

Industry Tools Description

In these notes, we desire to describe a little better how the EGEAS and Promod programs operate. First, however, we distinguish between sequential optimization and co-optimization for generation and transmission.

1. Sequential vs co-optimization of gen/trans

We have seen where MISO utilizes EGEAS to identify the type and amount of each generation technology. Promod is then utilized to study transmission solutions and perform cost allocation. It is important to notice that this approach identifies generation and then transmission, i.e., it solves the generation/transmission planning in two successive steps. It does not co-optimize generation and transmission planning. Essentially, the MISO process

- forecasts generation (with EGEAS) and then
- designs transmission (with Promod and other tools).

The process described by Mr. Stevens of MidAmerican Energy Company (MEC), although obviously different from the MISO process in many respects, was similar in that it also did not co-optimize the generation and transmission planning. Essentially, the MEC process

- forecasts transmission (with various data) & then
- designs generation (with Strategist, similar to EGEAS).

You should note that neither EGEAS nor Promod allows for co-optimization of transmission and generation, but, as Part B of the project suggest, Plexos does. Whether MISO or MEC would use this capability or not is questionable, since neither organization actually has authority to design (make decisions on) *both* generation and transmission (each organization *forecasts* the decisions of others for one, and designs the other).

Yet, the fact that neither organization designs both is due to industry structure; it is not due to an engineering reason why both should not be designed together. In fact, from a strictly engineering point of view, they *should* be designed together, as a co-optimized design of dependent systems always achieves an equal or better objective than when the systems are separately optimized.

One qualification here is that, because of the complexity of the generation/transmission planning problem, it may be very difficult to develop a single software application that can fully perform such co-optimization. For example, it may be too computational to expect an optimizer to account for constraints imposed by dynamic security, thus necessitating the need to perform a first-stage optimization that is refined in a second stage.

2. EGEAS

We provide an overview of EGEAS in Section 2.1, adapted from [1], and then we discuss the approaches implemented in EGEAS in Sections 2.2, 2.3, and 2.4.

2.1 Overview

The EGEAS computer model was developed by researchers at MIT under funding from the Electric Power Research Institute (EPRI). EGEAS can be run in both the expansion optimization and the production simulation modes. Uncertainty analysis, based on automatic sensitivity analysis and data collapsing via description of function estimation, is also available. A complete description of the model can be found in [2].

The production simulation option consists of production cost/reliability evaluation for a specified generating system configuration during one or more years. Probabilistic production cost/reliability simulation is performed using a load duration curve based model. Customer load and generating unit availability are modeled as random variables to reflect demand fluctuations and generation forced outages. Two algorithmic implementations are available: an analytic representation of the load duration curve (cumulants) and a piecewise linear numerical representation.

2.2 Screening Curve Approach

This is the simplest of the available options, which allows preliminary screening of planning alternatives overlooking intertemporal cost-benefit interactions and system reliability contributions of the various possible investments. Total costs during the operating life of planning alternatives are discounted and plotted against capacity factor values. The resulting “screening curves” provide a quick comparison of investment alternatives, allowing dominated alternatives to be identified and excluded from further consideration.

The screening curve method expresses the total energy production cost for a generating unit, including all capital and operating expenses, as a function of the capacity factor for the period of interests Annual time periods are generally used for screening curve studies, but other period lengths are possible. The following equation defines the cost curves of interest for this approach:

$$\$/\text{MWhr} = \frac{\text{Annual Fixed Cost } (\$/\text{MW})}{(8760 \text{ hrs}) \times \text{Cap Factor}} + \text{Var Costs } (\$/\text{MWhr})$$

where the Annual Fixed Cost is obtained from the overnight investment cost via the capital recovery factor:

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1}$$

We assume $i=0.10$ and $N=40$ years for all technologies.

Let's develop screening curves for the data given in the project. Note I assumed oil-fired plant is very cheap to build. It is probably not so cheap.

Technology	Variable Cost Data					Fixed Cost Data	
	Heat Rate Mbtu/MWhr	Fuel Cost \$/Mbtu	Emission Rate lb CO ₂ /Mbtu	Var Cost @ 0\$/lbs CO ₂	Var Cost @ \$50/lb CO ₂	Investment Cost \$/MW	Annual, 40 year life \$/kW
Nuclear	10.4	0.75	0	7.8	7.8	2475000	28.89178661
Pulverized Coal	9.2	1.8	215	16.56	66.01	1534000	17.90707097
NGCC	7.5	8	117	60	81.9375	706000	8.241455089
CT	10.8	8	117	86.4	117.99	500000	5.836724567
Wind	0	0	0	0	0	1434000	16.73972606
Oil	10.1	12	162	121.2	162.105	N/A	5.836724567
IGCC	8.765	1.8	199	15.777	59.382875	1733000	20.23008735
IGCC w/CarbSeq	10.781	1.8	20	19.4058	24.7963	2537000	29.61554045
Solar	0	0	0	0	0	5649000	65.94331416

Figure 1 shows screening curves for a 0-dollar carbon tax. The vertical axis is \$/MWhr and the horizontal axis is capacity factor.

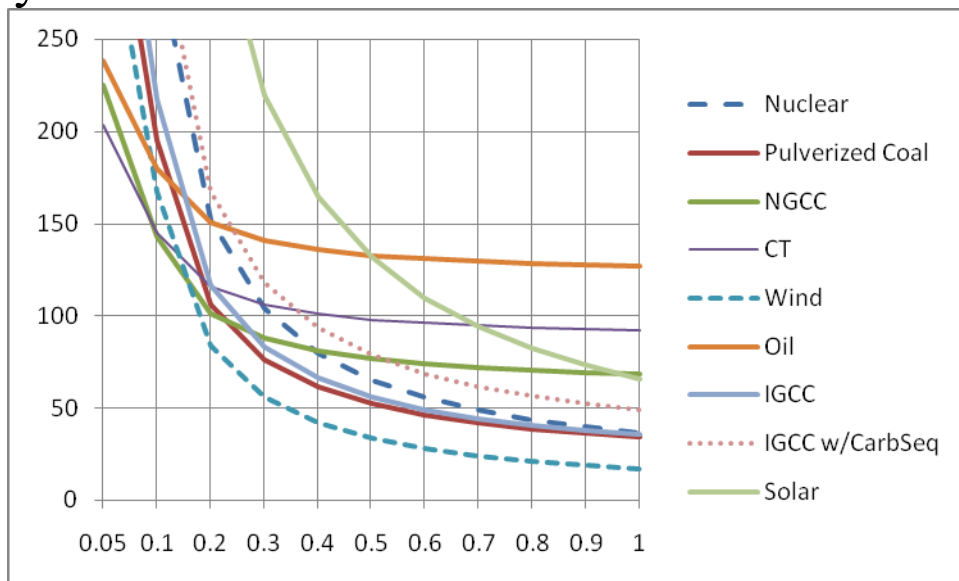


Fig. 1: \$0 carbon tax

Figure 2 shows screening curves for a \$50/ton carbon tax.

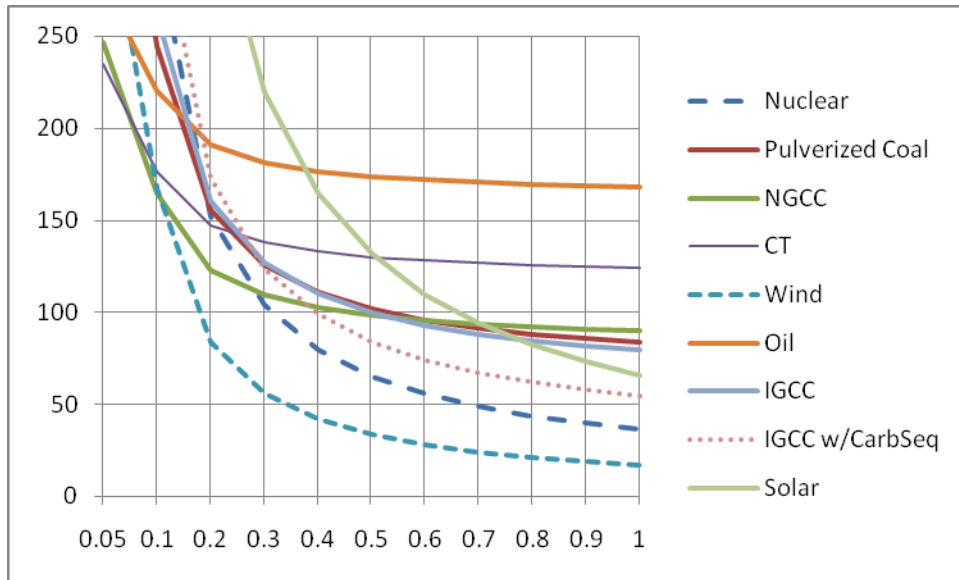
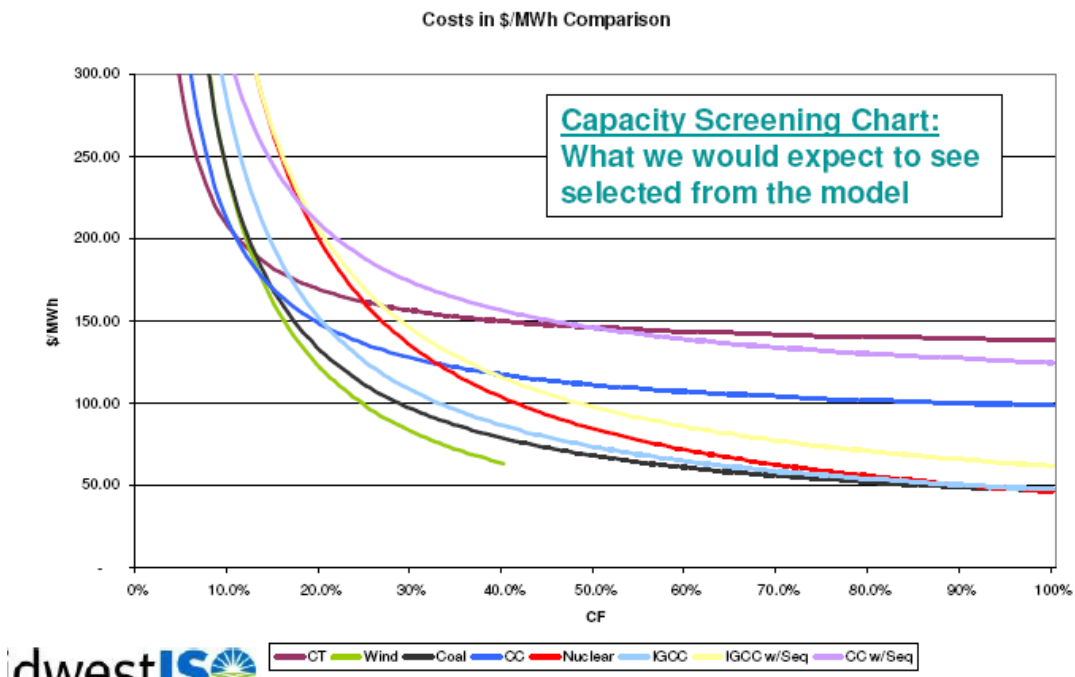
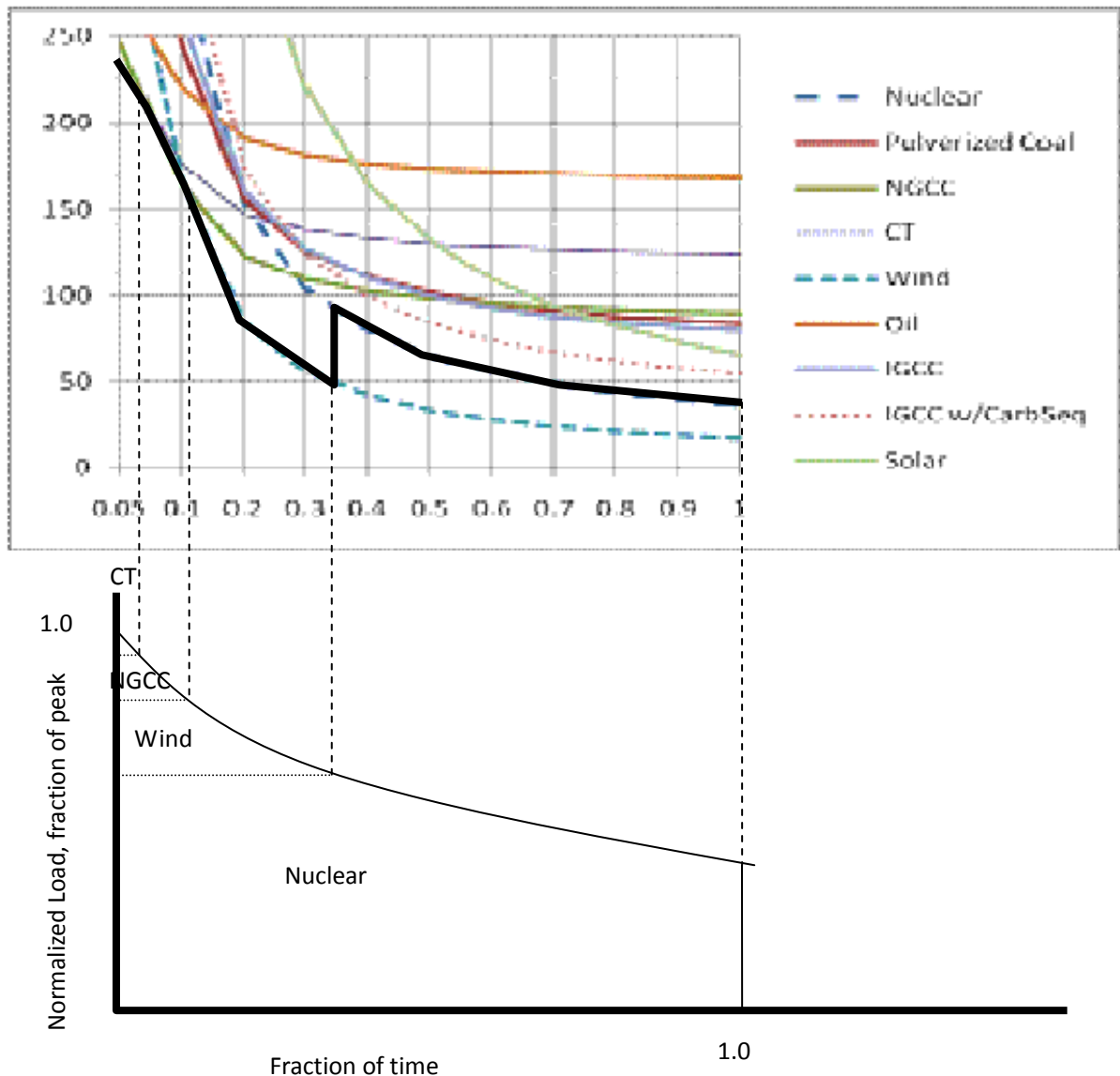


Fig. 2: \$50/ton carbon tax

The screening curves may be used together with an annualized load duration curve to identify the energy to be supplied by each technology, assuming there are no other influences beyond those accounted for in the screening curves, as shown in Fig. 3. These curves should be compared to the one that MISO showed us, below.





Screening curve analysis is not an adequate substitute for detailed production cost or expansion planning analysis since forced outages, unit sizes, intermittency, system reliability (including portfolio diversity) are not treated directly with screening curves, and others. A good discussion of strengths and weaknesses of screening curves is in [1, chap 10].

2.3 Generalized Benders (GB) Decomposition Approach

This is a non-linear optimization technique incorporating detailed probabilistic production costing.

- It is based on an iterative interaction of a simplex algorithm master problem with a probabilistic production costing simulation subproblem.
- After a sufficient number of iterations, non-linear production costs and reliability relationship are approximated with as small an error bound as desired by the user.
- It is computationally more efficient than the dynamic programming EGEAS option but produces optimal expansion plans consisting of fractional unit capacity additions.
- It resolves correctly among planning alternative unit sizes, and it models multiple units correctly in terms of expected energy generated and reliability impacts.
- System reliability constraints are modelled according to the probabilistic criterion of expected unserved energy.
- It is suitable for analyses involving thermal, limited energy and storage units, non-dispatchable technology generation, and certain load management activities.
- A unique capability of the GB option is the estimation of incremental costs to the utility

associated with meeting allowed unserved energy reliability targets. This capability replaces reliability constraints by an incremental cost of unserved energy to consumers.

- Finally, the GB option has not been developed in its present form to model interconnections or subyearly period production costing/reliability considerations.
- End effects are handled by an extension period model.

The formulation of the generating capacity expansion planning problem follows, adapted from [3].

$$\text{minimize}_{\underline{X}, \underline{Y}_1, \dots, \underline{Y}_T} Z = \underline{C}'\underline{X} + \sum_{t=1}^T EF_t(\underline{Y}_t) \quad (1)$$

$$\text{subject to } EG_t(\underline{Y}_t) \leq \epsilon_t \quad t = 1, \dots, T \quad (2)$$

$$0 \leq \underline{Y}_t \leq \delta_t \underline{X} \quad t = 1, \dots, T \quad (3)$$

- \underline{X} = vector of plant capacities, X_j Megawatts (MW) (decision variable);
- j = unique index for each plant;
- \underline{C} = vector of plant present-value capacity costs, C_j \$/MW;
- \underline{Y}_t = vector of plant utilization levels in period t , Y_{it} MW (decision variable);
- i = merit order position of plant in period t ;
- $EF_t(\underline{Y}_t)$ = present-value expected operating cost function in period t ;
- $EG_t(\underline{Y}_t)$ = expected unserved energy function in period t ;
- ϵ_t = desired reliability level in period t , measured in expected MWhr of demand not served;
- δ_t = matrix which selects and sorts plants, indexed by j , into merit order, indexed by i , in period t ;
- T = number of periods (years) in planning horizon.

In this formulation it is assumed that the capacities of all plants are decision variables in order to simplify the notation; however, existing plants of given capacity can be incorporated.

The objective function (1) consists of two components, the capacity costs of the plants and the expected operating costs of the system over the planning horizon.

The constraint (2) represents the reliability standard of the system.

The constraint (3) requires that no plant be operated over its capacity.

Associated with this capacity planning problem there is, for each period t in the planning horizon, an operating subproblem which results from fixing the plant capacities X at trial values.

There is one such subproblem for each period t in the planning horizon and the load duration functions, the operating cost coefficients, and the merit order all depend on the period. The index t has been suppressed below for clarity of notation.

The general subproblem has the following form:

$$\text{minimize}_{Y^1, \dots, Y^I} EF(\underline{Y}) = \sum_{i=1}^I F^i p_i \int_{U^{i-1}}^{U^i} G_i(Q) dQ \quad (4)$$

$$\text{subject to } EG(\underline{Y}) = \int_{U^I}^{\infty} G_{I+1}(Q) dQ \leq \epsilon \quad (5)$$

$$0 \leq Y^i \leq X^i, \quad i = 1, \dots, I \quad (6)$$

- i = index of plant in merit order;
- I = number of plants;
- Y^i = utilization level of i^{th} plant, MW (decision variable) (component of vector \underline{Y});
- X^i capacity of i^{th} plant, MW (regarded as fixed in the operating problem) (component of the vector $\delta_t \underline{X}$);
- F^i = operating cost of i^{th} plant, \$/MWhr;
- $p_i = 1 - q_i$ = availability of i^{th} plant; q_i = FOR of i^{th} plant;
- G_i = equivalent load duration function faced by i^{th} plant;
- U^i = cumulative utilization of first i plants in merit order (U^{i-1} is the loading point of the i^{th} plant).

The plant loading points are defined by

$$U^i - U^{i-1} = Y^i, \quad i = 1, \dots, I \quad \text{and} \quad U^0 = 0. \quad (7)$$

Equation (4) is a sum over each units production cost, where individual unit production cost was designated in previous notes (eq. (25) of 9/30/08 notes) as $C_j(E_j) = b_j E_j$,

$$E_j = TA_j \int_{x_{j-1}}^{x_j} F_{D_e}^{(j-1)}(\lambda) d\lambda$$

where $F_{D_e}^{(j-1)}$ is the equivalent load duration curve seen by the j^{th} unit, and

$$x_j = \sum_{i=1}^j C_i, \quad x_{j-1} = \sum_{i=1}^{j-1} C_i$$

state the same thing as eq. (7).

This model assumes linearity of the capacity costs with size and of the operating costs with output. In reality, capacity costs for constructing power plants generally exhibit economies of scale and plant operations have decreasing marginal costs at low output levels and increasing marginal costs as output approaches capacity.

The capacity expansion planning problem (1)-(3) can be written in equivalent form as a two-stage optimization

$$\text{minimize}_{\underline{X} \geq 0, \underline{X} \in \Omega} \left\{ \underline{C}'\underline{X} + \sum_{t=1}^T \left[\begin{array}{l} \text{minimum}_{\underline{Y}_t \geq 0} EF_t(\underline{Y}_t) \\ \text{subject to } EG_t(\underline{Y}_t) \leq \epsilon_t, \underline{Y}_t \leq \delta_t \underline{X} \end{array} \right] \right\}$$

where the optimization within the inner brackets is just the operating subproblem (4)-(6). The set Ω consists of all capacity vectors \underline{X} which allow a feasible solution in each of the subproblems.

In addition to [3], Bloom published a number of other papers addressing his work on applying Benders decomposition to the expansion planning problem. These include

- Reference [4]: This paper describes methods of including power plants with limited energy (e.g., hydro) and storage plants in the production costing convolution algorithm we have studied, for use in a Benders decomposition formulation of the expansion planning problem where the production costing problem is the subproblem, and there is one for each period of the planning horizon.
- Reference [5]:
- Reference [6]:

I have posted a set of notes that describe Benders decomposition for a mixed integer linear programming (MILP) problem. The concepts apply here as well. I will discuss these in more depth in the next class.

2.4 Dynamic Programming (DP) Approach

This is the most sophisticated and robust capacity expansion option in EGEAS and is based on an enumerative method of possible capacity additions and a standard dynamic programming technique for selecting the optimal path over the years of the planning period. Like the GB option, it utilizes detailed probabilistic production simulation. It produces a cost-minimizing expansion plan consisting of whole-unit-planning alternative installations. Whole-unit capacity addition is

its main advantage over the GB option. It is suitable for analysis of thermal, limited energy and storage units, non-dispatchable generation and certain types of load management. Computational requirements impose a restriction on the number of planning alternatives analysed simultaneously not to exceed five in each year of the planning period. The DP option is thus more effective for detailed analyses following prescreening performed with the other EGEAS options.

In addition to GB option capabilities, the DP option is suitable for incorporating interconnections, subyearly period production costing, and maintenance scheduling. Shortcomings of the DP option compared to the GB option are inability to produce incremental reliability constraint costs and possible inaccuracies in estimating immature availability rates. Finally, the DP option models reliability constraints in terms of reserve margin as well as probabilistic criteria including LOLP and expected unserved energy. End effects are handled in the same way as other options, through an extension period following the planning period.

3. Promod

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- [1] International Atomic Energy Agency, "EXPANSION PLANNING FOR ELECTRICAL GENERATING SYSTEMS: A Guidebook," 1984.
- [2] ELECTRIC POWER RESEARCH INSTITUTE, Electric Generation Expansion Analysis Systems — Vol. 1: Solution Techniques, Computing Methods, and Results, Rep. EPRI EL-256K1982).
- [3] J. Bloom, "Solving an Electricity Generating Capacity Expansion Planning Problem by Generalized Benders' Decomposition," Operations Research, Vol. 31, No. 1, January-February 1983.
- [4] J. Bloom and L. Charny, "Long Range Generation Planning With Limited Energy And Storage Plants, Part I: Production Costing," IEEE Transactions on Power Apparatus and Systems, Vol. -PAS-102, No. 9, September 1983, pp 2861-2870.
- [5] J. Bloom and M. Caramanis, "Long-Range Generation Planning Using Generalized Benders' Decomposition: Implementation and Experience," Operations Research, Vol. 32, No. 2, March-April, 1984.
- [6] J. Bloom, "Long-Range Generation Planning Using Decomposition and Probabilistic Simulation," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 4 April 1982.