ROLLING HORIZON METHOD: A NEW OPTIMIZATION TECHNIQUE FOR GENERATION EXPANSION STUDIES

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Abstract - This paper presents a new method called Rolling Horizon Method which is used to optimize expansion strategies for electric generation systems. The method allows planners to investigate the sensitivity of expansion plans to different look-ahead periods and derive financial objectives which best combines short-term and long-term benefits.

INTRODUCTION

Three classical questions addressed in generation planning are:

1) When to add a new generating unit: 1989, 1990, 1991, or 1992?

2) What type to add: Nuclear, coal, oil, or hydro?

3) What size to add: 50, 100, 200, or 500 megawatts?

From these three basic questions come a spectrum of associated questions like:

- What will happen if gas escalates at 15 percent instead of 12 percent?
- Is load management an economical strategy for delaying future capacity addition?
- What is the cost to a utility system if all coal units are required to have scrubbers?

The task of generation planners is to design optimal expansion strategies, i.e. strategies which minimize the total system cost while satisfying the required reliability, financial and environmental constraints. Generation planning decisions are in general not so much binary decisions in the sense they require yes or no answers, as they are trade-off decisions. For instance, in sizing units, planners have to trade off economy of scale against availability. In deciding which type of unit to build -- peaking, intermediate or baseload -- they have to trade off capital costs against operating costs. Optimization techniques allow automatic evaluation of trade-offs, leading to a solution which best harmonizes different competing objectives.

Time plays a crucial role in trade-off evaluations. The answer to the question, "What is best?", depends on the financial objectives of a utility -- does the company want to minimize costs over the next year, or over the next ten years, or instead over the next twenty years?

Optimization programs currently used by electric utilities perform either:

- A year-by-year optimization where the system is optimized one year at a time. In the year in which the optimization is made, no information is known about the future. Year-by-year optimizations usually favor the installation of peaking units -- units which have low capital cost, but high fuel costs;
- A year-by-year optimization with static look-ahead: the system is again optimized one year at a time, but this time a static estimate of the future is made, and information is fed to the optimization logic for trade-off calculations. A commonly made assumption for the static projection is that generating units operate at constant capacity factor throughout the look-ahead period. Programs which use this optimization technique can capture part of the information which is important in making generation planning decisions like cost escalation rates. But system characteristics which are dynamic in nature like load growth, or unit immaturity, or shift in order of unit dispatch, or changes in generating mix are still not taken into account in the decision making process.
- A global optimization: the system is optimized over the entire planning period which is usually twenty or thirty years, and the expansion plan which minimizes the present worth of the total system costs over the planning period is selected. Global optimization programs usually select large baseload units which have high capital costs, but low operating costs, penalizing the system over the short-term in order to obtain long-term benefits.

This paper presents a new optimization method, known as the Rolling Horizon Method. This method offers several benefits:

1) The method is highly flexible. By properly setting two parameters --length of dynamic look-ahead period and length of static look-ahead period, the planner can perform any of the three kinds of optimization described earlier: year-by-year optimization, year-by-year optimization with static look-ahead, and global optimization.

2) The method can perform dynamic optimization with intermediate look-ahead periods. The use of intermediate look-ahead periods, five or six years in the future for instance, allows the planner to derive expansion strategies which:

- achieve reasonably good long-term benefits without taking severe short-term penalties, and
- are less vulnerable to errors in long-range data forecasts.

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3) The method allows planners to investigate for the first time the sensitivity of proposed expansion plans to different financial objectives. From this analysis, planners can recommend to their management financial objectives which best combine short-term and long-term benefits.

ROLLING HORIZON METHOD

Problem Statement

Consider a utility system with load and capacity characteristics shown in Figure 1. Assume that the planning period starts in the current year (year 1) and extends twenty years in the future. Figure 1 shows three curves:

- Curve A projects annual peaks for the twenty-year planning horizon.
- Curve B shows capacity requirements to meet reliability constraints.
- Curve C shows actual installed capacity. This amount slightly fluctuates throughout the planning period as new committed units are added and old existing units are retired.

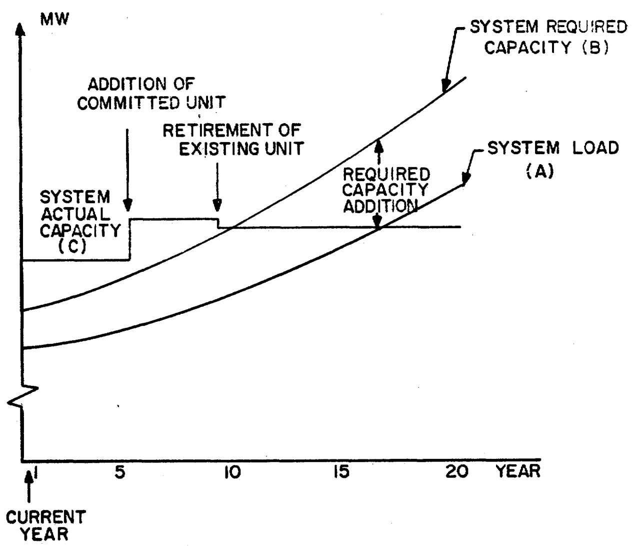


Figure 1. Load and Capacity Requirements

The hypothetical system described in Figure 1 has enough existing and committed generation to serve load until year 10. Starting in year 11, however, new capacity is needed. Because of the long lead-time to build generating units a planning decision needs to be made now in order to have new machines on line by year 11.

The task of generation planners is to evaluate different alternatives to expand the system and from this evaluation, recommend the best expansion strategy to management. The economic analysis normally proceeds as follows:

1) Make up a shopping list of unit addition candidates.

2) Use static breakeven curve analysis to screen out obvious poor candidates.

3) Use optimization program to derive optimal expansion plan.

4) Perform sensitivity analysis to study sensitivity of proposed plan to changes in key input parameters like load growth, fuel cost, and capital cost.

This paper proposes a new optimization method to perform step number three.

Algorithm

A flow-chart of the Rolling Horizon Method is shown in Figure 2.

1) The user selects:

- L_D = length of dynamic look-ahead period. In the dynamic look-ahead period the optimization logic recognizes annual changes in system characteristics like load growth, capacity retirement, capacity addition, shift in unit dispatch, and maturation of new units.
- L_S = length of static look-ahead period. A snapshot of the system is taken in the first year of the static look-ahead period. The operating characteristics of the system are assumed to remain the same throughout the static look-ahead period. Costs, however, are allowed to escalate.

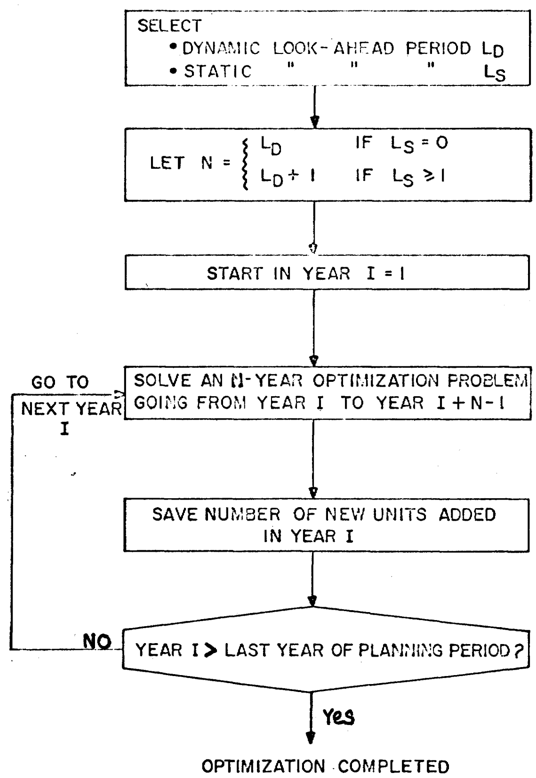


Figure 2. Flow Chart Describing Logic of Rolling Horizon Method

Figure 3 shows dynamic and static look-aheads for the first planning horizon. Year 1 to year 6 constitute the dynamic look-ahead period during which changes in system load and capacity are explicitly taken into account in trade-off calculations. Year 7 to year 14 constitute the static look-ahead period during which load and capacity are 'frozen'.

2) To derive the optimal expansion plan for the planning period, the program solves P N-year optimization subproblems where:

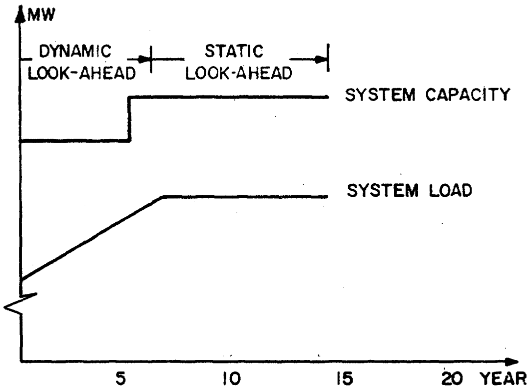


Figure 3. Look-Ahead Periods for First Planning Horizon

P = Number of years in planning period

$$N = \begin{cases} L_D & \text{if } L_S = 0 \\ L_D + 1 & \text{if } L_S \geq 1 \end{cases}$$

During the static look-ahead period, generating units are assumed to operate at constant capacity factor. By multiplying fuel and operation and maintenance costs of units by the factor F shown in Equation 1, we reduce a L_S-year production costing problem to a one-year production costing problem.

$$F = \sum_{M=0}^{L_S - 1} (1+E)^M = \frac{(1+E)^{L_S} - 1}{E} \qquad (1)$$

where E = escalation factor for fuel cost or or operation and maintenance cost

L_S = length of static look-ahead period

3) Start with the first rolling horizon; I=1.

4) Solve an N-year optimization problem going from year I to year I+N-1.

The objective function is:

$$\mathrm{Min}\left[\sum_{M=I}^{I+N-1} (FC(M) + VC(M))\right] \qquad (2)$$

where FC(M) = present worth of system fixed costs in year M

VC(M) = present worth of system variable costs in year M

5) Save IU(I, J), number of new units of type J which are added in year I.

6) If we reach the last year of the planning period, exit. Otherwise, go to step 4 and optimize the next planning horizon.

NUMERICAL EXAMPLE

Used as a test system is Utility E, a synthetic utility which represents a typical power company in the Texas-Oklahoma region. In 1980, Utility E has 31 generating units totaling 8500 megawatt in capacity. As shown in Table I, Utility E has a large block of generation burning gas -- 53 percent. 19 percent is nuclear capacity, 19 percent burn coal, and the remaining 9 percent is oil generation.

TABLE I. Characteristics of Utility E in 1980

System size: 8500 MW
Number of Units to dispatch: 31

Quantity	Unit Size (MW)	Unit Description	Heat-Rate (BTU/KWh)	Outage Rates Forced (%)	Outage Rates Scheduled (%)
2	800	Nuclear, Steam	10,400	15	9.6
3	600	Gas, Fossil	9,400	15	5.8
11	200	Gas, Fossil	10,050	7	5.8
2	600	Coal, Fossil	8,900	21	7.7
1	400	Coal, Fossil	9,000	13	7.7
10	50	Gas, Turbines	14,000	24	3.8
2	400	Oil, Fossil	9,400	13	7.7

From a generation planning point-of-view, Utility E is a very interesting case study because the company is currently operating on an unoptimal generating mix. The utility has too much peaking capacity, not enough baseload capacity. It is interesting to use the optimization approach to investigate the following questions:

- What can management of Utility E do to correct the current unoptimal mix?
- If addition of baseload capacity is the recommended solution, how fast should baseload units be brought on line?
- Is it economical for Utility E to have an overbuilding in baseload capacity?
- What is the optimal size for future unit additions?

The shopping list adopted for this sample study consists of four unit addition candidates: 50-megawatt combustion turbines, 200-megawatt, 400-megawatt, and 600-megawatt coal units (see Table II).

System peak load is 7000 megawatt in 1980 and is growing at 3 percent annually. To meet the pool reliability constraint, Utility E is required to maintain a 15 percent reserve.

Five expansion plans were developed for Utility E, corresponding to a dynamic look-ahead ahead of one, two, three, four, and 20 years, and a zero static look-ahead. Analysis of the results which are summarized in Tables III and IV lead to the following conclusions:

1) The answer to the question, "What constitutes an optimal expansion plan?", depends on a utility's financial objectives. When the utility is optimizing over the short-term, the economics call for the addition of small-size, peaking units. As the utility extends its look-ahead period and wants to capture long-term benefits, the economics favor the addition of large-size, baseload units. For Utility E, for instance, the optimal plan derived with a one-year look-ahead calls for the addition of 17 50-MW combustion turbines, 6 200-MW coal units, and 6 600-MW coal units while the optimal plan derived with a twenty-year look-ahead asks for 1 50-MW combustion turbine, 1 200-MW coal unit and 9 600-MW coal units.

2) Increasing the look-ahead period from one to twenty years saves Utility E 711 million dollars in total system costs over the twenty-year planning period. This represents a 3.9 percent savings in the total system revenue requirements.

3) As the look-ahead period increases, overbuilding of baseload capacity occurs, bringing baseload units on line before they are needed for reliability purposes. Figure 4 shows three curves:

TABLE II. Unit Addition Candidates

Unit Type	Size (MW)	First Year of Availability	Heat Rate (BTU/KWh)	Immature Outage Rates: Forced (%)	Immature Outage Rates: Scheduled (%)	Mature Outage Rates: Forced (%)	Mature Outage Rates: Scheduled (%)	Immature Period	Capital Cost ($/kW, 1980$)	Fixed O&M Cost ($/kW 1980$)	Maximum Number of Additions Per Year
Combustion Turbine	50	1985	14,000	10	3.8	9	3.8	2	207	2	3
Coal	600	1986	8,000	19	13.0	12	9.6	3	800	14	1
Coal	400	1986	9,000	17	13.0	11	9.6	3	860	16	1
Coal	200	1986	9,500	14	11.0	9	8.0	3	920	18	1

TABLE III. Optimal Installation Schedules for Utility E for Five Different Look-Ahead Periods

	NUMBER OF YEARS IN LOOK-AHEAD PERIOD														
	ONE			TWO			THREE			FOUR			TWENTY		
Year	50 MW CT	600 MW Coal	200 MW Coal	50 MW CT	600 MW Coal	200 MW Coal	50 MW CT	600 MW Coal	200 MW Coal	50 MW CT	600 MW Coal	200 MW Coal	50 MW CT	600 MW Coal	200 MW Coal
1980	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1982	0	1	0	0	1	0	0	1	0	0	1	0	0	1	0
1983	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1985	0	1	0	0	1	0	0	1	0	0	1	0	0	1	0
1986	0	0	0	2	0	0	0	0	0	0	0	0	0	1	0
1987	1	0	1	3	0	0	0	1	0	0	1	0	0	1	0
1988	1	0	1	0	1	0	0	0	0	0	0	0	0	1	0
1989	3	0	1	0	0	0	0	1	0	0	1	0	0	1	0
1990	2	0	1	0	1	0	0	0	0	0	0	0	0	1	0
1991	2	0	1	0	0	0	0	1	0	0	1	0	0	0	0
1992	3	0	1	0	1	0	0	0	0	0	1	0	0	0	0
1993	0	1	0	2	0	0	0	1	0	0	0	0	0	1	0
1994	2	0	0	0	1	0	2	0	0	0	1	0	0	0	0
1995	0	1	0	2	0	0	0	1	0	0	1	0	0	0	0
1996	3	0	0	0	1	0	0	1	0	0	0	0	0	0	0
1997	0	1	0	0	1	0	0	0	0	1	0	0	1	0	0
1998	0	1	0	0	0	0	0	1	0	1	1	0	0	1	0
1999	0	0	0	0	1	0	3	0	0	3	0	0	0	0	1
Totals	17	6	6	9	9	0	5	9	0	5	9	0	1	9	1

TABLE IV. Costs of Optimal Expansion Plans for Different Look-Ahead Periods

Number of Years in Look-Ahead Period	System Costs (10^6\$, 1980 Present Worth Dollars): Fixed	Variable	Total
1	4168	14871	19039
2	4248	14451	18699
3	4528	13996	18524
4	4678	13807	18485
20	5391	12937	18328

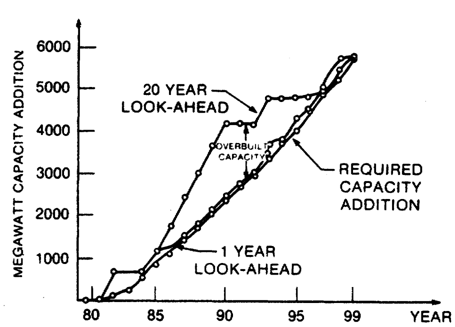
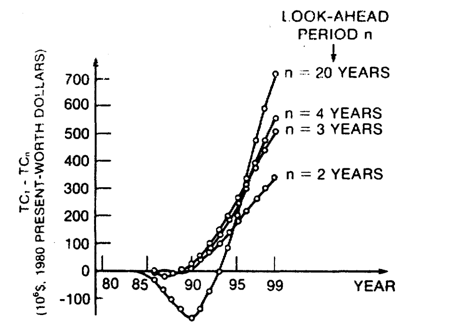


Figure 4. Optimal Versus Required Capacity Addition

- The bottom curve plots new capacity requirements for meeting the 15 percent reserve.
- The middle curve shows the megawatt addition for the plan which is derived with a one-year look-ahead.
- The top curve shows the megawatt addition for the plan which is derived with a twenty-year look-ahead.

Examination of the curves shows that the plan using a one-year look-ahead adds just enough capacity to meet the reliability requirement while the plan derived with a twenty-year look-ahead exhibits overbuilding. The amount of overbuilt capacity starts at zero in 1986, reaches a maximum of 1850 megawatts in 1990, and decreases back to zero in 1997. Early construction of baseload units brings production cost savings, but increases capital cost requirements.

4) The use of long look-ahead periods penalizes the system over the short-term, in order to realize long-term financial benefits. Figure 5 compares year-by-year the total cost of a plan derived with a n-year look-ahead with the cost of the plan derived with a one-year look-ahead. The figure shows that in the middle years, the cost of a plan derived with a n-year look-ahead is higher than the cost of a plan derived with a one-year look-ahead. For instance, the twenty-year look-ahead strategy costs more than the one-year look-ahead strategy from 1986 to 1993. In the worst year, which is 1990, the use of the twenty-year look-ahead period results in an increase in total revenue requirements of 175 million dollars.



TC_n = CUMULATIVE PRESENT-WORTH OF SYSTEM TOTAL COSTS OF EXPANSION PLAN DERIVED WITH A n-YEAR LOOK-AHEAD

Figure 5. Savings in Total Costs

5) Increasing the length of the look-ahead period accomplishes diminishing returns. As shown in Figure 6, the 711 million dollars which were saved from going from a short look-ahead of one year to a long look-ahead of twenty years are distributed as follows:

- 340 million or 48 percent when the look-ahead period is increased from one to two years.
- 175 million or 25 percent when the look-ahead period is increased from two to three years.
- 99 million or 5 percent when the look-ahead period is increased from three to four years.
- 157 million or 22 percent when the look-ahead period is increased from four to twenty years.

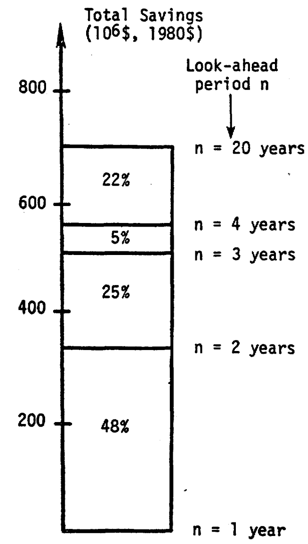


Figure 6. Breakdown of Total Savings

6) From the results of the sensitivity analysis, management of Utility E can rationally select a look-ahead period which best harmonizes short-term and long-term benefits. When economic conditions are unstable and key input data like load growth or cost escalation rates are hard to predict for the distant future, the use of intermediate look-ahead periods is highly recommended because it reduces the vulnerability of the optimal plan to errors in forecast data.

CONCLUSIONS

This paper presents a new technique for optimizing expansion strategies of electric generation systems. Advantages of the new technique are:

- The technique is highly flexible. By properly adjusting two parameters -- dynamic and static look-aheads -- the planner can perform any of three conventional optimizations: year-by-year optimization, year-by-year optimization with static look-ahead, and global optimization.
- The method can be used to determine proper look-ahead periods which best meet short-term and long-term financial goals of a utility.
- The method can perform dynamic optimizations using intermediate look-ahead periods. The use of intermediate look-ahead periods protects the planner from errors in data which are forecast for the distant future and insures an expansion plan which has near-term payoffs.

REFERENCE

[1] "Synthetic Electric Utility Systems for Evaluating Advanced Technologies," EPRI Report EM-285, Electric Power Research Institute, Palo Alto, CA, February, 1977.