An interdisciplinary approach to long-term modelling for power system expansion

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Abstract: This article describes an interdisciplinary approach to computer modelling of large-scale power systems over a long-term horizon. The goal is to simulate the interplay between the economic, technical and environmental factors in the system. Our approach is illustrated with a model based on data from the Western Electric Coordination Council (WECC). We present simulations to show the change in the WECC system over 20 years. We explain the challenge of simulating short-term behaviour such as hourly wholesale electricity prices within the longer-term model. The usefulness of the model is illustrated by showing simulated impacts on the WECC system due to a market for carbon allowances. This research demonstrates the importance of simulation models that are designed for interactive use by policymakers, engineers and researchers.

Keywords: interdisciplinary modelling; power system planning; system dynamics; transmission congestion; carbon markets.

1 Introduction

Recent history suggests that the western electric system has experienced a boom-and-bust pattern of private investment. Planners and policymakers are asking if we will see a repeat of boom and bust and the associated problems of poor reliability. Some argue that the western system experienced a one-time event, akin to a ‘perfect storm’. Others warn of a repeat of the crisis conditions of 2000–2001 unless we enact fundamental changes in wholesale electricity markets. Arguments about deregulation of the electric power system have been largely based on conventional and general wisdom regarding separate topics such as competition, service reliability, economic efficiency and environmental protection. However, few investigators have looked carefully at the interplay between the economic, technical, social and environmental factors that influence the production, transmission and consumption of electric energy. Further, no one has carefully investigated the long-term dynamics of the industry with models that include a representation of the necessary engineering.

This article reports on research to simulate the long-term changes in large-scale power systems, with explicit attention on interactions between regulatory policy, investor behaviour, environmental impacts and system engineering. The new research builds from previous modelling that involved two, distinctly different approaches to represent the industry. We use the terms engineering approach and system dynamics approach as general labels in this article. As a general rule:
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- The engineering approach relies on explicit mathematical representations to deal with the performance of the power system within its physical limits.

- The system dynamics approach relies on icon-based modelling of the feedback relationships that influence the long-term evolution of the system.

The paper begins with some background of our initial modelling efforts and then describes our goal of combining the methods to create an interdisciplinary model of the long-term dynamics of large-scale power systems.

## 2 Previous modelling

Figure 1 shows the spatial and temporal boundaries of previous models developed by the authors. The previous modelling of system security is represented by the box located at the base of the diagram. The security model represents the power flow in the steady state and dynamics ranging from fractions of a second to several seconds. Loads are aggregated at the level of substations, while the scope of the model extends to cover the entire Western Electric Coordination Council (WECC) representing more than 10,000 nodes in the current model. This model can calculate power flows, real and reactive reserves and system limits for a specified scenario.

**Figure 1** Spatial and temporal boundaries of previous modelling at WSU

![Spatial and temporal boundaries of previous modelling at WSU](image)

The upper box depicts the previous system dynamics modelling of the western electricity market. The model operated with load and resource data from the four regions of the WECC. The model simulated hourly operations for a typical 24-hour day in each quarter of a year. The model assumed adequate interconnections between loads and resources in the west, so the wholesale market was represented as a single market. The simulations began in 1998 and ran for a decade or more to allow sufficient time to see the boom and bust in power plant construction. The model was applied and verified by comparison with WECC conditions during 1998–2001.
Figure 1 draws attention to the different boundaries of the previous models. The models deal with the WECC, but their spatial and temporal resolutions are entirely different. They also deal with quite different problems. Finally, their approaches to mathematical representation are quite different. The mathematical challenges are discussed in more detail below.

2.1 Engineering models of system security and market operations

Under deregulation, precisely determining the transmission system operational limits has become exceptionally important because effective market operations require unfettered trades. These limits are bound by concerns of reliability. Operations are governed by the concept of security, which says the system should survive any credible contingency. More specifically, the response to a disturbance must satisfy standard operating criteria that have been established by regional councils such as the WECC guidelines (Western Systems Coordinating Council, 1998). These criteria include both dynamic and static performance measures, such as allowable frequency and voltage variations that depend on the severity of the event.

Operational planners employ detailed engineering studies to find the maximum allowable loadings in particular areas and the associated transfers across key interfaces of the grid. The loading must be such that, following any credible contingency (disturbance), the system can still maintain frequency and desired voltage levels. Disturbances act at several time scales, and studies use different models for each. For example, immediately following a fault, electromechanical oscillations may develop that require control actions within fractions of a second to prevent successive tripping of equipment. Alternatively, the disturbance may lead to overload and subsequent equipment overheating, which may allow for several minutes before action is required. The complexity of these phenomena and other engineering concerns is what renders difficult the coordination of system limits with the market. That is, the limits are a complex function of the loading and generation patterns, the available reserves, type of a disturbance and resources available for response, and so on. While there has been great progress in analytical techniques for determining system limits, the primary approach to analysing disturbances is through computationally intensive simulation studies using detailed models of the network. These studies assume particular stressed system-operating conditions and investigate all major contingencies. The results provide guidance for planners as well as detailed instructions for operators of the system. Operator experience is critical for implementing these guidelines.

Obviously, for reliable performance, market-based generation scheduling must be subservient to these physical system limits. Yet, many of the electricity market studies have completely ignored transmission problems. To be sure, security calculations do not lead naturally to useful market rules. More typically, the Independent System Operator (ISO), or its equivalent, will analyse the proposed schedules and trades for security on a one-day ahead basis. If trades produce system violations, adjustments are made to the schedules to relieve the congestion under the ISO rules. During operations, modern Energy Management Systems (EMS) provide sophisticated online security analysis applications to assist the operators in ensuring that the power system continues to be operated securely as events unfold during the day. Thus, one of the fundamental challenges in the deregulation of the electricity industry is how to impose transmission
limits in a fair and transparent manner while at the same time maintaining reliability. Accurately determining the Available Transmission Capacity (ATC) remains an active area of research (Dobson et al., 2001; Shaaban et al., 2000).

There has also been a wide body of research on basic market mechanisms and supplier bidding strategies, usually based on a game theory framework (Shahidehpour et al., 1997; Hao, 2000; Hobbs and Kelley, 1992; Wen and Kumar David, 2001). These models are also done at a more detailed level than is needed for longer-term studies. The challenge in our research is developing appropriately detailed transmission models that, while capturing the complexity of the network, are not so detailed as to prevent useful studies of longer-term trends.

2.2 System dynamics simulation of the wholesale market

The previous wholesale market model was constructed to help one understand if power plant construction would appear in waves of boom and bust. The boom/bust pattern is common in industries like commercial real-estate, which face long lead times to bring new capacity to market (Ford, 2002). Construction of new power plants can also appear in waves of boom and bust. The resulting cycles in wholesale prices and reserves can be devastating for an industry in which production and consumption must occur simultaneously across a complex grid.

Investment in new generating capacity was based on an endogenous theory of investor behaviour, which included the long delays for permitting and construction. Investors were represented as ‘merchant investors’ weighing the risks and rewards of investing in gas-fired Combined Cycle (CC) capacity based on estimates of future market prices. The theory was tested in the WECC system and found to be successful in explaining the under building that occurred in 1998–1999 and the overbuilding that appeared in 2000–2001 (Ford, 2002; 2001a–b). The simulated pattern of boom and bust was attributed to a combination of the delays in power plant construction and the real limitations on investor’s ability to anticipate the future trends in the wholesale market.

The wholesale market model was constructed using system dynamics, a simulation method pioneered by Forrester (1961) and explained in texts by Ford (1999) and Sterman (2000). System dynamics has its origins in control theory and has been defined by Coyle (1977) as that “branch of control theory which deals with socio-economic systems and that branch of management science which deals with problems of controllability.” The approach is valued in a rapidly changing electric industry with high uncertainty and high risk (Dyner and Larsen, 2001). The previous model was implemented with Stella®, one of several software program that facilitate the development and use of system dynamics models.

Market prices were based on the simulated actions of a system operator, which finds the wholesale price for each hour to bring forth the generation to meet the demands for electric energy and ancillary services. Some generation (such as hydro and nuclear) was bid as ‘must-run’ capacity. Most generators were assumed to submit bids at their variable costs. However, some generators were assumed to submit bids well above variable costs, a form of strategic behaviour known as economic withholding. Without strategic behaviour, the simulated prices reflected competitive conditions, so the results were checked against the ‘counterfactual’ benchmarks published by the California ISO. With
strategic behaviour, the simulated prices were shown to rise far above the published benchmarks during intervals with low reserves. These prices were checked against actual prices reported by the California ISO.

The previous model was designed for highly interactive simulation to promote learning in a group. This approach is in stark contrast to the way most models are used in the electric industry. From our experiences, most models are maintained by a small team of analysts who are proficient in the model, the supporting data and the software. The analysts use the models to prepare reports, and the rest of the organisation benefits from reading the reports. This mode of analysis and communication has evolved over time because of the complexity of models and their supporting software. But models do not have to be used in this manner. An alternative mode of communication is provided by highly interactive models, sometimes called management flight simulators because they provide managers with an opportunity to ‘experience’ and discuss the simulated dynamics. Management flight simulators are highly valued for engaging student involvement in the classroom (Ford, 1999; Sterman, 1992) and for improving the learning of a diverse mix of professionals in large organisations (Morecroft and Sterman, 1994). Models of electric systems may also be designed to promote highly interactive simulations and group learning, as has been demonstrated in recent research for the Electric Power Research Institute (Graves et al., 2000) and the California Energy Commission (Ford, 2001a).

The rapid simulation response of the previous models made interactive experimentation possible. But simulation speed began to be a problem as the previous system dynamics model was expanded over time to attend to a wide variety of questions. If the models were expanded further to deal with engineering constraints, they would suffer further deterioration in simulation speed. At some point, the previous approach would become too slow to serve as an interactive simulator suitable for group learning. A new approach was needed, and we looked for a way to combine the engineering approach with the system dynamics approach. Our goal was to improve both the speed and the realism of the previous models of the western electric system.

3 Development of an interdisciplinary model

The current research has developed an interdisciplinary model for simulation studies of long-term performance of the WECC. The model is designed to help one understand the various influences on system performance and characterise these influences with sufficient realism to allow useful simulation studies with more detailed models.

3.1 Challenges in interdisciplinary modelling

Our main goal is to develop a system of models that illuminates the interactions among the many factors in a large system such as the WECC. Still, the detailed modelling approaches of engineering studies on a minute-to-minute or hour-to-hour basis differ greatly from system dynamics studies designed to gain insight into trends developing over years or decades. Precise understanding of the future power system performance requires careful analysis of the transmission system. The details involved in accurately modelling a transmission network cannot be easily incorporated into market models. Even for daily operations, where specific details of the interconnections are known, many
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power exchanges use a simplified linearised transmission model to avoid computational problems. For the broader analysis proposed here, the data problem is even more difficult, as longer-term changes are nearly impossible to map into the detailed models of the network and generators.

Capturing longer-term trends in power plant and transmission line construction requires modelling not only the engineering and economic concerns, but also environmental and regulatory issues. Modelling such a complex system requires a synergy of different approaches. One approach is the classical detailed-planning approach used in engineering studies. Another approach is the higher-level, interactive simulation used in system dynamics studies. Combining these approaches requires careful consideration of the best way to obtain a synergistic combination of their most useful features. Finding the right combination is made difficult by differences in their mathematical representation of the power system.

We explain some of these differences using a simple model of the changes in peak demand based on a user-specified annual growth rate. Figure 2 shows a system dynamics model of the peak demand implemented with the Vensim® software.\(^4\) Figure 3 shows an engineering model of the peak demand implemented with the Matlab/Simulink\(^5\) software.

**Figure 2** Example of a system dynamics model (implemented in Vensim)

```
\[ \begin{array}{c}
\text{Growth in demand} \\
\text{Demand annual growth rate} \\
\text{Peak demand}
\end{array} \]
```

**Figure 3** Example of an engineering model (implemented in Matlab/Simulink)

```
\[ \begin{array}{c}
\text{12 Months} \\
\text{Demand Annual Growth Rate} \\
\text{Demand Growth} \\
\text{Integrator} \\
\text{Peak Demand}
\end{array} \]
```

### 3.2 Mathematical representation in system dynamics models

The system dynamics approach emphasises information feedback and icon-based modelling with a clear portrayal of the 'stocks' and 'flows'. Figure 2 illustrates with a Vensim diagram of a model to simulate the growth in peak demand. Vensim is similar to Stella in making it easy for the developer to assemble a combination of stocks and flows on the screen and to simulate their behaviour. The stocks are the state variables in the system. They represent the cumulative effect of the flows that have acted on them over
time. The flows are the action variables that change the position of the stocks. The remaining variables are called constants or auxiliaries. System dynamics models are mathematically equivalent to a coupled set of first-order differential equations, with a separate equation for each stock in the model. The dynamic behaviour is found by numerical integration. With Vensim, the user may select from a variety of methods, but the most common selection is Euler’s method. The user must also select the step size of the simulation. This selection is commonly based on the user’s knowledge of the shortest time constants in the model. A useful rule of thumb is to set the step size to half of the shortest time constant and simulate the model. The equations for the model are not shown in Figure 2, but the reader can guess the equations from the names of variables. If the demand model runs in months, for example, the growth in demand would be the product of the peak demand and the demand annual growth rate divided by 12. The equations may be viewed by opening each variable or by asking Vensim for a display of the ‘text’ (rather than the ‘sketch’, which is visible in Figure 2).

The system dynamics approach is well suited for the simulation of long-term dynamics such as power plant construction. But the approach is challenged when developers wish to include short-term dynamics (such as hourly price spikes) in a long-term model. Often, it is possible to ignore the short-term dynamics with the argument that different dynamics should be addressed with different models. On the other hand, the electricity market can exhibit unusually important price spikes, as occurred in WECC during 2000–2001. Since price spikes contribute strongly to revenues, it was important to include the impact of the hourly prices in the previous model of power plant construction. This was done by running the model in hours with an extremely short step size to ensure numerically accurate simulation of the prices. This approach provided a reasonable representation of the prices that actually appeared during 1998–2001, and it provided useful insights on public policy (Ford, 2002; 2001a–b). However, it required an unusual treatment of time. (The model simulated a typical 24-hour day for each quarter of a year. This meant that one-year really comprised 96 hours.) Furthermore, a new approach was needed if the models were to represent power flows across the transmission network.

3.3 Mathematical representation in engineering models

In contrast to the system dynamics approach, the engineering approach prefers explicit mathematical representations of the relations among the system variables. This allows more detailed analysis but also tends to force modellers to decide *a priori* the relevant variables, as one must first write down the equations and build the model in the appropriate simulation environment. Although these distinctions are not strict, they do influence the type of models developed. A common issue for both modelling approaches is dealing with algebraic constraints. Such constraints arise in many complex engineered systems, such as the power transmission system. These constraints can be more easily incorporated in the model when using the engineering approach because of its explicit mathematical nature, although care must be taken to avoid introducing computational problems.

The issue of algebraic constraints raises an important philosophical question. In a physical system, are the algebraic constraints true, hard constraints imposed on the system or simply equilibrium points arising from much faster dynamics? The answer to this question lies in yet another difference in the two modelling approaches. System
dynamists tend to include in the model all relevant dynamics of which they are aware. On the other hand, engineers may intentionally ignore fast dynamics and readily impose constraints based on their analysis and experience with the system. While the system dynamics approach may be more ambitious, the models that include both very fast and very slow dynamics are hard to simulate and, depending on the solver used, the simulation may be inefficient or, very often, fail completely. On the other hand, the engineering approach can also fail when the underlying assumption that the faster dynamics have reached an equilibrium point does not hold.

Philosophical differences are bound to arise when the approaches are developed for entirely different purposes. The engineering approach to power systems has evolved to deal with complex systems with uncertain behaviour, but whose underlying cause-and-effect relationships are known. The system dynamics approach has evolved to find the best way for the models to contribute to the general understanding of policymakers in corporations and public agencies (Forrester, 1961; Ford, 1999; Sterman, 2000; Coyle, 1977; Dyner and Larsen, 2001). The participants in these systems face much greater uncertainty about the cause-and-effect interactions in the system. The greater uncertainty about the system structure makes it difficult to know what phenomena can be neglected a priori, and the model development and simulations are used to ferret out the salient influences.

3.4 Software for a combined approach

Practical limitations on software solutions to algebraic equations are imposed by the system dynamics tools. These tools are relatively few in number and not amenable to specific user requirements, as are the engineering tools. An exception is the Vensim simulation environment, which allows for calling of external functions during the simulation. The gateway for these external functions in Vensim is provided via a Dynamic Link Library (DLL). The library is usually created in a C/C++ developing environment, but other languages may also be used. This DLL can contain any number of functions and it can also call other DLLs. Calling other DLLs is used when it is not possible to directly compile required functions within the environment used to create the gateway DLL.

On the engineering side, there are a vast variety of tools that can be used. In recent times, Matlab/Simulink (Sterman, 1992) has become the de facto standard in academic circles because of its ease of use, versatility and large library of functions. Matlab code can also be compiled into a stand-alone DLL, which can then be linked to Vensim’s DLL. For computational efficiency, the code can be first translated into C and then compiled. This process of linking is depicted in Figure 4. The combined approach enables us to enforce algebraic constraints using the most appropriate engineering techniques. The transmission system equations are an example of such hard constraints. The transmission models and their implementation are described next.
4 Transmission network models

Although it is possible to represent every technical detail of interest using the combined approach presented in Figure 4, their needs to be a balance in the depth within the overall system dynamics framework. For example, precise models of a transmission network cannot be easily incorporated into market models. For the broader analysis proposed here, the data problem is even more difficult, as longer-term broad assumptions are nearly impossible to map into the detailed models of the network and generators. Instead, a simplified approach is pursued here.

Solving a problem with algebraic constraints, such as an Optimal Power Flow (OPF), in a dynamic simulation environment is inherently difficult. In a more complex case, it may be impractical. Managing algebraic constraints using a math-oriented modelling approach and programming language is generally more tractable. As said earlier, we use Matlab and some of its functions from the accompanying libraries to apply more powerful methods within the Vensim environment. Still there remain important modelling decisions. In the following, the determination of price in the different areas considering operational constraints is detailed in order to highlight the modelling choices.

Neglecting for the moment the details of the bidding and market-clearing processes, assume the prices are determined by the marginal costs of the generator units. Further, assume that the generator costs are quadratic:

$$C_i(P_i) = \frac{a_i}{2} P_i^2 + b_i P_i + c_i$$  \hspace{1cm} (1)$$

with $P_i$ the generator output of unit $i$. Now, if no units are operating at their limits and there are no network constraints, all generators should operate at the same marginal cost, which can be found analytically as:
Optimisation approaches, as in the OPF, are applied by the ISO to satisfy system constraints and incorporate the market rules into operations. There are of course movements of prices at different time scales, but these movements do not follow directly from the market rules or underlying forces. Some researchers have attempted to model the price dynamics as simple linear systems (e.g., Alvarado, 1999). Unfortunately, such a modelling approach is completely unrelated to the forces that actually move prices. As such, it is difficult to set parameters appropriately. Moreover, it is not clear if such an artificial construct can provide insight. Others have shown that price movements tend to occur more as a complex switching between static models (Vucetic et al., 2001). Such a model is more suitable for the analysis of past movements rather than for causal analysis and the prediction of long-term patterns. Here, we enforce the operational constraints but do not attempt to model the daily or weekly price dynamics.

Continuing our illustration of modelling choices, the objective is to minimise the overall system cost:

$$\min_{P_g} C = \sum_{i=1}^{N} C_i(P_g) = \min_{P_g} \left( \frac{1}{2} P_g^T H P_g + P_g^T f \right)$$

subject to power balance and generators’ operating limits:

$$\sum_{i=1}^{N} P_g = \sum_{i=1}^{n} P_i, \quad P_g \leq P_g \leq \bar{P}_g.$$  

The above can be solved without difficulties using, for example, quadratic programming. But it can be costly to implement in a dynamic simulation environment, especially with the additional constraints introduced by the network. These include the power flow balance for each node and the loading limits for each of the network elements. One must solve the static algebraic problem that is introduced within the main simulation loop performing the numerical integration. This slows down simulation and, further, these constraints are not actually hard limits given but only an approximate operations model.

In order to address these issues, a proper choice of time is needed. We choose to represent each month by a typical daily model. Thus, the prices vary hour to hour, but they are found as a snapshot solution with no dynamics. Specifically, we solve an optimisation problem over a single-day horizon that respects the limits but allows for month-to-month dynamics as determined by external influences of supply and demand growth, weather variables, hydrology, and so on. Addressing these issues also requires a compact representation of the transmission network. Here, we present a compact, reduced version of the DC OPF, which in its standard form can be found elsewhere (e.g., Wood and Wollenberg, 1996). Its salient feature is that it eliminates nodal voltage phase angles from consideration and explicit network equality constraints.

We start from the standard DC power flow equations that relate nodal injections, $P_{inj}$, to line flows, $P_{flow}$:

$$P_{flow} = [P_{i,j}] = X^{-1} A^T (B^T)^{-1} P_{inj} = DP_{inj}$$
where $X$ is a diagonal matrix with line reactances, $B'$ is the imaginary part of the bus-admittance matrix, $A$ is the node-branch incidence matrix, and $D = X^{-1} A^T (B')^{-1}$. Nodal injections are the difference between generation and load power in each node. The loads are lumped in an equivalent load, but we keep generators separate, because their outputs are the decision variables in the optimisation. Standard DC formulations assume that there is only one, possibly equivalent generator per node. However, in the WECC model, a node is actually a whole area with many different generators. We introduce the ‘node-generator’ incidence matrix, $A_g$, with binary elements $a_{ij}$ that specify whether generator $j$ is connected to node $i$.

By breaking down nodal injections into their components, the inequality constraints imposed by the network elements’ capacities, $P_{cap}$, can be written as:

$$-P_{cap} \leq P_{flow} = D(A_g P_g - P_i) \leq P_{cap}.$$  

Written in a compact form, the inequality constraints are:

$$\begin{bmatrix} D \cdot A_g \\ -D \cdot A_g \end{bmatrix} P_g \leq \begin{bmatrix} P_{cap} + D \cdot P_i \\ P_{cap} - D \cdot P_i \end{bmatrix}$$

or

$$A_{in} \cdot P_g \leq b_{in}.$$  

Standard DC OPF formulations use network equations to specify power balance in each node, including the reference. Thus, a total of $n$ equality constraints are usually specified. The corresponding Lagrange coefficients for each of these constraints then give the Locational Marginal Prices (LMPs) for all nodes. In our formulation, we could specify the power balance in each node as:

$$AP_{flow} = P_{inj} = A_g P_g - P_i$$

but, since we have already expressed power flows in terms of injected powers in the independent nodes, the result will be a trivial set of equality constraints of the form $0 P_g = 0$. The only equality constraint that we can use is the one considering the reference node and the power balance in the whole network, given by Equation (4). For simplicity, we will not explicitly specify generators’ operating limits, but it is assumed that they will be enforced. So, the Lagrangian function for our DC OPF formulation is the following:

$$L = \sum_{i=1}^{N} C_i(P_{pi}) + \lambda \left( \sum_{i=1}^{N} P_{g_i} - \sum_{i=1}^{N} P_{pi} \right) + \mu^T (b_{in} - A_{in} \cdot P_g).$$

From here, after solving for Karush-Kuhn-Tucker optimality conditions, we find the following for the LMPs:

$$LMP_i = \lambda$$

$$[LMP]_{1..n} = \lambda + D^T [D^T \mu].$$

Observe that:
• The LMP at the reference node is given by $\lambda$, as the power flows do not depend on the injection in this node.

• For all the other nodes, the corresponding LMPs have to be adjusted for all congestion that appears in the network. These adjustments are done by multiplying the Lagrange coefficients for the congested lines with the sensitivities of the flows in those lines from the injection at the given node.

• In the special case when there are no congested lines, all LMPs are equal to $\lambda$.

• If there are congested lines, even a single one, all nodes in the system in general will have different prices owing to different sensitivities (Christie et al., 2000).

Reducing such a large system as the WECC to a much smaller system, as the one shown in Figure 6, cannot be done without introducing errors that result from inevitable approximations. Power systems are non-linear and the reduction process very often involves multiple linearisations. Thus, the obtained equivalent system is valid within a region whose boundaries may be hard to find. Knowing that the validity of the equivalent is confined, we may pursue another approach and find the relationship between power flows and injections, i.e., the sensitivity matrix $D$ in Equation (6), directly from the original system. This is done by fitting a plane through a set of solution points obtained from the original system. The fitting can be done, for example, by means of the least square estimators. This way, we do not explicitly calculate the reactances of the equivalent lines, but still use the DC OPF formulation from above. If necessary, more than one matrix can be constructed that describe, for example, different seasons, different generation and transmission scenarios, peak and off-peak hours. For example, one such matrix that describes the base case for the system shown in Figure 6 is given in Table 1. Note that the reference node, A1, is omitted from the sensitivity matrix. The limits on the inter-area flows are derived from current operating practices in the WECC.

**Figure 5** Opening view of the developed model
A. Dimitrovski, A. Ford and K. Tomovic

Figure 6  Areas and transmission lines of the simulated system

Table 1  Sensitivity matrix for the system shown in Figure 6

<table>
<thead>
<tr>
<th>Line</th>
<th>A2</th>
<th>A3</th>
<th>A4</th>
<th>A5</th>
<th>A6</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1–A5</td>
<td>−0.3872</td>
<td>−0.38</td>
<td>−0.6717</td>
<td>−0.2488</td>
<td>0</td>
</tr>
<tr>
<td>A1–A4</td>
<td>0.0819</td>
<td>−0.5475</td>
<td>−0.5367</td>
<td>−0.3091</td>
<td>0</td>
</tr>
<tr>
<td>A5–A4</td>
<td>−0.2836</td>
<td>−0.4236</td>
<td>−0.5879</td>
<td>0.6649</td>
<td>0</td>
</tr>
<tr>
<td>A3–A4</td>
<td>0.1576</td>
<td>1.036</td>
<td>0.0518</td>
<td>−0.2663</td>
<td>0</td>
</tr>
<tr>
<td>A2–A3</td>
<td>0.0153</td>
<td>0.0493</td>
<td>−0.0084</td>
<td>−0.0524</td>
<td>0</td>
</tr>
<tr>
<td>A2–A1</td>
<td>−0.0442</td>
<td>0.1539</td>
<td>0.0641</td>
<td>−0.006</td>
<td>0</td>
</tr>
<tr>
<td>A6–A1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>A1–A3</td>
<td>0.0133</td>
<td>0.0306</td>
<td>−0.0087</td>
<td>−0.0858</td>
<td>0</td>
</tr>
</tbody>
</table>

The formulation (10) can be solved with a standard routine. For the WECC model, we use Matlab’s ‘quadprog’ function. The solution is obtained relatively fast, although there is overhead in the calling procedure between Vensim’s and Matlab’s DLLs. Nevertheless, even this approach can be prohibitively slow if the time resolution is very high. Our current model uses a typical day to represent prices and costs for each month of the year. The model is normally used to simulate the WECC from 2005 to 2025. The entire simulation requires 240 steps, one for each month of the study interval. With this time resolution, the model can be simulated with the quick response needed for rapid experimentation, which is useful for group learning. If future studies indicate a need to include more than one typical day per month, the approach could be expanded. Still, such a model would simulate less rapidly, and could require data that is not readily available.
Other important optimisation procedures can be included in the model in a similar way; for example, scheduling of production from hydro resources and scheduling of maintenance for thermal units. In addition, some complex calculations also need a similar combined approach; for example, calculations of the Loss of Load Probability (LOLP) and expected unserved energy indices, which involve convolutions. As in the above-described case of OPF calculations, they are best done outside the main simulation loop and with different time resolution.

5 Illustrative simulation of the WECC

Figure 5 shows the opening view of the developed model. The Vensim software organises models in a series of views, and this is the first of 50 views. Navigating through the many views is made easier by the comment icons in Figure 5. The grey comments lead to different parts of the model; the green comments lead to the main simulation results; and the purple comments lead to recent test results that are still under study. With 50 views, the model is far larger than can be described here. However, a few selected results are shown to illustrate how the short-term results are incorporated within a model of the long-term trends in the system. The images in Figure 5 show the main components of the model: generation, transmission, distribution and consumption of electric energy. In this application, we are particularly interested in the carbon dioxide (CO2) emissions from electricity generation. We illustrate the model by simulating the impact of the carbon allowance market proposed in Senate Bill 139 on the western system.

This opening view serves as a point of departure for the team of researchers who experiment with the model. For example, when we click on the ‘Transmission Capacity’ comment, Vensim moves to the view shown in Figure 6. This diagram shows the level of aggregation in the simulated system.

The WECC is broken down into six areas interconnected by eight transmission lines. This approach grew out of a simpler model with four areas, one for each of the areas in WECC summary reports. However, given the substantial interest in the power flows between northern and southern California, we elected to break California into two areas. With this approach, the ‘T3’ line in Figure 6 corresponds to the much-discussed ‘Path 15’. More recently, there has been growing interest in carbon policies in the states of Washington, Oregon and California (WA/OR/CA). To permit clearer simulation of these policy initiatives, we broke the NorthWest Power Pool (NWPP) down into an area for WA/OR and a separate area for the remainder of the NWPP.

The green areas in Figure 6 correspond to the states with an interest in initiating carbon-reduction policies. The arrows in Figure 6 depict the eight transmission lines in the system. The directions of the arrows indicate our expectation for the primary direction of power flows, although these vary seasonally. The size of the arrows indicates our expectation for the magnitude of the flows. For example, large flows are expected on lines T1, T2, T3 and T4. And in scenarios with major development of the coal and wind resources in Area 6, we expect to see major flows along T7. The capacity of each of the transmission lines is specified by the model user. For the examples in this article, the capacities were set quite high. This allows us to show the model response when the capacities permit uncongested flow of power through the system.
Figure 7 shows the growth of peak loads in a ‘base case’ simulation to test the model. The peak loads are reported for a typical day of each month of the year. We assume the WECC peak appears in August each year. The system peak is just below 150 GW in the first year, and it grows at 2.5%/year for the entire simulation. Recent estimates of annual growth rates range from around 1% to 2.5%. We selected 2.5% because a high growth rate would provide a more revealing test of the model’s representation of new investment in generating capacity. The model simulates consumers’ response to changes in retail rates, so the actual growth in demand may vary from the user-specified trend. However, retail rates are relatively constant in the base case, so the upward trend in Figure 7 is essentially 2.5%/year.

**Figure 7** Growth in peak load in a Base Case (BC) simulation to test the model

![WECC Peak Loads](image)

Figure 7 is a stacked graph with the top portion showing the must-run generation. (Hydro, other and wind are treated as must-run generation.) We subtract the must-run generation to get the demand that must be satisfied by the thermal units. The thermal generators operate in a simulated spot market, so the spot price must rise sufficiently high to satisfy the demand placed on the market in each hour of the day. The prices are calculated for a typical day for each of the 240 months of the simulation.

Figure 8 shows a summary of the prices in the base case simulation. The peak price is shown in blue. This price is recorded at 2:00 PM each day. Peak prices in the first year rise to just over 60 $/MWh in the summer months. By the end of the simulation, the peak prices are around 70 $/MWh. The off-peak price is recorded at 2:00 AM of each day. Figure 8 shows that off-peak prices are relatively constant at just under 40 $/MWh. The dashed, red curve in Figure 8 is the average daily price in the region. The simulation begins with average daily prices at around 42 $/MWh.
To put this price in perspective, Figure 8 includes the weighted average cost of investing in a mix of four types of generating plants in Area 1. Investors wishing to build in WA/OR would face a fully levelised cost of new generation of around 56 $/MWh. Thus, daily average spot prices would fall far short of providing these investors the prices they need to justify such investments. The low wholesale prices in 2005 are caused by the large amount of generating capacity currently available in the WECC. The simulation begins with a planning reserve margin of 33%. Although the simulation is running with average hydro generation, this measure of reserves is calculated as if the hydro system experiences ‘critical conditions’. Planners normally call for resource plans which aim for a reserve margin of around 15% under critical conditions. Thus, our base case example begins with approximately twice the reserves thought necessary for reliable operation in a year with low hydro generation. (This starting condition matches the description of the WECC loads and resources by McCullough (2005).)

Figure 9 shows the loads and resources in the simulated spot market for thermal generation. The ‘peak load to market’ is shown in blue. The simulation begins with a peak load to market at around 100 GW in August of the first year. The dashed, red curve shows the total thermal-generating capacity that bids into this market. The simulation begins with over 160 GW of thermal capacity, and this grows even higher during the first year as the capacity initially under construction comes on line. The green, dashed curve in Figure 9 shows the thermal-generating capacity that is available to operate in each month of the simulation. The difference between the red and green curves reveals the effect of thermal outages.
The user specifies a forced outage rate and a planned outage rate for each of the thermal technologies in the model. Forced outage rates are applied uniformly throughout the year. Planned outage rates are subject to user-specified schedules. This simulation is based on scheduling 50% of the repairs in the spring, the rest in fall and winter. The base case simulation implies that no new construction is initiated for several years because of the high reserve margin. Consequently, the thermal capacity declines somewhat owing to retirements. We then assume that new construction will be initiated around the year 2008, as this initiation causes planning reserve margins to fall gradually into alignment with the 15% goal often used in resource planning. Figure 9 shows thermal capacity growing again around the year 2010. The capacity grows for the remainder of the simulation based on the assumption that construction will keep pace with growth in demand. This construction pattern rests on the assumption that investors will sign long-term contracts with a premium payment to make up for the low energy prices shown in Figure 8. This ‘implicit capacity payment’ is calculated in the model and included in the retail rates charged by the distribution companies.

We assume that investors can choose from a variety of generating technologies. For the base case simulation, the main choices are gas CCs, coal plants, wind machines and biomass. Construction of new wind capacity is assumed to require 12 months; CCs, 24 months; biomass and coal-fuelled plants, 36 months. The competition between these four choices is simulated for each of the six areas of the region. This approach allows for consideration of different fuel costs across the region. It also allows us to account for restrictions on new coal-fired power plants in California.

Table 2 shows the total investors’ costs for each of the generating technologies. (These particular costs are for a region like Area 6, an area with inexpensive coal and extensive wind resources.) The base case assumes that natural gas prices are constant at $5.50 per million BTUs, a value commonly forecasted when our research began. Coal
prices are assumed to remain constant at $1,000 per million BTUs. The cost of biomass is initially $1.50 per million BTUs, but this price may rise during the simulation as more and more land is devoted to the production of dedicated crops. With these assumptions, the investors’ cost for coal plants and CCs are approximately the same, around 55 $/MWh.

Table 2  Illustrative comparison of investors’ total costs

<table>
<thead>
<tr>
<th>Starting value of costs</th>
<th>Gas CC</th>
<th>Coal</th>
<th>Wind</th>
<th>Biomass</th>
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<tr>
<td><strong>Fixed costs</strong></td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>Construction cost ($/kW)</td>
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<td>1,600</td>
<td>1,000</td>
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<td>Fixed charge rate (1/year)</td>
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<td>0.145</td>
<td>0.145</td>
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<td>232</td>
<td>145</td>
<td>261</td>
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<tr>
<td>Fixed O&amp;M ($/kw-yr)</td>
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<td>40</td>
<td>20</td>
<td>40</td>
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<tr>
<td>Fixed transmission ($/kw-yr)</td>
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<td>15</td>
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<tr>
<td><strong>Total fixed costs ($/kw-yr)</strong></td>
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<td>287</td>
<td>185</td>
<td>316</td>
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<td>Capacity factor to get $/MWh</td>
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<td>0.75</td>
<td>0.33</td>
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<td><strong>Levelised fixed costs ($/MWh)</strong></td>
<td>14.2</td>
<td>43.7</td>
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<tr>
<td><strong>Variable costs</strong></td>
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<td></td>
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<tr>
<td>Cost of fuel ($/million BTU)</td>
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<td>Heat rate (BTU per kWh)</td>
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<td><strong>Regular variable costs</strong></td>
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<tr>
<td><strong>Total variable costs</strong></td>
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<td><strong>Levelised cost ($/MWh)</strong></td>
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<td>55.4</td>
<td>70.0</td>
<td>70.6</td>
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<tr>
<td>Production tax credit ($/MWh)</td>
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<td></td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td><strong>Total investor cost ($/MWh)</strong></td>
<td>55.0</td>
<td>55.4</td>
<td>57.0</td>
<td>57.6</td>
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Wind and biomass generators are assumed to both qualify for the renewable energy production tax credit, a federal incentive which is roughly equivalent to 13 $/MWh. With this assumption, the wind and biomass options are slightly more expensive than gas and coal-fired power plants. We allocate the market shares among the choices using the ‘logit’ function, with a shaping parameter to reflect diversity of conditions within each area. The ‘shaping parameter’ controls the extent to which a higher cost option (such as biomass) can capture a small fraction of the market. Choices that appear somewhat more expensive in a comparison of average costs can capture a small share of the market because of diversity of costs within the area. Also, a nominally more expensive choice (like biomass) might capture a portion of the market if investors are reluctant to put ‘too much’ of their investment into the lowest cost resource. Some investors may look for a mix of investments based on an ‘efficient frontier’ method to strike the right balance
between low cost and low risk in their investment portfolio. Depending on their attitude towards risk, the portfolio could include a wide range of investments whose average costs are somewhat higher than the nominally best choice in the comparison (Letzelter, 2005).

Figure 10 shows the market shares of new construction in the base case simulation. This is a stacked graph, so the fraction to each of four technologies adds to one. The market shares are a weighted sum for the entire region. With the high reserves at the start of the simulation, there is no need to initiate construction until the year 2008.

**Figure 10** Construction market shares in the base case simulation

![Region Wide Construction Market Shares](image)

Staring at the bottom of Figure 10, the wind market share is initially around 25% of new construction. This fraction of market share declines over time as investors move to sites with greater difficulties for transmission connection and integration with the system. The next segment of the stacked graph counts the market share for biomass-fuelled power plants. These are carbon-neutral power stations with dedicated crops grown on short rotation (Flynn and Ford, 2005). The large segment in the middle of Figure 10 shows that gas-fired combined cycle units would capture the majority of the market for new construction. This large market share arises from their ability to deliver the lowest cost if gas is available at $5.50 per million BTUs. It also arises from restrictions on coal construction in California. The segment at the top of Figure 10 shows the regional market share for coal-fired power plants. Coal plants capture around 20% of the market in the early years. Their share grows somewhat over time as the wind and biomass choices become more expensive owing to depletion of the best locations.

Figure 11 shows a graph of how the generating technologies would be dispatched during a typical August day in the final year of the simulation. This simulation is based on an ‘average year’ as far as hydro generation is concerned. The model uses monthly shape factors to divide the hydro energy into separate months. Hourly shape factors represent the ability of operators to shape some of the generation towards the middle of
the day. The model simulates pumped storage generation separately. We assume 50% pumping losses to move the water to the upper reservoirs during the off-peak hours. The generation is concentrated in the five hours around the 14th hour, the time of highest loads.

**Figure 11** Generation for a typical August day in the final year of the base case simulation

We treat other generation as must-run generation. (Other is a mix of geothermal, internal combustion and ‘other’.) Wind units are also must-run. Wind generation can be shaped to different parts of the day based on several scenarios for the daily wind patterns. The base case simulation spreads the wind generation out evenly over the day.

Figure 11 shows that nuclear, coal and biomass plants operate for the entire summer day. The model retires around 20% of the nuclear capacity that existed at the start of the simulation. Although the user can specify additions to the nuclear capacity, such additions are not part of our base case simulation. The model does add new coal capacity to the system, and Figure 11 highlights the coal generation in black. Coal accounts for 28% of the generation on this summer day at the end of the simulation. The gas CCs in Figure 11 are a combination of units existing in 2005 and the many new units that are constructed during the simulation. Some of the CCs would operate for the entire day; others would run for only eight hours in the day. Gas steam units operate for around four hours, and CTs are needed briefly to satisfy the peak demand. Figure 11 makes it clear that gas-fuelled units are on the margin for the entire day.
6 Illustrative analysis of a carbon allowance market

We conclude the illustrative simulations by showing preliminary results from an analysis of S139. Senate Bill 139 is the Climate Stewardship Act of 2003. It called for a cap-and-trade approach to control greenhouse gas emissions, and it proposed a market for carbon allowances to encourage the most efficient combination of investments to reduce the emissions. The proposed carbon market has been the subject of much debate and several studies, including an extremely detailed study by the Energy Information Administration (EIA). The EIA findings are summarised here to provide context for our analysis.

6.1 Summary of the EIA results for S139

Figure 12 summarises the key results from the EIA analysis of the nation’s electricity sector. Emissions are shown in Million Metric Tons of Carbon (MMTC) equivalent on the left scale. The cost of carbon allowances are shown in $/MTCO₂ on the right scale. The EIA used repeated simulations to search for an allowance price trajectory that would induce the entire economy to achieve the goals. Their search led to an initial price somewhat above 20 $/MTCO₂ followed by a rise to 60 $/MTCO₂ over the next 15 years. In other words, these prices would be sufficient for the nation to achieve the goals specified in S139.

Figure 12 shows that the electricity sector emissions would be reduced dramatically with these prices. Indeed, the electricity sector emissions would decline well below the allowances available to this sector. This indicates that the electricity sector would have extra allowances that could be banked for future use or sold to other sectors. For the purpose of this article, the most relevant finding from the EIA study is that the electricity sector could deliver a 76% reduction in emissions with an average retail rate increase of 46%.
Figure 13 puts these long-term results in perspective by showing CO₂ reduction on the vertical axis and price increases on the horizontal axis. The graph is divided into diagonal halves by a 50/50 line. The purpose of this line is to help us see which sectors would be most responsive under S139. (The idea behind cap-and-trade markets is that market forces will bring forth a strong response from those sectors with the greatest flexibility in response. Less flexible sectors would then buy the needed allowances from the more responsive sectors.) Figure 13 show that the transportation, industrial and residential sectors would fall well below the 50/50 line. It is clear that it is the electricity sector that would lead the way in reducing the carbon emissions.

**Figure 13** Comparison of EIA results for the nation with our base case results for the WECC system

6.2 Simulated response of the WECC under S139

Our simulation of the WECC indicates that the western system could achieve similar results. Figure 13 summarises our preliminary results by the red triangle. This ‘base case’ result was found by exogenously setting carbon allowance prices to follow the trajectory in Figure 12. (All other assumptions were the same as in the base case simulations shown previously.) The model responded with a combination of changes in short-term operations and long-term investments. By the year 2025, the result was a 75% reduction in carbon emissions and a 23% increase in the average retail rate for electricity. This base case result is extremely encouraging, as it shows the western system could achieve the same dramatic reduction in CO₂ emissions that the EIA projected for the nation as a whole. The retail rate result is even more encouraging – the base case simulation shows that the rate increase would be only half as large as the EIA projected for the entire nation. We explain some of the details behind these encouraging results below.

Figure 14 helps one anticipate the construction market shares that might emerge in a simulation with S139. This bar graph shows the investor costs that could appear in a simulation with higher and higher prices for carbon allowances. The first bar for each technology corresponds to the costs shown previously in Table 2. The remaining bars
show the costs that might appear as the price for allowances rises over time. For example, the bars for gas-fired CC show investor costs with carbon prices ranging from $50 to $250 per MTC. The $100 price is highlighted in Figure 14. With 3.67 pounds of CO₂ for every pound of C, this price corresponds to a price of 27 $/MTCO₂, a price that would be imposed shortly after the carbon market opens in the year 2010. Figure 14 shows that the full cost of a CC would be 65 $/MWh, but the cost of a coal plant would be over 80 $/MWh. This comparison indicates that coal plants would be far too expensive for new investment immediately after the market’s opening.

**Figure 14** Investor costs with selected values highlighted for a carbon allowance price of 100 $/MTC (27 $/MTCO₂)

The costs for biomass plants are shown next. The model assumes that the development of dedicated crops to support biomass generation will lead to higher and higher costs to harvest and deliver the fuel. The five extra bars show the investor cost depending on the additional cost to deliver the fuel. The highlighted bar shows that biomass capacity would be competitive with CCs if the biomass could be delivered with a 50 cents/million BTU increase in costs.

The wind costs in Figure 14 are arranged according to an increase in construction cost. The initial construction cost is 1,000 $/kW, but we assume that wind developers will face higher costs as they turn to less advantageous wind sites. The higher costs to connect to the transmission grid and to integrate the intermittent wind into the system have been the subject of several studies. These costs are translated into an equivalent increase in the capital cost. Figure 14 shows that wind would remain approximately competitive with CCs even if investors faced the need to spend an extra 200 $/kW in construction costs.
The lower portion of Figure 14 shows the total costs for a gas-fired combined cycle unit with the capability for carbon capture and storage. We assume that this technology could become available near the end of the simulation for a total cost of around 75 $/MWh. (This particular technology serves as the longer-term ‘back stop’ technology in the model.) Figure 14 shows the increase in costs from such a generator if there is some leakage from storage, and the leaked carbon is subject to the carbon allowance prices shown. For the base case test of S139, we assume that a CC with carbon capture and storage (and zero leakage) becomes available around the year 2020.

Figure 15 shows the negative feedback loops that control construction market shares in a scenario with rising carbon prices. Starting at the top of the diagram, higher carbon prices drive up investors’ cost of CCs. This increases the market share for wind capacity, so there is more total wind capacity, higher construction costs at the next location, an increase in investors’ cost and a subsequent reduction in the wind market share in the future. The ‘wind integration loop’ provides negative feedback in the simulated system.

Figure 16 shows the simulated impact of S139 on carbon emissions (measured in MMT/year). The carbon allowance prices are projected to reduce the WECC emissions by 75% by the year 2025. Figure 17 shows the simulated impact on the average retail electric rate. The base case electric rate is constant at 86 $/MWh. The generation portion of the retail rate is 56 $/MWh; transmission and distribution and other expenses amount to 30 $/MWh. The generation component is based on the wholesale price of electric energy (shown previously in Figure 8) plus a premium payment to induce construction of new power plants to keep pace with demand growth. The retail rate is driven up in the S139 scenario by a combination of higher wholesale prices and the higher costs faced by new investors. The average retail rate in the year 2025 is 106 $/MWh, roughly 23% higher than in the base case simulation.
Figure 16  Simulated impact on the carbon emissions (in MMTC/yr) in the WECC

![Graph showing carbon emissions over years for BC and BC S139.]

Figure 17  Simulated impact on the average retail rate (in $/MWh) in the WECC

![Graph showing average retail rates over years for BC and BC S139.]

Figure 18 shows how the generating technologies would be dispatching during a typical August day in the final year of the simulation with S139. A comparison with the corresponding chart in Figure 11 shows that S139 would lead to somewhat less demand. (The reduction is around 9%, and it is caused by the consumers’ reaction to the higher retail rates shown in Figure 17.) The hydro assumptions are the same as in the base case:
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Each year is an ‘average year’ and the operators are able to shape some of the hydro generation into the peak hours. The generation from nuclear and other units is also the same as in the base case simulation. Figure 18 shows much greater generation from wind and biomass. Figure 18 also shows a small contribution from the CCs with carbon capture and storage technology. However, the most dramatic change in the August day dispatch is the reduced need for coal generation. Indeed, Figure 18 shows that coal generation would be completely eliminated by the end of the simulation.

Figure 18  Generation for a typical August day in the final year of the S139 simulation

Coal generation was highlighted in black in the previous stack in Figure 11. It accounted for 28% of the generation, but it was responsible for a far larger portion of the CO₂ emissions. (The base case showed that coal would account for two-thirds of the CO₂ emissions in the year 2025.) Figure 18 shows that coal generation could be eliminated entirely under S139. This is achieved in two phases. The first phase is the elimination of investment in new coal plants immediately after the carbon market opens in the year 2010. The second phase is the gradual reduction in coal plant operating hours as higher carbon prices drive up the coal plants’ variable costs. Over time, more and more coal plants are pushed to the top of the stack. But since they are not able to operate for only a few hours each day, they are retired from service, and the model responds by investing more heavily in the carbon-free resources that are favoured under S139.

Figure 19 provides the final illustration of model results by showing power flows between WA/OR and Southern California. These are unconstrained power flows (calculated with a large capacity for all eight tie lines). The highest flows on this line appear at the peak hours of each day. So we show peak hour flows to learn the size of the lines needed to accommodate flows.
Figure 19  Impact of S139 on unconstrained power flows on line T2 from WA/OR to Southern California

Flows on Line T2: WA & OR to So CA

The first-year result has around 3.5 GW flowing south in the summer and 5.0 GW flowing north in the winter (not intended to represent the present conditions). This particular simulation shows declining flows in the summer and increasing flows in the winter. If all flows were to be accommodated, the capacity would have to grow to 10 GW by the year 2020.

Figure 19 shows the power flows in the S139 simulation in red. These are identical to the base case flows until the year 2012, two years after the carbon market opens. The S139 flows are only slightly different for the remainder of the simulation. This comparison teaches us that S139 would not change the capacity requirement for this particular corridor to accommodate uncongested power flows under the base case assumptions.

7 Summary

This article demonstrates an interdisciplinary approach to simulating the long-term trends in large-scale power systems. The test results for the WECC indicate that the short-term market dynamics can be incorporated within a longer-term model. The model can then be operated in the highly interactive fashion needed to support group discussion and leaning. The model is distinctive for its treatment of the interplay between the economic, technical and environmental factors in the system. The simulations shown here are for illustration only. Although they are preliminary, the results point to some important conclusions that will be the focus of further study. One important conclusion is that the WECC could achieve dramatic reductions in CO₂ emissions if the nation were to adopt the carbon allowance market envisioned in S139. Our preliminary results also indicate that the WECC could achieve this reduction with only half the increase in electric rates that have
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been predicted for the nation as a whole. And finally, the simulations indicate that the large reduction in CO₂ emissions could be achieved with relatively minor reliance on advanced generating technologies (such as power plants with carbon capture and storage). These results are important to the discussion of carbon reduction policies at both the national and the state level.

Acknowledgement

The work reported in this paper has been supported in part by the NSF and the Office of Naval Research under NSF grant ECS-0224810 and in part by NSF under ECS-0424461.

List of acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>ATC</td>
<td>Available Transmission Capacity</td>
</tr>
<tr>
<td>CC</td>
<td>Combined Cycle Generators</td>
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<td>Dynamic Link Library</td>
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<td>Washington State University</td>
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References


**Notes**

3. The *STELLA* software is provided by isee systems, formerly known as High Performance Systems. The software and users’ guides are available at [http://www.iseesystems.com/](http://www.iseesystems.com/).
4. The *Vensim* software is provided by Ventana Systems, Inc. The software and users’ guides are available at [http://www.vensim.com/](http://www.vensim.com/).