# Co-optimization

## 1 Introduction

Many of you are familiar with the basic electricity market operation which maximizes the economic surplus of the market, where the surplus may be loosely thought of as the difference between the aggregate willingness to pay for the commodity (energy) and the aggregate cost of supplying that commodity. A simple analytic statement of this problem is below:

$$\min \sum_{k\in\{generator\_buses\}} s_{gk} P_{gk} + \sum_{k\in\{load\_buses\}} - s_{dk} P_{dk}$$

Subject to:

$$\underline{P} = \underline{B}'\underline{\theta}$$
$$\underline{P}_B = (\underline{D}\times\underline{A})\times\underline{\theta}$$
$$-\underline{P}_{B,\max} \le \underline{P}_B \le \underline{P}_{B,\max}$$
$$0 \le P_{dk} \le P_{dk,\max}, \forall k \in \{load\_buses\}$$
$$0 \le P_{gk} \le P_{gk,\max}, \forall k \in \{gen\_buses\}$$

where

- $s_{gk}$ is the price offered in \$/puMWh from generator k
- $P_{gk}$, a decision variable, is the generation in puMW at bus k
- $s_{dk}$ is the bid made in \$/puMWh from demand k
- $P_{dk}$, a decision variable, is the demand in puMW at bus k
- $\underline{P}$ is the $N\times 1$ vector of nodal injections in puMW: $P_j=P_{gj}-P_{dj}$
- $\underline{B}'$ is the so-called "B-prime" matrix which is the negative of the imaginary part of the network's admittance matrix $\underline{Y}$, i.e.,

  $$\underline{B}' = -\mathrm{Im}\{\underline{Y}\}$$

  The B-prime matrix here must be $N\times N$, i.e., it must have dimension equal to the number of buses in the network.
- $\underline{\theta}$ is the $N\times 1$ column vector of bus angles, in radians.

- $\underline{P}_B$ is the $M \times 1$ column vector of branch flows in puMW; branches are ordered arbitrarily, but whatever order chosen must also be used in constructing $\underline{D}$ and $\underline{A}$.
- $\underline{D}$ is an $M \times M$ matrix having non-diagonal elements of zeros; the diagonal element in row $k$, column $k$ contains the negative of the susceptance of the $k^{th}$ branch.
- $\underline{A}$ is the $M \times N$ *node-arc incidence matrix*. It is also called the adjacency matrix, or the connection matrix.

We could also write this problem with fixed demand, i.e., with the $P_{dk}$'s specified and therefore no longer a decision variable. In that case, the problem is just a cost-minimization problem. In either case, the problem is an optimization problem, and not a co-optimization problem, because there is only a single resource being optimized – the MWh.

But this problem actually over-simplifies today's electricity market engines because it does not account for reserves. The simplest approach to account for reserves reformulates as follows:

$$\min \sum_{k\in\{generator\_buses\}} s_{gk} P_{gk} + \sum_{k\in\{load\_buses\}} - s_{dk} P_{dk} + \sum_{k\in\{generator\_buses\}} r_k P_{rk}$$

Subject to:

$$\underline{P} = \underline{B}' \underline{\theta}$$
$$\underline{P}_B = (\underline{D} \times \underline{A}) \times \underline{\theta}$$
$$-\underline{P}_{B,\max} \le \underline{P}_B \le \underline{P}_{B,\max}$$
$$0 \le P_{dk} \le P_{dk,\max}, \forall k \in \{load\_buses\}$$
$$0 \le P_{gk} + P_{rk} \le P_{gk,\max}, \forall k \in \{gen\_buses\}$$
$$\sum_{k\in\{gen\_buses\}} P_{rk} \ge RR$$

where $P_{rk}$ is the reserve at bus k, $r_k$ is the offered price of those reserves, and RR is the system reserve requirement.

This is a case of co-optimization because there are two different interdependent commodities (or resources) that are being optimized in the same problem. These commodities are energy and reserves. Energy cannot supply the reserve requirement and reserves cannot supply the energy requirement. Yet, the amount of energy that an agent (generator) provides sets a constraint on the amount of reserves that it can simultaneously provide, and vice-versa.

As an aside, we mention that the co-optimization of the electricity market actually coordinates at least[1] two different kinds of reserves: regulating reserves and contingency reserves (and the two combined are sometimes referred to as operating reserve). Figure 1 [1] below illustrates.

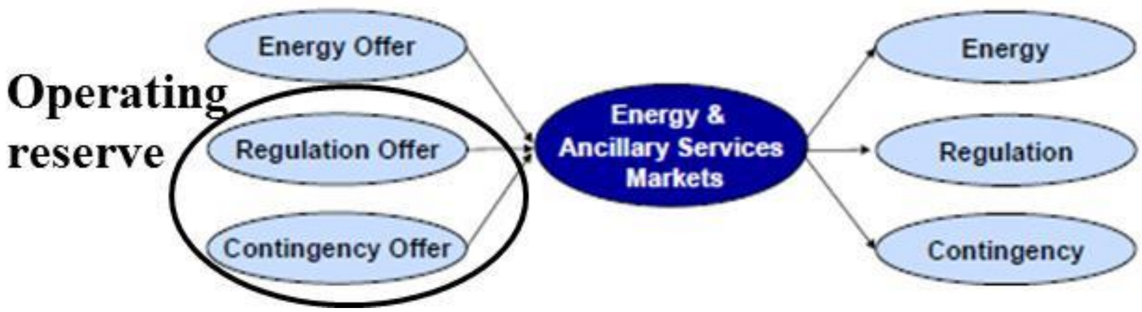



**Figure 1: Cooptimization within electricity markets**

With this introduction, we may proceed to propose a formal definition for co-optimization, as follows:

*Co-optimization is the simultaneous optimization of two or more different yet related resources within one optimization formulation*.

[1] Ramping reserves may be a third type in some electricity markets.

Co-optimization optimizes two (or more) objectives which depend on different but related decisions, as expressed in the following generalized co-optimization formulation.

$$\min f_1(\underline{x}) + f_2(\underline{y})$$

subject to:

$$\underline{g}(\underline{x}, \underline{y}) \geq \underline{0}$$

**P-CO**

There are three important observations to be made of the above problem:

1. Form of objective: The objective function consists of two (or more) functions, with each being dependent on a unique set of decision variables.
2. Interdependence: The two (or more) groups of decision variables are interdependent through the constraints.
3. Comparison to multi-objective optimization: Co-optimization is not the same as what is referred to as a multi-objective optimization. In multi-objective optimization, the objective functions depend on the same decision variables. Thus, a multi-objective optimization problem might appear as

$$\min \left\{ f_1(\underline{x}), f_2(\underline{x}) \right\}$$

subject to:

$$\underline{g}(\underline{x}) \geq \underline{0}$$

A standard multi-objective problem has *conflicting* objectives, i.e., when $\underline{x}$ is changed so as to improve $f_1$ (make $f_1$ smaller in this case), then $f_2$ degrades (gets larger in this case). Thus, the issue in multi-objective optimization is to select $\underline{x}$ to achieve the best tradeoff between the different objectives. The security-economy tradeoff problem is like this: we redispatch away from the most economic point to be secure, i.e., we choose operating condition $\underline{x}$ to minimize cost ($f_1$) but then redispatch from there to lower risk ($f_2$), necessarily incurring higher costs. Figure 2 illustrates [2].

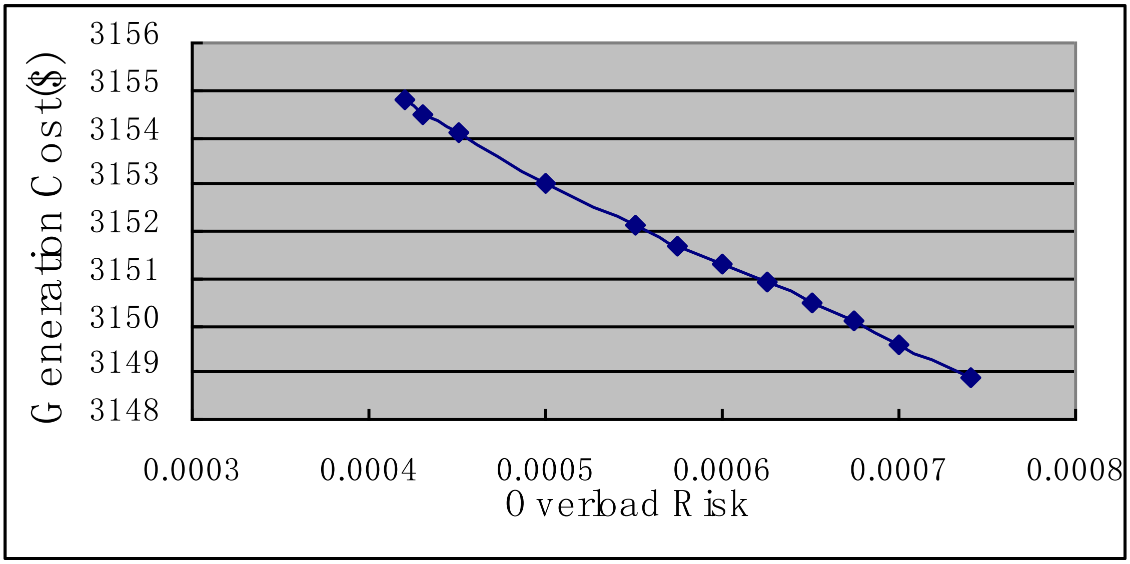



**Figure 2: A Pareto-optimal tradeoff curve of electric grid operational costs and risk**

In contrast, a cooptimization problem does not necessarily see a plus and minus tradeoff like this, i.e., it is possible that an increase in one objective $f_1(x)$ may result in either an increase or a decrease in another objective $f_2(y)$. Cooptimizing generation and transmission is like this. Building more generation x, increases $f_1(x)$, and connecting that generation may also incur more transmission y, increasing $f_2(y)$. On the other hand, building generation x close to the load may require high generation cost $f_1(x)$ and zero transmission cost $f_2(x)$; increasing the transmission cost $f_2(y)$ to reach remotely located but cheap generation may in this case reduce the generation cost $f_1(x)$.

There are two other co-optimization problems of interest which we briefly describe in this introduction.

### *1.1 Generation and transmission*

The first problem we describe is the co-optimization of both generation and transmission. In the past, planning was done by first solving the GEP problem and then the TEP problem, after which the planning effort concluded. This approach can be extended to an iterative approach, which is an approximate way of performing co-optimization, and finally, it can be done most effectively using a single analytical optimization. These three approaches are illustrated in Figure 3.

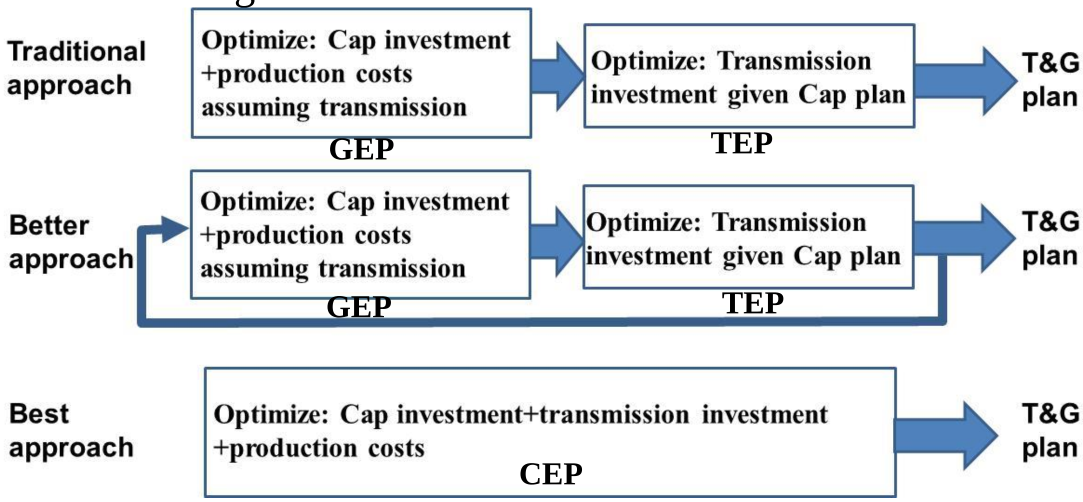



**Figure 3: Three GEP/TEP planning approaches**

To describe the iterative approach, we utilize the nomenclature of the co-optimization problem posed above as P-CO, with $\underline{x}$ representing the generation decision variables and $\underline{y}$ representing the transmission decision variables.

1. Let k=1
2. Choose transmission solution $\underline{y}_k$. Usually, we choose the solution to be the existing topology with lines having infinite capacity.
3. Solve the following GEP problem:

$$\min f_1(\underline{x})$$

subject to:

$$\underline{g}(\underline{x}, \underline{y}_k) \le \underline{0}$$

P-CO1

Denote the solution as $\underline{x}_k$.

4. Solve the following TEP problem.

$$\min f_2(\underline{y})$$

subject to:

$$\underline{g}(\underline{x}_k, \underline{y}) \le \underline{0}$$

P-CO2

Denote the solution as $y_{k+1}$

5. Check for convergence; if not converged, k=k+1; return to 3.

Experience with this approach indicates that it typically converges, though convergence is not guaranteed [3].

Unlike this traditional electric systems planning approach, where generation and transmission investment are typically identified in sequence (usually generation, then transmission), a co-optimized approach identifies them simultaneously. We formulate such a problem in the next section.

Figure 4 illustrates a typical decision problem that could be solved by a generation/transmission co-optimization where we observe the top figure has low capacity factor (CF) wind but located close to the load. The middle figure shows wind modeled both close to and remote from the load, with the total number of wind turbines being less than in the top figure (wind energy production is the same or higher; generation cost is less), but the transmission cost to reach the remote wind is significant. The bottom picture shows all wind located remotely, which further decreases the number of wind turbines necessary to build, but there will be increased transmission cost to handle the capacity of all the remote wind.

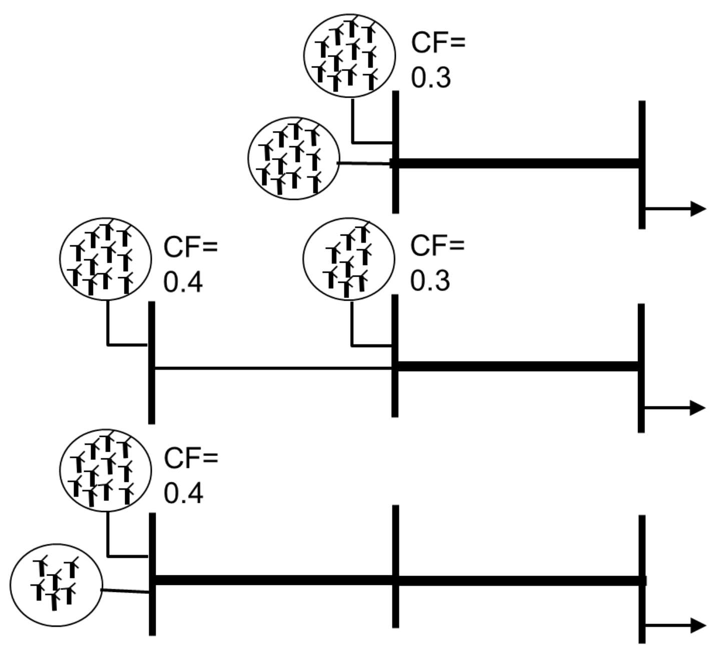



**Figure 4: Co-optimization of electric generation & electric transmission**

### *1.2 Generation, transmission, and natural gas*

The second problem we want to identify is the natural gas and electric co-optimization problem. The basic form of this problem would be as follows:

$$\min f_1(\underline{x}) + f_2(\underline{y}) + f_3(\underline{z})$$

subject to:

$$\underline{g}(\underline{x}, \underline{y}, \underline{z}) \geq \underline{0} \qquad \boxed{\text{P-CO3}}$$

Here, x̲ represents the generation decision variables, y̲ represents the transmission decision variables, and z̲ represents the natural gas pipeline decision variables. The nature of this problem is illustrated in Figure 5.

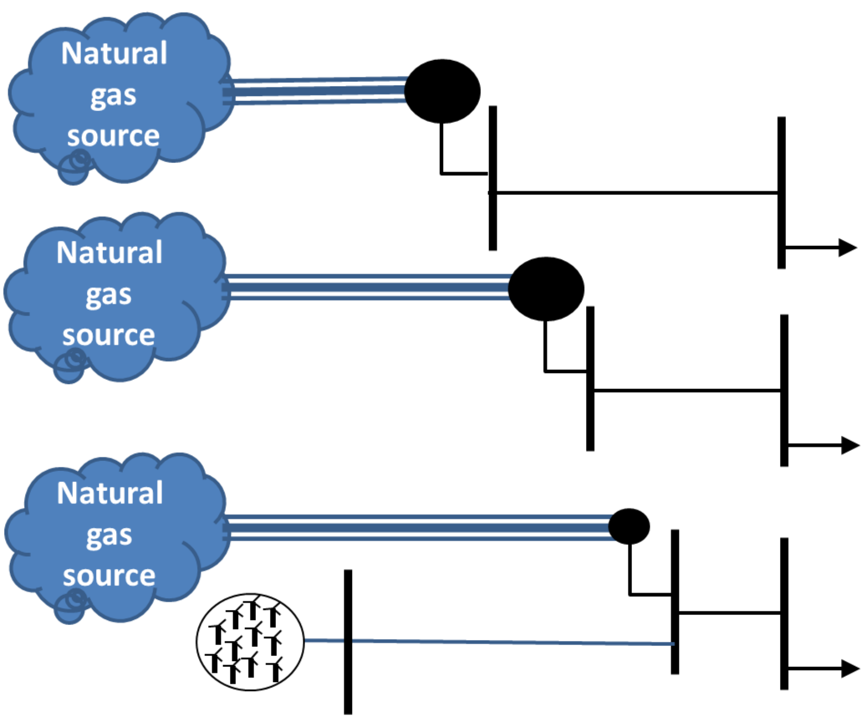



**Figure 5: Co-optimization of electric generation, electric transmission, and natural gas pipeline**

The top figure of Figure 5 shows a design that is all natural gas generation placed so that the lengths of pipeline and transmission line are about the same. The middle figure of Figure 5 shows a design that is all natural gas generation placed so that the length of pipeline is significantly greater than the length of transmission line. The bottom figure of Figure 5 shows a design where the natural gas generation is reduced, the reduction compensated by wind, with the length of natural gas pipeline being much greater than the length of transmission to the natural gas, but additional transmission is required in order to connect the wind. Wind capacity factor increases with distance from the load. Co-optimization is able to sort through all combinations of generation (x), transmission (y), and natural gas pipelines (z) in order to identify the least-cost solution, illustrated by the yellow point in Figure 6.

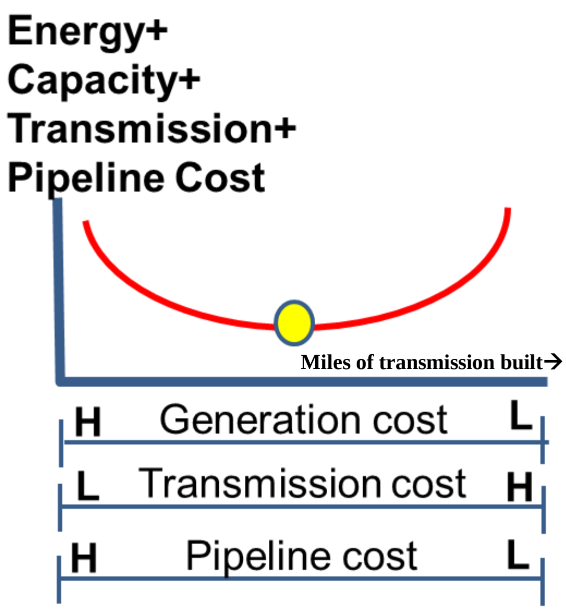
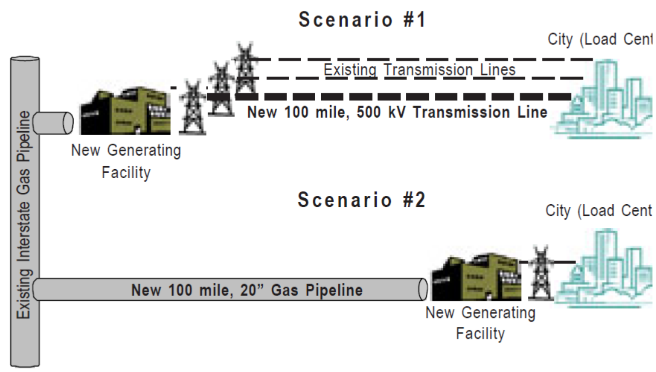



**Figure 6: Illustration of co-optimized solution**

Of course, real situations are more complex, although these simple examples well-serve to illustrate basic concepts. One study made a similar comparison, as indicated in Figure 7 [4]; though dated, it shows clearly that building pipeline is significantly less expensive than building electric transmission, an attribute that is still very true today.

**Scenario #1**
Build 100 miles of new 500 kV electrical transmission line to deliver the energy from a 1500 MW electrical generation facility located remote from the load center. Energy is then delivered to customers through existing electric wireline distribution systems.

**Scenario #2**
Build 100 miles of new 20” gas pipeline to fuel a 1500 MW electrical generation facility located near the load center. Energy is then delivered to customers through existing electric wireline distribution systems.




**Capital Cost Breakdown**

| Scenario #1 (cost per mile): 500 kV Wire Line Addition (1500 MW Generation) | | Scenario #2 (cost per mile): 20” Pipeline (250 MMcf) | |
|---|---|---|---|
| Material, design & construction | $1,300,000 | Material, design & construction | $617,500 |
| Environmental and land | $338,000 | Environmental and land | $148,500 |
| Upgrade at existing substation | $32,500 | Road and railroad crossings | $40,000 |
| New substation at generator | $152,750 | Mainline valve | $14,000 |
| Communications equipment & fiber | $130,000 | Internal inspection tool (Pig) launcher and receiver | $5,000 |
| Voltage stabilizing equipment (shunt capacitor) | $45,500 | Compression installed | $179,000 |
| **TOTAL CAPITAL COSTS** | **$1,998,750** | **TOTAL CAPITAL COSTS** | **$1,004,000** |

**Assumptions** (Scenario #1):
*Typical line segment length 50 miles*
*Varied terrain and ownership*
*New substation at generator*
*Upgrade (2-breaker bay addition) at existing substation*
*Shunt capacitor addition per 100 miles of wire line*
*Line loss excluded*

**Assumptions** (Scenario #2):
*Average environmental and land conditions*
*Road and railroad crossings every 5 miles*
*Mainline valve every 15 miles*
*Two pig launcher and receiver sets*
*Two compressor stations totaling 9,400 horsepower installed*
*Fuel use for compression excluded*

**Figure 7: Comparison of 2 different transmission/pipeline designs [4]**

# 2 Co-optimization formulation

We have developed only one co-optimization in the below notes; we could develop a series of models in a fashion similar to that done in introducing GEP. The different formulations will be referred to as co-optimization expansion planning (CEP) problems, denoted as Models CEP1, CEP2, ....

## *2.1 Simple CEP statement*

The simplest statement of the CEP problem is a single-period, multi-area formulation; transmission must (of course) be represented in order to consider transmission expansion. The fact that we must represent transmission also means we cannot model just a single area, i.e., the model must be multi-area. We must also represent transmission with limits; otherwise, we cannot know whether we need to build additional transmission. To obtain this, we adapt GEP-9 of GEP.pdf and the TEP model described in Section 2.3 of the notes TransmissionPlanningOptimization.pdf. We call this model CEP1. Some preliminary comments for this CEP1 follow:

1. Notation: Notation for the parts of the model originating with GEP9 has generally remained consistent with the GEP9 notation. Exceptions include:
    a. Load blocks: The GEP9 model included a variable *s* to enable the use of multiple load blocks. This modeling has been neglected here to maintain as much simplicity as possible, so only one load block is modeled. As a result, the duration parameters $h_s$ have all been replaced with *T*, and all summations over *s* have been collapsed. In particular, the constraint (7a) in GEP9 (which is an energy constraint accounting for capacity factors across all load blocks), becomes ineffective, as the constraint on capacity credit (4c) will generally be more constraining. One can see this as follows:

       Constraint (4c) is $0 \le P_{i,j,s} \le CC_{i,j,s} Cap_{i,j} \qquad \forall i, j, s$.

       but with only 1 load block becomes

       $$0 \le P_{i,j} \le CC_{i,j} Cap_{i,j} \qquad \forall i, j \qquad \text{(i)}$$

       Constraint (7a) is:

       $$\sum_s P_{i,j,s} h_s \le CF_{i,j} Cap_{i,j} \sum_s h_s \qquad \forall i, j$$

       but becomes (with only one load block):

       $\rightarrow P_{i,j} T \le CF_{i,j} Cap_{i,j} T \qquad \forall i, j \rightarrow P_{i,j} \le CF_{i,j} Cap_{i,j} \qquad \forall i, j$ (ii)

       Because CC<CF, constraint (i) must be more constraining than (ii).
    b. Transmission: The notation used in GEP9 for transmission has been replaced by notation used in the TEP model of Section 2.3 of the TEP notes).

2. Transmission model: The form (and most notation) of the TEP disjunctive equations came from Section 2.3 of the TEP notes (which is similar to that given in Li [5] and Bahiense [6] instead of the model given in the book by Wang [7]). This was done to maximize notational simplicity (the model by Wang is explicit in imposing non-negativity on decision variables and is more complicated as a result; it is not necessary to explicitly impose non-negativity on decision variables when using modern solvers like CPLEX as it is done internally).
3. Decision variables: There are two explicit decision variables: $Cap_{i,j}^{add}$ (for building technology $j$ at node $i$), and $z_l$ (for building transmission candidate $l$).
4. Branch index: We previously used ($i,j$) to index branches, and we used $A_n$ to identify the set of candidate branches. We will now use $l$ to index branches, where $l=(a,b); \forall b \in \Omega_a$ indicates a branch $l$, terminated by nodes $(a,b)$ where the node $b$ is contained in the set $\Omega_a$.
5. Node sets: The set $\Omega_a$ is the set of nodes $b$ connected to node $a$ via either an existing or a candidate branch. The set $\Omega_a^0$ is the set of nodes $b$ connected to node $a$ via an existing branch. The set $\Omega_a^+$ is the set of nodes $b$ connected to node $a$ via a candidate branch.
6. Node notation: We previously used $i$ and $j$ to denote nodes; we continue to use $i$, but we will also use $a$ and $b$. We use $j$ for generation technologies.
7. Time period: Because the model is single-period, there is no dependence on $t$. This also means there is no need for the "accumulator" used in the multi-period TEP (which we denoted by $S$), and any need for discrete representation of whether a circuit is "in" or "out" is handled by $z_l$.
8. Extensions: It would be useful to extend this modeling to account for (a) multiple load blocks (and capacity factor); (b) multiple time periods; (c) multiple transmission technologies; (d) effect of distance on AC transmission loadability; (e) transmission losses.

**Model CEP1**:

$$\min \underbrace{\sum_i \sum_j I_{i,j} Cap_{i,j}^{add}}_{GenInvestmentCosts} + \underbrace{\sum_i \sum_j FC_{i,j} H_j P_{i,j} T}_{OperationalCosts} + \underbrace{\sum_{a=1,\dots,n} \sum_{\substack{l=(a,b);\\ \forall b \in \Omega_a^+}} K_l z_l}_{\substack{TransInvestment\\ Costs}} \quad (1)$$

subject to

$$Cap_{i,j} = Cap_{i,j}^{existing} + Cap_{i,j}^{add} \qquad \forall i, j \quad (2)$$

$$0 \le P_{i,j} \le CC_{i,j} Cap_{i,j} \qquad \forall i, j \quad (3)$$

$$Cap_{i,j}^{add} \ge 0 \qquad \forall i, j \quad (4)$$

$$\sum_i \sum_j CC_{i,j} Cap_{i,j} \ge (1+r) \sum_i d_i \quad (5)$$

$$P_l - b_l(\theta_a - \theta_b) = 0; \quad l=(a,b); \quad b \in \Omega_a^0; \quad a = 1,\dots,n \quad (6a)$$

$$-P_l^{\max} \le P_l \le P_l^{\max} \quad l=(a,b); \quad b \in \Omega_a^0; \quad a = 1,\dots,n \quad (6b)$$

$$-M_l(1-z_l) \le P_l - (b_l + b_{l,exp})(\theta_a - \theta_b) \le M_l(1-z_l); \quad l=(a,b);\ b \in \Omega_a^+;\ a = 1,\dots,n \quad (7a)$$

$$-(P_{l,max} + z_l \Delta P_{l,max}) \le P_l \le (P_{l,max} + z_l \Delta P_{l,max}) \quad l=(a,b);\ b \in \Omega_a^+;\ a = 1,\dots,n \quad (7b)$$

$$\sum_{l=(a,b), b \in \Omega_a} P_l + d_a = \sum_j P_{a,j} \qquad a = 1,\dots,n \quad (8)$$

Variable definitions follow:

- i,a,b: indexes over nodes
- j: index over technologies
- $I_{i,j}$: investment cost for technology j in node i, \$/puMW
- $Cap_{j,j}^{add}$: capacity added for technology j in node i, puMW
- $Cap_{ji,}^{existing}$: capacity existing for technology j in node i, puMW
- $Cap_{i,j}$: capacity for technology j in node i, puMW
- $\theta_k$: angle of node k, radians
- $b_l$: negative of the susceptance of branch l
- $d_i$: total demand of node i, puMW
- $FC_j$: fuel cost for technology j, \$/MBTU
- $H_j$: heat-rate for technology j, MBTU/puMWhr
- $P_{i,j}$: Power generation level at bus i for technology j, puMW

- T: Planning horizon, hours
- $K_l$ is the investment cost of line l, $
- $z_l$ is an integer 0 or 1.
- $CC_{i,j}$ is the capacity credit for technology j in node i
- $F_l^{max}$ is the maximum flow on circuit l
- $\Omega_a^0$: Set of existing circuits connected to bus *a*, *i*=1, *n*
- $\Omega_a^+$: Set of candidate circuits connected to bus *a*, *i*=1, *n*
- $\Omega_a$: Set of existing and candidate circuits connected to bus *a*, *i*=1, *n* (union of $\Omega_a^0$ and $\Omega_a^+$)
- n: number of nodes in the network

An even simpler model can be obtained if we are willing to neglect the effect of impedance in the transmission representation. In this case, the multi-period TEP and the CEP both can be written as a linear program (LP) (much like our GEP), where decision variables include the transmission capacity (a continuous variable) rather than a binary indicator of whether a line is in or out. Such a model is called a "***transportation model***" or a "***pipes and bubbles***" model. We modify the above formulation to provide such a model, below.

Using the equation numbers (1)-(8), identify the equations in the above model that must be changed, those that remain the same, and those that must be eliminated to obtain a linear co-optimization model having only continuous decision variables (i.e., no integer decision variables) for generation capacity expansion and transmission capacity expansion. Also, for any equations that must be changed, re-write them accordingly, and provide rationale in regards to the change you are making. Use new nomenclature, but do so only if necessary and with minimal changes from the old nomenclature.

**Solution**:
Referring to Problem CEP1, the following changes must be made:
Equation (1) must be modified to be as follows:

$$\min \underbrace{\sum_i \sum_j I_{i,j} Cap_{i,j}^{add}}_{GenInvestmentCosts} + \underbrace{\sum_i \sum_j FC_{i,j} H_j P_{i,j} T}_{OperationalCosts} + \underbrace{\sum_{a=1,\ldots,n} \sum_{\substack{l=(a,b);\\ \forall b \in \Omega_a}} K_{l,j} Tcap_{l,j}^{add}}_{\substack{TransInvestment\\ Costs}} \tag{1}$$

Changes to (1) include:

- $Tcap_{l,j}^{add}$ is additional capacity added to transmission branch *l=(a,b)* using transmission technology *j*.

- $b \in \Omega_a^+$ is changed to $b \in \Omega_a$, that is, instead of a set of candidate branches, we consider additional capacity for all branches, both existing and candidate (by "existing" we mean paths *l=(a,b)* that are connected by an existing branch; by "candidate" we mean paths *l=(a,b)* that are not connected by an existing branch).
- $K_l$ is changed from the dollar investment for a specified candidate circuit *l=(a,b)* to $K_{,l,j}$, the $/MW investment for circuit *l=(a,b)* using transmission technology *j*. In this way, the transmission investment cost term is similar to the generation investment cost term.

Equations (2), (3), (4), and (5) remain the same: these pertain only to the generation capacity which is already a continuous variable.

Equations (6a) and (7a) are eliminated: these are KVL across each circuit which is not enforced under the "pipes and bubbles" model.

Equation (6b) is eliminated: this provides limits on existing transmission capacity, but we are here combining existing with candidate transmission capacity in (7b).

Equation (7b) becomes:

$$-P_l^{\max} - \sum_j Tcap_{l,j}^{add} \le P_l \le P_l^{\max} + \sum_j Tcap_{l,j}^{add} \qquad (7b)$$

$$l = (a,b); \quad b \in \Omega_a; \quad a = 1,...,n$$

Changes to (7b) include

- Existing capacity on branch *l=(a,b)* is augmented by capacity added to branch *l* using transmission technology *j*.
- $b \in \Omega_a^+$ is changed to $b \in \Omega_a$, as described under the changes to (1), above.

Equation (8) remains the same: this is power balance at each node which is enforced under the "pipes and bubbles" model.

Next we present the CEP problem with time dependence (note we do not include salvage value or end effects).

**Model CEP2**:

$$min \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j I_{i,j,t} Cap_{i,j,t}^{add}}_{GenInvestmentCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j FC_{i,j} H_j P_{i,j,t} T}_{OperationalCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_{a=1,\dots,n} \sum_{\substack{l=(a,b);\\ \forall b \in \Omega_a^+}} K_{l,t} z_{l,t}}_{TransInvestmentCosts} \qquad (1)$$

subject to

$$Cap_{i,j,t} = Cap_{i,j,t-1} + Cap_{i,j,t}^{add} - Cap_{i,j,t}^{ret} \quad \forall i, j, t \qquad (2)$$

$$0 \le P_{i,j,t} \le CC_{i,j} Cap_{i,j,t} \quad \forall i, j, t \qquad (3)$$

$$Cap_{i,j,t}^{add} \ge 0 \quad \forall i, j, t \qquad (4)$$

$$\sum_i \sum_j CC_{i,j} Cap_{i,j,t} \ge (1+r) \sum_i d_{i,t} \quad \forall t \qquad (5)$$

$$P_{l,t} - b_l\left(\theta_{a,t} - \theta_{b,t}\right) = 0; \qquad l=(a,b); \quad b \in \Omega_a^0; \quad a = 1,\ldots,n \quad \forall t \tag{6a}$$

$$-P_l^{\max} \le P_{l,t} \le P_l^{\max} \qquad l=(a,b); \quad b \in \Omega_a^0; \quad a = 1,\ldots,n, \quad \forall t \tag{6b}$$

$$-M_l(1-S_{l,t}) \le P_{l,t} - \left(b_l + b_{l,exp}\right)\left(\theta_{a,t} - \theta_{b,t}\right) \le M_l(1-S_{l,t}); \qquad l=(a,b);\ b \in \Omega_a^+;\ a=1,\ldots,n, \quad \forall t \tag{7a}$$

$$-\left(P_{l,max} + S_{l,t}\Delta P_{l,max}\right) \le P_{l,t} \le \left(P_{l,max} + S_{l,t}\Delta P_{l,max}\right) \quad \forall t \qquad l=(a,b);\ b \in \Omega_a^+;\ a=1,\ldots,n \tag{7b}$$

$$\sum_{l=(a,b),b\in\Omega_a} P_{l,t} + d_{a,t} = \sum_j P_{a,j,t} \qquad a=1,\ldots,n \quad \forall t \tag{8}$$

$$S_{l,t} = \sum_{n=1}^{t} z_{l,n} \tag{9}$$

Next we present CEP2 with time dependence, but using the transportation model.

**Model CEP2a**:

Changes made are referenced to Problem CEP2.

$$min \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j I_{i,j,t} Cap_{i,j,t}^{add}}_{GenInvestmentCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j FC_{i,j} H_j P_{i,j,t} T}_{OperationalCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_{a=1,\ldots,n} \sum_{\substack{l=(a,b);\\ \forall b\in\Omega_a}} K_{l,j} Tcap_{l,j,t}^{add}}_{TransInvestmentCosts} \tag{1}$$

Changes to (1) include:

- $Tcap_{l,j,t}^{add}$ is additional capacity added to transmission path $l=(a,b)$ using transmission technology $j$, at time $t$.
- $b \in \Omega_a^+$ is changed to $b \in \Omega_a$, that is, instead of a set of candidate branches, we consider additional capacity for all branches, both existing and candidate (by "existing" we mean paths $l=(a,b)$ that are connected by an existing branch; by "candidate" we mean paths $l=(a,b)$ that are not connected by an existing branch).
- $K_l$ is changed from the dollar investment for a specified candidate circuit $l=(a,b)$ to $K_{,l,j}$, the \$/MW investment for branch $l=(a,b)$ using transmission technology $j$. In this way, the transmission investment cost term is similar to the generation investment cost term.

Equations (2), (3), (4), and (5) remain the same: these pertain only to the generation capacity which is already a continuous variable.

Equations (6a) and (7a) are eliminated: these are KVL across each circuit which is not enforced under the “pipes and bubbles” model.

Equation (6b) is eliminated: this provides limits on existing transmission capacity, but we are here combining existing with candidate transmission capacity in (7b).

Equation (7b) becomes:

$$-\left( P_l^{max} + \sum_{n=1}^{t} \sum_j Tcap_{l,j,n}^{add} \right) \leq P_{l,t} \leq \left( P_l^{max} + \sum_{n=1}^{t} \sum_j Tcap_{l,j,n}^{add} \right) \qquad (7b)$$

$$l = (a,b); \;\; b \in \Omega_a ; \;\; a = 1,\ldots,n \qquad \forall t$$

Changes to (7b) include

- Existing capacity on branch $l=(a,b)$ is augmented by capacity added to branch $l$ using transmission technology $j$ for all investments made during time $t$ and previous to time $t$.
- $b \in \Omega_a^+$ is changed to $b \in \Omega_a$, as described under the changes to (1), above.

Equation (8) remains the same: this is power balance at each node which is enforced under the “pipes and bubbles” model.

Equation (9) is eliminated: this provides limits on existing transmission capacity, but we are here combining existing with candidate transmission capacity in (7b).

In discussing TEP formulations, reference [8] first describes the nonlinear integer TEP model (Section 2.1 below) and then the much simpler transportation model (Section 2.2 below).

### 2.1 DC model

When the power grid is represented by the DC power flow model, the mathematical model for the one-stage transmission expansion planning problem can be formulated as follows:

Minimise

$$\nu = \sum_{(i,j)} c_{ij} n_{ij} + \alpha \sum_{k} r_k \qquad (1)$$

Subject to

$$Sf + g + r = d \qquad (2)$$

$$f_{ij} - \gamma_{ij}\left(n_{ij}^0 + n_{ij}\right)\left(\theta_i - \theta_j\right) = 0 \qquad (3)$$

$$|f_{ij}| \leq \left(n_{ij}^0 + n_{ij}\right)\bar{f}_{ij} \qquad (4)$$

$$0 \leq g \leq \bar{g} \qquad (5)$$

$$0 \leq r \leq d \qquad (6)$$

$$0 \leq n_{ij} \leq \bar{n}_{ij} \qquad (7)$$

$$n_{ij} \text{ integer}, \; f_{ij} \text{ and } \theta_j \text{ unbounded} \qquad (8)$$

$$(i, j) \in \Omega, \; k \in \Gamma$$

where $c_{ij}$, $\gamma_{ij}$, $n_{ij}$, $n_{ij}^0$, $f_{ij}$ and $\bar{f}_{ij}$ represent, respectively the cost of a circuit that can be added to right-of-way $i$–$j$, the susceptance of that circuit, the number of circuits added in right-of-way $i$–$j$, the number of circuits in the base case, the power flow, and the corresponding maximum power flow. $v$ is the total investment, $S$ is the branch-node incidence matrix, $f$ is a vector with elements $f_{ij}$ (power flows), $g$ is a vector with elements $g_k$ (generation in bus $k$) whose maximum value is $\bar{g}$, $\bar{n}_{ij}$ is the maximum number of circuits that can be added in right-of-way $i$–$j$, $\Omega$ is the set of all right-of-ways, $\Gamma$ is the set of indices for load buses and $r$ is the vector of artificial generations with elements $r_k$ (they are used in certain formulations and to represent loss of load, and normally appear in the formulation multiplied by a cost $\alpha$ measured in \$/MW).

The constraint in eqn. 2 represents the conservation of power in each node if we think in terms of an equivalent DC network, this constraint models Kirchhoff's current law (KCL). The constraint in eqn. 3 is an expression of Ohm's law for the equivalent DC network. Notice that the existence of a potential function $\theta$ associated with the network nodes is assumed, and so Kirchhoff's voltage law (KVL) is implicitly taken into account (the conservation of energy in the equivalent DC network)—these are nonlinear constraints. The constraint in eqn. 4 represents power flow limits in transmission lines and transformers. The constraints in eqns. 5 and 6 refer to generation (and pseudo-generation) limits.

This is the nonlinear model.

The transmission expansion problem as formulated above is an integer nonlinear problem (INLP). It is a difficult combinatorial problem which can lead to combinatorial explosion on the number of alternatives that have to be searched.

### 2.2 Transportation model

This model is obtained by relaxing the nonlinear constraint eqn. 3 of the DC model described above. In this case the network is represented by a transportation model, and the resulting expansion problem becomes an integer linear problem (ILP). This problem is normally easier to solve than the DC model although it maintains the combinatorial characteristic of the original problem. An optimal plan obtained with the transportation model is not necessarily feasible for the DC model, since part of the constraints have been ignored; depending on the case, additional circuits are needed in order to satisfy the constraint in eqn. 3, which implies higher investment cost.

This is the transportation model, but it retains integer choices of transmission rather than continuous choices.

It is interesting that before reference [8] describes the disjunctive model, it first describes a "hybrid" model which includes impedance effects only on existing circuits but represents candidate circuits using the "transportation" form, as indicated below. In expanding a branch, the hybrid model represents the original branch there, with its impedance and original capacity, and adds a "pipe" (a branch with no impedance effects) in parallel with it to represent any branch capacity added. This is described below; I have added an illustration, Figure 8, to communicate the concept.

### 2.3 Hybrid model

The hybrid model combines characteristics of the DC model and the transportation model. There are various ways of formulating hybrid models, although the most common is that which preserves the linear features of the transportation model. In this model it is assumed that the constraint in eqn. 2, KCL, is satisfied for all nodes of the network, whereas the constraint in eqn. 3, which represents Ohm's law (and indirectly, KVL), is satisfied only by the existing circuits (and not necessarily by the added circuits).

The hybrid model is obtained by replacing the constraints in eqns. 2 and 3 of the DC model by the following constraints:

$$S_o f + S f' + g + r = d \quad (9)$$

$$f_{ij} - \gamma_{ij} n^0_{ij}(\theta_i - \theta_j) = 0, \quad \forall (i,j) \in \Omega_0 \quad (10)$$

$$|f_{ij}| \le n^0_{ij} \bar{f}_{ij}, \quad \forall (i,j) \in \Omega_0 \quad (11)$$

$$|f'_{ij}| \le n_{ij} \bar{f}_{ij}, \quad \forall (i,j) \in \Omega \quad (12)$$

where $S_o$ is the branch-node incidence matrix for the existing circuits (initial configuration), $f$ is the vector of flows in the existing circuits (with elements $f_{ij}$), and $f'$ is the vector of flows in the added circuits (with elements $f'_{ij}$).

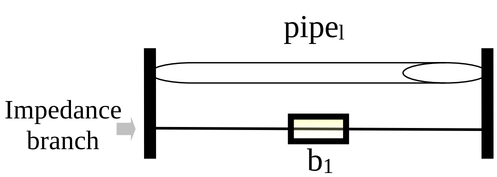



**Figure 8: Illustration of hybrid model configuration**

### 2.4 Disjunctive model

A linear disjunctive model has been used in [1–3]. It can be shown that under certain conditions the optimal solution for the disjunctive model is the same as the one for the DC model. This model can be formulated as follows.

Minimise

$$\nu = \sum_{(i,j)} c_{ij} y^p_{ij} + \alpha \sum_k r_k \quad (13)$$

Subject to

$$S_0 f^0 + S_1 f^1 + g + r = d \quad (14)$$

$$f^0_{ij} - \gamma_{ij} n^0_{ij}(\theta_i - \theta_j) = 0, \quad \forall (i,j) \in \Omega_0 \quad (15)$$

$$|f^p_{ij} - \gamma_{ij}(\theta_i - \theta_j)| \le M(1 - y^p_{ij}), \quad \forall (i,j) \in \Omega \quad (16)$$

$$|f^0_{ij}| \le \bar{f}_{ij} n^0_{ij} \quad (17)$$

$$|f^k_{ij}| \le \bar{f}_{ij} y^p_{ij} \quad (18)$$

$$0 \le g \le \bar{g} \quad (19)$$

$$0 \le r \le d \quad (20)$$

$$y^p_{ij} \in \{0,1\}, \quad (i,j) \in \Omega, \quad p = 1, 2, \ldots, p \quad (21)$$

$f^0_{ij}$, $f^p_{ij}$ and $\theta_j$ unbounded

where $p$ is the number of circuits that can be added to a right-of-way (these are binary variables of the type $y^k_{ij}$), $f^0$ is the vector of flows in the circuits of the initial configuration (with elements $f^0_{ij}$), $S_1$ is the node-branch incidence matrix of the candidate circuits (which are considered as binary variables) $f^1$ is the vector of flows in the candidate circuits (with elements $f^p_{ij}$), $n^0_{ij}$ are the circuits of the initial configuration, and $M$ is a number of appropriate size.

The appeal of this model is that the resulting formulation can be approached by binary optimisation techniques. On the other hand, it has two main disadvantages: the increase in the number of problem variables due to the use of binary variables, and the need to determine the value of $M$. An additional feature of this method is that it can be extended to AC models: this, however, is not of great value in practice, since most of the long term studies are performed with DC models only.

We provide the formulation for the hybrid model below. Observe that $P_l$ is flow on impedance branch and $P'_l$ is flow on pipe.

**Model CEP2b (hybrid model)**:

$$min \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j I_{i,j,t} Cap^{add}_{i,j,t}}_{GenInvestmentCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j FC_{i,j} H_j P_{i,j,t} T}_{OperationalCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_{a=1,\ldots,n} \sum_{\substack{l=(a,b);\\ \forall b \in \Omega^+_a}} K_{l,t} z_{l,t}}_{TransInvestmentCosts} \quad (1)$$

subject to

$$Cap_{i,j,t} = Cap_{i,j,t-1} + Cap^{add}_{i,j,t} - Cap^{ret}_{i,j,t} \quad \forall i,j,t \quad (2)$$

$$0 \le P_{i,j,t} \le CC_{i,j} Cap_{i,j,t} \quad \forall i,j,t \quad (3)$$

$$Cap^{add}_{i,j,t} \ge 0 \quad \forall i,j,t \quad (4)$$

$$\sum_i \sum_j CC_{i,j} Cap_{i,j,t} \geq (1+r) \sum_i d_{i,t} \qquad \forall t \tag{5}$$

$$P_{l,t} - b_l \left( \theta_{a,t} - \theta_{b,t} \right) = 0; \qquad l = (a,b); \quad b \in \Omega_a^0; \quad a = 1,\ldots,n \quad \forall t \tag{6a}$$

$$-P_l^{\max} \leq P_{l,t} \leq P_l^{\max} \qquad l = (a,b); \quad b \in \Omega_a^0; \quad a = 1,\ldots,n, \quad \forall t \tag{6b}$$

$$-\left( \sum_{n=1}^{t} \sum_j Tcap_{l,j,n}^{add} \right) \leq P'_{l,t} \leq \left( \sum_{n=1}^{t} \sum_j Tcap_{l,j,n}^{add} \right) \qquad l = (a,b); \; b \in \Omega_a^0; \; a = 1,\ldots,n \quad \forall t \tag{7b}$$

$$\sum_{l=(a,b), b \in \Omega_a^0} P_{l,t} + \sum_{l=(a,b), b \in \Omega_a^0} P'_{l,t} + d_{a,t} = \sum_j P_{a,j,t} \qquad a = 1,\ldots,n \quad \forall t \tag{8}$$

There is a final model that is very simple to implement. I call it the fixed reactance model. Here, each branch has a reactance and a flow limit. In the optimization using this model, the flow limit can be increased to account for increased branch capacity (and so the flow limit is a decision variable), but the reactance remains fixed. This of course is erroneous because expansion to achieve additional capacity necessarily means an additional branch will be paralleled with the existing branch and the reactance will decrease due to the parallel combination. But to avoid the MILP formulation of the disjunctive model, we ignore the change in reactance (and therefore retain an LP).

**Model CEP2c (fixed reactance model)**:

$$\min \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j I_{i,j,t} Cap_{i,j,t}^{add}}_{GenInvestmentCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_i \sum_j FC_{i,j} H_j P_{i,j,t} T}_{OperationalCosts} + \underbrace{\sum_t \zeta^{t-1} \sum_{a=1,\ldots,n} \sum_{\substack{l=(a,b);\\ \forall b \in \Omega_a^+}} K_{l,t} z_{l,t}}_{TransInvestmentCosts} \tag{1}$$

subject to

$$Cap_{i,j,t} = Cap_{i,j,t-1} + Cap_{i,j,t}^{add} - Cap_{i,j,t}^{ret} \qquad \forall i,j,t \tag{2}$$

$$0 \leq P_{i,j,t} \leq CC_{i,j} Cap_{i,j,t} \qquad \forall i,j,t \tag{3}$$

$$Cap_{i,j,t}^{add} \geq 0 \qquad \forall i, j, t \tag{4}$$

$$\sum_i \sum_j CC_{i,j} Cap_{i,j,t} \geq (1+r) \sum_i d_{i,t} \qquad \forall t \tag{5}$$

$$P_{l,t} - b_l \left(\theta_{a,t} - \theta_{b,t}\right) = 0; \qquad l = (a,b); \quad b \in \Omega_a^0; \quad a = 1,\ldots,n \quad \forall t \tag{6a}$$

$$P_l^{max} - \left( \sum_{n=1}^{t} \sum_j Tcap_{l,j,n}^{add} \right) \leq P_{l,t} \leq P_l^{max} + \left( \sum_{n=1}^{t} \sum_j Tcap_{l,j,n}^{add} \right) \qquad l = (a,b); \; b \in \Omega_a^0; \; a = 1,\ldots,n \quad \forall t \tag{7c}$$

$$\sum_{l=(a,b),b\in\Omega_a^0} P_{l,t} + d_{a,t} = \sum_j P_{a,j,t} \qquad a = 1,\ldots,n \quad \forall t \tag{8}$$

Although Model CEP2c is approximate (in that, for invested branches, the branch reactance is not consistent with the branch capacity), it can be adjusted via an iterative scheme. Such an iterative scheme is illustrated in Fig.

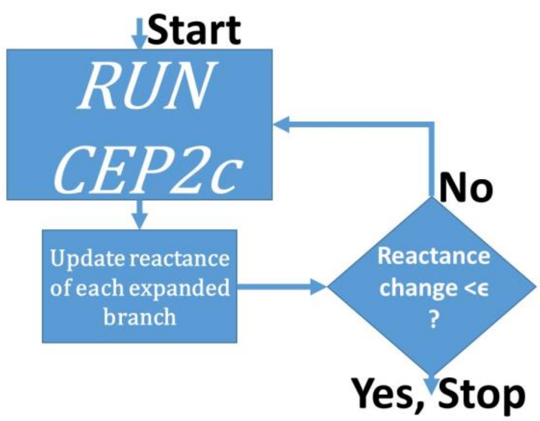



**Figure 9: A CEP2c iterative scheme for adjusting reactance**

## 3 Current industry thinking on co-optimization

The Eastern Interconnection States Planning Council (EISPC) [9] sponsored an effort to summarize current state-of-art and industry practices regarding co-optimization, and a report is available [10]. The executive summary of this document is copied below.

# EXECUTIVE SUMMARY AND RECOMMENDATIONS

## ES-1. Overview

Purpose

The purpose of this report is to describe and explain the benefits of using co-optimization for power system generation and transmission planning. Co-optimization models are computer-aided decision-support tools that search among possible combinations of generation and transmission investments to identify integrated solutions that are "best" in terms of cost or other objectives while satisfying all physical, economic, environmental, and policy constraints.

We review the state of the art in power system expansion planning tools including existing co-optimization models. We also summarize data and computational requirements of co-optimization models, specify design choices to be made in developing them, and describe methods for their validation. Three case studies illustrate potential applications and associated results of co-optimization and its benefits relative to planning approaches that optimize generation alone or transmission alone. Methods to address short-run resource variability and long-run uncertainties within co-optimization are described in some depth, given the centrality of these topics in planning for the future. Institutional concerns regarding co-optimization are explored, including confidentiality, public domain access, and potential roles of states.

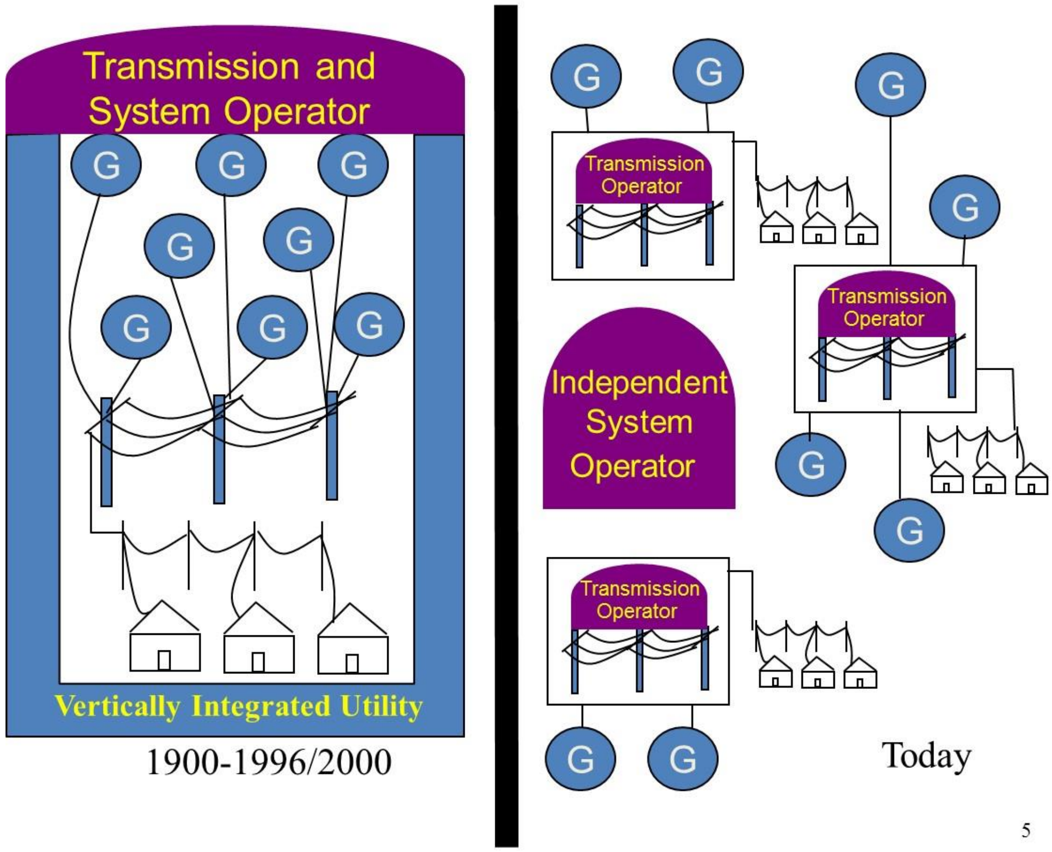
Is co-optimization useful for both vertically integrated and for unbundled structures?

Two central findings are as follows. First, co-optimization is useful where power utilities are vertically integrated because it identifies less costly solutions by considering the tight interactions of generation and transmission. Second, co-optimization is also useful within unbundled environments because it facilitates exploration of how generation dispatch and investment will respond to changes in transmission capacity, access, and congestion. This helps planners to identify grid reinforcements that encourage generation siting decisions that yield the lowest overall cost of power production and delivery. Co-optimization also facilitates integrated and simultaneous assessment of all planning alternatives, including supply-side options (bulk and distributed generation and storage), demand management, and transmission, so as to identify the most economically and environmentally efficient combinations.

What other planning alternatives can be considered within co-optimization.

Our findings imply that co-optimization is likely to be highly useful for system expansion planning, particularly within the Eastern Interconnection (EI). This is particularly important given the large transmission investments that are anticipated to promote interregional power trades and renewables integration. In the near term, there is immense value to applying research-grade co-optimization tools to the EI or its subsystems. Such studies would be highly beneficial because they would (1) further illustrate the benefits of co-optimization for industry-sized systems; and (2) facilitate exploration of several model design issues, including treatment of uncertainty and deployment on high-performance, paralleled computers. In the longer term, consideration should be given to developing commercial co-optimization applications that would

The next page illustrates the difference between vertically integrated industry structure (as exists in the southeast US) and unbundled industry structure (as exists where ISO markets are), in anticipation of a question on the page following.


Transmission and System Operator
G
Vertically Integrated Utility
1900-1996/2000
Transmission Operator
Independent System Operator
Today
5

incorporate operational constraints and variability to enhance model fidelity while conveniently interfacing with existing and newly developed data repositories.

## ES-2. Definition

We recommend use of the following general definition for co-optimization in this document.

> *Co-optimization is the simultaneous identification of two or more classes of investment decisions within one optimization strategy.*

Here, "*classes of investment decisions,*" in the context of electric systems planning, almost always include decisions to build generation and transmission. But they may include other types of decisions as well, such as demand-side solutions, decisions to install storage, or building of natural gas pipelines. "*One optimization strategy*" may consist of a formulation to solve a single optimization problem (e.g., minimize cost subject to constraints) or it may consist of a formulation to solve an iterative series of optimization problems (i.e., sequential yet coordinated generation and transmission planning).

The above definition is tool-focused; it refers to the operation of a particular kind of computational method. But it must be understood in the context of the planning process in which it is used. If co-optimization is used by a vertically integrated utility, then its main result is the identification of joint transmission-generation expansion plans that are lower in cost than expansion plans would be if transmission and generation plans were developed separately. However, co-optimization can also be used within used in utility regions that are no longer vertically integrated (unbundled) and where planning for transmission infrastructure is performed by one entity while planning of other classes of investments (e.g., generation) is performed by others. In particular, co-optimization is likely to be highly useful in an unbundled environment in which transmission infrastructure planning is separated from generation investment. In this case, the process in which co-optimization is used might be called "*transmission planning accounting for market response*" or "*anticipatory transmission planning.*" Key results of co-optimization computations would include not just how generation dispatch and grid congestion would be affected by alternative network configurations, but also ultimately how availability of transmission could incent changes in generation mix and siting decisions. Because transmission investments usually (but not always) have longer lead times than generation, it is appropriate for transmission planners to anticipate how alternative network configurations will affect the attractiveness of different locations for plant siting, and the resulting effects on costs, prices, and emissions.

Thus, to complement the above general definition of co-optimization, we also define a second term that reflects the nature of the many planning processes under which co-optimization could be usefully applied:

Co-optimization is the simultaneous optimization of two or more different yet related resources within one optimization formulation.

Other types of investment decisions...

Single optimization vs. iterative.

How would cooptimization be used in unbundled environments where trans investment and generation investment are generally done by different organizations?

Jim- thinking about your slides again... you're talking about optimization but how do you handle that when the generation and transmission parts of one company can't talk to each other?

The answer is what any transmission planner today must give – co-optimization is forecasting the generation expansion and then building transmission accordingly.
If you know nothing, your forecast is to identify what is most economic. If you know something (e.g., MISO generation queue), you build it into the model with appropriate constraints.

*Anticipatory transmission planning is a use of co-optimization to evaluate network investments while considering how generation decisions, both dispatch and investment, will respond to changes in transmission capacity, access, and congestion.*

Therefore, co-optimization can benefit the planning processes of states and Planning Coordinators regardless of market structure or regulatory regime. That is, no matter whether the power industry is vertically integrated or unbundled, co-optimization can be an effective tool for states and Planning Coordinators to better understand various risks, benefits and costs when assessing resource options, and to identify improved integrated solutions.

### ES-3. Benefits of Co-optimization and Anticipatory Transmission Planning

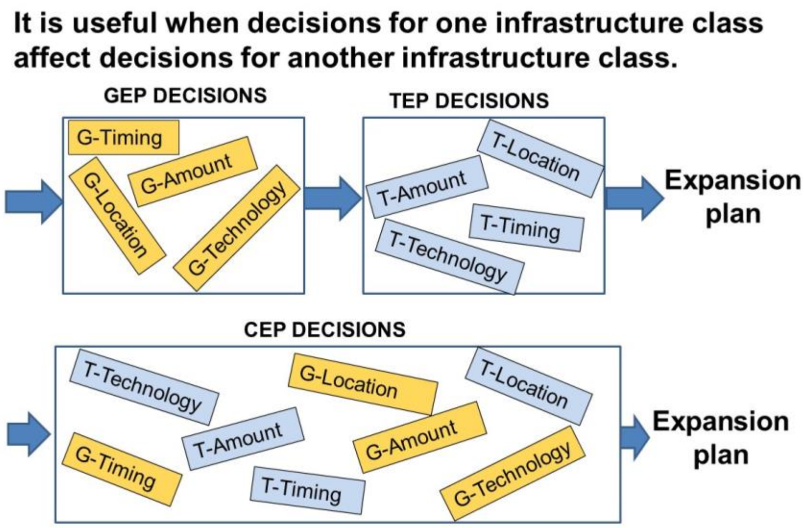
Co-optimization is a systematic approach to address critical questions in planning. One such question concerns the fundamental tradeoff that exists in many places between transmission investment and quality of renewable resources. In particular, how much transmission capacity would be needed to economically and reliably deliver the energy produced by remote high quality variable renewables, or is it more efficient to develop less efficient resources nearer to load centers? As another example, is it more economical/reliable to invest in remotely located large-scale thermal or hydro generating stations and provide long distance HVDC/AC transmission for power delivery, or would it instead be less costly and environmentally damaging to invest in locally distributed and variable generation resources in highly congested regions with limited availability of transmission right of ways?

Another such question concerns the diversity and flexibility value of linking power systems and markets. How much thermal generation capacity would be needed to reliably operate a power system with significant amounts of renewable energy? By more closely linking geographically separate markets, how would transmission investment increase the diversity of resources and thereby increase the capacity value and reduce the ancillary service requirements of the renewable resources? How much operating and planning flexibility do additions of transmission capacity provide, and how can that be compared to flexibility from traditional generation sources?

A final and crucial planning question concerns interaction of transmission and generation with emerging resources. For instance, how much generation and transmission capacity could be saved at the planning stage by more aggressive demand-side management and demand response programs?

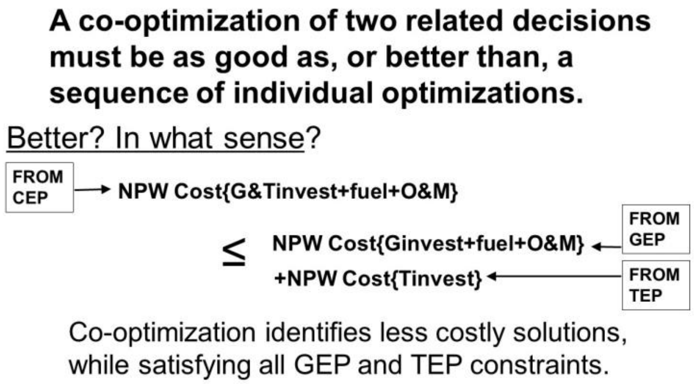
In this report, we illustrate the use of co-optimization models to answer these questions by comparing co-optimization with more traditional generation-only or transmission-only planning processes in a series of case studies. One group of case studies considers simple three to four bus examples that transparently illustrate how co-optimization reduces cost. Other case studies are based on a thirteen-region representation of the US power sector, and quantify the benefits of co-optimization of inter-regional reinforcements under various scenarios concerning renewable

The next page provides slides illustrating (a) when it is useful, (b) that co-optimized solutions must be as good as, or better than a sequence of GEP/TEP solutions (relates to next question); and (c) a CEP mental image.



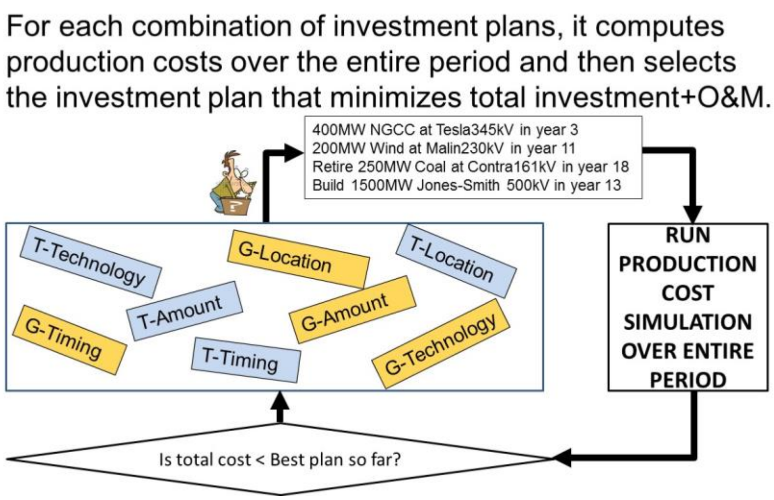
It is useful when decisions for one infrastructure class affect decisions for another infrastructure class.
GEP DECISIONS
G-Timing
G-Amount
G-Location
G-Technology
TEP DECISIONS
T-Location
T-Amount
T-Timing
T-Technology
Expansion plan
CEP DECISIONS
T-Technology
G-Location
T-Location
T-Amount
G-Amount
G-Timing
T-Timing
G-Technology
Expansion plan

(a)



A co-optimization of two related decisions must be as good as, or better than, a sequence of individual optimizations.
Better? In what sense?
FROM CEP
NPW Cost{G&Tinvest+fuel+O&M}
≤
NPW Cost{Ginvest+fuel+O&M}
FROM GEP
+NPW Cost{Tinvest}
FROM TEP
Co-optimization identifies less costly solutions, while satisfying all GEP and TEP constraints.

(b)



For each combination of investment plans, it computes production costs over the entire period and then selects the investment plan that minimizes total investment+O&M.
400MW NGCC at Tesla345kV in year 3
200MW Wind at Malin230kV in year 11
Retire 250MW Coal at Contra161kV in year 18
Build 1500MW Jones-Smith 500kV in year 13
RUN PRODUCTION COST SIMULATION OVER ENTIRE PERIOD
T-Technology
G-Location
T-Location
T-Amount
G-Amount
G-Timing
T-Timing
G-Technology
Is total cost < Best plan so far?

(c)

energy policies and technology developments. Through these examples, we have documented how co-optimization can lower the total cost of electricity provision through:

1. savings of transmission and generation investment and operating costs;
2. more efficient decisions concerning generation retirements and uprates;
3. more appropriate treatment of variable resources;
4. efficient integration of non-traditional resources such as demand response, customer-owned generation, other distributed resources, and energy storage;
5. fuel mix benefits;
6. improved assessment of the ramifications of environmental regulation and compliance planning; and
7. reduced risk and attendant effects on resource adequacy and costs.

Why is co-optimization better than sequential (GEP and then TEP) optimization?

The simple examples show how co-optimization can yield a more balanced and economic mix of resources compared to transmission-only planning (transmission expansion subject to a fixed scenario of generation investment) and generation-only planning (generation investment subject to a fixed network). Generally, the lowest cost solution results from a combination of transmission and generation investments, and considering only one or the other results in unnecessarily higher costs and emissions, and perhaps even a deterioration in reliability. The interactions between plant siting and transmission routing decisions can be complicated and surprising. Sometimes investments in transmission defer the need for new generation capacity investments, while in other situations, development of costly local generation is preferred to building cheaper or more efficient generation in remote locations plus the transmission necessary to access it. These phenomena can occur on radial networks, and become even more complex on looped grids, even for our three to four bus examples.

In our national applications, we find that, under some assumptions about renewable technology and cost developments, full co-optimization can save up to 10% or more of total generation and transmission costs compared to generation-only planning, and 5% or more compared to transmission-only planning given an assumed fixed pattern of generation investment. These savings are larger in magnitude than the transmission investments themselves, demonstrating the critical role of transmission in economically integrating renewable energy. The savings occur because co-optimization can result in appreciably different patterns of investment than generation- or transmission-only planning. The results show that the most profitable locations for renewable and nonrenewable plant investment strongly depend on where grid reinforcements are made. Differences of 50 GW or more in regional capacity expansion are sometimes found. Conversely, the cost-minimizing transmission investments are very different if a fixed scenario of generation expansion is assumed than if possible shifts in generation siting in response to transmission additions are considered.

Is co-optimization better than iterative (GEP and then TEP, then GEP/TEP, …etc); optimization? An example…

The examples also illustrate two different types of co-optimization. The most efficient (but computationally challenging) type considers generation and transmission investment simultaneously. The other iterates, first expanding generation with a fixed grid (generation-only), then second expanding transmission given the first generation expansion solution (transmission-only), then back to generation-only, and so forth. We find that compared to generation-only planning, the iterative process can reduce costs quite significantly. However, after five iterations, this process yielded a plan for expanding interregional transmission in the US that is still $22 billion more expensive (present worth of generation and transmission costs) than the co-optimized plan, a difference of 1.3%. By comparison, the amount of transmission investment in the Eastern Interconnection in 2012 was approximately $3 billion, an amount that is expected to grow significantly in coming years.

That application also illustrates a major benefit of co-optimization. Full co-optimization spent approximately $60 billion more on transmission, but saved $150 billion (in present worth) compared to a solution in which generation was first planned, and then transmission was planned to deliver that generation. That is, there was a 2.5 benefit/cost ratio for the incremental transmission investment. Forty percent of the generation cost savings were derived from reductions in generation capital costs from more efficient generation siting and mixes, and 60% were variable cost savings. Thus, traditional transmission planning processes, which do not consider changes in generation siting and capital costs, miss a potentially very important benefit of transmission.

### ES-4. General Recommendations on Model Development and Demonstration

Because of the many benefits of co-optimization that we have illustrated and quantified with our simplified models, we recommend that EISPC initiate efforts to develop a co-optimization tool for long-term electric systems planning. Although various research-grade co-optimization tools already exist, none have all of the features necessary to satisfy the long-term needs of the EISPC. We expect that the benefits available from such a tool would far outweigh the costs of developing it.

As an initial step, we also recommend that one or more Planning Coordinators or States collaborate with a research group to apply an existing co-optimization tool using detailed data from their region to quantify the benefits of co-optimization in a realistic setting. Such a study would reveal more precise estimates of co-optimization benefits than are possible from our simple three and four bus examples and US model. The study would also provide more information on the effort required to apply co-optimization, and on the insights that could be obtained.

### ES-5. Recommendations on Tool Design

Development of a co-optimization tool that can be used in an actual planning setting requires a number of design decisions. These decisions often involve choosing between model fidelity (realism) and computational intensity. The following summarizes the most critical of these design decisions as well as our recommendation in each case.

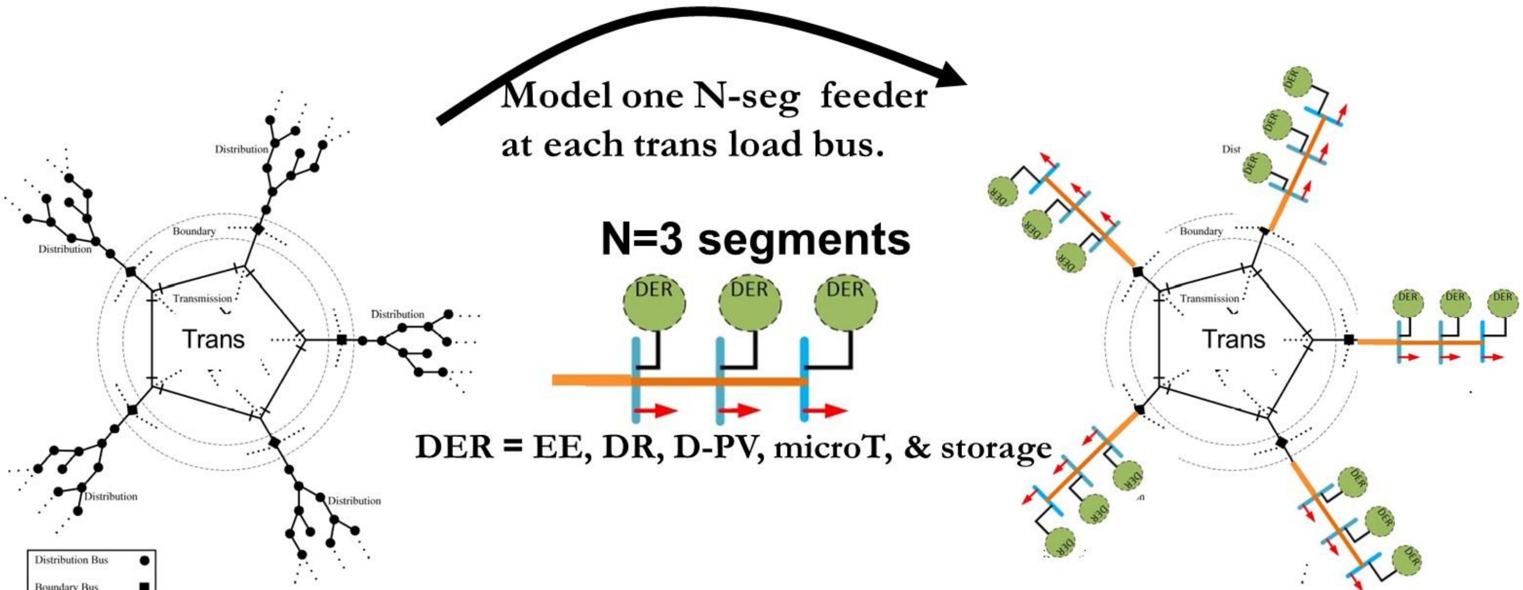
1. *Pre-processing step:* We recommend a pre-processing step be included that would prepare data for input to the co-optimization tool. There are a number of functions that could be included in this pre-processing step, but the most important of them is identification of candidates for new transmission circuits that the co-optimization tool should consider.
2. *Co-optimization solvers:* The co-optimization tool should avoid use of nonlinear optimization solvers and instead rely on highly efficient linear continuous optimization solvers and/or linear mixed-integer optimization solvers. Nonlinear solvers cannot handle as large of a problem, and take longer to execute.
3. *Network model:* There are three choices for a network model, AC-flow, DC-flow, and transportation ("pipes-and-bubbles") flow. Of these, we recommend use of the DC-flow network model as it provides good fidelity for MW flows for a modest computational burden.
4. *Resource and transmission options:* The co-optimization tool should allow for selection from multiple resource and transmission technologies. Resources should include fossil-based and renewable-based generation, demand-side technologies, and various types of storage. Transmission technologies should include both AC and DC lines, each at multiple voltage and capacity levels. AC transmission capacity should be modeled as a function of distance between substations having voltage control equipment. DC transmission should include technologies employing line-commutated (thyristor-based) converters and technologies employing voltage-source converters. Simple demand response programs, such as critical peak pricing or peak-time rebate programs, can be practically and realistically modeled as programs that trigger an amount of demand reduction if price exceeds a threshold.
5. *Multiyear representation:* The co-optimization tool should have the ability to represent a given time frame (e.g., 20 years) as a sequence of multiple periods (such as 2 years) such that optimal timings can be identified for each investment.
6. *Policy representations:* There are many policies that profoundly influence power sector investment decisions. These include environmental policies on the federal, state, and local levels that address air pollution, once-through cooling, facility siting, and greenhouse gasses; market design features, such as capacity markets and regulatory preferences and incentives for particular resources; and the effects of regulatory policies on the attractiveness of transmission investments considering rate-of-return regulation and, in special circumstances, merchant transmission. Because of their profound effects, these policies should be explicitly represented in co-optimization models.
7. *Outputs:* The tool should not only identify economically and environmentally attractive near-term investments in transmission, it should also provide information on prices and costs, and their distribution among regions and market participants. This can be helpful in

Distributed energy resources (DER) should include (1) rooftop solar for industrial, commercial, and residential buildings; (2) community-based solar; (3) energy efficiency programs; (4) demand response programs; (5) distributed storage; (6) microturbines. See figure on the next page, which came from Shikha Sharma's PhD dissertation.

We have not explored this issue very much, but it is important. You can have operational years (simulating operation but not allowing investment) and investment years (simulating operations and allowing investment). Simulation of operations for an operational year can be modeled by actually performing a dispatch for every operational block (and therefore having operational decision variables), or it can be modeled by simply duplicating the operational cost in the last investment year. In either case, an operational year has no investment-related decision variables. An investment year has both operational and investment-related decision variables.

# Modeling – DER Representation

357 bus reduced WECC model; 99 buses in BPA region; 47 transmission-level load buses converted to 3-seg dist feeders; increase total buses to 498, 2018-2038.

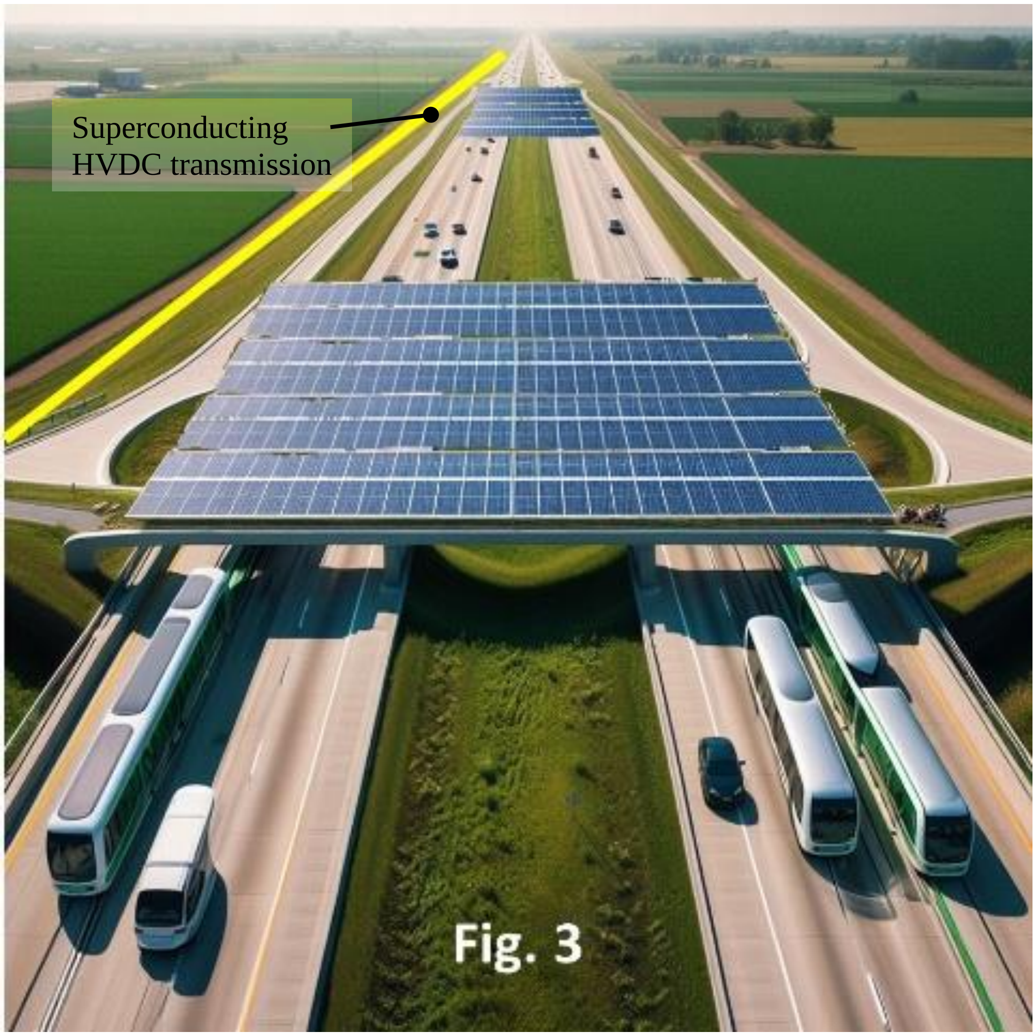



**Enables multi-segment loss representation & investment without increasing model size too much. Can choose N according to computation/fidelity needs.**

understanding where generation siting would be most attractive, and who benefits from transmission expansion. Because users and stakeholders will have many objectives, such as lower power prices, emissions, regional job creation, and fuel supply security, another design decision is what objectives should be optimized. A co-optimization tool could be designed to have more than one objective function, and thereby be used to identify a set of solutions that represent a range of tradeoffs among objectives. This tradeoff information could inform negotiations among the interests involved in transmission planning, and so multiobjective capabilities should be built into co-optimization models.

In addition to the above decisions concerning tool design, there are several other considerations that will become increasingly important in the future, and should therefore receive consideration both in designing new co-optimization methods and in research on the topic.

1. *Handling uncertainty*: The past four decades shows that power system planning is subject to profound long-run uncertainties in policy, technology, fuel costs, and load growth, and that surprises are sure to be in store for power system planning in the future. It is possible to conceive of uncertainty in terms of parametric uncertainty around an expected value (local uncertainty). For instance, one might expect 1% demand growth ±0.5% over the next 10 years. Uncertainty can also be conceived in terms of dramatic shifts that significantly change the future (global uncertainty), for instance, we might expect natural gas prices to rise to only $7/MBTU over the next 20 years, or we may expect natural gas prices to rise to $15 over the next 20 years, or a policy change may occur related to certain resource (e.g., nuclear). It is possible to develop co-optimization tools that handle both types of uncertainty, but at a significant increase in computational burden.
2. *Value of transmission expansion:* The co-optimization tool should be able to assess all categories of benefits that transmission brings. These include (a) energy market efficiency enhancement; (b) ancillary service market efficiency enhancement; (c) emissions reductions; (d) increased network integrity (or "insurance" value) for multi-element contingencies; and (e) enhanced competition in bulk power markets.
3. *Generation flexibility*: Some RTOs recognize the need to explicitly incent operational flexibility. As renewable penetration increases, this issue will grow in importance. Therefore, co-optimization should include the ability to impose flexibility (e.g., ramping capability) requirements on resource portfolios as a function of net load variability. Modeling operational reserve requirements and proper modeling of the costs of fossil-fuel unit cycling would need to be considered.
4. *Transmission operations*: In theory, a co-optimization tool could consider operational issues such as system dynamics, reconfiguration, switching, right of way and voltage support, whose implications for planning may become more important in the future.
5. *Multi-sector modeling:* The electric system influences and is influenced by the performance of other infrastructure systems. Among these, the natural gas pipeline system is today perhaps the most consequential, but the passenger transportation system


Superconducting
HVDC transmission
Fig. 3

will become more influential as it becomes more electricity-dependent. Including the ability to represent interdependencies between these other infrastructure systems and the electric system is likely to be important in the future.

6. *Advancements in computational efficiency:* Even a conservatively-designed co-optimization tool is computationally demanding. Developing a co-optimization tool with the ability to run on high-performance parallel computers will be very useful. Advanced optimization/decomposition algorithms could facilitate the consideration of long-run uncertainties as well as a greater range of load and renewable operating conditions. One particular aspect of co-optimization modeling that could benefit from such advancements is the treatment of operational constraints and variability. Current models usually focus on the "big picture" of expansion planning without including a great deal of operational details. This is in part necessary because of limitations in the size of models that present solvers and computers can handle. However, as computation capabilities improve, larger models with more realistic operations become possible. The need for better operations models is also driven by the deployment of smart grid technologies such as demand response, microgrids, and electric vehicles, which mean that the operations of the future electricity power systems could be very different from today. Improved representations of operations could also include unit commitment considerations or storage optimization.
7. *Market structure:* Although the deregulation process of electricity market began long ago, the market is still not fully deregulated. The current status quo is that vertically integrated regulated utilities and unbundled deregulated markets exist side by side. The implications of their co-existence for co-optimization, especially of interconnections between different systems, need to be better understood.

The first issue, that of uncertainty, receives particular attention in this report. Traditional planning methods have typically applied simple and ad hoc methods to address power system uncertainties. These methods have served the industry relatively well in the past. However, the industry is increasingly challenged by the needs to address a large number of new issues, including the growth of distributed power systems, uncertainties concerning the location of new energy resources and the retirement of older generators, integration of large amounts of variable energy resources, more dynamic loads, increasingly stringent environmental regulations driving changes to the generation portfolio, and long lead times to construct major facilities. These issues have led to significantly more complex and less predictable power systems and raised the question of whether existing planning methods are adequate. In particular, existing methods cannot quantify the economic value of flexibility and adaptability of transmission plans. As an example, some transmission investments might leave more options open than other investments for resource interconnection in the future because the regions they access might have a larger variety of resources. The option value associated with such flexibility can be important in transmission planning, but is not considered by present planning models, whether co-optimized or not. It is necessary for co-optimization model formulations to explicitly consider multiple future scenarios, and how future decisions might anticipate or adapt to them, instead of simply running analyses on many different scenarios.

### ES-6. Data requirements

Co-optimization tools require more input data to run than generation- or transmission-only models alone. Building co-optimization models is a data-intensive task requiring significant effort to collect, maintain and share data without violating network security and organizational confidentiality standards. However, to the extent that the data sets required by co-optimization is more detailed, consistent, and of higher quality than data used by other models, it can also benefit more focused analyses. In particular, the incremental data for co-optimization could potentially facilitate improved analyses of demand response, energy storage, energy efficiency, distributed generation, variable-output resources, capacity additions, uprates, and retirements, capacity degradation, and fuel prices. The benefit of better data for those studies might by itself justify the incremental cost of data for co-optimization planning.

We recommend development of data repositories for use with co-optimization tools, if such tools are developed. These data repositories should include characteristics of existing and already planned infrastructure, characteristics of infrastructure options from which the tool will select, and future conditions.

In developing these data repositories, it is important to capture geographical variability in infrastructure data. There are such variations in (1) availability, quality, and investment cost of renewable resources such as wind, solar, and biomass; (2) investment and fuel expenses for non-renewable resources such as coal and natural gas; and (3) investment costs of electric transmission. These variations should be reflected in the data set. It is precisely these variations in costs over space that co-optimization takes advantage of in order to lower costs relative to traditional generation- or transmission-only planning.

In addition, co-optimization modeling inevitably involves *data aggregation* in order to reduce the model size and computational burden involved in regional infrastructure planning. This implies a need for the various entities involved to share data and identify regional boundaries for resource aggregation (e.g., to account for transfer capacities).

### ES-7. Institutional Considerations

A well-designed planning process for generation and transmission that uses co-optimization needs to identify the needs of state regulatory and planning bodies, balance competing objectives of concern to stakeholders (such as cost, reliability, and environmental impact), and help allocate scarce resources among potential investment choices. Our analysis of the institutional issues associated with co-optimization concludes that robust co-optimization-based planning methods, reflecting the interests of local jurisdictions in the region, would likely be more effective in relieving regional transmission congestion and ensuring long-term resource adequacy. Such planning processes should provide a formal role for state governments and thus facilitate active participation by state officials: utility regulators, energy offices, consumer advocates, and environmental regulators, as appropriate to each state. It should also involve consumer and citizen interests as well as market players to guide the planning process. These are requirements under FERC Order 890, and co-optimization tools can facilitate informed involvement by stakeholders in this process.

Another institutional issue is co-ordination across different markets or regulatory jurisdictions. As the discussions over FERC Order 1000 have shown, there is strong interest in coordinating regional planning efforts in order to facilitate integration of renewables and lower the cost of power to consumers. Those discussions also show how difficult it is to achieve such coordination given our federal, devolved system of government and the diversity of institutions involved in planning. Institutional developments under Order 1000 should be followed closely to identify lessons that would be useful for conducting co-optimization studies. Co-optimization tools that encompass multiple regions will yield better estimates of the benefits of coordination of operations and investment across regions, which supports Order 1000's objectives.

A final issue is: who can interact in the planning process that utilizes co-optimization software and associated data? In unbundled markets, it is the case that generation owners are restricted to only the transmission information that is on OASIS and are limited in the communication they can have with transmission operators and planners. But yet co-optimization by definition considers interactions between generation investment and transmission reinforcements. It can be fairly asked: how can the need for separation be reconciled with the need to represent interactions and to have extensive data on both generation and transmission? We believe that the data necessary for informed co-optimization can be obtained and used by transmission processes overseen by utilities, states, and RTOs, but that restrictions on permissible communications will need to be understood and respected in those processes.

A final but very important point, made below.

**Co-optimized Expansion Planning –
A Mental Picture**

It is not a <u>predictive</u> application.

Rather, it is an exploratory application.
It enables exploration of how

- various designs perform
- over various conditions.

## References

[1] K. Wissman, "Competitive Electricity Markets and the Special Role of Ancillary Services, slides presented at the Licensing/ Competition and Tariff/Pricing Comm Meeting, Feb 4-5, 2008.

[2] F. Xiao and J. McCalley, "Power System Risk Assessment and Control in a Multi-objective Framework," *IEEE Transactions on Power Systems*, Vol. 24, No. 1, Feb. 2009, pp 78-87.

[3] E. Spyrou, J. Ho, B. Hobbs, R. Johnson, and J. McCalley, "What are the benefits of co-optimizing transmission and generation investment? Eastern Interconnection Case Study," under review by IEEE Transactions on Power Systems.

[4] "Comparing Pipes & Wires: A Joint Study by the Bonneville Power Administration and the Northwest Gas Association A capital cost analysis of energy transmission via natural gas pipelines and overhead electric wire lines," A Joint Study by the Bonneville Power Administration and the Northwest Gas Association, 2004, www.northwestchptap.org/nwchpdocs/transmission_and_n_gas_comparing_pipes_and_wires_032304.pdf.

[5] Y. Li and J. McCalley, "A Decimal-Binary Disjunctive Model for Value-based Bulk Transmission Expansion Planning," under development.

[6] L. Bahiense, G. C. Oliveira, M. Pereira, and S. Granville, "A mixed integer disjunctive model for transmission network expansion," *Power Systems, IEEE Transactions on*, vol. 16, no. 3, pp. 560–565, Aug. 2001.

[7] X. Wang and J. McDonald, "Modern Power System Planning," McGraw Hill Book Company, London, 1994.

[8] R. Romero, A. Monticelli, A. Garcia and S. Haffner, "Test systems and mathematical models for transmission network expansion planning," in Proc. 2002 IEE Generation Transmission Distribution, vol. 149, No. 1.

[9] Web page of the *Eastern Interconnection States Planning Council (EISPC)*: www.naruc.org/ncep/resources/eastern-interconnection-states-planning-council-eispc/.

[10] A. Liu, B. Hobbs, J. Ho, J. McCalley, V. Krishnan, M. Shahidehpour, Q. Zheng, "Co-optimization of transmission and other supply resources," Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, September 2013.