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A SCREENING MODEL FOR LONG RANGE PLANNING AT THE POOL LEVEL

by

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ABSTRACT

This paper develops a multi-period, multi-utility model for analyzing macro effects over extended horizons of 20 to 40 years. Plants are aggregated into categories and lumped at load centers, which may be interconnected by lossy lines. There may be more than one load center per utility. The generation, transmission and operation planning problems for this set of load centers is formulated as a linear programming problem. A decomposition and means-end analysis method is used to solve the problem. The results are useful for analyzing macro effects: generation expansion by plant category; control technology retrofits; changes required in tie line capacities; long term, inter-utility energy exchanges; long term fuel scheduling; and the impacts of bubble constraints for pollutants such as SO₂.

1. INTRODUCTION

The running of a utility involves collaboration with other utilities. Activities contributing to, and factors affecting, these collaborations include

- remote siting and sharing of generating plants.
- inter-utility energy flows.
- bubble constraints on emissions (ceilings on the total emissions produced by the plants in a region that could encompass several utilities). Though such constraints are not now in effect, they are being seriously considered by regulatory bodies and could soon be adopted.

The possibility of collaboration increases the number of alternatives available to planners. For instance, some of the alternatives available to reduce the total SO₂ emissions produced by a utility are: (1) switch to lower sulfur fuels, (2) retrofit the coal burning plants with scrubbers, and (3) purchase energy from other utilities. To determine the optimal mix of these alternatives over an extended time horizon, one needs to simultaneously consider all the utilities that could collaborate over the entire horizon. This, of course, results in a very large optimization problem. To make it computationally tractable, we have adopted the following measures:

- aggregation to reduce the number of variables.
- representation of all the relevant phenomena by linear models so that the overall problem becomes one of linear programming.

- the use of a special decomposition and means-end analysis to solve the linear programming problem (even though linear, the problem is too large to be conveniently tackled by more direct methods).

The net result of this approach is a screening model, that is, a model that provides a comprehensive, but relatively undetailed, view of the activities of multiple, interacting utilities over multiple time periods. The most natural application of the screening model is to power pools because pools are the basic organizational units for promoting interactions among utilities. But the model can also be applied to other groupings of utilities. In fact, since it works off a database that contains information on all the generating units in the continental US, it can be applied to any subset of the generating units.

In function, the screening model is best suited to providing inertia to the activities of utilities. These objectives can be used for high-level decision making or to provide inputs, targets, and guidelines for more detailed planning models that consider only one utility at a time. The alternatives to using screening models are either to treat utilities as if they were independent with no interactions, or to guess the interactions in advance. Neither is an attractive alternative.

The remainder of the paper is organized as follows. Section 2 formulates the linear programming problem. Section 3 describes the decomposition and means-end analysis used to solve the linear programming problem. Section 4 presents an example.

2. FORMULATION OF THE LINEAR PROGRAMMING PROBLEM

2.1. Assumptions

1. The net exports of electrical energy from the group of utilities considered to the rest of the country are known in advance.
2. Operating costs and emissions are linear functions of operating level of generating plants and pollution control technologies.
3. Capital costs for both generating plants and pollution control technologies are linear functions of their sites.
4. Plants are aggregated into 10 categories.
5. Fuel alternatives for each plant category are aggregated into at most 3 categories.
6. Load demand points are aggregated into load centers.
7. Transmission losses between load centers are linear functions of power flow.
8. Retirement years of generating units are known in advance.

2.2. The Model

The multi-period multi-utility planning (MUP) problem is formulated as a linear programming model using aggregated, rather than the individual, plant and fuel categories. Instead of directly solving the problem as a single linear programming problem, which is potentially unmanageable, the problem is handled instead by a heuristic decomposition technique.

The MUP problem is defined as:

Given:

1. A Time horizon divided into several periods.
2. The demand in each utility for each period, given in the form of a load curve.
3. The cost, availability, heating value and pollution content of a set of representative fuels for each utility in each period.
4. The cost* and other characteristics of a limited number of types of generating plants for each utility in each period*
5. The costs, efficiencies and other characteristics of a set of pollution control technologies for each utility in each period.
6. The transmission lines between the utility nodes, their capacities and loss characteristics in each period.
7. The emission caps for individual utilities and/or the emission caps for the whole region (including the many utilities).

Find:

1. The inter-utility energy transfers in each sub-period.
2. The type, timing, size and location (by utility) of generation expansions and pollution control retrofit*.
3. Utility emission caps, if they were not specified in the input. Also, the marginal cost of SO₂ abatement.
4. The types and amounts of the fuels used in each period and each utility.

The problem is formulated as a Linear Programming (LP) problem*

2.3. Notation

The terms used in the linear programming formulation are defined below:

Symbol Description

<u>Indices/Subscripts</u>	
i	Type of generating plant/CT plant
k	Temporary index for time ($k=1$ to t)
m	Segments of the load curve

t	Time period
j	Fuel type (j is removed if no fuel selection is allowed, e.g. nuclear plants)
n	Utility in the region

Generating Plant Characteristics for utility n

C_{in}	Capital cost (\$/MW)
$fuel_{itj}$	Operating cost with fuel type j (\$/MWhr)
P_{in}	Initial plant capacity (MW)
R_{it}	Retired capacity in period t (MW)
AV_{in}	Availability limit
CF_{in}	Capacity factor limit
e_{itjn}	pollution coefficient (tons of SO ₂ /MWhr)

Control Technology Characteristics for utility n

V_{in}	Capital cost of CT type i (\$/MW)
U_{itja}	Operating cost (\$/ton of SO ₂ removed)
X_{in}	Initial CT capacity (MW)
R_{it}	Retired CT capacity in period t (MW)
k_{itjn}	Conversion factor from tons of SO ₂ to MW (MW/ton)

Exogenous Variables

d	Discount Factor
L_{mna}	Segments of load curve (MW) for utility n
h_{ma}	Duration of segment m of load curve (hours)
Th_t	Total hours in period t
η_{trn}	Efficiency of the transmission line between utilities r and n
$E_{max,t}$	Regional emission constraint in period t (tons)

Decision Variables for utility n

P_{in}	Generation addition of type i in period t (MW)
g_{itijn}	Operating level of generating plant i (MW)
x_{in}	CT addition of type i in period t (MW)

τ_{itja} Aetnal CT atifisasio ia period t (tons of SO₂ removed)

O_{mtra} Power outflow from atifty r to atifty a ia segment aLof the load <duration curve

5. CT constraints (CT cannot remove more SO₂ than is produced)

$$\sum_m \theta_{itmjn} k_{mt} e_{itjn} - w_{itjn} \leq 0$$

for all j, i, t, n

1.4. Linear Progmmaiig Formialarioai

The following famalntiim of the MUP problem applies to a region containing N atiftiai aad for an extended planning horizon (typically 20 to 40 year hi length). The horizon is divided into periods and the load curve for each period b divided into segments. Then the total prjint worth of all capital and operating expenses ia all the atifties ia the region b mtmimieH over the horizon te yield:

Minimize

$$\sum_a \left(\sum_i v_{itn} x_{itn} + \sum_j U_{itjn} w_{itjn} \right) + \sum_{ijmj} \theta_{itmjn} k_{mt} f_{itjn} + \sum_i (E_i C_{itn} p_{itn})$$

subject to:

1. Demand constraints (generation should be at least equal to demand):

$$\sum_{i,j} \theta_{itmjn} + \sum_{r \neq n} \theta_{itrn} O_{mtra} - \sum_{r \neq n} O_{mtra} \geq L_{itn}$$

for aO m, t, a

2. Generation constraints (generated power should not exceed power capacity):

$$AV_{in} \sum_{k=1}^i p_{ikn} - \sum_j \theta_{itmjn} \geq AV_{in} \left(\sum_{k=1}^i R_{ikn} - P_{itn} \right)$$

for all i, m, t, a

3. Capacity factor constraints (generated energy should not exceed energy capacity):

$$CF_{in}(Th)_t \sum_{k=1}^i p_{ikn} - \sum_{m,j} k_{mt} \theta_{itmjn} \geq CF_{in}(Th)_t \left(\sum_{k=1}^i R_{ikn} - P_{itn} \right)$$

for all i, t, n

4. CT (Control Technology) constraints (CT usage should not exceed capacity):

$$\sum_{k=1}^i x_{ikn} - \sum_j k_{itjn} w_{itjn} \geq \sum_{l=1}^t T^X * m'$$

for all i, t, n

6. Regional emissions constraints on SO₂:

$$\sum_{n,i,m,j} \theta_{itmjn} k_{mt} e_{itjn} - \sum_{n,i,j} (Emax)_t \leq 0$$

for all t

7. Non-negativity of all variables.

8. Other constraints may be imposed as needed, for instance:

- Upper limits on the regional efficiencies of pollution control technologies.
- Upper limits on the amounts of plants that may be installed in a utility or in the region.
- Upper limits on the amounts of funds that may be needed by a particular utility.
- Upper limits on inter-utility transmission line capacities and availabilities.
- Constraints on SO₂ at the individual utility level.
- Constraints on several other emissions such as NO_x at the utility and/or regional level.

In order to minimize the usual short-period effects (i.e. overstated capital expenditure), it is assumed that, after the final period, the system will operate indefinitely at those levels. To do this, the cost coefficients for the operations variables (x and w) in the final period are multiplied by 1/(1-d).

3. A NEW PROCEDURE TO SOLVE THE MUP PROBLEM

3.1. Overview

Even with the various aggregations and hierarchies, for most realistic applications, the MUP model can be quite large. The size of the problem (the number of variables and number of constraints) is proportional to N²T, where N is the number of utilities in the region, and T is the number of periods in the time horizon. For a representative set of values of N and T (N ≥ 10, and T ≥ 15), the problem becomes very large, and existing LP codes would have trouble solving it in any reasonable amount of time. (The number of constraints would exceed 1000, and the number of variables would exceed 15000.) Therefore, a different solution procedure is developed for the MUP problem.

The MUP problem decomposes, in a natural way, into several single-period problems with the capital variables (generation capacity and CT capacity) being the control variables. That is, with fixed capital variable values, the problem can be divided into several smaller single-period electric power dispatch type problems, in which the plant operating levels and inter-utility flow are the

unknown variables.

A few words about the decomposition are appropriate here. There are several standard ways to decompose an LP problem [1-5]. Unfortunately, the general decomposition methods offer little in the way of improved running time or diminished storage requirements over the various sparse-matrix implementations of the Simplex algorithm. Instead of using one of these, knowledge of the problem and a "means-ends" approach has been used to obtain a new decomposition method.

Using the bounds on the capital variables as controls, the decomposition, for each period,

1. allocates the total generation plant requirements for the region to the individual utilities,
2. allocates the energy generation for the region to the individual utilities (It determines inter-utility energy transfers),
3. and subdivides the regions emission caps among the individual utilities.

In making these allocations and subdivisions, the algorithm takes the inter-utility transmission losses and capacities into account.

Theoretically, it may be necessary to reiterate over the periods until the solutions converge, however, in general no more than one or two iterations ought to be required for a satisfactory solution. Details of the decomposition method follow.

3.2. Assumptions

Following assumptions about the MUP problem have been made when developing a heuristic decomposition method:

1. Electric power demand is expected to increase over time, hence the total million capacity requirements are expected to increase with time.
2. The time horizon of study is generally such that capacity brought online during the period of study will be operable at least until the end of the horizon.
3. The allowable emission limits are expected to decrease (or at least not increase) over time, hence CT capacity requirements are expected to increase with time.
4. The final period of study is a steady utility model, hence it is likely that the profile of capital additions for the solution of just the last period problem would be similar (and in many instances identical) to that for last period portion of the exact solution to MUP.

These assumptions together with other features of the MUP problem suggest the use of a means-end algorithm using the capital variables as the control variables. The algorithm essentially tries to find the optimal capital configuration for the final period (which is a steady-state problem), and works back toward the beginning periods.

3.3. A Decomposition Algorithm

Besides the existing data, such as present capacities, demands, variable costs, and emission limits, the inputs to each of the single-period problems are the various capital costs and upper and lower bounds on the variables corresponding to new capital construction. These capital variables refer to total new capacity that is online

during that period, which may be both during or before the final period. Hence a capital variable \bar{p}_{it} (the subscript i referring to utility i and t referring to the disbursement) refers to all new capital construction of type i in the periods up to and including t . It is the bounds and costs for these variables that are the main control for the dynamic programming algorithm.

Before proceeding with the steps of the algorithm, let us examine how the bounds and costs for the variables are computed. For the final period problem (which is to be solved first), the lower bounds are all 0 and the upper bounds are maximum amount of generation capacity that can be added for all the periods. For example, in a ten period problem, if 1000 MW can be added in each period, the upper bound would be 10000 MW. The cost for the capital variable would simply be the discounted cost of construction in the final period. For any other period, t , the upper bound is the minimum amount of generation that can be built up to and including that period and the value of $\bar{p}_{i,t+1}$, the amount online in the next period. The lower bound is the minimum amount of capacity that can be constructed in period $t+1$ alone. For example, if $\bar{p}_{i,t+1}$ were equal to 7500, and the maximum amount of construction allowed in period $t+1$ were 1000, then $\bar{p}_{i,t+1}$ would be 6500, for if less than 5500 MW were constructed in period t , then it 7500 could not be constructed by period $t+1$. These bounds are derived from the minimal conditions for feasibility of capital additions. The cost for the capital variables is given by the discounted cost of construction in period t minus that for period $t+1$. That is, $\bar{p}_{i,t+1}^j$ is the amount of new capacity online in period $t+1$, and $\bar{p}_{i,t}^j$ is the cost of bringing the capacity online one period earlier.

The decomposition algorithm used to solve the MUP problem is as follows:

- STEP 0. (Initialization) Set $t = T$ (the final period).
- STEP 1. Compute the costs and upper and lower bounds for the capital variables (as above).
- STEP 2. Solve the single-period problem for period t . Save the values of the capital variables.
- STEP 3. Set $t = t - 1$. If $t = 0$, Stop. Otherwise go to STEP 1.

In general, the algorithm yields a near-optimal solution to the MUP problem, in a very reasonable time. It is possible to modify the algorithm to incorporate multiple passes in time, modifying the bounds on the capital variables using information from previous passes and the current pass. It is also possible, and not very difficult, to test for optimality for the entire problem using the dual variables for the capital upper bound constraints for the single-period problems.

3.4. Single Period Problem Formulation

A formulation of the single-period problem follows:

For each period t ,
Minimize

$$\sum_n \{ (\sum_i (\bar{c}_{it} p_{it} + \sum_{i,m,j} \theta_{itjm} h_{mt} f_{itjm} + \sum_i (\bar{v}_{it} p_{it} + \sum_j U_{itjm} w_{itjm})) \}$$

subject to:

1. Demand constraints (generation should be at least equal to demand):

$$\sum_{i,j} \theta_{ijm} + \sum_{r \neq n} \eta_{trn} O_{mtrn} - \sum_{r \neq n} O_{mtrr} \geq L_{mtn},$$

for all m,

2. Generation constraints (generated power should not exceed power capacity):

$$AV_{in} P_{itn} - \sum_j \theta_{ijm} \geq AV_{in} \left[\sum_{k=1}^t R_{ikn} - P_{itn} \right],$$

for all i, m, a

3. Capacity factor constraints (generated energy should not exceed capacity):

$$CF_{in}(Th) P_{itn} - \sum_{m,j} h_{mj} \theta_{ijm} \geq$$

$$CF_{in}(Th) \left[\sum_{k=1}^t R_{ikn} - P_{itn} \right],$$

for all i, a

4. CT (Control Technology) constraints (CT usage should not exceed capacity):

$$z_{itn} - \sum_j k_{ijm} w_{ijm} \wedge \sum_{k=1}^t T_{ikm} X_{itn} \leq 0,$$

for all i, a

5. CT constraints (CT cannot remove more SO₂ than is produced)

$$\sum_m \theta_{ijm} h_{mj} e_{ijm} - w_{ijm} \leq 0$$

for all j, i, t, a

6. Regional emissions constraints on SO₂:

$$\sum_{n,i,m,j} \theta_{ijm} h_{mj} e_{ijm} - \sum_{n,i,j} w_{ijm} \leq Em_{n,t}$$

7. Non-negativity constraints on all variables, and

$$P_{i,t,n} \leq P_{i,t+1,n}$$

for all i, n, and for t < T

8. Other constraints may be imposed as needed, for instance:

- Upper limits on the removal efficiencies of pollution control technologies.
- Upper limits on the amounts of plant capacities that may be installed in the utility or the region.
- Upper limits on the amounts of funds that may be used by a particular utility.
- Upper limits on inter-utility transmission line capacity and availability.
- Constraints on SO₂ at utility level.
- Constraints on several other emissions such as TSP and NO_x at utility and/or regional level.

The special notation used here that is different from that in the formulation in Section 2 is:

$$P_{itn} = \sum_{k=1}^t p_{ikn}, \text{ for all } i$$

$$z_{itn} = \sum_{k=1}^t z_{ikn}, \text{ for all } i$$

$$\bar{C}_{itn} = C_{i,t,n} - C_{i,t+1,n} d^{t+1}/d^t, \text{ for } t < T$$

$$\bar{V}_{itn} = V_{i,t,n} - V_{i,t+1,n} d^{t+1}/d^t, \text{ for } t < T$$

The solution procedure is implemented using the XMP linear programming package [6].

4. AN EXAMPLE

In this section, we present some of the results obtained from a study of seven utilities. Such results are at least as sensitive to the input data as they are to the methodology. Our objectives here are to illustrate the sort of output the MUP methodology can generate. We have neither the space to present all the input data nor to comment on its accuracy. Therefore, we will not identify the utilities involved.

Information on the existing and announced generating rates for the utilities were obtained from the Unit Inventory File [7] that has been compiled for all the rates in the U.S. under another part of the project that supported this work. Much of the information on costs and characteristics of fuels and control technologies was also obtained from databases and models developed for this project. The remainder of the input information, particularly on emissions ceilings and demand growths and demand shapes is conjectured.

The basic problem consists of seven utilities interconnected by lossy lines over a time horizon of 20 years that are divided into 10 periods (5 1-year periods, 2 2-year periods, 2 3-year periods, and one 5-year period) using a 2% per annum demand growth. The basic groupings or pools (defined by the transmission lines) are utilities A, C, D, and G comprising one pool and B, E, and F comprising the other, with C also pertaining to the second pool. The demand load curves used were typical 3-segment load duration curves. The energy demands used for the seven utilities during the first period were approximately 12, 8, 12, 3, 24, 20, and 20 1000 GWhrs/Year. Since one of the reasons for power transfers

is differing peak times, and that using load duration curves instead of a skyline curve implies simultaneous peaking, the solution can be expected to be biased toward peaking units. (I.e. the peak-shaving that power transfers can accomplish are not reflected in this example.)

Results of two runs are summarized below. The first is with an allowable emission level that is binding only during the final period; the second uses a 30% lower level that becomes binding during the final three periods. The differences in answers occur only during the final three periods (11 years) of the study. The only generation capacity added during the first 7 periods were those that were already scheduled (i.e. the model did not predict the need for other additions).

The net power transfers for four of the first seven periods are given in Table 4-1. Nuclear facilities were scheduled to come on line between 1985 and 1987 for utilities A and F, and this accounts

Table 4-1: Inter-Utility Power Transfers—First Seven Periods

Net Power Export GwHrs/Year				
Utility	1985	1987	1989	1993
A	350	4090	3000	2827
B	-2624	-5010	-3821	-719
C	-5149	-5935	-6448	-4008
D	552	159	292	84
E	4281	3000	2745	955
F	-1258	2630	1546	-12
G	4057	1410	2368	1011

for the change in the transfer patterns during those periods. Utilities B and C were scheduled to have coal units come on line for the 1993 period, and this accounts for most of the pattern change there.

Table 4-2: Inter-Utility Power Transfers—Final Three Periods

Loose Pollution Standard			
Net Power Export GwHrs/Year			
Utility	1996	1999	2004
A	2221	4469	2126
B	-1675	-2152	-432
C	-2443	-251	-23
D	-102	-199	149
E	2481	2351	-221
F	-998	-3135	673
G	277	-783	-2228

Tight Pollution Standard			
Net Power Export GwHrs/Year			
Utility	1996	1999	2004
A	2221	2623	2126
B	-1539	-2016	-432
C	-2793	93	-98
D	-102	-311	149
E	2702	3362	-221
F	-998	-3135	673
G	673	-428	-2152

Tables 4-2 and 4-3 summarize the inter-utility transfers and generation additions, respectively, for the last three periods of the two runs. Even though four different generation technologies were permitted, (natural gas, oil, nuclear, and coal), only natural gas (for a peaking unit) and coal (for a base unit) were selected by MUP. The differences in the generation additions for the two runs are slight. Utility A brings on 17 more MW of peak capacity earlier for the tighter emission standard case, and utility C builds slightly less coal and more peak for the tighter emission case.

Table 4-3: Natural Gas/Coal Accumulative Additions MW

Loose Pollution Standard			
Utility	1996	1999	2004
A	0/0	354/0	474/0
B	0/0	119/0	119/446
C	0/0	670/0	670/625
D	0/0	21/0	156/0
E	0/0	0/0	0/1469
F	0/0	0/0	0/1323
G	0/0	517/0	517/0

Tight Pollution Standard			
Utility	1996	1999	2004
A	0/0	337/0	474/0
B	0/0	119/0	119/446
C	0/0	687/0	687/606
D	0/0	21/0	156/0
E	0/0	0/0	0/1469
F	0/0	0/0	0/1323
G	0/0	517/0	517/0

The differences in flows for the two examples can be explained primarily in terms of existing non-polluting generating units that were basically uneconomical to dispatch for the loose emission constraint case, but became useful when the emission standard became tighter, raising the marginal cost of power. This occurred for utility E, and to a lesser extent, utilities B, C, and G, for periods 8 and 9 (years 1996 and 2004). In the final period, these units were utilized for both runs. It is this that accounts for utility A's difference in exported power in 1999 (utility E replaced A for exports to some extent).

5. CONCLUSIONS

A tractable model for multi-utility planning has been developed using deterministic data. It is also possible to include some uncertainties that are common to electrical power generation problems. The sorts of uncertainties that are important can be included through another heuristic and chance constrained programming.

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