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OPTIMIZATION-BASED SALE TRANSACTIONS AND HYDROTHERMAL SCHEDULING

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Abstract- Selling and purchasing power are important activities for utilities because of potential savings. When a selling utility presents an offer including prices, power levels and durations, a purchasing utility selects power levels and durations within the offered range subject to relevant constraints. The decisionmaking process is complicated because transactions are coupled with system demand and reserve, therefore decisions have to be made in conjunction with the commitment and dispatching of units. Furthermore, transaction decisions have to be made in almost real time in view of the competitiveness of the power market caused by deregulation. In this paper, transactions are analyzed from a selling utility's viewpoint for a system consisting of thermal, hydro and pumped-storage units. To effectively solve the problem, linear sale revenues are approximated by nonlinear functions, and non-profitable options are identified and eliminated from consideration. The multipliers are then updated at the high level by using a modified subgradient method to obtain near optimal solutions quickly. Testing results show that the algorithm produces good sale offers efficiently.

Key words: power transactions; power sales; Lagrangian relaxation; nonlinear approximation.

I. INTRODUCTION

Since utilities have quite different generating units and must meet their time-varying system demand and reserve requirements, they usually have different marginal generation costs. If the marginal costs of neighboring utilities are substantially different, it would be mutually beneficial for these utilities to sell or purchase power and maximize the savings or profits from transactions. When a selling utility makes an offer including prices, power levels and available durations, a purchasing utility selects power levels and durations within the offered range subject to relevant constraints. The problem is difficult because transactions are coupled with system demand, therefore they have to be considered in conjunction with the commitment and dispatching of units. The unit commitment problem itself is believed to be "NP hard," i.e., the computational requirements for obtaining an optimal solution grow exponentially with problem size. The resolution of the integrated transaction and scheduling problem is thus even more involved. In addition, in view of the recent deregulation trend and the resulting competitiveness of the power market, transaction decisions have to be made in almost real time to lock in on favorable opportunities. It is therefore very important to obtain near-optimal decisions with quantifiable quality within a reasonable amount of computation time.

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An overview of the types of transactions and their increasingly important role in utilities' daily activities was presented in [1]. A limited power purchase problem was considered in [2] where the total amount of energy purchased within a time period was allocated among hours using a peak-shaving method. A probabilistic technique to assess the import/export of energy and spinning reserve to offset inadequate operating capacity and reduce unit commitment risks was presented in [3]. In our previous work [4], purchase transactions and the scheduling of thermal units were considered as an integrated problem and solved by using the augmented Lagrangian decomposition and coordination technique. In [5], an integrated hydrothermal scheduling and power exchange problem was considered. The overall problem was decomposed into subproblems by using the Lagrangian relaxation technique, and transaction subproblems were solved by using the simplex linear programming approach.

In this paper, transactions are analyzed from a selling utility's viewpoint for a system consisting of thermal, hydro and pumped-storage units. This problem is more complicated than the purchase transaction problem discussed in [4] because the selling utility has to ensure that once an offer is made, any legitimate purchase must yield profits. Another difficulty is associated with the Lagrangian relaxation technique, a well-recognized way to solve this type of problems. The basic idea of Lagrangian relaxation is to relax the system-wide constraints by using Lagrange multipliers, and decompose the overall problem into individual subproblems. The multipliers are then adjusted iteratively at the high level based on subproblem solutions to gradually enforce the relaxed constraints. The method has been successfully applied to solve unit commitment problems, e.g., [6], [7] and [8] to name a few. However, if the standard Lagrangian relaxation technique is used to solve the problem considered here, the solution of a sale subproblem may jump from its maximum to minimum and vice versa with a slight change of Lagrange multipliers because of the linear sale revenue ([8], [9]). Furthermore, the subproblem solution will be singular when the linear cost coefficient becomes zero. Although these difficulties were also encountered for a purchase transaction subproblem, they are more severe here since we are dealing with the selection of offer levels and durations, which by definition are larger than purchasing levels and durations, respectively. These difficulties result in poor algorithm convergence, and effective sale decisions may not be obtainable in a timely fashion.

The mathematical formulation of the objective function and relevant sale constraints are presented in Section II. To effectively overcome the above mentioned difficulties, linear sale revenues are approximated by nonlinear functions, quadratic in this case. After system-wide coupling constraints are relaxed by using Lagrange multipliers and the overall problem is decomposed into individual subproblems, the optimal sale level for each duration can be obtained by minimizing a single variable quadratic function, given the set of multipliers. Subsequently, non-profitable sale options are identified and eliminated from consideration, and optimal sale transaction decisions across the planning horizon are determined by dynamic programming. The multipliers are then updated at the high level by using a modified subgradient method to obtain near optimal solutions quickly. The solution methodology is presented in Section III. Testing results based on data from Northeast Utilities are presented in Section IV. Compared with the standard Lagrangian relaxation technique, the nonlinear approximation method reduces the solution oscillation and singularity difficulties, and generates consistently better schedules in less time.

II. PROBLEM FORMULATION

The integrated sale transaction and scheduling problem is formulated as a mixed-integer programming problem. Transaction prices are determined by utility engineers with a knowledge of the system's marginal costs and current market information. The prices can also be suggested by the algorithm after adding a markup value to the system marginal costs obtained by running the system without sale transactions. The problem is to determine the sale levels and durations to be offered to purchasing utilities, and the commitment and dispatching of units so that the total cost (thermal unit fuel cost minus sale revenue) is minimized. This minimization is subject to system demand and reserve requirements, and individual transaction and unit constraints.

II.1 The Objective Function and System-wide Constraints

Consider a power system with I thermal units, J hydro units, K pumped-storage units and N sale transactions. The time unit is one hour and the planning horizon may vary from one week to ten days. The cost function to be minimized is:

$$J = \sum_{t=1}^{T} \left\{ \sum_{i=1}^{I} [c_i(p_i^t(t)) + s_i(t)] - \sum_{n=1}^{N} c_n^s(t) p_n^s(t) \right\}, \qquad (2.1)$$

where $c_i(p_i^t(t))$ is the fuel cost of thermal unit i at generation level $p_i^t(t)$, $s_i(t)$ the unit's start-up cost, $c_n^s(t)$ the unit price of sale transaction n at hour t (in \$/MW), and $p_n^s(t)$ the offer level (in MW) for the sale transaction at time t.

According to the current transaction practice for utilities in New England, a day is divided into on-peak, off-peak and shoulder load periods as shown in Figure 1. For reasons to be detailed later, transaction prices $\{c_n^s(t)\}$ and offer levels $\{p_n^s(t)\}$ within each on-peak or off-peak load period are required to be constant, and these values for a shoulder period can go either with those of the adjacent on-peak load period or off-peak load period. For simplicity of notation, however, the symbols $c_n^s(t)$ and $p_n^s(t)$ will be used.

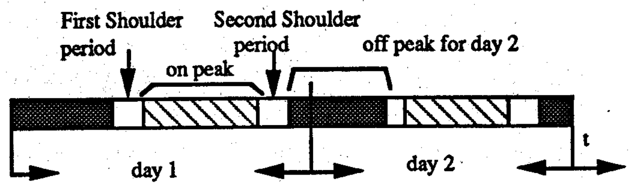

Figure 1. Load periods

For sale transaction n, the periods available for transaction and the maximum offer level $p_n^{s-max}(t)$ for that period are assumed to be given based on system capacity and demand. The decision variables are offer levels $\{p_n^s(t)\}$ and durations (characterized by beginning and ending hours within the periods available for transactions), and the generation levels of thermal units $\{p_i^t(t)\}$, hydro units $\{p_j^h(t)\}$, and pumped-storage units $\{p_k^p(t)\}$. Transaction prices are assumed to be determined by the methods mentioned earlier, and are not part of the decision variables. For otherwise the separability of the problem will be lost and the problem cannot be decomposed into individual sale transaction subproblems as will be explained later. The minimization in (2.1) is subject to the following system-wide constraints:

System Demand:

$$\sum_{i=1}^{I} p_i^t(t) + \sum_{j=1}^{J} p_j^h(t) + \sum_{k=1}^{K} p_k^p(t) - \sum_{n=1}^{N} p_n^s(t) = p_d(t); \qquad (2.2)$$

System Reserve:

$$\sum_{i=1}^{I} r_i^t(p_i^t(t)) + \sum_{j=1}^{J} r_j^h(p_j^h(t)) + \sum_{k=1}^{K} r_k^p(p_k^p(t)) \geq p_r(t), \qquad (2.3)$$

where $r_i^t(p_i^t(t))$, $r_j^h(p_j^h(t))$ and $r_k^p(p_k^p(t))$ are, respectively, the reserve contributions of thermal, hydro and pumped-storage units; and $p_d(t)$ and $p_r(t)$ are, respectively, the system demand and reserve requirements at hour t. Individual thermal unit constraints include capacity, minimum up/down time, ramp rate, etc. Individual hydro unit constraints include available hydro energy, capacity and minimum generation, etc. Pumped-storage constraints include pond capacity, pond level dynamics, generation and pumping capacity, and minimum generation/pumping, etc. These constraints are described in detail in our previous work ([7], [10] and [11]). Power sale constraints including minimum time requirements, allowable sale patterns and profitability constraints will be presented in the next subsection.

It should be mentioned that once an offer is made, a purchasing utility may not select the offered levels $\{p_n^s(t)\}$ and durations. Rather, it could select levels $\{p_n^b(t)\}$ (with $p_n^b(t) \leq p_n^s(t)$) and appropriate durations to fit its own needs, subject to minimum time requirements and allowable transaction patterns ([4]). The exact variables to be used in the cost function (2.1) and in the system demand constraints (2.2) should therefore be $\{p_n^b(t)\}$ instead of $\{p_n^s(t)\}$. However, there is no way for the selling utility to know $\{p_n^b(t)\}$ when it is trying to figure out what to offer. Therefore variables $\{p_n^s(t)\}$ are used. Nevertheless, checks will be made (equation (2.5)) to safeguard the selling utility's profitability for possible values of $\{p_n^b(t)\}$.

II.2 Power Sale Constraints

Minimum Time Requirements and Allowable Transaction Patterns

Generally thermal base load units with minimum up/down time requirements and ramp rate constraints are used to provide power for transactions. To ensure that these constraints are satisfied, the current practice for utilities in New England requires transaction prices and levels to be constant within each load period. It also requires transaction durations to satisfy minimum time requirements, and transaction across adjacent load periods to follow certain allowable patterns. The minimum time requirements state that if a transaction is to take place in a load period, it should last at least for a minimum amount of time in that period (the number of hours could be different for on-peak load periods and for off-peak load periods). After the minimum transaction time is satisfied, the transaction can be discontinued, however, if it is continued it is subject to certain patterns. Allowable transaction patterns include an on-peak interval with one constant level, or an off-peak interval with one level. Shoulder periods do not stand alone and are either appended to an on-peak interval or an off-peak interval. If power is transacted for successive off-peak and on-peak periods, power should also be transacted for the shoulder period in between in a contiguous manner. From the selling utility's viewpoint, the offer levels and durations should satisfy the above requirements. It can then expect that a purchasing utility will purchase power within the offered ranges while satisfying these requirements.

Interval-wise Profitability Constraints

Any interval within a load period satisfying the minimum time requirements is called a **"sale interval."** Within a load period, there are many sale intervals with different starting and ending hours, each characterized by a constant offer level. Hours in a shoulder period can be appended to a sale interval in an adjacent on-peak or off-peak load period in a contiguous manner. The way we shall look at the problem is to examine individual intervals first, and then combine intervals across adjacent load periods to form a good sale offer.

From the selling utility's viewpoint, any sale interval should not result in a loss; for otherwise, this interval should have been taken out of consideration without affecting the rest of the transaction. To analyze the profit of a sale interval, suppose first that the purchasing utility agrees to purchase power at the offered level $p_n^s(t)$ for the entire duration of the interval. Jumping ahead a little bit, let $\lambda(t)$ be the system marginal cost at hour t with $p_n^s(t)$ included (equal to the Lagrange multiplier associated with the system demand constraint at that hour, as will become clear in the next section). Then the profit for the interval is given by

$$\sum_{t_b}^{t_e} c_n^s(t)p_n^s(t) - \sum_{t_b}^{t_e} \lambda(t)p_n^s(t), \tag{2.4}$$

where t_b and t_e are, respectively, the beginning and ending hours of the interval. Since $c_n^s(t)$ and $p_n^s(t)$ are constant across the interval, the interval-wise profitability constraint can be expressed as:

$$c_n^s(t) - \bar{\lambda}(t) > 0, \tag{2.5}$$

where $\bar{\lambda}(t)$ is the average marginal cost for the interval, i.e.,

$$\bar{\lambda}(t) \equiv \frac{1}{(t_e - t_b + 1)} \sum_{t_b}^{t_e} \lambda(t). \tag{2.6}$$

Note that if (2.5) is satisfied for all individual intervals of a sale transaction, the entire transaction must be profitable.

Although (2.5) appears to be independent of the exact transaction level, the evaluation of $\bar{\lambda}(t)$ within the solution process (to be presented in the next section) implicitly requires the knowledge of exact transaction level. As mentioned, there is no way for the selling utility to know $\{p_n^b(t)\}$ when it is trying to figure out what to offer. Therefore if power is transacted at a level $p_n^b(t)$ strictly less than the offered level $p_n^s(t)$, (2.5) provides an approximate (rather than exact) profitability check.

III. SOLUTION METHODOLOGY

III.1 The Lagrangian Relaxation Approach with Nonlinear Approximation

From the above problem formulation, it can be seen that individual transactions and thermal, hydro and pumped-storage units are essentially independent, but together they have to meet the system demand (2.2) and reserve (2.3) requirements. The cost function to be minimized is also additive with respect to individual transactions and units. The problem is therefore ideal for Lagrangian relaxation which exploits the decomposable structure of the problems. By using standard Lagrangian relaxation, however, a decomposed sale subproblem has a linear cost function with the coefficient determined by Lagrange multipliers. When the coefficient is close to zero, the optimal solution of the subproblem could oscillate between the maximum and minimum values with a slight change of the multipliers [9]. To overcome this difficulty, linear sale revenues are approximated by nonlinear functions, quadratic in this case, and the modified objective function is given by:

$$J = \sum_{t=1}^{T} \left\{ \sum_{i=1}^{I} [c_i(p_i^t(t)) + s_i(t)] - \sum_{n=1}^{N} [a_n(t)(p_n^s(t))^2 + b_n(t)p_n^s(t)] \right\}, \tag{3.1}$$

where $a_n(t)$ and $b_n(t)$ are coefficients for the quadratic approximation of the linear sale revenue, and are selected so that the two revenues are the same at the maximum offer level $p_n^{s-max}(t)$. The quadratic coefficient $a_n(t)$ should be negative to have a meaningful subproblem solution, and be sufficiently small to avoid significant mismatch between the two revenues. The Lagrangian for the modified problem is given by:

$$J = \sum_{t=1}^{T} \{ \sum_{i=1}^{I} [c_i(p_i^t(t))+s_i(t)] - \sum_{n=1}^{N} [a_n(t)(p_n^s(t))^2 + b_n(t)p_n^s(t)]\}$$
$$+ \lambda(t)\{p_d(t) - [\sum_{i=1}^{I} p_i^t(t) + \sum_{j=1}^{J} p_j^h(t) + \sum_{k=1}^{K} p_k^p(t) - \sum_{n=1}^{N} p_n^s(t)]\}$$
$$+ \mu(t)\{p_r(t) - [\sum_{i=1}^{I} r_i^t(p_i^t(t)) + \sum_{j=1}^{J} r_j^h(p_j^h(t)) + \sum_{k=1}^{K} r_k^p(p_k^p(t))]\}, \tag{3.2}$$

where $\{\lambda(t)\}$ and $\{\mu(t)\}$ are, respectively, the multipliers relaxing the demand and reserve requirements. After re-grouping relevant terms, a two-level structure can be formed following the framework of [7]. Given the multipliers, the low level consists of solving individual sale transaction and unit subproblems. The high level is to update the multipliers so as to maximize the dual function. Heuristics are then used to modify subproblem solutions to obtain a feasible solution.

III.2 Solving Sale Transaction Subproblems

After collecting sale related terms from (3.2), the following sale subproblem is formed, one for each sale transaction:

$$\min_{p_n^s(t)} L_n^s \text{ with } L_n^s(t) \equiv \sum_{t=1}^{T} \left\{ -a_n(t)p_n^{s\,2}(t) + [-b_n(t)+\lambda(t)]p_n^s(t) \right\}. \tag{3.3}$$

With multipliers and sale prices given, (3.3) is to determine the optimal offer levels and durations to minimize the subproblem cost subject to minimum time requirements, allowable transaction patterns and interval-wise profitability constraints (2.5). As mentioned, the way we look at the problem is to examine individual sale intervals first, and then combine intervals across adjacent load periods to form a good sale offer.

Optimal Level for a Sale Interval

To obtain the optimal offer levels for individual sale intervals, let t_b and t_e denote, respectively, the beginning and ending hours of the sale interval under consideration. From (3.3), the optimal offer level for the interval $p_n^{s*}(t)$ can be obtained as:

$$\min_{p_n^s(t)} \left\{ -a_n(t)(p_n^s(t))^2 + [-b_n(t) + \bar{\lambda}(t)]p_n^s(t) \right\}. \tag{3.4}$$

The optimal offer level for the interval can therefore be obtained by minimizing the above single variable quadratic function.

After the optimal sale level for the interval is determined, the interval-wise profitability condition (2.5) (derived from the original sale revenue $c_n^s(t)p_n^s(t)$) is checked. If the condition is not satisfied, the sale interval is eliminated from further consideration. In addition, if a sale interval, say interval A, contains the non-profitable interval, it is also eliminated although A itself could be profitable. The rationale is that if A is offered, a purchasing utility might pick the non-profitable interval within A as a legitimate transaction, and the selling utility would suffer a loss. After all non-profitable intervals and intervals containing them are eliminated, the optimal sale levels and durations for the entire planning horizon (for the given set of multipliers) can be determined by using dynamic programming following [4]. Results for checking the profitability when the purchasing level $p_n^b(t)$ is less than the offered level $p_n^{s*}(t)$ are provided in Section IV.

III.3 Difficulties for a Linear Sale Subproblem

If Lagrangian relaxation is used with linear sale revenues as given in (2.1), the optimal sale level $p_n^{s*}(t)$ for an interval equals the maximum offer level $p_n^{s-max}(t)$ when $c_n^s(t) > \bar{\lambda}(t)$, and $p_n^{s*}(t) = 0$ otherwise. The solution of this subproblem therefore oscillates between the minimum and the maximum levels when $c_n^s(t)$ varies around $\bar{\lambda}(t)$. Moreover, the solution is singular if $c_n^s(t)$ equals $\bar{\lambda}(t)$, in which case the optimal sale level can take any value between the minimum and maximum levels, and the subproblem cost is zero. These difficulties are reflected in the high level by the zigzagging of multipliers across different surfaces of the dual function, as described in our previous work [9].

Solutions to thermal, hydro and pumped-storage subproblems are similar to those described in our previous work ([7], [10] and [11]), and will not be repeated here.

III.4 Solving the Dual Problem and Constructing a Feasible Solution

The high level problem is to update the multipliers λ and μ associated with system demand and reserve requirements, respectively. These multipliers are updated by using the modified subgradient method, in which the current search direction is a linear combination of the current subgradient and the search direction of the previous iteration [12]. This search direction forms a smaller angle with the direction pointing towards the maximum, as compared with the direction of the standard subgradient method. This method therefore reduces the zigzagging behavior described earlier and enhances the speed of convergence as reported in [13].

Subproblem solutions may constitute an infeasible schedule, i.e., the demand and reserve requirements may not be satisfied because of the discrete decision variables involved. A heuristic is used to generate a feasible schedule based on subproblem solutions following ([7], [10] and [11]). The sale decisions are not adjusted in the heuristics as they couple across hours and thus are difficult to adjust.

Because of the increasing competitiveness of the power market, utilities will try to lock in on favorable transaction opportunities to maximize their profits/savings. This will result in more flexible transaction options, e.g., smaller minimum transaction hours (possibly with minimum = 1 hour), varying prices and levels from one hour to the next, etc. In such a case, the minimum time requirements and allowable transaction patterns can be suitably modified or even dropped. The problem should still be solvable by using the method (or an extended version of it) presented here.

IV. TESTING RESULTS

The algorithm was implemented in FORTRAN on a SUN Sparcstation 10 for scheduling the power system of Northeast Utilities Service Company (NU). All billing rules of New England Power Pool are satisfied, and many practical considerations are included. There are about 70 thermal units, 7 hydro units and 1 large pumped-storage unit. Four data sets each with 2 to 7 sale contracts were selected from 1993 and 1994 with sale prices and periods modified to examine various test conditions. The system characteristics associated with the data sets are presented in [4].

Testing results are summarized in Table 1. For each data set, the total generation costs with and without sales are listed. The cost savings derived from sale transactions are the difference between sale revenues and the increase in generation cost, assuming that purchasing utilities purchased all the power offered. The duality gap, a measure of the solution quality, is also presented. The few minutes of CPU time indicate that the algorithm is computationally efficient to support sale transactions in almost real time.

TABLE 1. SUMMARY OF TESTING RESULTS

Data sets 1993-94	IT	Time (sec)	Duality Gap (%)	Cost without sales($)	Cost with sales ($)	Savings ($)
Apr w4	39	243.05	1.35	5,416,329	5,392,573	23,756
May w1	33	197.13	0.96	5,417,418	5,415,761	1,657
May w3	37	222.31	1.11	5,787,086	5,646,743	1,40,343
May w4	50	194.76	1.152	6,794,754	6,787,565	7,189

IT : number of high level iterations

Testing results for the May week 4 data set with a few combinations of purchasing levels and durations are summarized in Table 2. It can been seen that the savings are always positive. The sale in row 4 of Table 2 is for a duration that is greater than the minimum time requirement for that load period.

TABLE 2. SUMMARY OF TESTING RESULTS FOR MAY WEEK 4 1994 DATA SET

% Offer Level	% Offer Duration	IT	Time (sec)	Duality Gap (%)	Savings ($)
100%	100%	50	194.76	1.152	27,150
60%	100%	46	234.05	0.992	14,138
30%	100%	42	300.67	0.881	5,466
100%	50%	52	210.91	1.092	16,002

IT : number of high level iterations

In Fig. 2, the sale levels and durations suggested by the algorithm for May week 1, 1993 are depicted. It can be seen that the offer levels are not necessarily at the maximum offer levels or zero, and only part of the sale intervals specified by utility engineers are profitable. The offer levels are also constant across each sale interval, and allowable transaction patterns are complied. To provide some insight behind Fig. 2, marginal costs and sale prices specified by utility engineers are shown in Fig. 3. Table 3 compares the results obtained from the standard Lagrangian relaxation method and the nonlinear approximation method. It can be seen that the costs of the nonlinear approximation method are consistently lower than those of the standard Lagrangian method.

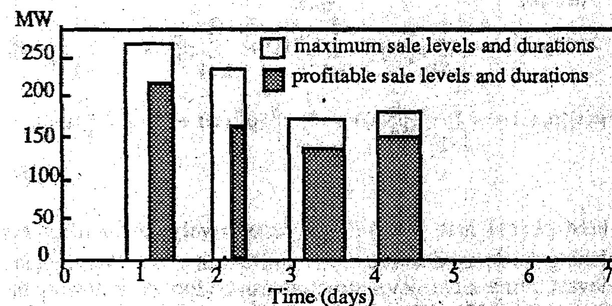

FIGURE 2. SALE LEVELS AND INTERVALS

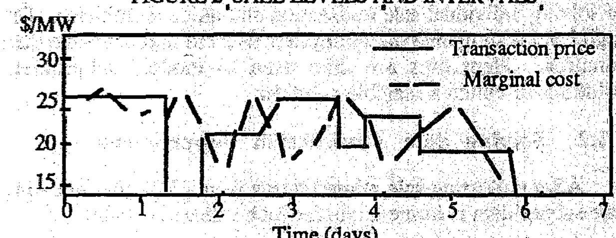

FIGURE 3. MARGINAL COSTS AND TRANSACTION PRICES

TABLE 3. COST COMPARISON OF NA AND SLR METHODS

Data Set	SLR			NA			Savings ($)
	IT	Cost ($)	Sec	IT	Cost ($)	Sec	SLR-NA
Apr W4	60	5,724,159	300	51	5,474,349	260	2,49,810
May W1	51	5,529,484	204	40	5,445,866	217	83,618
May W3	34	5,823,246	161	41	5,700,846	211	1,22,400
May W4	51	6,878,128	211	50	6,831,542	209	46,586

IT : number of high level iterations
Sec : CPU time in seconds on a Sun Sparc 10
SLR : Standard Lagrangian Relaxation Method
NA : Nonlinear approximation Method

The effective use of pumped-storage units is essential to provide competitive sales offers. For another data set of September week 3, 1994, the generation of the pumped-storage unit Northfield is depicted in Figure 4 for two cases: without any transaction and with a sale transaction introduced between hours 105 to 114. For most part, generation and pumping levels are very similar, but the generation levels increase between hours 105 to 114 to reduce the dependence on expensive thermal units. The pond level constraints of NU require that the pond level, which is full at the start of the week, be full again at the end of the week. The extra energy used by the pumped-storage unit for the transaction therefore has to be pumped back at periods with low marginal costs. This is indicated by the higher pumping levels during the weekend (hours 145-165).

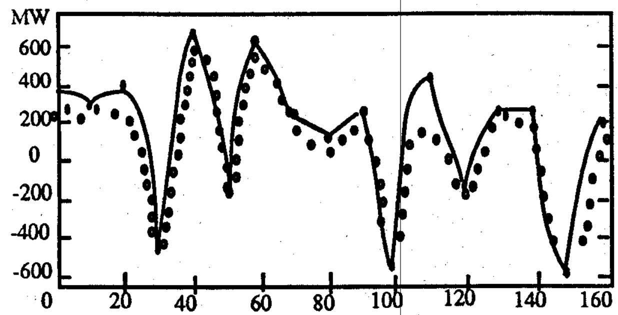

Figure 4. Generation of Pumped-storage unit, Northfield

V. CONCLUSION

An effective algorithm based on Lagrangian relaxation with nonlinear approximation has been developed to solve the integrated sale transaction and hydrothermal scheduling problem. After obtaining sale levels for individual sale intervals, the profitability constraints are used to eliminate non-profitable sale options. The sale solution for the entire planning horizon is then obtained by using dynamic programming. The nonlinear approximation of sale revenues and the modified subgradient method for updating multipliers reduce the solution oscillation difficulties and accelerate algorithm convergence. Testing results show that this algorithm is efficient, and significant savings are obtained from sale transactions. The algorithm will assist NU engineers in making effective sale transaction decisions along with the scheduling of their units.

VI. ACKNOWLEDGMENT

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VIII. BIOGRAPHY

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Lan Zhang received her B.S. degree in Control Engineering from Shaanxi Mechanical Engineering Institute, Xi'an, P. R. China, in 1982, and the M.S. in Electrical Engineering from the University of Connecticut in 1993. Currently, she is with Advanced Control Systems, Norcross, U.S.A.

Discussion

Ji-Yuan Fan (Advanced Control Systems, Inc) :

The authors have presented a very interesting paper by addressing a practical subject for power industry. With the deregulation and the brokerage system being introduced to the power industry, transaction contracts among power utilities will play a more and more important role. Traditionally, power utilities schedule only purchase transactions with given prices, fixed time intervals and known maximum and minimum MW levels while committing their generation units. Unsolicited sale transactions are mostly offered within the base unit commitment environment determined by meeting local load demands. In this paper, the authors attempted to deal with the sale transaction scheduling problem incorporated with unit commitment which appears to be a new concept.

From a technical point of view, scheduling unsolicited sale transactions would be a very challenging task. It requires to determine the transaction time intervals, transaction pricies, maximum and minimum MW levels at each interval by meeting the specified profit margins within reasonable risk indices. Because the time intervals, prices and MW levels can all be decision variables, it can result in several different types of scheduling problems, as listed below:

Type	Price	Interval	MW Level
1	Fixed	Fixed	Open
2	Fixed	Open	Fixed
3	Fixed	Open	Open
4	Open	Fixed	Fixed
5	Open	Fixed	Open
6	Open	Open	Fixed
7	Open	Open	Open

where "Fixed" means the value is given and "Open" means to be determined.

It can be seen from the above table that the first three types schedule the transactions with given prices while the later four involve pricing which may be constrained to meet prespecified profit margins. What the authors has attempted to deal with in the paper is the third type that determines the time intervals and maximum MW levels with given transaction prices. It would be appreciated if the authors can commend the other types, especially the seventh one which would be more interested by power utilities while providing an unsolicited offer.

In addition, the authors have used a decision rule that guarantees the profitability for every MW sale within the offer range. This means that the scheduled sale offer is of zero risk to the sale utility and guarantees from loss of any penny even when a purchase utility may take only a small portion of the offer. From a realistic point of view, an offer based on such a decision rule may be too conservative and may loss a lot opportunities because many possible sales that are quite profitable (if sold) but subject to small risk of loss (if not sold) would have to be eliminated. In other words, any sale offer that needs to commit a new unit associated with a startup cost would be eliminated because it would not be able to guarantee the profitability for every MW sale since a small portion of sale contribution from the unit may not be sufficient enough to make up for the startup cost. As a result, a sale offer based on the zero-risk rule is very likely to be the same one as obtained within the base unit commitment environment that is obtained by solely meeting the sale utility's local load. I would appreciate the authors comments about their experience regarding this concern. It appears to the discusser that it may be more appropriate to set up a decision rule based on risk indices in practice. For instance, if a sale transaction of 100 MWH in an interval has a chance of 70% to be taken that may result in a profit margin of $1/MWH, it would be advantageous to be scheduled, although it has a chance of 30% to loss up to $70 when only a small portion of the offer would be actually taken. Another alternative way to avoid such loss could be simply setting a lower limit MW level for each time interval.

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B. Prasannan, P. B. Luh, H. Yǎn, J. A. Palmberg, and L. Zhang :

We would like to thank the discusser for his comments and questions on this paper. The comments and questions will be answered as follows:

1. As mentioned in the problem formulation, the sale prices are determined by utility engineers with a knowledge of system marginal costs and market information, currently done by adding markup values to the marginal costs of the system without transactions. If the current model is used to determine sale prices as in eq. (2.1), the prices would be as high as possible for maximum profit, making sale subproblems meaningless. A model including the market demand/supply relationship is needed for the sale prices to be decision variables.

2. Regarding the issue of risk analysis, the model described in the paper addresses the present needs of utilities in New England in general, and Northeast Utilities in particular. The profitability constraints are based on the current allowable transaction patterns of New England and are somewhat conservative. When the market becomes more competitive in the future, the allowable patterns will be more flexible. The nonprofitability constraints might still hold, but would base on more flexible patterns. This would create more transaction opportunities than the current model, making the model less conservative. Transactions tailored to meet the requirements of specific buyers and/or with lower bounds on transaction levels can be analyzed by extending the current framework. Risk analysis will gain its importance as the market becomes more competitive, and will be critical when electricity is traded in a commodity-like market. We are not in a position to comment on risk analysis without further investigation.

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