Transmission Planning and Co-optimization with Market-Based Generation and Storage Investment

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1 Introduction

Optimal transmission expansion planning (TEP) is not simply the addition of lines to already congested corridors in order to lower fuel costs through more efficient dispatch of the existing generation fleet. This is because the amount and location of generation investment as well as its dispatch might shift to take advantage of changes in network capabilities, and these shifts will in general unfold over the multidecadal lifetime of the transmission assets. In sum, transmission investment will change not only operating costs of generation but also investment costs. Thus, a TEP planner should anticipate changes in generation plant siting, amounts, and mixes. The traditional approach of evaluating the economic benefits of transmission just by valuing the resulting savings in operating costs results in distorted estimates of the benefits of transmission reinforcements and potentially suboptimal grid expansion decisions (CAISO 2004; MISO 2010).

Transmission–generation expansion co-optimization tools are designed for this job: they help TEP planners to plan transmission in a proactive manner so that transmission planners are able to select the lines anticipating the market reactions of generation investors (Krishnan et al. 2015; Liu et al. 2013). Several generation–transmission co-optimization models have been published and are being tested by regional transmission agencies. Most are formulated as optimizations that minimize the total capital and operating cost of the joint transmission–generation system or as maximizing net market benefits (value of energy consumption minus those costs). The assumption of such models is that the underlying generation market is perfectly competitive with no major market failures (which is equivalent to net market benefits

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maximization for just generation) and that the transmission planner's objective is also to maximize net market benefits (van der Weijde and Hobbs 2012). Thus, the bi-level structure of decision making in the market (transmission acting as a "Stackelberg leader" with respect to generation followers) reduces to a convenient-to-solve single-level optimization. Other models, however, recognize that serious imperfections exist in the generation market (externalities, subsidies, market power, regulated prices) that mean that instead an explicitly bi-level optimization approach is called for. Such problems are inherently more difficult to solve, but recent progress has been made (Pozo et al. 2013; Tohidi et al. 2017).

In addition to market failures in generation markets, another challenge to TEP is the rise of new types of supply technologies, as well as storage and demand response. The challenges of a load growth together with renewables could be met with a greatly expanded grid, but storage and demand technologies hold the promise of lowering the cost of renewables integration and also being less costly in at least some cases than new transmission. A proactive TEP should therefore anticipate the response of investments in new technologies. This is the focus of this chapter; in particular, we expand least-cost types of co-optimization models to include storage as well as transmission and generation. With the cost of energy storage plummeting rapidly, consideration of storage might greatly affect TEP.

To anticipate energy storage sizing and siting, the classic generation–transmission co-optimization TEP model needs to be expanded. Here, we show an example of such an expanded TEP approach. The model selects the best set of lines while simulating the profit-maximizing reaction of competitive generation and storage investors in terms of the siting and sizing of new facilities. After parameterizing the model for the Western Electricity Coordinating Council (WECC, consisting of the western provides and states of Canada and the USA, respectively), we identify at what levels of battery investment costs it becomes economically valuable to consider storage expansion in TEP.

The rest of this chapter is organized as follows. In Sect. 2, we provide some background: the interactions of transmission and generation and the complications posed by storage; a historical view of co-optimization of transmission and generation expansion; finally, a procedure to calculate the economic value of considering storage expansion in TEP. In Sect. 3, we formulate a static (single year) co-optimization of transmission, generation, and storage expansion. In Sect. 4, we present a case study for the WECC regions. We conclude this chapter in Sect. 5.

2 Background

2.1 Interactions Among Transmission, Generation, and Storage

Generation and transmission expansions interact in complex ways. Fundamentally, they can be complements (investment in one increases the market value of investment in another) or substitutes (investment in one lowers the market value of the other). Transmission is valuable just because of its capability to deliver electricity from a cheap resource to the demand, avoiding turning on an expensive local generation; thus, transmission is a complement to the remote resource but a substitute for the local one. As specific examples, transmission and generation complement each other in cases such as mine-mouth coal power plants and wind farms that are distant from load centers: cheap power is only valuable when deliverable. The opposite can also be true: when local generation, such as gas turbines or rooftop solar panels, became cheap, it diminishes the value of new transmission into a load pocket, and so, generation and transmission become substitutes.

The rise of electricity storage, especially distributed storage in the form of batteries, is making this story more complicated. First, storage can both compete with and complement generation. Storage can compete with conventional generation, for instance in meeting peak loads. Regulators encourage this competition: Order No. 841 (FERC 2018) from the U.S. Federal Energy Regulatory Commission requires that independent system operators adjust their rules and market software so that storage can compete with the generation in the energy, ancillary service, and installed capacity markets. The fast ramping response of electric storage implies that storage and generation may compete fiercely in reliability markets as the cost of storage decreases. However, storage, because of its fundamental ability to shift supply from one time period to another, can be a complement to generation with less operational flexibility (e.g., base-loaded thermal plants) or intermittent availability (e.g., variable renewable energy, VRE). Indeed, pumped storage plants were often justified in the 1960s and 1970s because of this complementarity with nuclear plants which are most efficient when run flat out for all hours. Nowadays, however, the focus is on storage's complementarity with VRE; such storage will be essential to achieving the very high renewable penetrations that are the targets in some jurisdictions (e.g., 100% in Hawaii and California).

Storage also interacts with the transmission, but in a somewhat subtler way: they are both arbitragers of the energy, with the transmission arbitraging over space and storage doing so over time. They can both facilitate higher penetrations of VRE. A better interconnection can help in the following way: at a certain point in time, unexpected under-generation of VRE in one place can be made up by transmission delivering available production from another plant (e.g., another VRE) from hundreds of km away. This may, for instance, avoid starting up or ramping of local generation that is perhaps both costly and polluting. On the other hand, storage can also resolve local shortfalls by, in effect, delivering cheap output of a plant that was produced several hours or even days or months ago (e.g., from wind or hydro energy that would have otherwise been curtailed or "spilled").

Transmission and storage are not always competing. As a simple case, we can imagine a distant wind farm might be more economical because of a bundled storage facility, and hence, a transmission project also becomes valuable. On the other hand, this nearby storage could enable a transmission facility to be downsized and still deliver the same amount of VRE production.

Overall, the interactions among transmission, generation, and storage will strongly affect the economic value of transmission reinforcements. Hence, from the perspective of transmission planner, a planning model with the ability to capture the above interactions becomes valuable and informative. We shall next discuss co-optimization tools that have this capability.

2.2 Using Co-optimization to Support Transmission Expansion Planning

Co-optimization of transmission and generation planning is not a new topic. The mathematics problems describing siting generation and transmission together can be dated back at least to 1977 (Sawey and Zinn 1977). However, the meaning of co-optimization of transmission and generation expansion changed with time went by, and the major breaking point was the deregulation of the power sectors in Europe and the USA.

"*Co-optimization*" used to mean co-planning of just generation and transmission. When most of the power industry was still vertical integrated, generation planners and transmission planners were able to work together: generation expansion plans were first developed and handed to the transmission planners, transmission plan was then developed and may or may not be handed back to the generation planners for more iterations. In this iterative manner, the interaction between generation and transmission was at least partially accounted for by these vertically integrated monopolies.

The meaning of co-optimization has enriched since the deregulation of the power industry in Europe and the USA in the 1990s. In the newly established markets, the planning of transmission and generation expansions is separated and, respectively, performed by grid owners/transmission system operators (TSOs)/regional transmission organizations (RTOs) and generation companies. Without the full co-operation of the generation planners and, at the same time, lacking tools to anticipate how generation siting would respond to grid changes, many transmission planners have been forced to treat the locations and amounts of generation capacity as purely exogenous "boundary conditions": they would have to assume scenarios in which the generation siting is known and then plan the transmission expansion based on the scenarios. This is called "*reactive*" transmission expansion planning: transmission planners react to the generation expansion.

In contrast to "reactive" transmission expansion planning, "*proactive*" transmission expansion planning anticipates how generation investors will choose the sites, types, sizes, and timing of changes in their assets in reaction to the network plan and then choose the best set of transmission expansion projects. From the point of view of game theory, the game between transmission and generation is a bi-level or "Stackelberg" game. The transmission planner is a leader who optimizes subject to the anticipated reactions of a set of generation investors who are Nash players who do not anticipate how the grid plan would change in response to generation decisions. It is natural to place transmission in the role of a leader because transmission assets generally take much longer to plan and build than the natural gas-fired or renewable generating assets that constitute most or all of generation additions in North America and Europe today.

Transmission and generation co-optimization models can be seen as one of several types of "proactive" transmission expansion planning models if the following strong assumptions are made (Liu et al. 2013; Spyrou et al. 2017; Sauma and Oren 2006):

- The transmission expansion planner has an objective of maximizing market surplus (what the economists call "market efficiency" or "social welfare"). This is defined as the sum of surpluses accrued by all market parties, including profits earned by each resource and storage; transmission congestion surplus minus incremental grid costs; consumer surplus. If demand is perfectly inelastic (fixed), this objective is equivalent to minimizing the sum of resource, storage, and transmission costs.
- Short-run (spot) electricity markets, including energy, ancillary service, and capacity markets, are perfectly competitive. All suppliers are price takers and profit maximizers.
- Similarly, in the long run, generation expansion planners are siting optimally and competitively to maximize their profits, given the cost of transmission as reflected in locational marginal prices, which depend on the grid and all suppliers' decisions.

Of course, this basic proactive model simplifies reality but then does all models. These assumptions enable the bi-level game to be solved as a single optimization model since the TEP objective of maximizing market surplus is consistent with perfect competition on the lower level, which can be modeled by maximizing total market surplus as well. Relaxing any of those three assumptions will generate a new type of "proactive" transmission planning model that in general will have a difficult to solve bi-level structure in which the leader and follower objectives are not aligned. Although out of the scope of this chapter, readers that are interested in "proactive" transmission expansion models formulated explicitly as bi-level or multi-level games are referred to Pozo et al. (2013), Tohidi et al. (2017), Sauma and Oren (2006), Jenabi et al. (2013), Jin and Ryan (2014), Jin and Ryan (2014), Gonzalez-Romero et al. (2019).

Another way in which co-optimization models can be broadened is by including more types of market players, including consumers (i.e., demand response) and the storage. As mentioned before, in Feb. 2018, the FERC issued Order No. 841 to urge the US markets under its purview to modify their tariffs to make sure that electric storage can compete with the conventional generators in the energy, ancillary service, and capacity markets so that energy storage can participate fully in spot markets and are able to set prices.

With electricity storage coming into play, co-optimization models must now co-optimize (or anticipate) the siting and operation of storage. As a result, additional assumptions are needed, namely that storage owners are competitive. They therefore choose the timing, type, size, and location of storage facilities to maximize their profit subject to locational commodity prices that they assume they cannot alter. Reflecting the new FERC rules, practical co-optimization models usually assume that storage owners can either let the ISO dispatch their facilities optimally or, equivalently, they self-schedule with perfect foresight of the time-varying prices they will receive.

2.3 Quantify the Economic Value of Considering Storage Expansion in Transmission Expansion Planning

As battery costs continue to decline, batteries, fly wheels, compressed air, and other storage devices will more likely interact with and change the value of transmission and generation. Traditional vertically integrated utilities will likely adapt their generation and transmission planning methods to consider how possible investments in storage might change optimal investments in other assets. In restructured, vertically disintegrated markets, on the other hand, storage is another player whose operating and investment decisions will need to be anticipated by transmission planners in the proactive paradigm. If the effects of grid reinforcements on the siting, sizing, and timing of storage investment are disregarded in TEP, the result might be a different—and economically inferior—transmission plan. We now address the question: how can we quantify the value of considering storage in a proactive TEP? We propose and demonstrate a procedure for quantifying this value in the remainder of this chapter. The demonstration is for the western USA and Canada system (WECC) for the year 2034. Previous work (Spyrou et al. 2017) has quantified the value of anticipating how grid reinforcements affect generation expansion in TEP (i.e., the "value of generation-proactive TEP") for the eastern USA and Canada system. There, we show that iterating between (1) solving a TEP subject to a fixed generation build-out and (2) solving a generation expansion problem (GEP) subject to a fixed network can realize only part of the value of generation-proactive TEP.

In summary, the quantification of the value of considering storage in proactive TEP involves three steps: (1) plan with co-optimization of storage, generation, and transmission; (2) plan disregarding the possibility of storage installation and how it reacts to network expansions; and (3) evaluation of the latter, potentially flawed plan by modeling the "actual" reaction of storage and generation to that plan. The first step is the full co-optimization, where the transmission expansion is planned anticipating the reactions of both generation and storage installations. The results of this step are the optimal plan (a set of selected transmission projects) and a minimized system cost. In the second step, a transmission expansion plan is obtained from a "flawed" planning model, where the installation of storage is ignored and only generation is considered in a co-optimization framework. Finally, we evaluate this "flawed" plan by plugging it into the co-optimization model (fixing the network decision variables at their flawed values) and getting a new minimized cost for the generation and storage followers, which may involve installation of storage but at potentially different locations and in different amounts than the full co-optimization. The difference in the costs between steps 1 and 3 is the value of considering storage in transmission expansion planning. Because step 3 is more constrained than step 1, its cost will be no lower than the full co-optimized model and is potentially higher. We call this increase in cost the "*value of model enhancement for storage*" (VoMES). Another closely related term, "*value of storage*" (VoS), can also be defined as the objective function improvement if storage is allowed to be expanded in the system, i.e., the differences in the objective function values resulting from step 1 and 2. For example, the VoS under alternative incentive mechanisms for merchant transmission expansions is calculated for IEEE test-systems in Khastieva et al. (2019). These results show that the VoS is relatively small compared to system cost ($2 Million comparing to $442 Million) but can be more than three times higher than that amount if transmission expansion incentives are provided. The conceptual differences and relationship between VoMES and VoS will be discussed at the end of this section.

We now present the details of each step, including the TEP co-optimization models that we apply.

Step 1. Planning with Co-optimization (Benchmarking) Imagine we have a TEP tool which can select the best set of new transmission lines (T) by anticipating the construction of new generation (G), the installation of new storage (S), and the system operation (P) to minimize annualized system cost $C(T, G, S, P)$ (in $/yr) for some future scenario year. (Existing facilities are implicitly in the model as well.) All the decision variables are subject to the feasible region (F) which is defined by the physical operating constraints for the network as well as individual resources (e.g., Kirchhoff's laws, line and resource capacity limits, ramp limits, state-of-charge relationships, etc.) and policy constraints such as renewable portfolio standards or emissions limits. An abstract mathematical programming problem (MP1) can be shown as follows, whose detailed formulation can be found in the next section:

$$\begin{aligned} \text{Minimize}_{T,G,S,P} \quad & C(T, G, S, P) \\ \text{s.t.} \quad & (T, G, S, P) \in F \end{aligned}$$

If this is solved to optimality, it will return a solution of (T^*, G^*, S^*, P^*) and a system cost of $C(T^*, G^*, S^*, P^*)$. (Note that if demand is elastic, instead of minimizing cost, we would instead be maximizing net market surplus, recognizing the value of benefits associated with different levels of consumption as captured by the integrals of demand curves).

By definition, $C(T^*, G^*, S^*, P^*)$ is the lowest cost that the model can achieve and T^* is the optimal transmission plan provided by the model. In other words, any transmission plan other than T^* will lead to a system cost no lower than $C(T^*, G^*, S^*, P^*)$, and hence, that network configuration and the associated cost can be used as a benchmark.

Step 2. Planning without storage anticipation Imagine the planner chooses to ignore the storage installation in the TEP. Mathematically, it means forcing $S = 0$ in the formulation above (MP1). Thus, we are solving the following problem (MP2) instead:

$$\begin{aligned} \text{Minimize}_{T,G,P} \quad & C(T, G, 0, P) \\ \text{s.t.} \quad & (T, G, 0, P) \in F \end{aligned}$$

Let the solution of this TEP model be $(\hat{T}, \hat{G}, 0, \hat{P})$ and the associated system cost be $C(\hat{T}, \hat{G}, 0, \hat{P})$. $\hat{T}$, therefore, stands for the optimal transmission expansion plan that the planner can get if they ignore the possibility of installing storage.

Step 3. Plan Evaluation Imagine the transmission expansion plan from Step 2 is implemented. Mathematically, it means forcing $T = \hat{T}$ in MP1; equivalently, we are solving the following problem (MP3):

$$\begin{aligned} \text{Minimize}_{G,S,P} \quad & C(\hat{T}, G, S, P) \\ \text{s.t.} \quad & (\hat{T}, G, S, P) \in F \end{aligned}$$

Let $(\hat{T}, \overline{G}, \overline{S}, \overline{P})$ be the solution of MP3 and $C(\hat{T}, \overline{G}, \overline{S}, \overline{P})$ be the associated objective function. By definition, $C(\hat{T}, \overline{G}, \overline{S}, \overline{P})$ is no lower than $C(T^*, G^*, S^*, P^*)$ since the former is the system cost resulted from choosing a transmission plan $\hat{T}$ other than the optimal T^*. One can thus naturally conclude that the cost of ignoring storage installation leads to a different plan and a cost no lower than the optimal. And the difference between $C(\hat{T}, \overline{G}, \overline{S}, \overline{P})$ and $C(T^*, G^*, S^*, P^*)$ is the "*value of model enhancement to consider storage*" (VoMES) in TEP:

$$\text{VoMES} = C(\hat{T}, \bar{G}, \bar{S}, \bar{P}) - C(T^*, G^*, S^*, P^*).$$

In a sense, this is the value of "smart" planning that proactively anticipates how storage will be installed and used, versus a naïve plan that overlooks storage.

This value of smart planning is distinct from the overall "*value of storage*" VoS to the system, as in Khastieva et al. (2019), which is the cost improvement from a co-optimized plan that only includes transmission and generation to a plan that co-optimized storage as well. This is the reduction in cost from MP2 (no storage) to MP1 (all options):

$$\text{VoS} = C(\hat{T}, \hat{G}, 0, \hat{P}) - C(T^*, G^*, S^*, P^*)$$

Note that VoMES $\leq$ VoS because the cost of MP3 will necessarily be no higher than MP2's cost. This is because MP2 and MP3 have the same value of T, but MP3 is free to choose both G and S, while MP2 can only choose G since S is constrained to zero. Their relationship is shown in Fig. 1. One implication of this inequality is that the economic value that storage can potentially provide to the system can be offset by naively disregarding storage expansion and its response to transmission in TEP, in which case, the net benefit will be the remainder of (VoS–VoMES). Thus, the larger VoMES is (as proportion of VoS), the greater the loss of storage benefits will be if naïve rather than proactive transmission planning is undertaken; in other words, the benefits of storage to the system are more dependent on transmission expansion planning.

In this chapter, our focus is on the value of modeling to implement proactive TEP, so our major interest is in the calculation of VoMES to show what can be gained from proactive planning. But the calculation of VoS is also useful as it illustrates one of the many types of insights that can be obtained from applying TEP models. Readers should also bear in mind that the term of VoMES and VoS are not limited to the anticipated storage expansion, and we can easily extend such concepts to other aspects

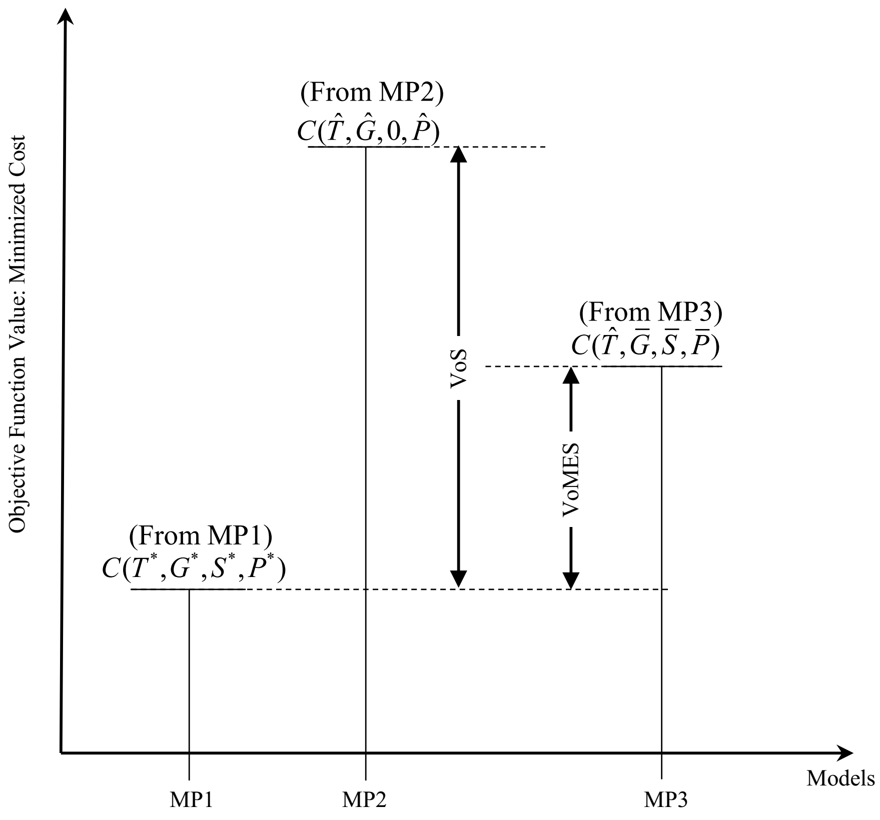

Fig. 1 Diagram of Value of Model Enhancement to consider Storage (VoMES) and the Value of Storage (VoS)

of electricity system. The value of enhancing a model with generation–transmission co-optimization is calculated in (Spyrou et al. 2017) (i.e., VoME of co-optimization), showing that co-optimization can double the net cost savings from transmission expansion, comparing to purely reactive TEP; iterative planning (alternating between transmission and generation capacity expansion models) can partially but not fully realize these benefits. For a review of enhancements that have been implemented in transmission expansion models, reader is referred to (Xu and Hobbs 2018).

3 Detailed Formulation

In this section, we show a formulation of the static transmission expansion problem co-optimized with generation and storage expansion. For a review of literature on co-optimization transmission and storage but omitting generation expansion, we refer the reader to (Khastieva et al. 2019; Qiu et al. 2017). Some general assumptions include the following.

- In general, TEP models need to consider both short- and long-run uncertainties since elsewhere we have shown that considering a range of long-run economic, regulatory, and technological scenarios in a two-stage stochastic programming framework can make a significant and economically important difference in transmission plans. However, for the sake of simplicity in this chapter, the consideration of uncertainty will be limited to short-term variability, namely load, wind, solar, and hydro conditions. For reviews of TEP models that consider long-term uncertainties, readers are referred to van der Weijde and Hobbs (2012), Ho et al. (2016), Munoz et al. (2014) and Park et al. (2018).
- The operating constraints and costs of this model include the linearized unit commitment formulation that was proposed in Kasina et al. (2013), in which start-up costs are included in the cost objective, while ramp rates, start-ups, and minimum output levels constrain generation levels. A more comprehensive version of this formulation with long-term planning and long-run uncertainties can be found in Xu et al. (2017). Meanwhile, classic unit commitment formulations that use binary variables to represent generator commitment status are given by Takriti et al. (1996) and Morales et al. (2013); such variables are difficult to include in long-term planning models due to the desire to avoid nonlinearities and impractically large MILP models, and so, transmission planning models tend to use simpler operating models.
- The network formulation is based upon a combination of a linearized DC load flow (DCOPF), which represents how Kirchhoff's Voltage Law induces parallel flows in the network, and disjunctive constraints that utilize the Big-M formulation (Winston et al. 2003). Only high voltage facilities are represented. For more advanced power flow modeling including transmission losses and reactive power, readers are referred to Zhang et al. (2013), Ozdemir et al. (2016).

- Renewable portfolio standards by state are represented, including rules allowing one state to use renewable energy credits generated in other states to meet renewable obligations. Carbon policy is represented by a tax on carbon emissions.

We begin by introducing notation, and then, the objective function and constraints of model MP1.

Sets

A	Load areas, index a
ES	Storage facilities, index esk
K	Generators, index k
H	Hours, index h
I	Buses, index i
L	Transmission lines, index l
RP	Unidirectional renewable energy credit trading paths, index rp
ST	States, index stt

Variables

$\mathrm{g}_{k,h}$	Power production by the generator (MW)
gcap_k	Capacity of the generator (MW)
gexp_k	Generation capacity expansion (MW)
$\mathrm{gr}_{k,h}$	Operating reserve provided by the generator (MW)
gret_k	Generation retirement (MW)
$\mathrm{gsd}_{k,h}$	Minimum run capacity shut down at hour h (MW)
$\mathrm{gsu}_{k,h}$	Minimum run capacity started up at hour h (MW)
lav_l	Transmission line availability (binary)
lexp_l	Transmission expansion (binary)
$\mathrm{nl}_{i,h}$	Curtailed load on the bus i at the hour h (MW)
nr_{stt}	Non-compliance with RPS policy (MWh)
rt_{rp}	Renewable energy credit traded on the path rp (MWh)
sav_{esk}	Storage availability (binary)
$\mathrm{sch}_{esk,h}$	Charging energy withdrawn from the network by storage (MW)
$\mathrm{sdc}_{esk,h}$	Injection of the storage into the network (MW)
sexp_{esk}	Storage expansion (Binary)
$\mathrm{sl}_{esk,h}$	State of charge of storage at the beginning of the hour h
$\mathrm{sr}_{esk,h}$	Operating reserve provided by storage when injecting
$\mathrm{pf}_{l,h}$	Power flow on the transmission line (MW)
$\mathrm{pmin}_{k,h}$	Minimum run level of the generator (MW)
$\theta_{i,h}$	Voltage phase angle at bus i

Cost Parameters

CB	Carbon tax (\$/metric ton CO_2e)
CD_k	Shutdown cost (\$/MW)

CFG_k	Fixed operation and maintenance cost of the generator ($/MW-year)
CFS_{esk}	Fixed operation and maintenance cost of the storage ($/MW-year)
CG_k	Capital cost of generation expansion ($/MW-year)
CL_l	Capital cost of transmission expansion ($/year)
CS_{esk}	Capital cost of storage expansion ($/MWh-year)
CU_k	Start-up cost ($/MW)
$CVG_{k,h}$	Variable cost of generator injection without carbon cost ($/MWh)
SG_k	Salvage value of generator retirement ($/MW-year)

Constraint Parameters

ACP_{stt}	Alternative compliance penalty for RPS compliance ($/MWh)
B_l	Susceptance of line (p.u.)
$BAI_{i,a}$	Bus area incidence, 1 if bus i is located in the area a
BM_l	Big M for DCOPF disjunctive constraints
$BSI_{i,stt}$	Bus state incidence, 1 if bus i is located in state stt
$D_{i,h}$	Load on the bus i (MW)
ER_k	Carbon emission rate of generator k (Metric Ton CO_2e/MWh)
$GBI_{k,i}$	Generator bus incidence, 1 if generator k is located on bus i
$HAV_{k,h}$	Hourly resource availability (fraction of capacity)
HW_h	Number of hours that hour h is representing per year (hour/year)
$IGCAP_k$	Initial (existing) capacity of the generator (MW)
$ILAV_l$	Initial availability of the transmission line, 1 if available (binary)
$IRPS_{stt}$	In-state requirement for a particular state's RPS (fraction)
$ISAV_{esk}$	Existing availability of the storage, 1 if available to the grid (binary)
$LBI_{l,i}$	Line bus incidence, -1 if i is the from-bus of line l, 1 for the to-bus
MC_{esk}	Maximum charge capacity for the storage to expand (MW)
MD_{esk}	Maximum additional investment in storage discharge capacity (MW)
MDT_k	Minimum down time of the generator
MG_k	Maximum additional investment that can be added for a generator (MW)
ML_{esk}	Maximum energy capacity for the storage to expand (MWh)
MRT_k	Minimum (scheduled) retirement of the generator (MW)
MUT_k	Minimum up time of the generator
PBASE	The base power unit of the system (MW)
$QMIN_k$	Minimum run (fraction of maximum capacity)
$RE_{stt,k}$	RPS eligibility, 1 if generator k is tagged as renewable in state stt
$REX_{rp,stt}$	1 if trading path rp is from state stt
$RIM_{rp,stt}$	1 if trading path rp is to state stt
RM_a	Operating reserve margin of the area a
RPS_{stt}	Renewable portfolio standard of state stt (fraction of total annual MWh)
RR_k	Ramp-rate (fraction of started up capacity)
$SBI_{esk,i}$	Storage bus incidence, 1 if storage esk is located on the bus i
TM_l	Thermal limit of transmission line (MW)

VL Value of loss load ($/MWh)
η_{esk} Single-trip efficiency of the storage (%)

Objective Function
The co-optimization's objective is to minimize annualized system cost. The capital costs of generation, transmission, and storage are incorporated by annualizing those costs using capital recovery factors. Total system cost is as follows:

$$\begin{aligned}
\text{Objective} = {} & \sum\nolimits_{k} \left(\mathrm{CG}_k\, \mathrm{gexp}_k - \mathrm{SG}_k\, \mathrm{gret}_k\right) + \sum\nolimits_{k} \mathrm{CFG}_k\, \mathrm{gcap}_k + \\
& \sum\nolimits_{esk} \mathrm{CS}_{esk} \mathrm{ML}_{esk}\, \mathrm{sexp}_{esk} + \sum\nolimits_{esk} \mathrm{CFS}_{esk} \mathrm{MD}_{esk}\, \mathrm{sav}_{esk} + \\
& \sum\nolimits_{k,h} \mathrm{HW}_h \left(\mathrm{CVG}_{k,h}\, \mathrm{g}_{k,h} + \frac{\mathrm{CU}_k}{\mathrm{QMIN}_k} \mathrm{gsu}_{k,h} + \frac{\mathrm{CD}_k}{\mathrm{QMIN}_k} \mathrm{gsd}_{k,h}\right) + \\
& \sum\nolimits_{l} \mathrm{CL}_l\, \mathrm{lexp}_l + \\
& \sum\nolimits_{i,h} \mathrm{HW}_h\, \mathrm{VL}\, \mathrm{nl}_{i,h} + \sum\nolimits_{stt} \mathrm{ACP}_{stt}\, \mathrm{nr}_{stt} + \sum\nolimits_{k,h} \mathrm{HW}_h\, \mathrm{CBER}_k\, \mathrm{g}_{k,h}
\end{aligned} \tag{1}$$

The objective function is composed of five components [lines 1–5 in (1)]. The first line is the build cost/salvage value of the generation as well as generation's fixed operation and maintenance costs. The second line is the build cost and fixed operation and maintenance cost of storage. The third line is the variable cost, start-up, and shutdown cost of generation. The fourth line is the build cost of transmission lines. And finally, the last line is the cost of curtailed load and two policy-related costs: the alternative compliance penalty of the RPS policy and the carbon tax.

Constraints–Investment

$$\mathrm{gcap}_k = \mathrm{IGCAP}_k + \mathrm{gexp}_k - \mathrm{gret}_k \quad \forall k \tag{2}$$

$$\mathrm{sav}_{esk} = \mathrm{ISAV}_{esk} + \mathrm{sexp}_{esk} \quad \forall esk \tag{3}$$

$$\mathrm{lav}_l = \mathrm{ILAV}_l + \mathrm{lexp}_l \quad \forall l \tag{4}$$

$$\mathrm{gret}_k - \mathrm{MRT}_k \geq 0 \quad \forall k \tag{5}$$

$$\mathrm{gcap}_k - \mathrm{MG}_k \leq 0 \quad \forall k \tag{6}$$

Constraints (2)–(6) establish the relationship between the investment decision and the availability of the generation capacity, storage facility, and the transmission line.

Constraints–Generation Operation

$$\mathrm{g}_{k,h} + \mathrm{gr}_{k,h} \le \mathrm{HAV}_{k,h}\,\mathrm{gcap}_k \quad \forall k, h \tag{7}$$

$$\mathrm{g}_{k,h} \ge \mathrm{pmin}_{k,h} \quad \forall k, h \tag{8}$$

$$\mathrm{g}_{k,h} + \mathrm{gr}_{k,h} \le \frac{\mathrm{pmin}_{k,h}}{\mathrm{QMIN}_k} \quad \forall k, h \tag{9}$$

$$\mathrm{pmin}_{k,h} \le \mathrm{QMIN}_k\,\mathrm{gcap}_k \quad \forall k, h \tag{10}$$

$$\mathrm{pmin}_{k,h} - \mathrm{pmin}_{k,h-1} = \mathrm{gsu}_{k,h} - \mathrm{gsd}_{k,h} \quad \forall k, h \tag{11}$$

$$\left(\mathrm{g}_{k,h} + \mathrm{gr}_{k,h} - \mathrm{pmin}_{k,h}\right) - \left(\mathrm{g}_{k,h-1} - \mathrm{pmin}_{k,h-1}\right) \le \frac{\mathrm{RR}_k}{\mathrm{QMIN}_k}\mathrm{pmin}_{k,h-1} \quad \forall k, h \tag{12}$$

$$\left(\mathrm{g}_{k,h} - \mathrm{pmin}_{k,h}\right) - \left(\mathrm{g}_{k,h-1} + \mathrm{gr}_{k,h-1} - \mathrm{pmin}_{k,h-1}\right) \ge -\frac{\mathrm{RR}_k}{\mathrm{QMIN}_k}\mathrm{pmin}_{k,h-1} \quad \forall k, h \tag{13}$$

$$\left(\mathrm{g}_{k,h-1} + \mathrm{gr}_{k,h-1}\right) - \mathrm{gsd}_{k,h} \le \frac{\mathrm{pmin}_{k,h}}{\mathrm{QMIN}_k} \quad \forall k, h \tag{14}$$

$$\left(\mathrm{g}_{k,h} + \mathrm{gr}_{k,h}\right) - \mathrm{gsu}_{k,h} \le \frac{\mathrm{pmin}_{k,h-1}}{\mathrm{QMIN}_k} \quad \forall k, h \tag{15}$$

$$\mathrm{pmin}_{k,h} \le \mathrm{QMIN}_k \mathrm{gcap}_k - \sum_{(h-\mathrm{MDT}_k \le h' \le h)} \mathrm{gsd}_{k,h'} \quad \forall k, h \tag{16}$$

$$\mathrm{pmin}_{k,h} \ge \sum_{(h-\mathrm{MUT}_k \le h' \le h)} \mathrm{gsu}_{k,h'} \quad \forall k, h \tag{17}$$

Constraints (7)–(17) constrain the operation of the generators. Constraint (7) is for the generators that are not subject to unit commitment constraints, i.e., (8)–(17); in particular, the wind, solar, hydro, and other intermittent resources are subject to hourly profiles, i.e., $\mathrm{HAV}_{k,h}$ for those resources range between 0 and 1 depending on availability of the resource. Constraints (8)–(17) are the linearized version of the unit commitment, featured by the continuous variable $\mathrm{pmin}_{k,h}$ with a unit of MW. The reader should notice that the linearized version of unit commitment enables the transmission planner to consider the limited generation flexibility in a large system with aggregated capacity without adding any binary variables, thus speed up the TEP model with generation to optimization. The explanation of the unit commitment constraints (8)–(17) is shown below.

Constraint (8) is the minimum run constraint, and constraint (9) is the maximum run constraint. Note if the minimum run started up is $\mathrm{pmin}_{k,h}$, the maximum run started up is thus $\text{pmin}_{k,h}/\text{QMIN}_k$. Constraint (10) restricts that the maximum run can be started up cannot exceed the available capacity. Constraint (11) is the start-up–shutdown relation constraint.

Constraints (12) and (13) are the ramp-rate constraints: the generation above minimum run that needs to be ramped down/up in the next hour is subject to the ramp rate. In particular, constraints (12) and (13) are more conservative than a normal ramp-rate constraint: (12) is showing the ramp-up constraint is assuming the awarded operating reserve $\text{gr}_{k,h}$ will be activated in hour h; while (13) is assuming the awarded operating reserve $\text{gr}_{k,h-1}$ has been activated in hour $h-1$.

Constraint (14) is a type of shut-down-ready constraint: if at hour h, a part of the minimum run will be shut down, and the corresponding capacity must be operated at the minimum run (equals to $\text{gsd}_{k,h}$) in hour $h-1$. Furthermore, the remaining part of the generation in hour $h-1$ (i.e., $\text{g}_{k,h-1} + \text{gr}_{k,h-1} - \text{gsd}_{k,h}$) is subject to the remaining part of capacity $\text{pmin}_{k,h}/\text{QMIN}_k$. Similarly, in constraint (15), if some capacity is started up at h (i.e., $\text{gsu}_{k,h} > 0$), then the maximum electricity provided (excluding the newly started up capacity) by this generator is actually the maximum capacity at $h-1$.

Constraints (16) and (17) are the minimum uptime and downtime constraints. In particular, (16) is showing the minimum run at hour h cannot be higher than the total minimum run minus the minimum runs that are just shut down (i.e., $\text{gds}_{k,h'}$ where $h\text{-MDT}_k \le h' \le h$). The similar deduction can be made for constraint (17).

Constraints–Storage Operation

$$\text{sl}_{esk,h+1} = \text{sl}_{esk,h} + \eta_{esk}\text{sch}_{esk,h} - \frac{1}{\eta_{esk}}\text{sdc}_{esk,h} \quad \forall esk, h \tag{18}$$

$$\text{sl}_{esk,h} \le \text{ML}_{esk}\text{sav}_{esk} \quad \forall \text{esk}, h \tag{19}$$

$$\text{MD}_{esk}\text{sch}_{esk,h} + \text{MC}_{esk}\left(\text{sdc}_{esk} + \text{sr}_{esk,h}\right) \le \text{MD}_{esk}\text{MC}_{esk}\text{sav}_{esk} \quad \forall esk, h \tag{20}$$

$$\text{sl}_{esk} \ge \frac{1}{\eta_{esk}}\left(\text{sdc}_{esk,h} + 0.5\,\text{sr}_{esk,h}\right) \quad \forall esk, h \tag{21}$$

Constraints (18)–(21) are for storage operation simulation. Constraint (18) is tracking the state of charge of the storage, and (19) is the state-of-charge upper limit. Constraint (20) is a tight constraint for storage output upper limit and is particularly useful to mitigate the situation where charge and discharge are simultaneously non-zero, and discharge and charge capacities are different. If both are non-zero, (20) will make sure they limit each other since they shared the power capacity. If one of them is zero, (20) will become the capacity constraint of the other: for instance, if $\text{sch}_{esk,h} = 0$, (20) becomes $(\text{sdc}_{esk,h} + \text{sr}_{esk,h}) \le \text{MD}_{esk}\ \text{sav}_{esk}$. Constraint (21) guarantees that the state of charge is enough for generation and a half-hour activation of any operating reserve capacity that storage has provided to the market.

Constraints–Transmission

$$\sum\nolimits_k \mathrm{GBI}_{k,i}\, \mathrm{g}_{k,h} + \sum\nolimits_{esk} \mathrm{SBI}_{esk,i}\left(\mathrm{sdc}_{esk,h} - \mathrm{sch}_{esk,h}\right) + \sum\nolimits_l \mathrm{LBI}_{l,i}\, \mathrm{pf}_{l,h} + \mathrm{nl}_{i,h} - \mathrm{D}_{i,h} = 0 \quad \forall i, h \tag{22}$$

$$\left|\mathrm{pf}_{l,h}\right| \le \mathrm{TM}_l \mathrm{lav}_l \quad \forall l, h \tag{23}$$

$$\left|\mathrm{pf}_{l,h} + \mathrm{PBASE\,B}_l \sum\nolimits_i \mathrm{LBI}_{l,i}\theta_{i,h}\right| \le \mathrm{BM}_l(1 - \mathrm{lav}_l) \quad \forall l, h \tag{24}$$

$$\left|\sum\nolimits_i \mathrm{LBI}_{l,i}\theta_{i,h}\right| \le \frac{\pi}{6} \quad \forall l, h \tag{25}$$

Constraints (22)–(25) are the network constraints. Constraint (22) is Kirchhoff's Current Law and (23) is the thermal limit constraint, which may also reflect security-based limits where such limits are tighter. Constraint (24) is Kirchhoff's Voltage Law and (25) limits the phase angle difference on the transmission line.

Constraints—Operating Reserve and RPS

$$\sum_i \mathrm{BAI}_{i,a}\left(\sum_k \mathrm{GBI}_{k,i}\, \mathrm{gr}_{k,h} + \sum_{esk} \mathrm{SBI}_{esk,i}\left(\mathrm{sr}_{esk,h} + \mathrm{sdc}_{esk,h}\right)\right) \ge \mathrm{RM}_a \sum_i \mathrm{BAI}_{i,a}\mathrm{D}_{i,h} \quad \forall a, h \tag{26}$$

$$\sum_{k,h} \mathrm{HW}_h \mathrm{RE}_{k,stt}\mathrm{g}_{k,h} + \sum_{rp}\left(\mathrm{RIM}_{rp,stt} - \mathrm{REX}_{rp,stt}\right)\mathrm{rt}_{rp} + \mathrm{nr}_{stt} \ge \mathrm{RPS}_{stt} \sum_{i,h} \mathrm{HW}_h \mathrm{BSI}_{i,stt}\mathrm{D}_{i,h} \quad \forall stt \tag{27}$$

$$\sum_{k,h} \mathrm{HW}_h \mathrm{RE}_{k,stt}\mathrm{g}_{k,h} - \sum_{rp} \mathrm{REX}_{rp,stt}\mathrm{rt}_{rp} + \mathrm{nr}_{stt} \ge \mathrm{IRPS}_{stt}\mathrm{RPS}_{stt} \sum_{i,h} \mathrm{HW}_h \mathrm{BSI}_{i,stt}\mathrm{D}_{i,h} \quad \forall stt \tag{28}$$

Constraint (26) is the operating reserve constraint, and constraints (27) and (28) are the RPS constraints. In particular, constraint (28), as the in-state RPS requirement constraint, shows the total local generation minus all the exported renewable credits has to be larger than the in-state RPS requirement.

4 Example

In this section, an example of co-optimization of transmission, generation, and storage is presented. This example is based on a 54-node network aggregated from the system of Western Electricity Coordinating Council (WECC) in the USA, and the planning target year is 2034. The network data are from the WECC 2026 Common Case (WECC 2026), and we plan for year 2034 based on the load, fuel cost, and policy data that are specified by WECC's Long-Term Planning Tool (WECC 2013). We shall use this example to demonstrate that anticipation of storage siting/sizing decisions can change the transmission expansion plan and this change to the plan can provide considerable economic benefits.

4.1 Test Case Description: 54-Node System for WECC

In this subsection, the test system, the 54-node system for WECC is summarized.

All 54 nodes are aggregated from the 2026 Common Case of WECC (2026). Each node stands for one or part of single Transmission Expansion Planning Policy Committee (TEPPC) subarea of WECC. When one TEPPC subarea is totally within one state, one node will be designated; when one TEPPC area has assets spanning several states, e.g., the Los Angeles Department of Water and Power (LADWP), several nodes will be designated, and one node will be defined for each state (see Fig. 2, where LADWP has nodes in States of California, Nevada and Utah).

There are 519 aggregated existing generators and 238 generator candidates in this network. These span 25 technologies, including different types of coal, gas, nuclear, hydro, wind, solar, geo, and biomass generation.

As for generation candidates, on each node, two types of generation can be invested without limit: Gas Combustion Turbine and Gas Combined Cycle. On the other hand, the renewables, i.e., wind, solar, bio, and geothermal, can only to be expanded at 53 candidate sites and will need new transmission lines to be interconnected with the existing grid. The 53 candidate sites (not the same as nodes) and their maximum installed capacity are identified in (Western Governors' Association and U.S. Dept. of Energy 2009). A system-wide view of the building cost and the expandable capacity is shown in Table 1.

There are two types of transmission lines: backbone reinforcements and renewable connections. Backbone reinforcement candidates, which are 39 in number, expand capacity on the arcs shown in Fig. 2. In addition, there are 53 renewable connection candidates, corresponding to the 53 renewable candidate sites. All of the transmission capacity expansion costs are calculated based on the length and the voltage level of the buses in the original network. The average line cost is 640 Million \$/line, with a lifetime of 60 years. Assuming a 5%/year discount rate, the average annualized cost of transmission lines is about 34 million\$/line-year.

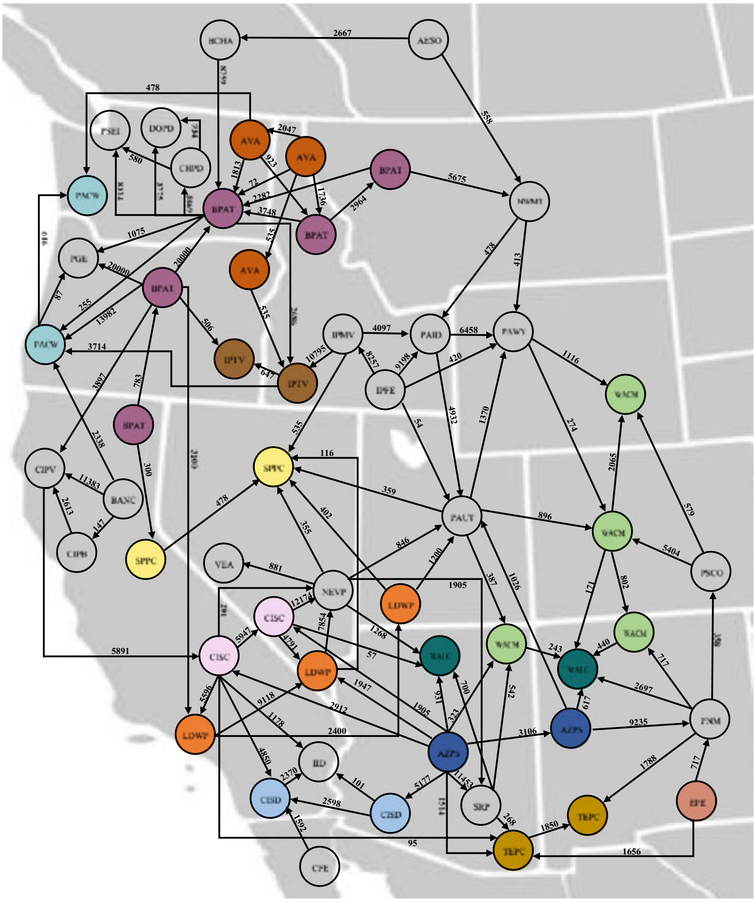

Fig. 2 Map of the test system. Colors represent different TEPPC subareas

The type of storage we consider is a battery electric storage system (BESS). We assume that a BESS will have 4-h of storage using Li-ion technology with round-trip efficiency of 92%. The build cost is assumed to be \$440/kWh in the year 2034 (i.e., \$1760/kW); with assumptions of 15-year lifetime and 5% discount rate, this corresponds to an annualized cost of \$42.5/kWh-year. Storage can be sited (1) at any of the 54 existing nodes in the system or (2) co-sited with the renewables at the 53 candidate renewable sites. Different siting locations will incur different fixed operation and maintenance costs (FOM cost), with the average being \$30/kW-year. More details on the cost assumptions can be found in WECC (2017). Storage is expandable up to a capacity of 1000 MW at each location.

There are four representative days that are selected, and each day is composed of 24 h. Thus, 96 h are simulated to represent the variability of load and renewable output conditions.

Table 1 System-wide Expansion Cost Assumptions for Generation in Year 2034

Gen. type	Fixed O&M ($/kW-year)	Overnight build cost ($/kW)	Lifetime (year)	Annualized build cost ($/kW-year)[a]	Potential capacity (MW)[b]	Capacity factor[c]
Biomass	120	4300	20	345.04	3272	–
Combined Cycle	10	1213	20	97.33	–	–
Combustion Turbine	9	825	20	66.20	–	–
Geothermal	120	5000	25	354.76	4719	–
Solar PV	20	1471	35	89.82	85144	26.0%
Onshore Wind	40	1355	20	108.72	95288	30.6%

[a]Assumes a 5% discount rate
[b]Summation over all candidate sites
[c]Weighted average over all candidate sites, weights are the potential capacity

We assume that future policies in the WECC region will incentivize significant increases in renewable generation. There are two types of environmental policies that are assumed to affect the system in the year 2034: Renewable Portfolio Standards (RPS) and Carbon Pricing. The RPS data for year 2034 are from the DSIRE [Database of State Incentives for Renewables and Efficiency, (N.C. Clean Energy Technology Center 2018)], and the demand data are from LTPT (WECC 2013) from WECC. RPS policies are implemented on the state-level, and we consider the fact that some states have in-state requirement. For examples, in 2034, California requires 60% of its demand to be supplied by renewables, and 90% of the renewables should come from within the State. Overall, in 2034, the WECC system requires 38% of its demand (1091 TWh/year) to be supplied by renewables; and for the USA part of the WECC, this requirement is 34% of a total energy demand of 854 TWh/year. The non-compliance penalty is assumed to be $100/MWh, which is imposed in the objective function if a given state's RPS is not met.

For carbon pricing policy, we assume a universal carbon tax will be implemented upon the WECC system (or equivalently, a carbon cap-and-trade system is implemented within WECC, and the carbon price reaches the assumed equilibrium level). The carbon tax varies among the different study cases we consider.

In the application of this chapter, we omit the voltage law constraint in the network representation in order to accelerate solution times. Our numerical experiments indicate that this assumption results in a minor overstatement of the network's transfer capability and results in only minor distortions in near-term transmission investments (Xu and Hobbs 2019). Thus, the power flow is a "pipe-and-bubbles" (transshipment) formulation. Furthermore, binary variables for both transmission and storage expansion are relaxed (i.e., are continuous in the range [0,1] rather than binary), again in the interest of faster computation times. In its use of continuous variables, the model resembles classical generation expansion planning models, which are formulated as linear programs. More realistic models can be used in an actual planning, but this model suffices for the purpose of this chapter which is to illustrate the use of co-optimization.

4.2 Questions to Be Answered and the Experimental Design

With the numerical results from the application of the above model and data, we shall answer the following questions:

- *Would the anticipation of the amount and siting of battery storage change the transmission expansion decisions and how? Will the electric storage incentivize more or less capacity expansion of transmission?* Less transmission indicates that, overall, batteries and transmission are substitutes; more would indicate that they are complements.
- *What is the economic value of enhancing the TEP model to include storage (VoMES)? And how will the VoMES change with the build cost of the storage?* Note that this is the not, per se, the benefit of storage itself, which is VoS, equal to the difference in cost between MP1 and the naïve model without any storage at all MP2. Rather, VoMES is the benefit of "smart TEP with storage," anticipating where storage will be sited and adjusting transmission decisions to take advantage of that; as explained at the end of Sect. 2, this is the difference between MP1 and MP3's objective function values.
- *Will the stringency of carbon prices impacting electricity markets change VoMES? I.e., if the carbon price is applied to the system, will anticipating the siting of storage be more or less valuable to the TEP?*
- *What are the sources of cost savings from proactive TEP? In particular, when there is a positive VoMES, were the cost savings from investment in transmission or generation, or from reduced fuel or carbon costs?* Ignoring the storage in transmission expansion planning will change the transmission expansion plan and may consequently incentivize investors to make suboptimal siting and the operating decisions—which of those will be distorted more? It is also conceivable that transmission costs will also increase; perhaps disregarding the possibility of storage in model MP2 will result in overbuilding of transmission versus that optimal TEP from model MP1, which might find that transmission and storage substitutes. That would indicate that, overall, transmission and storage are substitutes. On the other hand, reduced investment in T in MP2 (no storage S) would indicate that T and S are instead complements.

We design the experiments as shown in Table 2 to answer the questions above.

Table 2 Experimental design for value of storage in TEP: Sets of model runs

Set ID	Set name	Planning model description
MP1	TEP with storage and generation expansion	10 levels of build cost of storage (from 100% of base level \$42.5/kWh-year to 10% of base level); 10 levels of WECC-wide carbon tax from \$0 to \$90/t. There are a total of $10 \times 10 = 100$ runs
MP2	TEP with generation expansion	10 levels of WECC-wide carbon tax from \$0 to \$90/t. There are 10 runs
MP3	Storage and generation expansion	Same as Set MP1; except that transmission expansion plan is fixed at the levels selected in MP2 with the same carbon tax. There are $10 \times 10 = 100$ runs

4.3 The Impact of Storage on Transmission Expansion Plans

In this section, we show how the storage expansion would affect the transmission expansion plan. Several conclusions can be drawn from the detailed results below:

(1) Anticipation of storage siting/sizing will change the transmission expansion plan. An example is given in Fig. 3, where cheaper storage results in more line construction in some places (substitution relationship) and less in others (complementary relationship);
(2) The greater the level of carbon tax that is applied to the system, the more impact the storage expansion anticipation will change the transmission expansion plan;
(3) Storage expansion anticipation can both encourage and discourage transmission expansion, with complement effects dominating under some assumptions and substitution effects in other; and finally,
(4) The way that the transmission expansion plan changes differs between types of transmission candidates, i.e., backbone reinforcement and renewable interconnectors. While the interactions between the backbone reinforcement and storage expansion are mixed and location dependent, the interaction between the renewable interconnectors and the storage expansion is more clear and is larger in magnitude: (a) while carbon cost is low, storage substitutes for renewable interconnectors, while (b) when carbon cost is high, then as the BESS cost is decreased, storage first substitutes for renewable interconnectors and then complements them.

Now, we shall examine the numerical result more closely.

Figure 4 shows the difference between MP1 and MP2's investment in the backbone reinforcements (on inter-regional lines) in 33 (out of 110) study cases: carbon tax = \$0, 60, 80/t CO_2e, and battery cost ranges from \$42.5 to \$4.25/kWh-year. The capacity of all new backbone lines, in MW, is added up to create this index. The figure shows that in cases where carbon tax = \$0/t, anticipating storage expansion does not change the total backbone reinforcements from the "No BESS" case. The

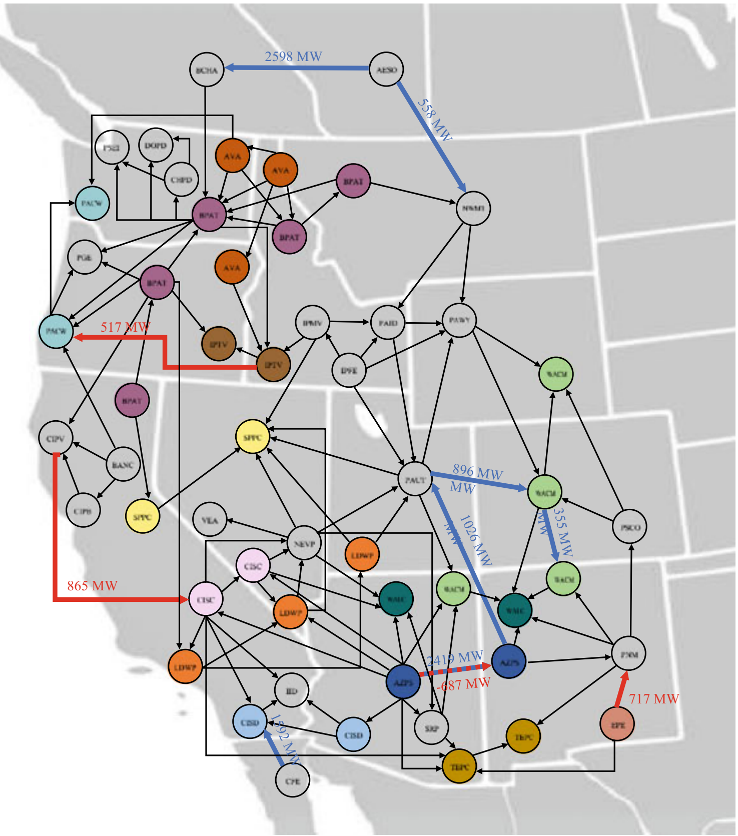

Fig. 3 Map of Backbone Reinforcement Expansion: Comparison between battery costs of 100% of the base case level ($42.5/kWh-year) and 10% of that level. Blue lines represent the expansion plan at a battery cost level of 100%, and solid red lines are additional lines included in the expansion plan when the battery cost level becomes 10%. Note the additional lines expanded between Idaho and Oregon, Northern and Southern California, and within Southern New Mexico when the battery cost is decreased; meanwhile, one line between Arizona and New Mexico is canceled (dashed line). Carbon Tax is $80/t CO_2e

locations of additions do not change either. On the other hand, the results show some impact when carbon price is high, and the battery cost is lower, in particular, when carbon price is set to $80/t CO_2e, considering storage expansion can cause both the addition and the cancelation of lines, depending on the cost of batteries. So, whether backbone lines and storage or complements depend on battery cost assumptions, and surprisingly, this effect is nonmonotonic. Under the highest carbon cost, the magnitude of the effect does not increase uniformly as battery cost falls, and the direction of the effect changes twice as that cost is adjusted.

We now turn to locational effects. Figure 5 is a zoom-in of the case of carbon tax = $80/t CO_2e in Fig. 4. When the 4-h battery cost dropped from 40 to 30%

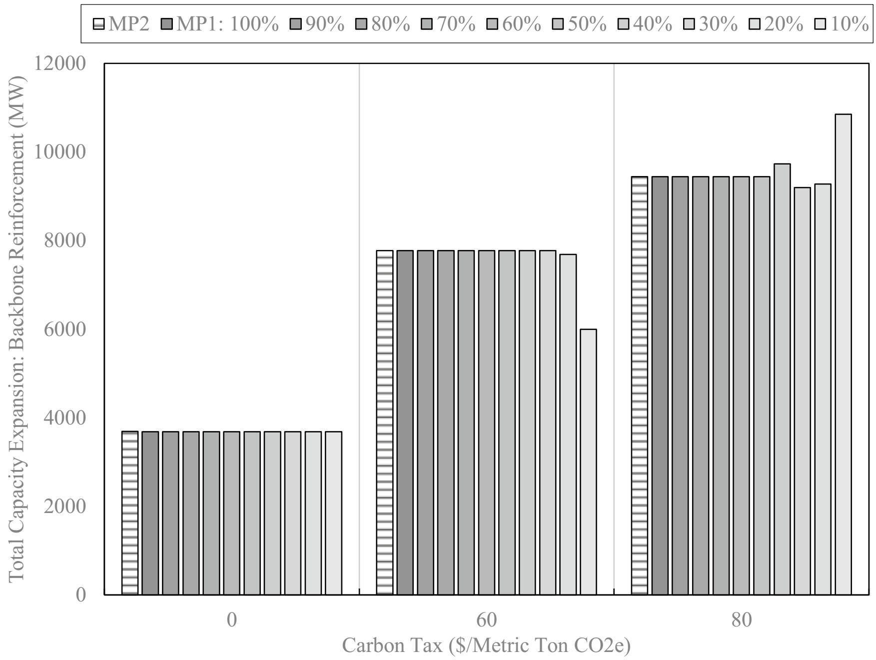

Fig. 4 Transmission capacity expansion (backbone reinforcements only) by proactive TEP models MP1 with different BESS costs compared to the result of the TEP model with "No BESS" MP2 (Energy Storage Cost at 100% = $42.5/kWh-year)

(corresponding to $16.98 and $12.74/kWh-year, respectively), one line from Arizona to New Mexico is canceled; while the battery cost goes lower, several line capacities are added to the system, encouraged by the storage expansion. The locations of those additions are scattered throughout the west, some near load centers (California) and others closer to renewable solar resources (New Mexico). This is essentially showing that the storage system can both substitute (in cases where lines are canceled because of lower storage cost) and complement (in cases where lines are built because of lower storage cost) the transmission expansion.

When we turn from backbone line expansion to renewable interconnections, the story goes in a similar direction but with a much larger magnitude. Renewable interconnectors are the lines necessary to deliver new renewable developments to market. The expanded capacity of those interconnectors is much higher than the backbones. For instance, backbone reinforcement expansion ranges from 3.7 to 11 GW, while for renewable interconnectors, the range of additions is 31–86 GW. This much higher expansion of interconnectors reflects the impetus toward renewable development throughout the west resulting from our assumed renewable and carbon policies as well as declining costs of renewables. Figure 6 shows that anticipation of the storage expansion can both discourage or encourage interconnector expansion. We highlight that in both cases with carbon tax = $60 and $80/t CO_2e, lower battery costs will first

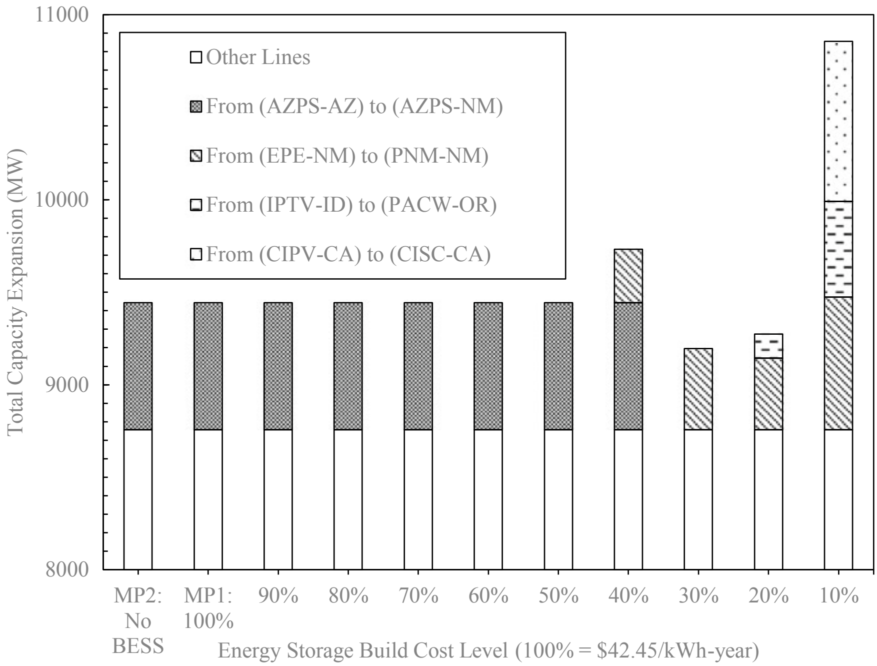

Fig. 5 Transmission capacity expansion of backbone reinforcements selected by models with carbon tax = \$80/t CO_2e in the year 2034

slightly complement the renewable interconnector expansion (expanded capacity is slightly higher when battery costs go lower), then substitute for expansion (expanded capacity is lower with battery cost goes lower), and then, reverse again, returning to a complementary effect.

We can intuitively understand how the storage can substitute for interconnector expansion: you either transport the excessive energy out for consumption, i.e., transmission expansion, or save it for later, i.e., storage expansion, and the model (and assumedly the market) will choose the most economical approach. Meanwhile, in cases where the storage expansion encourages renewable interconnectors, the reason is basically that the cheaper storage makes some originally uneconomical intermittent power become economical and worthwhile to be connected. An example is solar in New Mexico that is only available but very strong in the middle of the day; it is not developed at all in high battery cost cases, but at some levels of battery costs, we see expansion of that renewable source. In one case where carbon price is at \$80/t CO_2e and battery cost is at 10% of the base level, a 1000 MW BESS is co-sited with a 1575 MW Solar PV facility at a renewable candidate site at Southwestern New Mexico, and a transmission line with 850 MW capacity connects both of them to a main grid node at El Paso Electric (EPE) at New Mexico; however, none of these lines are invested in when battery cost is above 20% of base level.

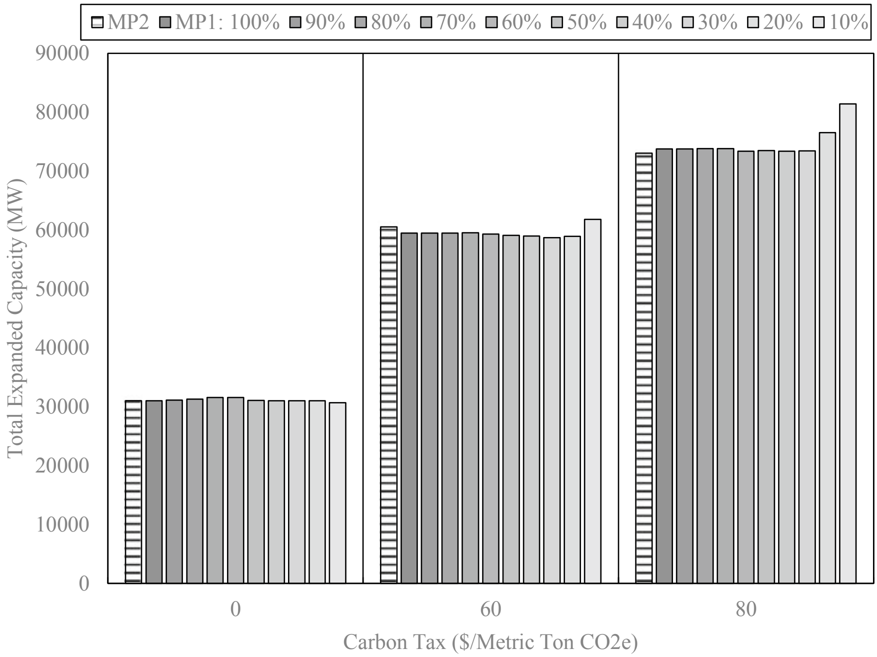

Fig. 6 Transmission capacity expansion of renewable interconnectors by proactive TEP models MP1 with different BESS costs compared to the result of the TEP model with "No BESS" MP2 (Energy Storage Cost at 100% = 42.5/kWh-year)

Overall, we see from the results that anticipation of storage expansion will change the transmission expansion plan from our TEP model, sometimes encouraging it, and at other times the opposite. How much does this anticipation, with the resulted expansion change, benefit us? Or equivalently, if we transmission planners ignore storage siting/sizing while making the plan, what is the cost we will bear? As was explained in Sect. 2, this benefit/cost is called VoMES, and the value of TEP model enhancement to proactively anticipate storage will be discussed next.

4.4 Value of Considering Storage in Co-optimized Transmission Expansion Planning

In this subsection, we calculate the value of storage in transmission expansion planning VoMES. As a reminder, we first plan transmission expansion T anticipating both generation G and storage S investments (MP1); second, we plan the transmission expansion without considering storage (MP2, having only T and G as variables); finally, we plug the resulting naïve plan from MP2 into a co-optimization model that includes storage expansion to simulate the reaction from the market to the naïve transmission plan (MP3, optimizing *S* and *G*, but freezing *T* at MP2's levels). The intent of VoMES is to simulate the efficiency loss resulting from situation that transmission expansion planner naively ignores the possibility of storage investment, as well as the reaction of storage siting and operation to transmission reinforcements, but the storage investors still have the chance to react. The difference between the objective function values of MP1 and MP3 is this index.

The VoMES in TEP in all 100 test cases are shown in Fig. 7, and the amount of investment for new lines is shown in Fig. 8. Two basic observations can be made concerning the trends in these figures.

First, with the carbon tax fixed at a certain level, VoMES is monotonically increasing as the battery cost goes lower. In other words, the lower the battery cost is, the greater the value of storage expansion anticipation is the transmission planners. The value is zero for the highest battery costs and lowest carbon costs, because no storage is added by model MP1 in those cases, so the MP1 and MP3 solutions are identical. Unsurprisingly, the highest values of VoMES are associated with solutions that install the most battery capacity.

Second, the carbon tax is a factor in the value of anticipating storage, but the effect is not monotonic. In other words, a higher carbon tax does not necessarily make VoMES higher. For example, when the battery cost is half the base level (50% case), as the carbon tax goes higher, the VoMES will first go down then up.

To help interpret the magnitude of VoMES, first, we compare it to the incremental transmission investments. Their ratio gives an indication of the relative importance of incorporating the proactive/anticipative perspective in planning. Figure 8 shows the transmission expansion cost in all 100 MP1 test cases as well as the 10 MP2 cases that is without the storage siting. Sixty eight out of 100 MP1 test cases have lower transmission expansion investment costs than the corresponding the "No BESS" case, implying that anticipating storage results in less transmission investment (substitution effect). In the remaining 32 cases, proactive planning including storage results in more transmission (complementary effect). The ratios of VoMES to the MP1 transmission investments are shown in Fig. 9. This shows that the value of proactive planning that recognizes storage is a significant fraction of total transmission investment under the higher carbon cost assumptions and lower battery costs, which are the runs that have the most battery investment.

Although how carbon policy will affect the transmission is largely out of the scope of this chapter, Fig. 8 also shows that carbon policy has more impact on the transmission expansion than the storage expansion, the major topic here.

The overall value of storage to the system (VoS) results is shown in Fig. 10. As pointed out in the Sect. 2, the larger VoMES is (as a proportion of VoS), the stronger the impact that naïve transmission expansion decisions (which disregard storage reactions) will have upon the final realization of the economic value of storage. Among all the test cases, VoMES is about 0–27% of the VoS, and the average is about 14%. Thus, anticipating how storage siting and amounts will react to grid expansion can significantly enhance the value of storage.

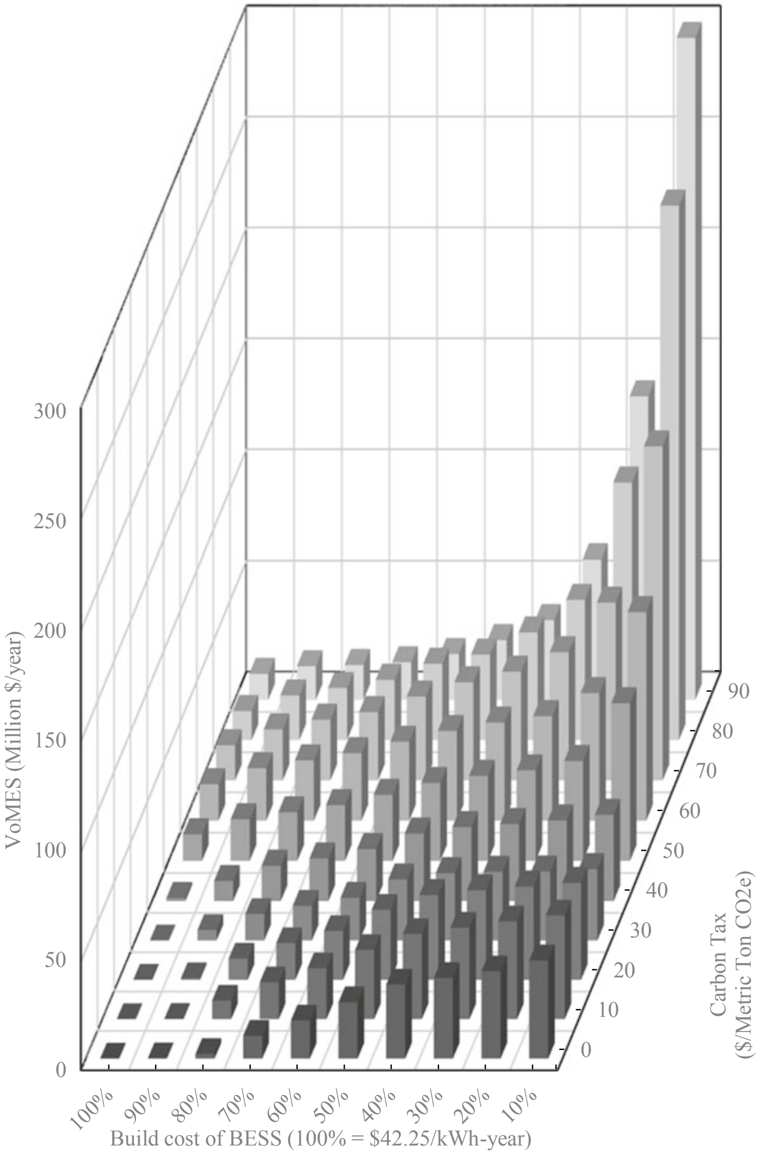

Fig. 7 VoMES in TEP in different test cases

4.5 Sources of VoMES in Transmission Planning

We have seen that anticipating the sizing/siting of the storage will change the transmission expansion and this change will provide an economic benefit (VoMES in TEP)

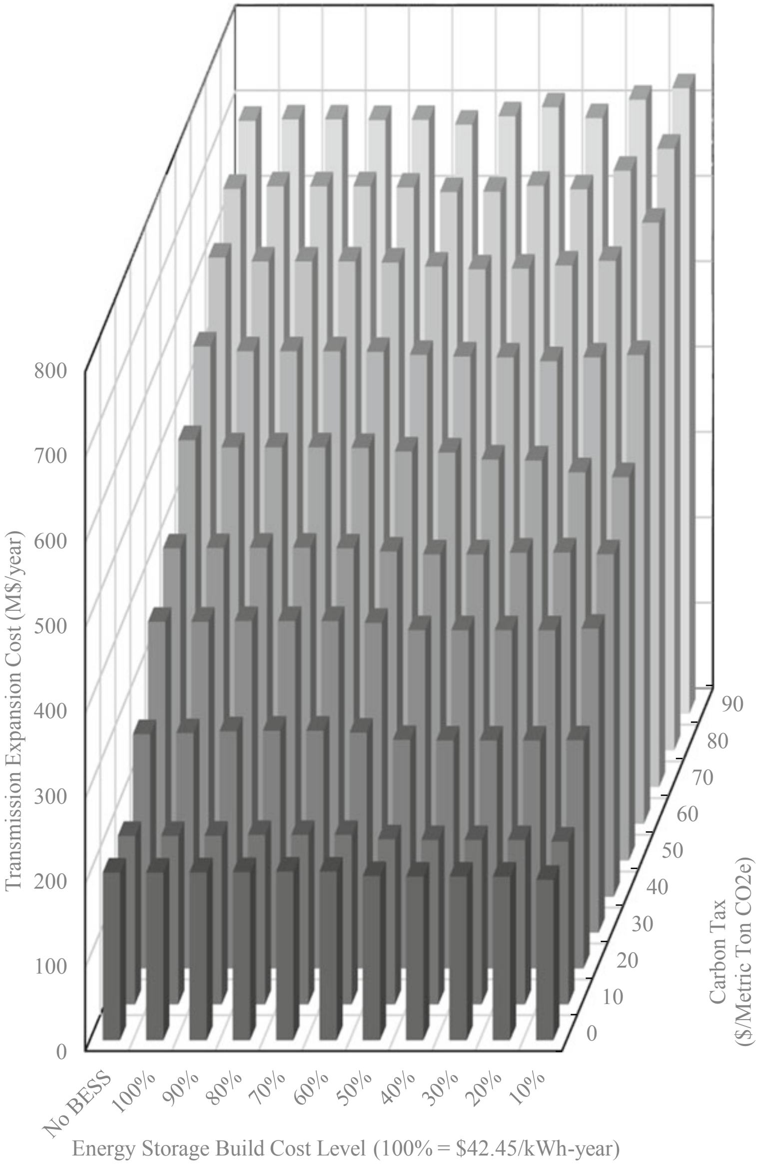

Fig. 8 Backbone and Renewable Interconnection Transmission Investment Cost in TEP in different test cases

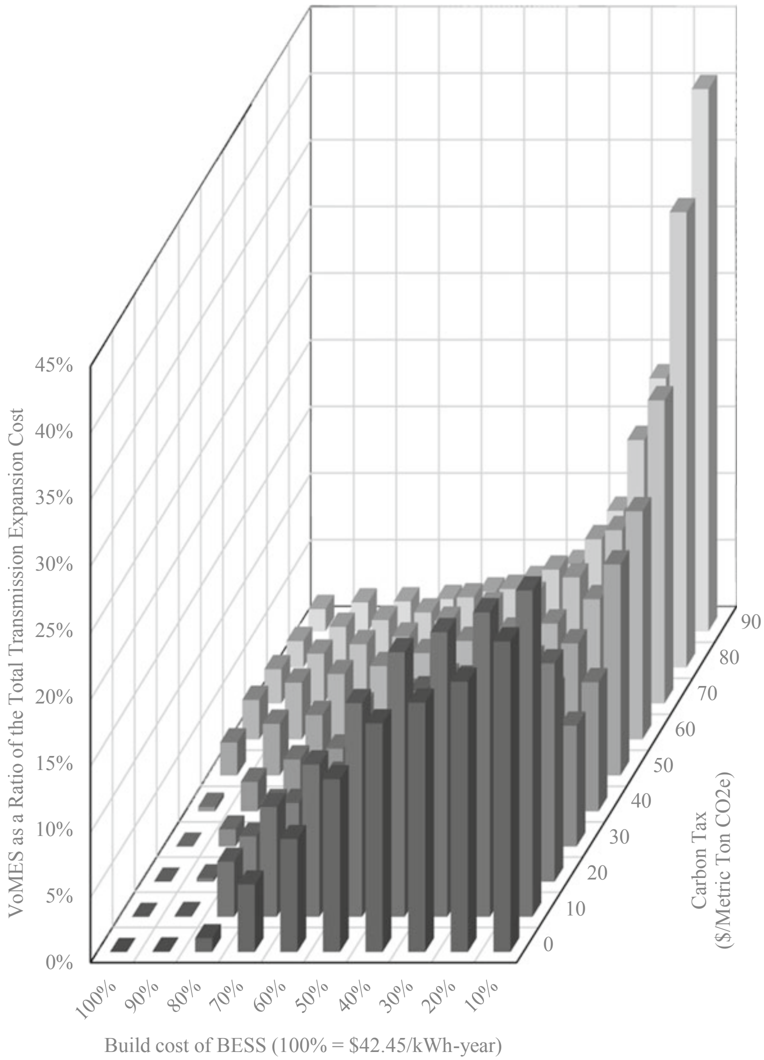

Fig. 9 VoMES as a Ratio of total Transmission Expansion Cost

to transmission expansion planners. To understand why, it is important to examine the sources of the VoMES, in terms of whether it is reduced investment (and if so, of what type) or reduced operating costs. Is VoMES positive because given the changed transmission plan, the market will react with different generation/storage expansion, or are those investments relatively unchanged and it is transmission investments that shift? Is most of VoMES comprised of fuel and carbon cost savings, or do capital cost savings contribution a large portion? We shall see the source of VoMES in the figures as follows.

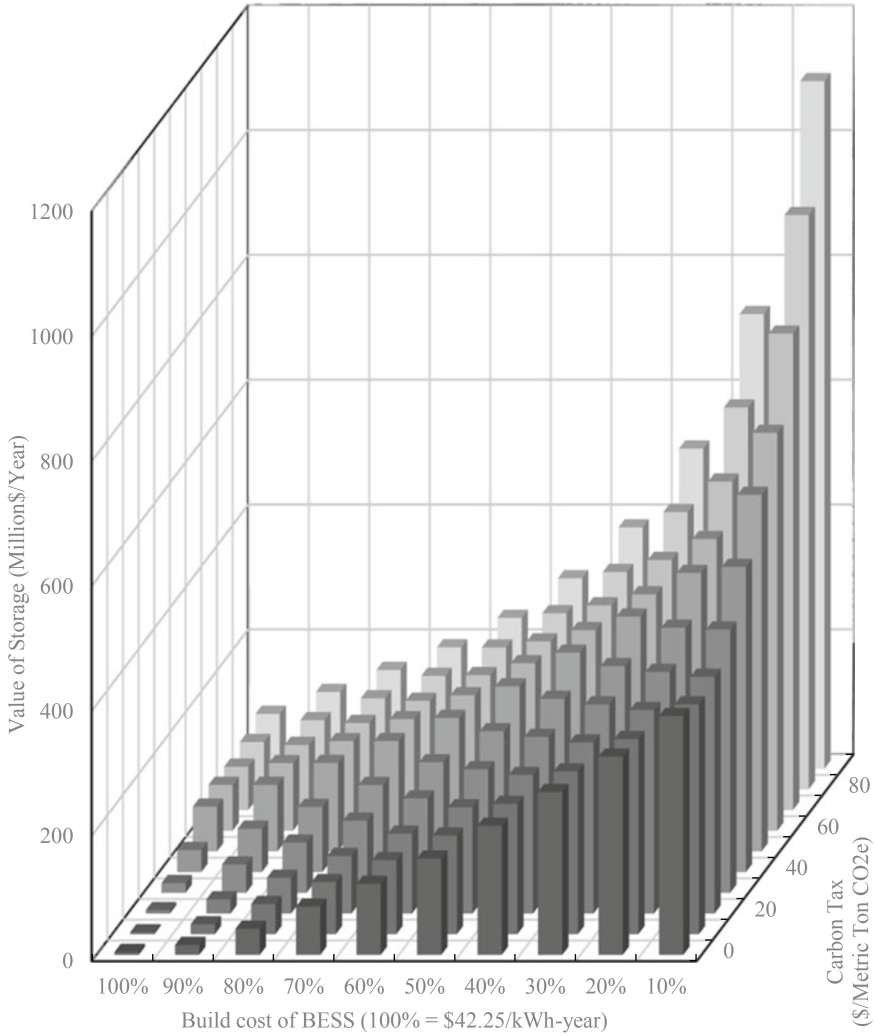

Fig. 10 VoS in TEP in different test cases

Figures 11, 12, and 13 show the components of VoMES for 60 different test cases (one figure per carbon price = \$0, 60, 80/t CO_2e, and within each figure, BESS costs from 100% level to 10%). As a reminder, VoMES is calculated by taking the difference between two objective functions: (1) the objective of MP1, i.e., TEP with generation–storage anticipation and (2) the objective of MP3, i.e., generation/storage expansion simulation with transmission expansion fixed from the “No BESS” case (MP2). Here, we now consider the differences in individual sets of objective function terms, shown in Eq. (1) in Sect. 3. The five components we break out are the separate investments in transmission, generation, and storage; fuel and variable O&M costs

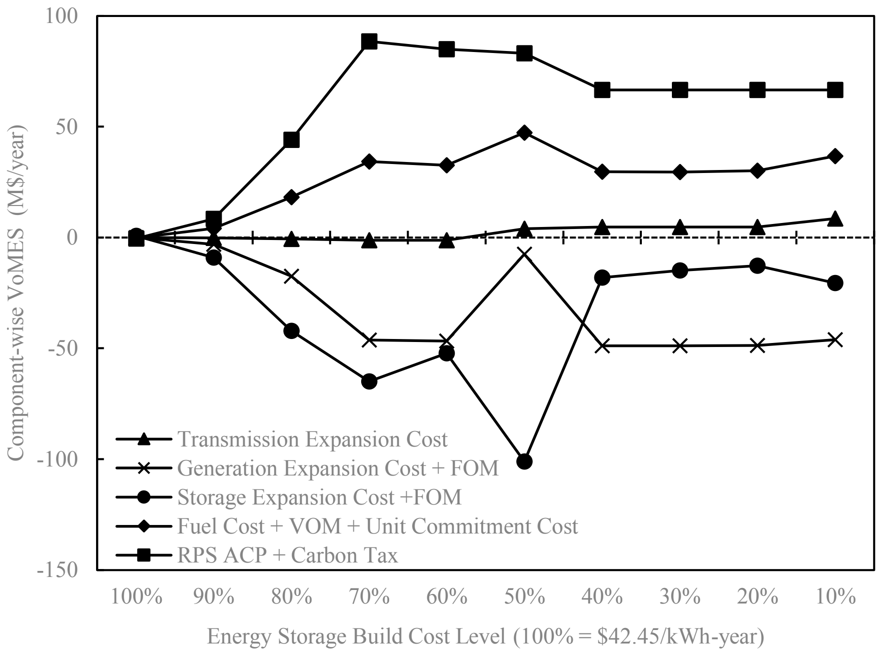

Fig. 11 Component-wise VoMES in TEP, carbon tax = $0/t

of generation (excluding carbon costs); and environmental terms, namely the carbon tax and any penalties ("ACP") associated with non-compliance with the state-level renewable portfolio standards.

All three figures show the same pattern:

(1) The proactive transmission plan (MP1, which anticipates storage in TEP) is introducing more generation and storage expansion than the naïve plans (MP2, without storage anticipation), and thus, the VoMES components associated with generation and storage investments are negative. Thus, by proactively planning, transmission planners also encourage investment in generation and storage.
(2) VoMES arises mostly from savings in operating costs and policy compliance: the additional *G* and *S* investment just discussed more than pays for itself in terms of lower fuel costs, variable operation and maintenance costs, start-up and shutdown costs, carbon taxes and the RPS alternative compliance penalty.
(3) Consistent with the changes in transmission expansion cost discussed in Sect. 4.3, most scenarios have slightly more transmission investment but about a third have less investment. However, the changes in transmission investment itself are not a significant portion of VoMES.

Interestingly, these results imply that although the total amount of transmission investment does not change greatly, there is a magnification effect in which

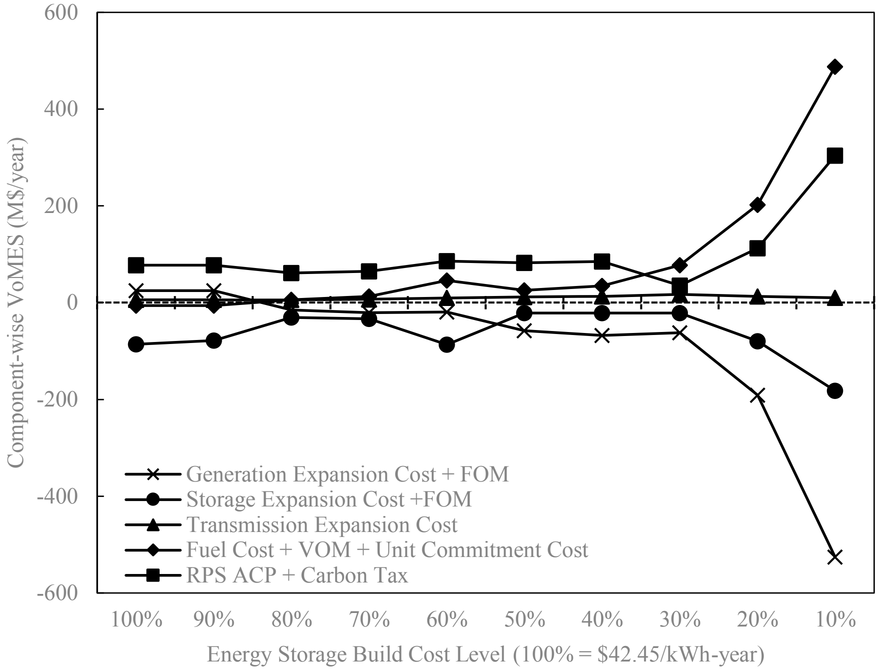

Fig. 12 Component-wise VoMES in TEP, carbon tax = $60/t

the changes that do occur in amount and location induce much larger changes in generation and storage investment.

We see an example of this impact in Fig. 14. There, the generation expansion and storage expansion gave different transmission plans. (Only wind and solar are shown in the figure because other generation expansions are minor.) MP1 is showing the optimal expansions, and while MP3 is the reaction of the market if instead, the naïve transmission plan is implemented. The results first show that in both models MP1 and MP3, solar is more impacted than wind by battery installations spurred by low battery prices. Second, they show that the effect of naïve TEP is correspondingly greater on solar investments than wind investments. Proactive TEP that anticipates storage will facilitate a roughly doubling of the amount of storage installation under low battery prices and up to a 30% increase in solar installations. There are much smaller increases in wind capacity. The reason is that solar is only available during the day, and the storage is potentially more valuable to it than the wind resource, which is distributed more evenly over all 24 h. Thus, ignoring storage expansion in TEP will undervalue the combination of solar and storage, resulting in less transmission being built for solar and, ultimately, less solar development since the ability to convey remote inexpensive solar to markets is reduced.

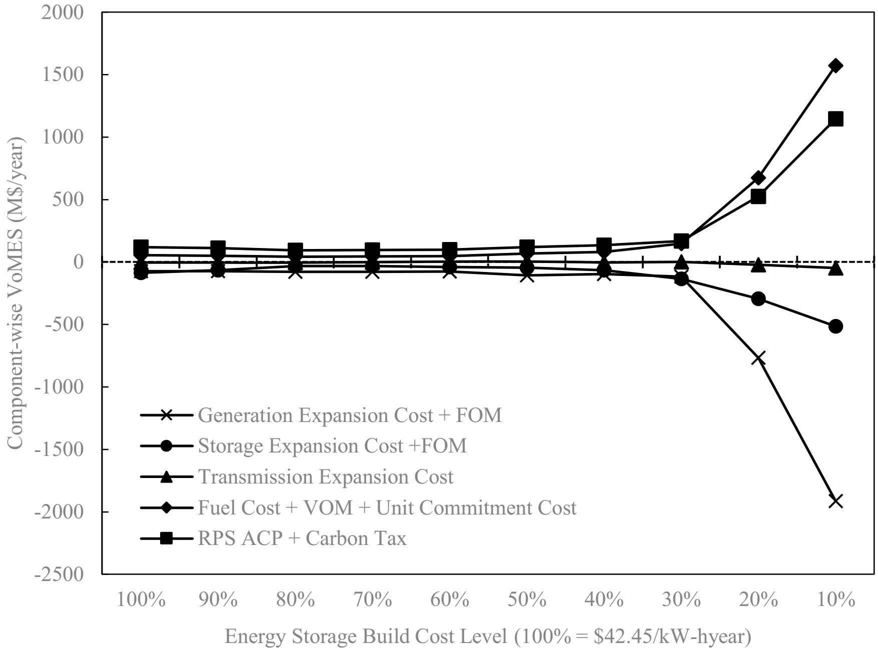

Fig. 13 Component-wise VoMES in TEP, carbon tax = $80/t

5 Conclusion

With renewable penetration increasing in many power systems, the need for transmission to bring remote renewables to market is growing, as is the need for storage. Because of the ten year or longer lead times for grid reinforcements, this transmission should be planned in a proactive manner, anticipating how generation and storage siting, amounts, types, and timing will be affected (Krishnan et al. 2015; Liu et al. 2013; Spyrou et al. 2017; Sauma and Oren 2006). Will the best plans for integrating renewables include large amounts of transmission, large amounts of storage, neither, or both? It remains to be seen. Whatever the answer is, a transmission expansion planning tool with generation and storage co-optimization will decrease the cost of renewable integration relative to naïve planning that does not anticipate how supply and storage investors will react to changes in the grid.

This chapter presents and applies a proactive transmission expansion planning model with generation–storage co-optimization, building on our previous work on transmission–generation co-optimization (Ho et al. 2016). After applying this model to the test case, we show examples to calculate the economic value of model enhancements to proactively consider storage expansion (VoMES) in TEP.

The results show that considering storage expansion in TEP will change the transmission plan by helping to identify and correct: (1) overbuilt line capacities that can be avoided by building storage, primarily near renewable energy generation locations

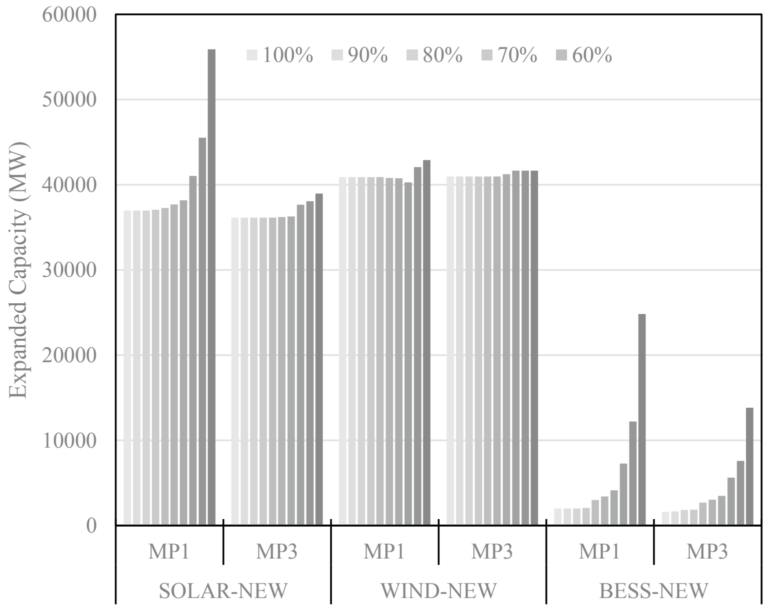

Fig. 14 Solar, Wind and Storage Expansion given transmission plans from different TEPs, MP1 is the TEP model with storage siting anticipation, MP3 is the model reoptimizing *G* and *S* given the transmission plan from model MP2 (TEP without storage anticipation). (Carbon Price = \$80/t CO2e, Battery cost at 100% level = \$42.45/kWh-year)

and (2) underbuilt line capacities that convey renewable resources that turn out to be economic only when accompanied by storage. In other words, the result shows that the storage can both complement and substitute for transmission expansion.

The VoMES in our example is primarily the net of two cost changes: the incremental investment for larger amounts of generation and storage expansion in a fully proactive TEP model and the savings that the increased investment makes possible in operating costs, such as fuel and carbon costs. Both occur because of improved transmission planning resulting from co-optimization with storage. On the other hand, a naïve transmission plan, which is the result of a planning process that disregards potential storage expansion, can discourage investment in solar generation and storage expansion.

As shown in the example, application to western USA and Canada, as storage costs are reduced in year 2034, the VoMES in TEP increases. This highlights the needs for transmission planner to consider storage expansion in the planning process. However, this VoMES is sensitive to the policies that are affecting the power system: in our case, the carbon price will affect the VoMES in TEP significantly.

To conclude, improved TEP models have value if they result in system plans with lower costs. This chapter has shown how this value can be quantified for one particular improvement, the incorporation of storage. Elsewhere, we have quantified the value of enhancing transmission models to include just generation co-optimization

(Spyrou et al. 2017) and the value of recognizing long-run uncertainties in regulatory, economic, and technology conditions. In several cases, these values are comparable in magnitude to the size of the transmission investments themselves.

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