can be realized by bidding a zero price while specifying quantity nomination. Unfortunately, as can be seen from our simulation results, resources that would experience the highest profit volatility are those operating in the price setting range. A process that would induce such units to bid a price of zero will undermine the efficiency of the unit commitment by withholding crucial cost information necessary for achieving an economically efficient schedule.

The simulation results also illustrate potential negative side-effects of resource disaggregation resulting from utility divestment of resources. While such disaggregation reduces the danger of horizontal market power due to concentration of resources, the inherent volatility in the net revenue of individual resources suggests that over-disaggregation is undesirable.

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APPENDIX

TABLE A:
RESOURCE SUPPLY CURVES FOR CALECO SYSTEM

Unit Name	Output level	MC ($/ MWH)	FC($ / H)	Unit Name	Output level	MC ($/ MWH)	FC($ / H)
NUKE1	No load		0	GAS-STM5	No Load		1515
	0	10			50	21	
	250	10			165	21.1	
	500	10			248	21.1	
	1000	10			330	21.3	
NUKE2	No load		0	GAS-STM6	No Load		1515
	0	10			50	21	
	250	10			165	21.1	
	500	10			248	21.1	
	1000	10			330	21.3	
QF	No Load		0	GAS-STM7	No Load		2575.5
	0	0			85	21	
	250	0			170	21.1	
	500	0			255	21.1	
	1000	0			340	21.3	
COL-STM1	No Load		2775	OIL-STM1	No Load		5975
	125	13.2			125	32.7	
	250	13.5			250	34	
	375	14.2			375	35.9	
	500	15.5			500	39	
COL-STM2	No Load		2775	OIL-STM2	No Load		5975
	125	13.2			125	32.7	
	250	13.5			250	34	
	375	14.2			375	35.9	
	500	15.5			500	39	
GAS-STM1	No Load		2560	CTS	No Load		4230
	50	20.1			100	42.3	
	188	20.5			1000	42.3	
	375	21.1			1750	42.3	
	750	23.2			2500	42.3	
GAS-STM2	No Load		7680	ECON01	No Load		17.5
	150	20.4			1	17.5	
	375	21.1			750	17.5	
	563	22			1500	17.5	
	750	23.2			3000	17.5	
GAS-STM3	No Load		5340	ECON02	No Load		30
	150	21			1	30	
	300	21.7			100	30	
	450	23			250	30	
	600	25.7			500	30	
GAS-STM4	No Load		3560				
	100	22.3					
	200	23					
	300	25.5					
	400	26					