Counterexamples to commonly held assumptions on unit commitment and market power assessment

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***Abstract*-- In the context of the ongoing deregulation of the electricity industry, we revisit the commonly held assumption that, under the condition of perfect information, a decentralized unit commitment would lead to the same power quantities traded and the same optimal social welfare as a centralized unit commitment. Taking operating cost independent of the output quantity into account, we show in the first part that meeting decentralized performance objectives of the individual market participants can lead to a lower efficiency than minimizing total operating cost in a decentralized way. This result concerns short-term optimization, and does not consider long-term investment issues. In the second part, we use an abstract example to show that a generator owner's optimum bid sequence for a centralized auction market can be above marginal cost even when there is no market power-related strategic bidding. We conclude that marginal production costs cannot be used as baseline for the assessment of market power in electricity markets as generators bid higher than MC because of intertemporal constraints and uncertainties about prices of consecutive hours.**

***Index Terms*-- Centralized unit commitment, Decentralized unit commitment, Market power, Power generation dispatch, Power generation economics**

I. Introduction

In the deregulated industry, competition between market participants should improve economic efficiency and lower prices for customers. Tasks that were performed in a centralized, coordinated fashion, are now performed by market participants and questions arise as to how much of the control and planning should remain in the hands of a centralized organization, and how much should be taken care of by the market, in which each market participant will try to commit its resources in such a way as to maximize his own profits.

This paper contributes to current debates in the context of deregulation by supporting the following two points: First, a centralized unit commitment can be economically more efficient than a decentralized unit commitment in the short run and under the assumption of complete knowledge about demand and the generators' marginal cost. Earlier work [1] considered this question strictly as a numerical optimization problem and argued for a decentralized unit commitment because a centralized system operator would lack the necessary economic rationale for his commitment decisions in the presence of many near-optimal solutions. Here we analyze the actual optima, assuming no such numerical issues.

Second, higher than marginal cost bids in electricity auctions do not necessarily indicate the exercise of market power, but can be explained by the fact that rational market participants have to internalize the cost of being on when not selling and the uncertainties of market outcomes into their market bids. Yet, much of the work written on market power assessment in the electricity industry refers to the difference between marginal cost and actual electricity prices as a measure for the level of market power exerted [2], [3].

We will illustrate the two statements in the following two sections.

II. Centralized versus decentralized unit commitment

In the following expressions, C_i is the cost function of and Q_i the quantity produced by generator i. Q_D is the total demand, n the total number of available generators, and u_i a binary variable that determines whether the generation unit i is turned on or off at a given moment.

A. The commonly used Argument

1) Conventional Economic Dispatch

Mathematically, a centralized economic dispatch is the problem of minimizing the total generation cost, using the quantities produced by each of the possible generators as decision variables [4].

$$\min_{Q} \sum_{i=1}^{n} C_i(Q_i) \tag{1}$$

such that total generation equals total load.

$$\sum_{i=1}^{n} Q_i = Q_D \tag{2}$$

This basic version of an unconstrained economic dispatch finds a solution to this optimization problem for a system of arbitrary size. A necessary condition for solving this basic economic dispatch problem is:

$$\frac{\delta C_1}{\delta Q_1} = \dots = \frac{\delta C_n}{\delta Q_n} = \lambda \, . \tag{3}$$

The term λ is known as the short-run marginal cost (SRMC) and, at the optimum, all unit marginal costs are equal to it.

2) Conventional Centralized Unit Commitment

The basic unit commitment problem (without start-up costs or minimum up/down time constraints) is as follows [4]

$$\min_{u_i, Q_i} \sum_{i=1}^{n} u_i C_i(Q_i) \, , \tag{4}$$

subject to

$$\sum_{i=1}^{n} Q_i = Q_D \tag{5}$$

where u_i equals 0 or 1 depending on whether the unit if off or on. Following the Lagrangian relaxation method, one first forms the Lagrangian function,

$$L(u, Q, \lambda) = \sum_{i=1}^{n} u_i \left(C_i(Q_i) - \lambda Q_i \right) + \lambda Q_D \, . \tag{6}$$

By minimizing (6) over Q first, one obtains the conventional economic dispatch equal incremental condition, that is,

$$\frac{\delta C_1}{\delta Q_1} = \ldots = \frac{\delta C_n}{\delta Q_n} = \lambda \, . \tag{7}$$

which permits one to solve for Q in terms of λ, the system incremental cost. The Lagrangian can be written as

$$L(u, \lambda) = \sum_{i=1}^{n} u_i \left(C_i \left(Q_i(\lambda) \right) - \lambda Q_i(\lambda) \right) + \lambda Q_D \, . \tag{8}$$

Finally, the Lagrangian method minimizes $L(u, \lambda)$ with respect to u giving the switching curve law

$$u_i = \begin{cases} 0 & \text{if } C_i - \lambda Q_i > 0 \\ 1 & \text{if } C_i - \lambda Q_i < 0 \end{cases} \tag{9}$$

that is, the unit is off if the average cost $C_i / Q_i > \lambda$ and on otherwise. Once on, a conventional economic dispatch is used to adjust to demand changes if these are monitored more frequently.

3) Decentralized Economic Dispatch

When competitive bilateral transactions take place, each party's objective is to maximize its profit,

$$\max_{Q_i} \pi_i(Q_i) \tag{10}$$

where $\pi_i = PQ_i - C_i(Q_i)$ stands for the profit made by the market participant i through some sort of trading process, given known price P. Thus, under perfect conditions, when the market converges to a single electricity price, one can maximize π_i to yield:

$$\frac{\delta C_1}{\delta Q_1} = \ldots = \frac{\delta C_n}{\delta Q_n} = P \, . \tag{11}$$

This is simply obtained by each market participant optimizing its own profit for the assumed exogenous market price P [4]. The process of bilateral decisions will stabilize P at the systemwide economic equilibrium under a perfect information exchange among all market participants.

4) Decentralized Unit Commitment

We assume a generator owner to be a price taker in a competitive market place. He must make a unit commitment decision typically by certain time day ahead, before actually knowing the spot price of the next hour. After the spot price is known, the generator decides how much power to sell in order to maximize profit. The only control for the problem is u_k whether to turn on or off at stage k. The expected generation level $\widehat{Q}_k$ may be regarded as a function of the control u_k and the expected price $\widehat{P}_k$. In the case of assuming deterministic price, and ignoring start-up costs, must-run time constraints, etc. it can be shown that an individual decision maker would arrive at the same average cost versus market price decision rule as the rule often used by a system operator scheduling plants in a coordinated way. The proof for this goes as follows [4]: Given a generator i, its profit while on is

$$\hat{\pi}_{on} = \widehat{P} \cdot \widehat{Q_i} - C_i(\widehat{Q_i}) \tag{12}$$

The generator will turn on only if $\hat{\pi}_{on} > 0$, which is equivalent to

$$\widehat{P} > \frac{C_i(\widehat{Q_i})}{\widehat{Q_i}} \tag{13}$$

which is the average cost rule used for coordinated unit commitment.

Based on this derivation, one could conclude that under perfect market assumptions and when neglecting minimum run time constraints, startup costs, etc. a system operator would schedule the same units as the individual power producers would in a decentralized way. Thus, both a centralized and a decentralized commitment process should lead to the same power quantities traded, and to the same total social welfare optimum. Most importantly, in this case the optimal electricity price is reached under the same conditions as the social welfare is maximized. The performance objectives of the individual market participants (to maximize profits) and the objective of a centralized entity (to minimize total operating cost) are considered to be equivalent.

B. The Counterexample

What follows is a mathematical proof that a centralized and a decentralized commitment process can differ even if intertemporal constraints are neglected. We will construct a situation with two generators in which the given demand can be satisfied at least cost with both generators scheduled, but in which one generator would prefer not to be scheduled because it would incur loss otherwise. A PoolCo-type market would schedule generator *2* to minimize costs and pay it the fixed operating costs to prevent it from loss. We assume generators bid true marginal cost curves.

1) Derivation

Demand is considered to be given, and we regard only one particular hour. We consider fixed operating costs for being scheduled. In the following derivation, subscript *2* stands for the particular generator g, *1* for one or an aggregation of other generators. The total cost of each generator i is described by

$$C_i(Q_i) = a_i Q_i^2 + b_i Q_i + c_i \tag{14}$$

The marginal costs are linear functions as shown in Fig. 1. Parameter a_i describes the coefficient for the linear marginal cost curves of generator i.

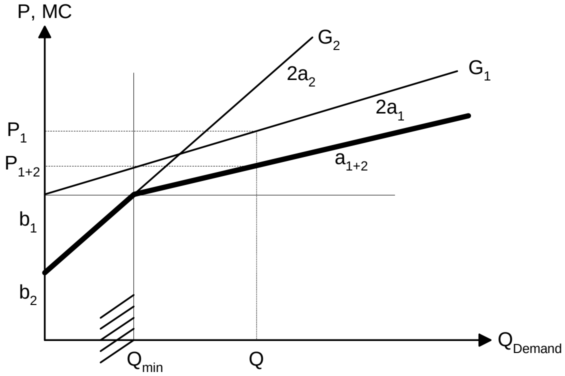

Fig. 1. Generator supply functions

If both generators participate, the slope of the supply function becomes

$$a_{1+2} = \frac{2a_1a_2}{a_1+a_2} \tag{15}$$

for

$$Q \geq Q_{\min} = \frac{b_1-b_2}{2a_2}$$

P_{1+2} and P_1 are the market prices obtained when generator *2* does or does not participate respectively with

$$P_{1+2} = b_1 + a_{1+2}(Q-Q_{\min}) = \frac{a_1b_2+a_2b_1}{a_1+a_2} + \frac{2a_1a_2}{a_1+a_2}Q \tag{16}$$

Three conditions must hold simultaneously:

- Generator 1 always wants to be on, independent of generator 2's decisions to participate during the hour:
$$a_1Q_1^2 + b_1Q_1 + c_1 < P_{1+2}Q_1 \tag{17}$$
- Generator 2 incurs loss if it is scheduled and does not receive extra payment:
$$a_2Q_2^2 + b_2Q_2 + c_2 > P_{1+2}Q_2 \tag{18}$$
- The total cost for supplying the given demand is smaller if generators 1 and 2 are scheduled than if only generator 1 supplies electricity:

$$a_1Q^2 + b_1Q + c_1 > a_1Q_1^2 + b_1Q_1 + c_1 + a_2Q_2^2 + b_2Q_2 + c_2 \tag{19}$$

In addition, we know

$$Q_1 + Q_2 = Q \tag{20}$$

and

$$2a_1Q_1 + b_1 = 2a_2Q_2 + b_2 \tag{21}$$

a) Generator 1

We introduce new dimensionless parameters $\nu_1 = Q_1/Q$ and $\nu_2 = Q_2/Q$. We write them as:

$$\nu_1 = \frac{Q_1}{Q} = \frac{P_{1+2}-b_1}{2a_1Q} = \frac{a_2 - \frac{b_1-b_2}{2Q}}{a_1+a_2} \tag{22}$$

and

$$\nu_2 = \frac{a_1 - \frac{b_2-b_1}{2Q}}{a_1+a_2} \tag{23}$$

Using the formula for P_{1+2}, (16), inequality (17) can be written as

$$a_1Q^2\nu_1^2 + b_1Q\nu_1 + c_1 < \frac{a_1b_2+a_2b_1}{a_1+a_2}Q\nu_1 + \frac{2a_1a_2}{a_1+a_2}Q^2\nu_1 \tag{24}$$

Further using the formula for ν_1, (22), we obtain after some transformations the condition

$$\boxed{Q > \frac{(a_1+a_2)\sqrt{\frac{c_1}{a_1}} + \frac{b_1-b_2}{2}}{a_2}} \tag{25}$$

b) Generator 2

Using the formula for P_{1+2}, (16), we write inequality (18) as

$$a_2Q^2\nu_2^2 + b_2Q\nu_2 + c_2 > \frac{a_1b_2+a_2b_1}{a_1+a_2}Q\nu_2 + \frac{2a_1a_2}{a_1+a_2}Q^2\nu_2 \tag{26}$$

and obtain after using the formula for ν_2 and some transformations:

$$\boxed{Q < \frac{(a_1+a_2)\sqrt{\frac{c_2}{a_2}} + \frac{b_2-b_1}{2}}{a_1}} \tag{27}$$

c) Total Costs

We use the formula for ν_1, (22), to rewrite inequality (19) as

$$\begin{aligned} a_1Q^2 + b_1Q + c_1 > \left(a_1\nu_1^2 + a_2(1-\nu_1)^2\right)Q^2 \\ + b_1Q\nu_1 + b_2Q(1-\nu_1) + c_1 + c_2 \end{aligned} \tag{28}$$

and obtain after some transformations the inequality

$$\boxed{Q > \frac{\sqrt{(a_1+a_2)c_2} - \frac{b_1-b_2}{2}}{a_1}} \tag{29}$$

d) Numerical Example

If all of the three above deduced inequalities (25), (27), and (29) hold, a centralized and a decentralized commitment would lead to different results. The following tables and graphs give a numerical example for this situation.

TABLE I
PARAMETERS FOR QUADRATIC COST CURVES EXAMPLE

	G_1	G_2
a	1	2
b	1	1.6
c	1.1	0.7
Q	2	

The literature gives several examples of cases in which individual objective functions are not aligned with those of the overall social welfare. The most famous example was given by Hardin in *The Tragedy of the Commons* [5]. Another one is Braess' article on traffic networks [6] in which he gives an example in which drivers' attempt to minimize their transit times leads to increased congestion and increased traffic times for all participants. Braess' paradox has become an important issue in the context of queuing networks [7].

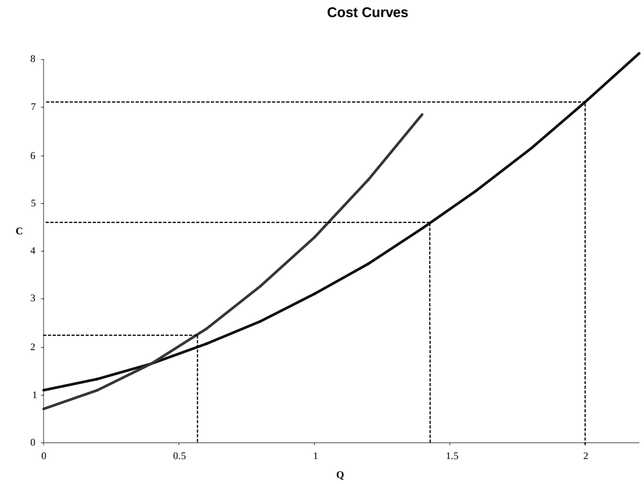

Fig. 2. Quadratic cost curves of numerical example

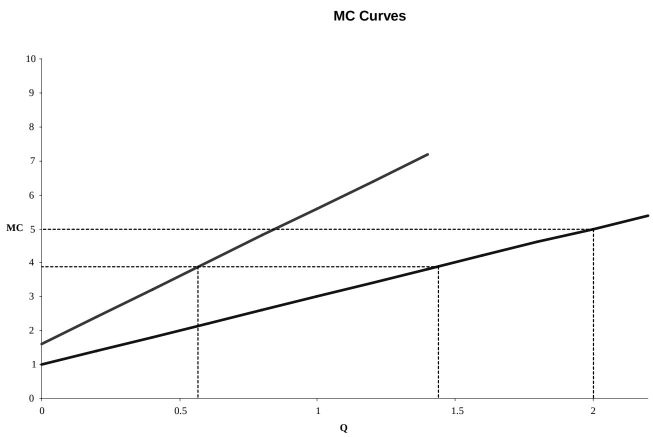

Fig. 3. Market supply functions for quadratic cost curve example

TABLE II
OUTCOMES OF QUADRATIC COST CURVES EXAMPLE

	G_1	G_1 and G_2		
P	5	3.87		
	G_1	G_1+ G_2	G_1	G_2
ν	100%	100%	72%	28%
C	7.1	6.84	4.59	2.25
Rev	10	7.73	5.54	2.19
π	2.9	0.9	0.95	-0.06

In power systems, however, the commonly held assumption is still that, at least in theory, a centralized and a decentralized commitment should lead to the same power quantities traded, and to the same optimal social welfare. The performance objectives of the individual market participants are considered equal to the one of minimizing total operating cost [8], [4], [9], [10].

The important implication of the examples given in this section is that, even in the absence of load uncertainties and intertemporal constraints, decentralized decision making, by which the market participants schedule themselves, need not necessarily lead to the same maximized welfare as centralized decision making. The reason is that, under certain circumstances, several generators can supply the load at a lower overall cost than the subset of generators that would make positive profits in a market setting if switched on during the hour.

In the Pennsylvania-New Jersey-Maryland and the New York electricity markets, the ISO offers a voluntary unit commitment service, based on three-part bids, allowing generators to bid actual operating costs more precisely and permitting a more efficient unit commitment. Generators may also self-schedule their own units, but they may also allow the ISO to determine the most economic unit commitment for their plants. Participating generators are guaranteed recovery of their start-up and minimum generation costs in the event they fail to recover these costs from the prices received in the ISO-coordinated markets [11], [12]. This mechanism eliminates the uncertainty of whether a generator will be committed only to lose money, and it allows for a more efficient dispatch. The quadratic cost curve example shows how a PoolCo-type market would work more efficiently than a power exchange (for which the one-part bids result in some inefficiency).

It is important to state at this point, that the conclusions here focus on the short run, in that they do not take into account the long-term motivational effects of a decentralized commitment on investment decisions and the possible entry of new firms or generating plants. The literature gives several qualitative arguments why a decentralized commitment process might be preferable, despite the better overall efficiency of the centralized process [12], [13].

III. MARGINAL COST BIDDING AND MARKET POWER

This section addresses the optimization problem that generators with intertemporal constraints face when bidding into wholesale markets which require the generators to internalize their start-up costs. Prices are assumed to be exogenous random variables with known probability distributions, and we will show that the optimal bidding strategy is to bid higher than marginal costs despite the generator's lacking market power, and that different assumptions of price correlation change the optimal bidding behavior.

A. Example

We consider a generator whose marginal costs (MCs) are constant over the output range. The owner can offer his electricity by submitting a bid to a centralized market for each hour and is scheduled if the bid price turns out to be lower than or equal to the market price. We neglect the case of the generator being the marginal unit and scheduled for less than full output. Because of the constant MC, the most efficient way to operate the generator is to either produce full output or nothing, and to use a flat bid curve. In addition to variable costs, the generator incurs hourly fixed cost (HFC) for every hour of operation regardless of whether it is producing electricity or not, and also start-up (SU) and shut-down (SD) cost. Once the generator is switched on, it has to remain in that state for at least 2 hours, during which it incurs the HFC. If the generator gets scheduled for one hour, but not for the other, it still incurs the HFC for the second hour as well. Hence, the generator has to internalize these intricacies when it is bidding into an hourly market. The generator does not know the market prices when bidding, but has some knowledge about the probability distribution of the prices, which are considered to be exogenous variables, not influenced by the behavior of the generator (Fig. 4).

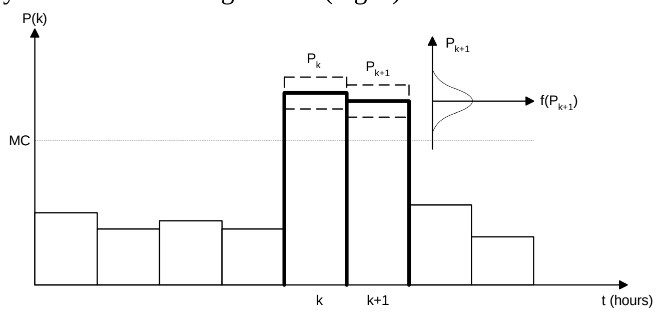

Fig. 4. Marginal cost and hourly predicted prices for the next day

We now consider the specific situation in which only 2 successive hours have price distributions above MC. The problem of finding the optimal bids is drastically simplified and can be solved in a closed form. In this special example, the costs of SU, SD, and 2 hours of HFC can be united into one constant term FOC (fixed operating cost) which will be incurred once the generator starts up. This aggregation does not change the optimal strategy, but simplifies the formulation. Fixed costs, such as capital costs, which are incurred regardless of the generator producing output or not during one hour, do not affect the optimal decision. For the numerical calculation, we assume that prices can have only a limited number of discrete values during the two hours (Fig. 5): $P_1 \in \{P_{11},...,P_{1i},...,P_{15}\}$ and $P_2 \in \{P_{21},...,P_{2j},...,P_{25}\}$.

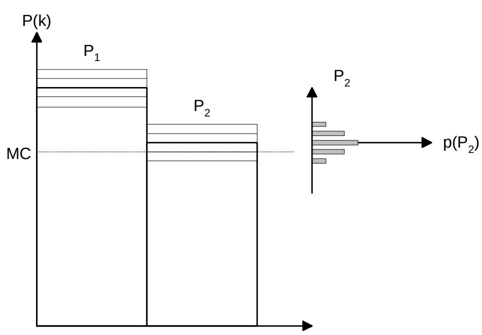

Fig. 5. Assumed price distribution of two relevant hours

We consider two different assumptions about the probability distributions of prices. In the first variant, we assume that the probability distribution of the prices of the second hour does not change with the additional information of the first hour's price. Hence, the two hours are uncorrelated (Fig. 5). In the second variant, the hourly prices are correlated and knowledge of the first hour's prices changes the probability distribution for hour 2 (Fig. 6): $\mathrm{p}(P_2 = P_{2j}) = \mathrm{p}(P_2 = P_{2j} \mid P_1 = P_{1i})$. In order to compare the results, we chose the unconditional probability distribution of the second hour to be the same as in the uncorrelated variant.

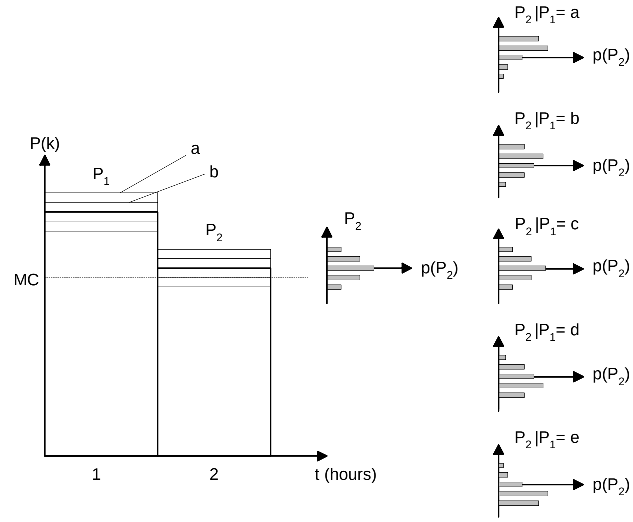

Fig. 6. Variant 2: prices between periods are correlated

The generator submits bids for both hours at the same time, which corresponds to a day-ahead market, in which the generator has to decide on bids for several hours simultaneously. If it does not get scheduled in any of the two hours, the generator will not start up. We assume that if it gets scheduled in only one of the two hours, it nevertheless has to provide the energy and will incur the total FOC, which incorporates SU, SD and HFC for running two hours. It can, however, sell its energy only during one of the two hours in which it makes positive revenue if the accepted bid was above its MC.

B. Mathematical Formulation

1) Variant 1 - prices independent

In order to find the optimal bidding behavior, the profits for all possible combinations of bid heights have to be compared:

$$J = \max_{b_1, b_2} \left[J(b_1, b_2) \right] \tag{30}$$

with $\{(b_1, b_2) \big| (b_1, b_2) = (P_i, P_j)\}$ and (P_i, P_j) being possible prices for the respective hours. In order to calculate the expected profit for the bid combinations, all possible price outcomes have to be compared:

$$\begin{aligned} J(b_1, b_2) = & \sum_{P_i | P_i \geq b_1} \sum_{P_j | P_j \geq b_2} \mathrm{p}(P_1 = P_i) \cdot \mathrm{p}(P_2 = P_j) \cdot \begin{pmatrix} \left(P_i + P_j - 2MC\right) Q \\ -FOC \end{pmatrix} \\ & + \sum_{P_i | P_i \geq b_1} \sum_{P_j | P_j < b_2} \mathrm{p}(P_1 = P_i) \cdot \mathrm{p}(P_2 = P_j) \cdot \left(\left(P_i - MC \right) Q - FOC \right) \\ & + \sum_{P_i | P_i < b_1} \sum_{P_j | P_j \geq b_2} \mathrm{p}(P_1 = P_i) \cdot \mathrm{p}(P_2 = P_j) \cdot \left(\left(P_j - MC \right) Q - FOC \right) \end{aligned} \tag{31}$$

An alternative formulation is:

$$J(b_1,b_2) = \mathrm{p}(P_1 \geq b_1)\cdot \mathrm{p}(P_2 \geq b_2)\cdot\left(\begin{pmatrix}\mathrm{E}\left\{P_1 \mid P_1 \geq b_1\right\} + \\ \mathrm{E}\left\{P_2 \mid P_2 \geq b_2\right\} - 2MC\end{pmatrix} Q - FOC\right)$$
$$+\mathrm{p}(P_1 \geq b_1)\cdot \mathrm{p}(P_2 < b_2)\cdot\left(\left(\mathrm{E}\left\{P_1 \mid P_1 \geq b_1\right\} - MC\right)Q - FOC\right)$$
$$+\mathrm{p}(P_1 < b_1)\cdot \mathrm{p}(P_2 \geq b_2)\cdot\left(\left(\mathrm{E}\left\{P_2 \mid P_2 \geq b_2\right\} - MC\right)Q - FOC\right). \quad (32)$$

Whereas finding the optimal bidding sequence in our example is still possible, the same task becomes computationally infeasible when optimizing for more periods. The time for calculation increases exponentially with the number of periods.

2) Variant 2: prices correlated

The formulation for this variant is similar to the first variant with the only difference being the conditional probability distributions for the second hour:

$$J = \max_{b_1,b_2}\left[J(b_1,b_2)\right] \quad (33)$$

and

$$J(b_1,b_2) = \sum_{P_i \mid P_i \geq b_1}\ \sum_{P_j \mid P_j \geq b_2} \mathrm{p}(P_1 = P_i)\cdot \mathrm{p}(P_2 = P_j \mid P_1 = P_i)\cdot \left(\left(P_i + P_j - 2MC\right)Q - FOC\right)$$
$$+\sum_{P_i \mid P_i \geq b_1}\ \sum_{P_j \mid P_j < b_2} \mathrm{p}(P_1 = P_i)\cdot \mathrm{p}(P_2 = P_j \mid P_1 = P_i)\cdot\left(\left(P_i - MC\right)Q - FOC\right)$$
$$+\sum_{P_i \mid P_i < b_1}\ \sum_{P_j \mid P_j \geq b_2} \mathrm{p}(P_1 = P_i)\cdot \mathrm{p}(P_2 = P_j \mid P_1 = P_i)\cdot\left(\left(P_j - MC\right)Q - FOC\right). \quad (34)$$

C. Numerical Example

We chose certain numerical values for the parameters that illustrate some conclusions. The parameters are listed in the Appendix and Table III contains numerical results. Bold numbers represent the expected profits for each of the optimization methods and assumed dependencies. The values in brackets are the optimal bid heights.

TABLE III
OPTIMAL BIDS AND EXPECTED PROFITS, NUMERICAL EXAMPLE

	Bid Sequence	Exp.Profit
Prices independent	(58,52), (60,54)	**1.1720**
	(58,54)	**1.1538**
	(56,50),(56,52), (60,56),(62,56)	**1.0798**
	(60,52)	**0.9266**
Prices correlated	(60,52)	**1.7650**
	(58,52)	**1.6838**
	(60,54)	**1.6834**

D. Interpretations

This simple numerical example allows us to draw several conclusions:

1) Market Power

Many of the recent papers on assumed market power abuse in deregulated electricity markets assume that market participants bid their true marginal costs in a competitive market if no market power is exerted. However, in the context of bidding decisions of power plants, which not only incurs MC, but also start-up, shut-down costs and minimum commitment constraints, these assumptions lose their basis. Generators bid higher than MC not because they can exercise market power, but because of intertemporal constraints and uncertainties about prices of consecutive hours.

The literature disagrees as to what exactly constitutes market power, but generally agrees that it has to do with actively raising the prices at which one is willing to sell output (one's price offer) above MC in order to change the market price [14]. MC include both the variable costs due to fuel and the other variable operating and maintenance costs. E.g., [2] states that "Offering power at a price significantly above marginal production (or opportunity) cost, or failing to generate power that has production costs below the market price, is an indication of the exercise of market power," and that "the offer price of a competitive firm, one without market power, will always be its marginal cost, which will be the greater of marginal production cost or its opportunity cost of selling the power elsewhere."

In the formulation of this paper, the power producer is modeled as a price taker. He has assumptions about the probability distributions of prices for certain hours. Its bidding decision does not affect the prices and, hence, it has no market power. Nevertheless, its optimum bids deviate from MC. It is, therefore, not market power that creates prices above MC, but the necessity to incorporate start-up and shut-down constraints in the presence of uncertain prices. The generator in the example responds to the simple economic incentive of maximizing profits given uncertain prices. As a result, the competitive price does not equal marginal cost at peak periods under competition, and therefore simple price-cost margin studies cannot confirm the exercise of market power.

We state as a conclusion that above MC bids of generators do not indicate the exercise of market power. Especially in times when prices are very volatile, generators have to bid above marginal costs in order to take account of the possibility of being scheduled for one hour and not the following one.

2) Knowledge about Correlation

If prices have the same unconditional probability distribution, but correlation between successive hours exists, then the optimal bid decisions are different. In our numerical example, the optimal bid sequence in the independent case is either (58,52) or (60,54), whereas it is (60,52) in the case that the prices of each hour are correlated (Table I). Applying either of the optimal bidding sequences to the other variant leads to suboptimal profit maximization. In order to calculate the most effective bidding strategy, it is therefore important to take the price correlation between different hours of the day into account.

IV. Conclusions

We have shown that decentralized and centralized commitment do not lead to the same amounts of power traded, even in the theoretical case of absence of uncertainties. Neglecting the influence of long-term capacity effects, we could show that the performance objectives of the individual market participants are not equal to the one of minimizing total operating cost: a centralized unit commitment can achieve an overall higher economic efficiency in the short run. We draw the analogy to *The Tragedy of the Commons* [5], which became famous for exemplifying how individual objective functions are not necessarily aligned with those of the overall societal welfare.

Second, we illustrated why market power in electric power auctions cannot be measured by referring to the marginal production cost as the baseline of competitive prices. In order to incorporate intertemporal constraints dominating the operation of electric power plants, generation owners have to bid higher than a simple marginal cost analysis would predict. Market power measures like the Lerner Index are, therefore, not able to measure level of market power exerted in electric power auctions. [15] proposes to compare the actual prices to benchmark prices, that take into account several factors unique to electricity markets, when assessing market power.

V. Appendix: Numerical Values

MC=50; $P_1 \in \{56,58,60,62,64\}$
Q=1; $P_2 \in \{46,48,50,52,54\}$
FC=10;

With $p_i=p(P_1=P_{1i}) = p(P_2=P_{2i})$ and $p_{i|j}=p(P_2=P_{2j} | P_1=P_{1i})$:

$p_1=0.1888$	$p_{1\|1}=0.45$	$p_{1\|2}=0.20$	$p_{j\|3}= p_j$
$p_2=0.1624$	$p_{2\|1}=0.20$	$p_{2\|2}=0.32$	
$p_3=0.2978$	$p_{3\|1}=0.27$	$p_{3\|2}=0.33$	$p_{j\|4}= p_{5-j\|2}$
$p_4=0.1624$	$p_{4\|1}=0.06$	$p_{4\|2}=0.08$	
$p_5=0.1888$	$p_{5\|1}=0.02$	$p_{5\|2}=0.08$	$p_{j\|3}= p_{5-j\|1}$

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VII. Biographies

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Dr. Marija D. Ilic has been a Senior Research Scientist in the Department of Electrical Engineering and Computer Science at MIT since 1987. Her interest is in control and design of large-scale systems. She conducts research and teaches graduate courses in the area of electric power systems. Prior to her years at MIT, Dr. Ilic was a tenured faculty member at the University of Illinois, Urbana-Champaign. Dr. Ilic received her M.Sc. and D.Sc. degrees in Systems Science and Mathematics from Washington University in St. Louis.