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Simulating Electricity Restructuring in California: Interactions with the Regional Market

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ABSTRACT

This paper presents some simulations of the proposed California power exchange, or pool, as it might interact with the regional market in the Western U.S. Pooling will increase interdependence with the regional market. We study this using a multi area chronological production simulation model. We find that overall operating economies resulting from pooling are small. Physical changes in the dispatch of the electrical system, however, are rather large in comparison with the economic effects. The two driving forces for the physical changes are the reduced unit commitment resulting from pooling and transmission pricing policy. As a result of increased regional trade, transmission congestion increases. The costs of congestion appear small, however, since marginal costs in the regional are quite close to one another. Within the California pool, marginal cost pricing will produce economic rents for the generating companies. These rents are not particularly large, especially in light of the fixed operating and maintenance costs of the plants that must be covered by those rents. Finally we examine the potential for new entry into the market. Entry conditions in the near term do not appear particularly favorable. If the fixed costs of new supply are sufficiently low to allow entry, regional economics show no clear preference for siting within California versus more remote locations. The trade-off between moving gas versus transmitting power do not show a clear trend. These results are quite preliminary, but suggest that quantitative modeling of electricity restructuring can yield useful insights.

1.0 Introduction

The California initiative on electricity industry restructuring has moved from the initial California Public Utilities Commission (CPUC) "Blue Book" proposal of March, 1994 (CPUC, 1994) to an

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implementation phase based on the CPUC decision of December, 1995 (CPUC, 1995). This initiative has spanned a broad range of questions including the definition, estimation and recovery mechanisms for stranded costs; the formulation of performance based rate making mechanisms, and the fate of public goods programs. Much discussion has focused on issues associated with the organization of wholesale, or bulk power markets. This paper addresses some questions associated with bulk power market organization, in particular the effect of a California pool on the rest of the regional power market in the West.

California has historically relied to a considerable degree on electricity imports from other Western states, either through shared ownership of facilities, long term contracts or short term sales. The electrical interdependence with the Western System Coordinating Council group of utilities was a focus of concern in the original Blue Book decision, called out in particular by President Fessler’s concurring opinion (Fessler, 1994). Subsequent discussion has focused on other issues. With implementation of the December 1995 decision now requiring attention to the detailed structure of the new California market, attention remains appropriately concentrated on intra-California matters. Nonetheless, the electrical and market interactions of new California institutions with the WSCC remain significant.

We examine these interactions using a production simulation model. The theoretical discussions of market organization that proceed from first principles use abstract models or stylized characterizations to define issues and argue for one approach or another to market organization. Significant contributions include Garber, Hogan and Ruff (1994), Chao and Peck (1995), Wu *et al* (1994) and Wu and Varaiya (1995). We take note of these efforts, but seek instead to address some issues raised by restructuring in a more empirical fashion. Engineering simulation is useful for quantitative assessments.

Simulation modeling of the electricity system can be applied to engineering management or economic and policy analysis. Depending upon the question asked and the use that will be made of the results, very different techniques and data detail will be appropriate. Simulation modeling has been used in California regulation for at least ten years to address a variety of economic and policy questions (Kahn, 1995). The questions raised by restructuring are similar in some ways to issues analyzed previously, but also raise new complexities. We begin therefore in Section 2 with an overview of simulation modeling to define more precisely which questions are amenable to analysis with these tools, and which are not. We use this discussion to motivate and characterize the approach that we adopt.

Models require appropriate data. Increasing sophistication of modeling approaches is only feasible if there is reliable data available that corresponds to the level of representation required by a model. In Section 3 we describe the data that we use for this discussion. For our base case representation of the California electricity system and the Western System Coordinating Council (WSCC) area, the data comes from publicly available sources. We summarize the principal features of this data in that section.

Since transactions between California and the WSCC form the basis for this analysis, we discuss the transaction logic used in some detail in Section 4. Simulations are specified in Section 5. Results are summarized in Section 6. Section 7 applies the results to long run questions involving the likelihood of new entry into the market and the comparative economics of siting new facilities within California or at other locations in the WSCC region. Section 8 offers some conclusions.

2.0 An Overview of Simulation Models

In this section we give a brief overview of engineering simulation methods in the electricity industry. Stoll (1989) is a good comprehensive treatment of many of these topics. Our purpose is to situate the modeling approach adopted here in the spectrum of techniques that are available in principle and in practice. Section 2.1 examines some of the boundaries in the space of simulation models, ranging from the more complex to the less complex approaches. This discussion argues for the impossibility of a single universally applicable model. Section 2.2 considers more closely the trade-offs involved in trying to study economic policy questions associated with reforming the market structure in electricity; which features of the electricity system can be approximated, which need to be represented in more detail. Finally, Section 2.3 discusses restructuring issues that are amenable to simulation modeling and which are not. The approach taken here is justified in that context.

2.1 Defining the Boundaries

It is useful to explore briefly some upper and lower bounds on the complexity of problem specification, level of data detail and sophistication of solution method used in simulation models of the electricity industry. This very brief survey will help to illustrate the impossibility, under currently available technology, of formulating and solving a "complete" model of large electricity systems, simply because such a model will be "too large" to solve and use efficiently. We make this case heuristically by considering first two difficult sub-problems, unit commitment and optimal power flow, and then by reviewing a widely used approximation, single area production costing. A defining characteristic of modeling problems is the time horizon that they address.

Unit Commitment

The unit commitment problem, i.e. deciding which units to turn on and off and when to do it, arises because generating units do not respond instantaneously to changes in demand. There are significant lags in start-up and shut-down, and other important constraints on operation such as ramping limits, minimum up-times and down-times. To operate a power system at minimum cost, these constraints must be taken into account. The standard approach to operational planning with these constraints considered in the problem requires explicit optimization methods. This problem is computationally complex, since there are many combinations of units that may be used, and since timing considerations may require a solution which is not optimal at a given point, but is optimal from the perspective of a longer time horizon. A typical time horizon in these models is one week, although daily and monthly studies may also be done. There is a large literature on solution methods for the unit commitment problem (Sheble and Fahd, 1994). In most cases, the algorithms do not take transmission network constraints into account, or do so only in an incomplete fashion. Baldick (1995) discusses the current state of the art. Johnson, Oren and Swoboda (1996) use a unit commitment model to study potential impacts of pooling.

Optimal Power Flow

Power flow over an electrical network follows Kirchoff's laws. The problem requires specification of voltage parameters as well as resistance. For a given set of network parameters, power injections and demands at different network nodes, there may or may not be a feasible solution of the power flow equations. When the power flow problem is feasible for one set of power injections, then many feasible solutions will typically be possible for the same fixed set of demands and network parameters. Under these conditions, which are the usual case, the power flow problem can be generalized to include a representation of the cost functions of the generators. There is a class of simulation models used in this situation, known as optimal power flow (OPF), which solves for the least cost set of power injections, i.e. the optimal dispatch, given a fixed demand and network parameters. Solving an OPF gives results for the instantaneous state of the electricity system. As conditions change, a new OPF solution would be required. While these models are useful for research and planning purposes, they have not achieved implementation as yet in utility control centers. Utility dispatchers typically rely on modeling tools that are less rigorous in their solution method, but easier to use. Papalexopoulos *et al* (1994) describe recent experience with OPF implementation at PG&E. Additional detail describing the computational issues associated with on-line OPF implementation is given in Papalexopoulos (1996). Even large-scale OPF models typically neglect the unit commitment problem.

Single Area Production Cost

Single area production cost models lie at the opposite end of the complexity scale. These models neglect explicit representation of the electricity network, and if they treat unit commitment, it is through a heuristic approach, rather than an explicit optimization. While such approximations are severe compared to the more specialized models, their value lies in the ability to analyze economic and policy problems using the single area models at relatively low cost and with reasonable flexibility and precision. These models are typically applied to problems with a time horizon of at least one year, and often involve multi-year simulations. Sometimes these models are embedded in a capacity expansion framework for long range studies.

Even within this broad category of models, there is a range of representations. One important distinction involves the characterization of demand. For computational efficiency, production costing models developed in the 1970s relied extensively on the load duration curve model of demand, which suppresses chronology. More recently, chronological representation of demand has become computationally practical, even on small computers. Studies comparing models using different load representations indicate that significant operational economies and constraints are lost in the load duration curve framework (Kahn, Marnay and Berman, 1992).

2.2 Intermediate Approaches

For the economic policy questions considered here, the operational detail of the complex models may be unnecessary, and the data unavailable. Unfortunately, the single area representation fails to address regional questions in a meaningful way. Electricity trade requires some representation of network limits. Congestion in the transmission network has important implications for the issues of pooling benefits and potential market power. Therefore some account of this factor is necessary. There are two standard approaches to incorporating network effects in an approximate manner into production simulation modeling. The simplest is known as a transportation model, the more complex relies on the DC approximation to the AC load flow.

The transportation model neglects all electrical characteristics of the transmission network except for capacity limits. This is analogous to considering electric power being transported between regions in trucks on highways. Once such an approximation has been made, it is no longer necessary to represent separate lines between regions. They can be collapsed into a corridor characterized by the aggregate line capacity. This makes for a substantial reduction in the computational size of the problem, but imposes a cost in accuracy. The DC approximation retains reasonable fidelity to electrical properties, but involves significantly larger data requirements than the transportation approach. One advantage of the DC approximation is that it captures important transmission constraints due to voltage. There is no clear agreement about the cost implications of voltage constraints (Hogan, 1993; Kahn and Baldick, 1994). In both the transportation and DC approximations, the appropriate representation of available transmission capacity includes accounting for contingencies that require spare capacity in the network.

We proceed here by adopting a chronological model of demand and relying on the transportation approach to network representation,. We use the MULTISYM model,[1] which has been previously used in CPUC proceedings and elsewhere in California by Southern California Gas Company (CGR, 1995). A description of the capabilities of and modeling approach taken by MULTISYM is given in the model's documentation (The Simulation Group, 1995) and summarized in Lee (1993). There are other approaches to the modeling problem which differ in their choices of data representation, i.e. where to aggregate and where to disaggregate, and their choice of network properties, i.e. DC load flow versus transportation modeling. One example which has been used to study electricity restructuring is described in LCG (1996).

2.3 Relevance to Restructuring

The engineering simulation models described here cannot address certain important issues that have arisen in the restructuring debate. In particular, they are much better adapted to studying pooling institutions than trading regimes based on bilateral contracts. The reason is that there is

[1]MULTISYM is the multi area version of the PROSYM chronological simulation modeling system.

no simple way to generate the characterization of bilateral contracts that might arise. Even within a pooling framework, these models have limitations. The most important of these is the inability to formulate bidding strategy and the exercise of market power. In principle, bidding strategy could be incorporated into models of this kind, simply by adjusting the generators' costs typically used for simulating commitment and dispatch to reflect the desired pricing strategy. This mechanical adjustment, however, begs the more important question of how such strategies would be formulated in light of competitive circumstances. In particular, if a generator had market power it could raise price profitably, but this behavior is complex. For a given bidding strategy, these models can test for profitability. Newbery (1995) is a good general account of market power issues in the UK pool. Lucas and Taylor (1995) discuss bidding strategy and its characterization.

The engineering simulation tools are a reasonable guide to issues involving social costs, the role of transfer prices, and electric system dispatch assuming the absence of market power. They also can provide approximate information concerning congestion between the regions represented, which has implications for market power issues. While these are not the full spectrum of restructuring issues, they are significant pieces of the overall puzzle.

In our case, the level of network aggregation, discussed in Section 3.1 below, precludes analysis of the "fine structure" of the California market. In particular, we make no allowance for municipal utilities acting separately from the major control area operator in their transmission area. In all cases, we assume that transmission areas are dispatched as a whole. Therefore, questions such as whether the smaller municipal utilities will join the power exchange, mandated for the investor-owned utilities in the December, 1995 CPUC decision, cannot be addressed at the level of aggregation adopted here.

3.0 Base Case Data

The most complete publicly available characterization of the database used in this study is Pando (1995). While it is not practical to describe every feature of the data in detail, it is important to characterize the most important and unique features. Section 3.1 describes the network characterization. Section 3.2 discusses assumptions about loads and resources in the time frame analyzed.

3.1 Network Characterization

Figure 1 is a schematic representation of the WSCC region as characterized in the MULTISYM database used here. Table 1 lists those utilities (or regional parts of a utility) that belong to each area
or node in this network representation. Table 1 is not an exhaustive list; certain small utilities which are included in the data are omitted from this list.

The path rating data is taken from WSCC (1995). It represents the rating assigned to multiple lines in a transmission corridor by the WSCC. These line rating studies are quite detailed; a recent example is discussed in Lee *et al* (1995). The database also contains a lengthy characterization of firm wholesale transactions between utilities. The schedules included here embody long term contractual commitments that are not expected to be changed by restructuring in California. Failure to include scheduled transactions will result in over-estimates of available transmission capacity, and overestimates of resources available for electricity trade.

The choice of transmission areas given in Table 1 is a qualitative estimate of those regions within which there are no binding transmission limits. When that is the case, then there is effectively a single marginal energy cost for the area apart from losses. It is an empirical question whether the estimate embodied in the characterization used here is correct, but it is no small task to determine this. The data and methodological problems associated with this question has been investigated very carefully by Ruganis (1986) in the context of the New York Power Pool (NYPP). He uses five minute data from historic dispatch records to determine what an appropriate estimate of marginal cost is for the NYPP as a whole, and how many transmission areas are required to model production cost. He concludes that although operators tend to divide New York state up into 11 transmission areas, for the data he examined, significant peak period marginal cost variation could only be found in four. The resolution possible in the Ruganis study greatly exceeds what is currently available in the public domain for California and the WSCC. A recent study by Walton and Tabors (1996), however, using the MAPS[2] model produced a "zonal" characterization of the WSCC, segmenting the region into transmission areas where marginal costs were homogeneous within zones and heterogeneous between zones. The resulting representation is strongly similar to that used here.

There can be little doubt that the representation adopted here introduces inaccuracies in the simulations, most probably resulting in over-estimates of the operating cost savings associated with restructuring. Our defense of this representation is the standard argument on behalf of successive approximation.

[2]MAPS is described by Simons *et al* (1993).

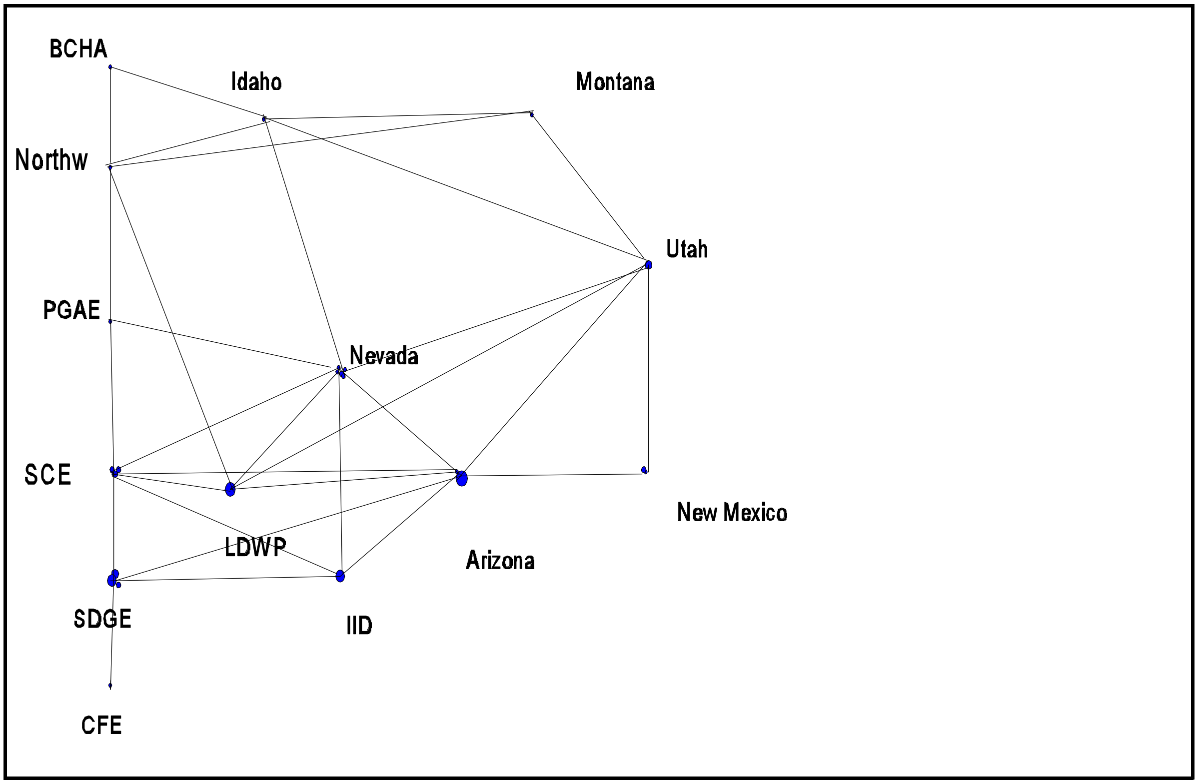

Figure 1 MULTISYM Representation of WSCC

Table 1. Transmission Area Mapping

PGAE	Pacific Gas & Electric, SMUD, NCPA, TID, MID, DWR-North, WAPA-Mid pacific
SCE	Southern California Edison, Anaheim, Riverside, Vernon, MWD, DWR-South
SDGE	San Diego Gas and Electric
LDWP	Los Angeles Dept of Water and Power, Glendale, Burbank, Pasadena
CFE	Comission Federal de Electricidad
IID	Imperial Irrigation District
Northw	Pacificorp (NW), BPA, Puget, Portland General, Seattle, WWP, PUDs, WPPSS
BCHA	BC Hydro, Alberta utilities
Idaho	Idaho Power, BPA-USBR South Idaho
Montana	Montana Power, WAPA-Upper Missouri
Utah	Pacificorp (Utah), Deseret G&T, UAMPS, WAPA-Upper Colorado
Arizona	Arizona PS, Tucson EP, AEPC, Salt River Project
Nevada	Nevada Power, Sierra Pacific, WAPA-Lower Colorado
New Mexico	PS New Mexico, Farmington, El Paso

3.2 Loads and Resources

We focus on the year 2000. This is sufficiently close in time to the present so that fuel prices can be forecast, but also sufficiently far so that we can assume a functioning California pool. By this time load growth should require new resources in the WSCC. We cannot forecast whether plans made in 1994, which are the basis of Pando (1995), will be realized or not. Therefore we take a scenario approach. In one case we assume 1994 forecasted loads and resources. This includes projects that would have been commissioned under the procedures of the CPUC's BRPU process. This assumption is identical with the MULTISYM data sets used in the 1995 California Gas Report (CGEU, 1995). For projects located outside of California, the main source of data is WSCC (1995). This includes private power projects under construction, such as the Hermiston and Tenaska combined cycle gas projects in the Pacific Northwest, and new peaking resources in Alberta (Trans Alta Utilities), Nevada (Nevada Power's Allen plant) and Baja California (Rosarita). As an alternative, we assume almost no new resource development, either in California or in the WSCC. The sole exception is the assumption of a large (approximately 1500 MW) inframarginal resource in Arizona. We include this case to test the robustness of the WSCC network to major shifts in the regional pattern of electricity trade. The output of this resource is substantially less than the energy associated with projects removed when 1994 planned resources are removed.

There are difficult issues associated with the characterization of California QF resources for simulation purposes. These projects have many different energy pricing categories, and there are expected to be significant changes in project pricing over time due to contractual provisions. These changes would occur in the absence of restructuring. We use the California Energy Commission (CEC) ER94 forecast (Miller and Korosec, 1994) to characterize the California QFs. There is considerable uncertainty about the financial viability of some QF resources as the contract pricing changes occur. Furthermore, there will be changes in QF pricing that are mandated by the December 20, 1995 CPUC decision. We have not attempted to forecast these. Instead we simply adopt the CEC forecast. In all likelihood this results in an over-estimate of QF production in the time frame considered.

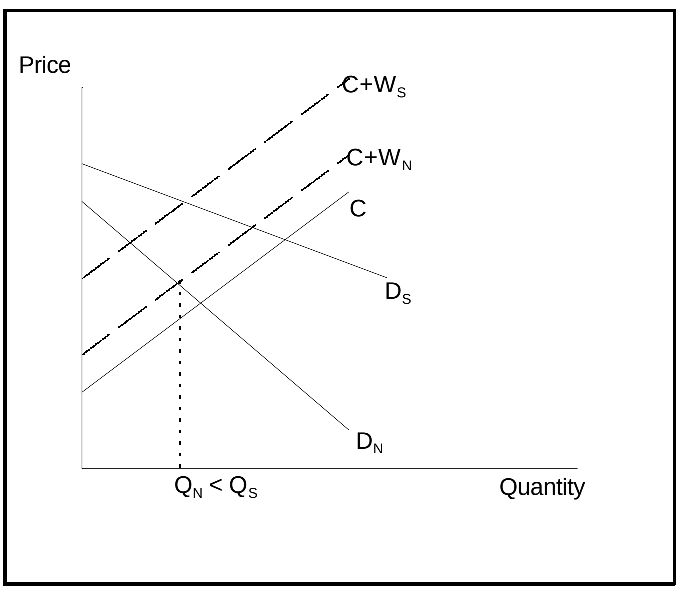

Figure 2 Wheeling Example

4.0 Transactions Modeling

The model of commercial behavior embodied in MULTISYM for a two party transaction is that the buyer will purchase from the seller if the buyer's cost is greater than the sellers price plus losses plus the wheeling rate. The seller's price is any value greater than cost. This amounts to what is called "net-back" pricing in the oil and gas industry, where sellers capture buyer's value less transportation cost. The multi-area trading logic is essentially an iteration of the two area logic which continues until there are no more profitable trades.

This transaction logic results in "pancaking" of wholesale transmission rates; i.e. the price of power delivered from one utility to a second utility, which flows "through" the area of two intermediate utilities has wheeling charges from both intermediate utilities added to the purchase price. The additive effect of wheeling through multiple transmission areas is consistent with the FERC Mega-NOPR approach to transmission pricing. This is why we use it in our base case characterization. Joskow (1995) argues that the FERC Mega-NOPR will result in wheeling charges that could reduce efficiency by eliminating trades that would have been profitable previously; i.e. in those times when there would have been no wheeling price, or at least a lower rate.

Figure 2 illustrates the wheeling problem in a simple schematic fashion. Imagine there is one seller represented by the cost curve C, who is located to the north of the first buyer, N. There is a second buyer, S, who is located to the south of N. The demand curve for S, called D_S, is shown above the demand curve for N, reflecting the greater value of power to S, relative to N. Broadly speaking this corresponds to the situation in California, where the single seller represents the Northwest region, and we ignore all interconnections to the east.

Figure 2 shows the effect of wheeling charges by shifting the cost curve upward. Because N is adjacent to the seller, the wheeling rate W_N is lower than that facing S, W_S. Because N has the first opportunity to purchase, it will buy the amount Q_N, where $C+W_N$ intersects D_N. If N were not in the market and only required wheeling revenues to provide access to S, then S would purchase a quantity Q_S, where $C+W_S$ intersects D_S. As Figure 2 is drawn, this is more than Q_N. When N purchases Q_N, however, then that quantity is not available to S. Figure 3 shows the cost curve facing S in that situation, it is $C-Q_N+W_S$. Even though S has a higher willingness to pay than N, she must pay higher prices and purchase less than N.

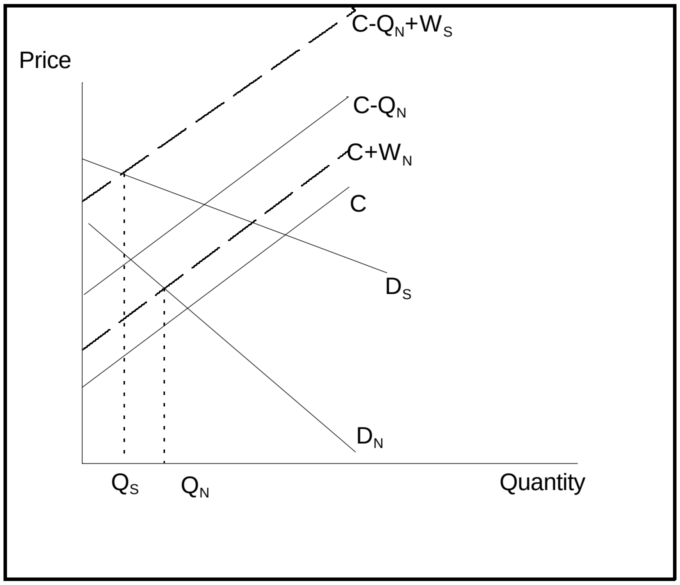

Figure 3 Wheeling Example: Cost Curve Adjusted

When pooling occurs, one of the effects may be to reduce W_S. This is a policy choice which may be initiated by California utilities and regulators, but would require FERC approval. In such a case, if the wheeling rate declines sufficiently, then S may end up purchasing larger quantities than N. Similarly, when the WSCC topology is represented fully, as in Figure 1, pooling with reduced wheeling rates would improve Northern California access to resources in the Southwest.

The base case data used in the simulations assumes that wheeling rates are $2/MWh uniformly between each transmission area and that losses range from 2% to 6% (Pando, 1995).

MULTISYM also calculates congestion costs, which are conceptually important and which will be incorporated into intra-California transmission pricing. Within the approximation limits of the modeling approach taken here, these costs turn out to be quite small relative to production cost. The main reason for this result is that the marginal costs in different transmission areas are relatively close to one another. Section 6.2 presents some numerical results in this vein.

5.0 Tests: Methodology and Specification

We proceed in the standard fashion by first establishing baseline electric system operating costs for California absent restructuring. We limit attention to the year 2000. Since our primary concern is with operating economies and what determines them, it makes sense to focus closely on particular details that illustrate larger questions. Multi-year simulations produce a large quantity of numerical results, which tend to obscure the driving forces in a welter of detail. This section describes the tests we conducted, and the manner in which we specify the scenarios examined. Results are tabulated in Section 6.

5.1 Pooling Institutions

One of the central issues in the restructuring debate involves the question of pooling institutions. Opinions on the value of these institutions differ widely, but there have not been many recent empirical studies. We briefly discuss a few studies which examine short-run, i.e. operating, economies due to pooling. Gilbert, Kahn and White (1993), using unit specific national level data, found no convincing evidence that pooling institutions increased efficiency, as measured by the utilization of baseload coal plants. Institutional studies of particular pooling arrangements report practices that are barriers to increased efficiency (NYPSC, 1991). In particular, the use of a unaminity rule for changes in procedures prevents the adoption of practices that might benefit most, but not all members. Nonetheless, detailed examination of California data by White (1995) suggests that there may be pooling economies. White's study neglects transmission limits and losses, and by focusing on only one peak month in detail also omits the potential effects of multi-area unit commitment during the off-peak months.

We neglect any potential economies that might arise from coordinated maintenance scheduling in a pool setting. It has been argued that different implementations of a California pool might affect the efficiency of maintenance scheduling (CUE, 1995). We make no attempt to incorporate this factor, and treat maintenance scheduling invariantly across all our cases.

In this study we model pooling in the following fashion. The California pool, which is not assumed to include the LDWP transmission area, is modeled to commit units on a joint basis, i.e. there is one reserve target for the entire pool area. Multi-area unit commitment has been found to be the source of substantial economies in the simulation studies of Lee and Feng (1992). In our setting, there may also be pooling economies involving hydro dispatch, since these resources are not distributed geographically on a uniform basis. Transactions between areas in the pool will still involve transmission losses, but different approaches to transmission pricing for transactions into and within California will be examined in our scenarios

5.2 Scenario Features

We characterize our scenarios qualitatively by dividing effects into those involving unit commitment issues, those involving transmission pricing, and those involving variable operations and maintenance costs and operating procedures.

Unit Commitment Effects

MULTISYM uses a heuristic approach to unit commitment. This is a practical necessity for a model using a database of this size. Even where explicit optimization is used, computational limits can impose bounds on the search for an optimum and result in solutions that are higher cost than those which could be found "by hand." The basic trade-off made in solving the unit commitment problem involves the high fixed costs of operating efficient units versus the low fixed costs of operating less efficient units. The fixed costs of operation include start-up costs, minimum operating levels, and minimum run times. Jackups *et al* (1988) discuss these issues in a practical setting.

In our simulations these issues arose with particular prominence in connection with Southern California Edison's Ormond Beach units. These two 750 MW units compete in a California pool with Pacific Gas and Electric's Moss Landing units 6 and 7, which are about the same size and vintage and have similar, if slightly superior, efficiency. Important differences between the Ormond Beach units and Moss Landing 6 and 7 involve operating constraints. In particular, according to data used by the California Energy Commission, the minimum up time for Moss Landing 6 and 7 is 10 hours, whereas for the Ormond Beach units it is 72 hours. In addition Ormond Beach unit 1 has a minimum capacity of 250 MW, where the other three units have a 50 MW minimum. The net effect of these constraints is to raise the fixed operating costs of committing the Ormond Beach units relative to Moss Landing 6 and 7. When a California Pool is simulated, MULTISYM only commits the Ormond Beach units rarely. The result is a substantial drop in their production relative to the base case, from 5912 GWh to 1152 GWh.

We regard these results as somewhat artificial. The specification of operating constraints typically involves judgment. As competitive conditions change, we expect that similar units will converge to similar operating restrictions, particularly where there would be no significant cost to such changes. Therefore we set the minimum up and down times for the Ormond Beach units to the same values as Moss Landing 6 and 7. We make no change in the minimum capacity of Ormond Beach 1, since the retrofits required to reduce the minimum capacity at Ormond Beach 2 to 50 MW cost $11 million in the mid-1980s (House, 1985). We report some of the results using the existing constraints as a sensitivity case, referring to it as the Low Commit case. Other operating constraints affecting unit commitment will also be tested.

Transmission Pricing

The December, 1995 CPUC decision mandates that transmission pricing within the California pool be organized along nodal pricing principles. Since this represents a considerable difference from FERC policy, it is by no means guaranteed that this will occur.

We test various transmission pricing policies for the pooling cases. These include: (1) all transactions within California are priced at zero, (2) all transactions within and into California are priced at zero, and (3) no change from the base case, i.e. all transactions priced at $2/MWh. The purpose of exploring these variations is to estimate the sensitivity of pooling impacts to transmission pricing policy. We view these variations in pricing policy as bounding the alternatives that are currently being discussed.

Operations and Maintenance

In a vertically structured, franchised monopoly industry, firms can adopt different policies toward operations and maintenance (O&M) expenses, particularly in how they allocate them to fixed and variable cost categories. As the market becomes more competitive, there will be pressure to reduce these costs and in particular to reduce the amount assigned to variable prices. Our original data set is based on the practices reported historically by individual utilities. Even in this case, we found that non-uniformity can cause implausible results. To test for the effects of converging behavior more broadly, we assume that competition will tend to reduce the allocation of O&M costs to the variable side. For gas units we limit the variable O&M cost to $1.2/MWh and for coal units we limit it to $3/MWh. To equalize the treatment of operating constraints on gas units, we also test scenarios in which we limit the minimum up times and minimum down times to 24 hours maximum. We refer to these cases as "competitive' pricing of variable O&M and reduced up/down times for gas units.

5.3 Summary

Table 2 summarizes the features of the cases examined.

Table 2. Scenario Summary

Scenario	Supply Assumptions	Transmission Pricing: Pool Case	Sensitivity Case
Case 1	1994 Expectations	All CA transactions priced at 0	Low Commit
Case 2	No new CA or WSCC resources, except new AZ inframarginal resource; "competitive' pricing of variable O&M, reduced up/down times for gas units	All transaction into and within CA priced at 0	Transmission pricing in Pool case same as base
Case 3	1994 expectations; new AZ inframarginal resource; "competitive' pricing of variable O&M, reduced up/down times for gas units	All transactions priced at $2/MWh	

6.0 Results

We separate the numerical results into those which characterize the WSCC as a whole, discussed in Section 6.1, and those which are of interest for California only, discussed in Section 6.2.

6.1 WSCC Impacts

Table 3 presents the impact of pooling in the WSCC from a social cost perspective. It only accounts for fuel costs and variable O&M costs. MULTISYM calculates both wheeling and congestion costs, but they are omitted from Table 3, because they are essentially transfer payments. Wheeling revenues contribute to fixed cost recovery of the network. Under the pricing proposals designed to implement the December, 1995 CPUC decision for congestion pricing within California, these charges would also function in the same way; i.e. to reduce fixed network costs.

Table 3. Total Cost Impacts

Scenario	Base Case Costs ($ millions)			Pool Savings	Sensitivity Case Savings
	Fuel	V O&M	Total		
Case 1	7118.9	1401.6	$8520.5	$17.7	$2.7
Case 2	7373.7	1075.6	$8449.3	$30.9	$14.5
Case 3	6981.0	1063.8	$8044.8	$23.2	

Table 3 shows that the operational economies from pooling are small. As a percentage of base costs, they range from a low of about 0.03% in the Low Commit case to a high of about 0.36% in Case 2. These results are roughly an order of magnitude less than the estimate of White (1995).

Transmission pricing policy has a significant impact on pooling economies. The Case 2 sensitivity shows that without a reduction in transmission rates in the pooling case, half the savings in this scenario are lost. Similarly, Case 3 has much greater availability of low cost resources than Case 2, but maintaining transmission rates at their "pre-pooling" level results in less savings in the pooling case than Case 2 where pancaking is reduced significantly (see Tables 6 and 9 below).

Table 3 also indicates the substantial magnitude of the variable O&M sensitivity, about $320 million. Just over half of this comes from U.S. coal production, where the average reduction in variable O&M is about $1/MWh. The rest comes from gas, where the average unit price reduction is also about the same. It is not clear that this represents a social cost savings. It may be just a shift to fixed O&M costs.

Table 4 shows the changes in electricity production by regional fuel categories. This table also gives regional fuel prices, illustrating the extent to which fuel costs are lower outside of California than inside California. Pooling shifts production out of California, to the degree that fuel cost differentials are not offset by wheeling charges.

The generation shifts in Table 4, which average about 7800 GWh, represent a change of about 2.9% of California demand (the four main transmission areas in California have a combined load of about 265,000 GWh in the year 2000), and about 1% of WSCC production (about 751,000 GWh). Thus, for the WSCC as a whole, the percentage change in quantities is approximately 3 to 4 times greater than the percentage change in costs. In the Low Commit Case, the quantity changes are larger, about 12,000 GWh, or 1.6% of WSCC production and the cost changes are about 0.03%. This phenomenon, a large change in quantities for a small change in total cost, is quite common in dispatch problems. It has been observed by Papalexopoulos *et al* (1994) in an OPF setting and by Johnson, Oren and Swoboda (1996) in a unit commitment setting.

Table 4. Fuel Mix Impacts 2000 [3](GWh)

Fuel Type	Fuel Price ($/MBtu)	Case 1	Case 2	Case 3
Gas SCal	2.52	(7693)	(10,473)	(5348)
Gas RM[4]	2.21	1026	745	628
Gas AZ/NM[5]	2.20	2851	3607	2675
Coal RM	1.21	1256	1972	(44)
Gas Alberta	1.82	666	472	464
Coal AZ/NM	1.66	1326	1796	1028
Gas NW	2.55	1305	1315	914
Gas NCal	2.72	277	15	(842)

[3]This data is taken from the MULTISYM Station Group Report.

[4]The Rocky Mountain (RM) region includes the Montana and Utah transmission areas.

[5]The Arizona/New Mexico (AZ/NM) region includes the Nevada transmission area.

6.2 California Impacts

Imports

Pooling increases California imports. Table 5 gives data on these effects for each transmission area. The increased imports which result from pooling are disproportionately flowing to Southern California, particularly SCE and SDG&E. By comparison, the PGAE and LDWP transmission areas show much smaller swings.

Table 5. Imports by Utility (GWh) [6]

		PGAE	SDGE	SCE	LDWP
Case 1	Base	12566	4706	13014	22447
	Pool	18824	8218	22850	20691
Case2	Base	13759	7822	17406	23104
	Pool	15560	11136	29759	27186
Case 3	Base	14043	6722	13965	22068
	Pool	15208	8613	19197	23178

Table 6 presents more disaggregated data for Case 1 representing the major export regions. It shows both the changes in wheeling rates (in $/MWh) and the changes in physical flows. The sum of the increased imports from these four regions (7585 GWh) is approximately equal to the decrease in gas-fired generation in Southern California (7693 GWh). As expected, SCE and SDG&E increase their purchases from the Northwest (by 3205 GWh) and Montana (by 1594 GWh) as the wheeling charges decline. PG&E's purchases decline from these regions (by 688 GWh and 366 GWh respectively). In the case of Utah and Arizona, the situation is somewhat reversed. PG&E's wheeling costs for access to these regions declines, and the PG&E purchases increase (by 463 GWh from Utah and 525 GWh from Arizona). The purchases by SDG&E and SCE from these areas also increase, indeed by much greater amounts. Reduced unit commitment

[6] This data is from MULTISYM Transmission Area Generation, Imports and Exports

in southern California makes room for increased purchases.

An additional consequence of reduced commitment is that peak power is also imported in significant
quantities. This is a logical consequence of pooling.[7] Examples from Case 1 include increased production from the new combustion turbines in Nevada, Alberta and Baja California. Table 7 gives data on the production changes and prices for these plants. These three stations alone account for nearly 20% of the total generation shift due to pooling. When wheeling and losses are taken into account these units all have higher costs than Ormond Beach 1 (the unit whose reduced commitment in the pooling case was discussed in Section 5.2), which has an average cost of $25.82/MWh. But the costs are sufficiently close so that the increment due to running the peakers does not offset the economies due to increased low cost imports and reduced minimum load operation. In Case 2, the same phenomenon occurs, but the peaking imports are spread out over more units and somewhat smaller in magnitude. Case 3 resembles Case 1.

Table 6. Changes in Imports and Wheeling Rates: Case 1

	Northwest				Montana			
	Base		Pool		Base		Pool	
	GWh	Wheel Rate	GWh	Wheel Rate	GWh	Wheel Rate	GWh	Wheel Rate
SDGE	410	7.79	621	3.65	1124	9.54	1928	6.83
SCE	2131	3.34	5125	2.21	2525	6.19	3315	4.91
PGAE	2606	2.00	1918	2.01	3008	4.43	2642	4.41
Total	5147		7664		6657		7885	
	Utah				Arizona			
SDGE	505	5.03	996	4.58	925	2.02	1632	2.06
SCE	2220	4.02	3377	3.69	2010	2.57	2517	2.33
PGAE	1084	6.13	1547	4.14	972	4.91	1497	2.62
Total	3809		5920		3907		5646	

[7]This point was made in the context of planning reserve studies in an early study of the potential for pooling among the California utilities (Kahn, 1977).

Table 7. Peaking Unit Increases: Case 1

Station	Trans Area	Base (GWh)	Pool (GWh)	Δ GWh	Cost ($/MWh)
Trans Alta CT	BCHA	1329	1543	214	24.84
Allen	Nevada	1970	2894	924	27.06
Rosarita	CFE	1243	1617	374	30.63

Finally, imports increase transmission congestion. Given the highly aggregated representation of network effects used here, this can only be observed at a very general level. Table 8 gives some data on path congestion from the MULTISYM Links Report. We show the number of hours that particular paths into and within California are fully loaded in both the Base Case and in the Pool Case. It is important to recall that the capacity of each link represents the net of available capacity and firm contracts. If power is not being taken under those contracts, then path congestion will be less than the estimates in Table 8.

Table 8. Path Congestion: Full Load Hours

Path	Case 1		Case 2		Case 3	
	Base	Pool	Base	Pool	Base	Pool
PGAE to SCE	473	2228	330	968	306	492
Northw to PGAE	513	1112	527	706	457	476
SDGE to SCE	174	1640	32	1194	24	30
Arizona to SDGE	254	2831	2882	7260	1570	3581
Arizona to SCE	1426	1372	5674	5243	4879	5358

The pattern of data in Table 8 is broadly consistent with that in Table 5. For the PGAE area, Case 1 represents the biggest change in imports, which shows up as the largest increase in congestion from the Northwest. A good deal of the increased flow in this corridor ends up increasing the flow south to SCE. For SCE and SDG&E, the presence of the large inframarginal resource in Arizona in Cases 2 and 3 corresponds to a major increase in congestion from that area. In Case 2, some of these imports to SCE must move by way of SDG&E, thereby increasing congestion in that corridor.

This increase in transmission line utilization corresponds to an increase in congestion costs. We show data on the relative magnitude of wheeling charges and congestion costs in Table 9 for

Cases 1 and 2. For most utilities, wheeling costs dominate congestion costs. The only cases where congestion costs increase significantly involve SCE and SDG&E. In Case 1, these costs approximately triple. Since their base level is so low, however, they are still small.

Table 9. Wheeling (W) and Congestion (C) Costs ($ million)

	Case 1				Case 2			
	Base		Pool		Base		Pool	
	W	C	W	C	W	C	W	C
PG&E	41.3	5.8	34.5	5.7	51.3	7.8	13.3	9.4
SCE	48.3	8.8	63.1	26.4	58.4	14.3	20.0	36.1
LDWP	54.4	16.6	56.1	16.1	60.7	19.1	18.9	17.0
SDGE	24.3	0.9	32.5	3.6	34.8	5.0	17.2	5.9

Revenues

Utilities selling into the California pool will be paid the market clearing price for all the energy that the pool purchases from them. While this will generate some economic rent, because marginal cost (i.e. the market clearing price) is above average cost, it may or may not be sufficient to cover the fixed cost of operating the generators. In Table 10 the utility production costs, including variable O&M (but not fixed O&M), are compared to the pool revenues for Case 1. Non-utility production and its costs are not included in the totals. We also exclude, where possible, the effect of firm purchases. Utilities may be able to arbitrage these with the pool, depending upon how the bidding rules are written. It is also possible that these contracts may be assigned to the exchange or to the distributors. In the case of PG&E, we include all of the hydro that the utility controls, some of which is not owned, but purchased. If the sellers recapture the economic rent, then the surplus calculated for PG&E in Table 10 will be correspondingly reduced. Fixed O&M costs must be recovered from the surplus. It is not clear, particularly in Southern California, whether this will be feasible. Settlements involving the treatment of nuclear plants will be important for this question, but they are not the sole issue. Fixed O&M for coal plants is also large.

Table 10. Utility Revenues vs. Costs: Case 1

	Utility	PG&E	SCE	SDG&E
1	Net Utility Sales	55018	52088	9840

2	Marginal Cost[8] ($/MWh)	24.19	24.63	24.91
3	Revenues ($ millions) (1*2)	1330.9	1282.9	245.1
4	Utility Costs	759.6	901.6	221.4
5	Surplus (3-4)	571.3	381.3	23.7

These results are highly sensitive to the estimate of marginal cost. MULTISYM's estimate of marginal cost may contain a downward bias due to the manner in which it models unit outages. This subject has only been discussed briefly in the technical literature, for example, Scully *et al* (1992). Further use of models such as this will require testing of this question.

7.0 Entry Conditions and the Comparative Economics of Siting in a California Pool Market

In this section we apply the simulation results to long run questions associated with new entry into a California pool market. We first formulate the minimal requirements of entry and then apply parameters from the simulations to assess qualitatively the plausibility of these conditions being met. Next, we assume that entry conditions are met and formulate the trade-off between siting new projects in California versus other locations in the WSCC region. This trade-off amounts to comparing the costs of transporting natural gas to California, versus transmitting power.

7.1. Entry Conditions

General Conditions

Assuming that there is no capacity payment to help finance entry, then operating cost rents will be the funds used to amortize the capital costs of new generation. Let

MP = market price of electricity, per kWh
C = unit operating cost of the potential entrant, per kWh
r = annual cost of new capacity, $/kW
O = output of the new entrant, in hours

[8]These estimates do not include commitment costs.

The risk neutral condition[9] for entry is

$$[MP - C]*O \geq r.$$

We can re-write this by expressing MP as a function of the local gas price, G_L, and an efficiency factor which is conceptually similar to the IER which the CPUC has used in short-run avoided cost determinations. We will call this efficiency factor IER; it is expressed in units of Btu/kWh.

Then $MP = IER*G_L$. Using HR to denote the conversion efficiency of the potential new entrant, and assuming that the fuel of choice is also local gas, then $C = HR*G_L$. So we can re-write the entry condition as a heat rate spread on the local gas price

$$\{[IER - HR]*G_L\}*O \geq r.$$

Parameter Estimates

We use weighted annual average estimates for economic parameters. The highest plausible estimate for IER in the California market based on our simulations is 11,000 Btu/kWh. A new combined cycle plant might achieve an HR of 7000 Btu/kWh, and operate in California for 7000 hours per year.[10] At a gas price of $\$2.50/10^6$ Btu, the operating cost rents under these assumptions would be

$$[4000 \text{ Btu/kWh} * \$2.50/10^6 \text{ Btu}]*7000 \text{ hrs} = \$70/\text{kW}.$$

It is unclear whether a new entrant could finance a highly efficient local area plant at an annual rate of \$70/kW per year. The least cost IPP project analyzed by Comnes, Belden and Kahn (1995), the Hermiston project, has fixed costs of about \$114/kW-yr and O&M costs of about \$24/kW-yr.[11]

7.2. Siting Trade-offs

Even though the parameter estimates in Section 7.1 suggest that entry at expected pool prices is problematic, we assume here that costs are sufficiently low to allow entry, and assess the factors

[9]The theory of investment under uncertainty says that a higher return is required to compensate for the uncertain nature of the operating cost rents (Dixit and Pindyck, 1994). We ignore this complication for the sake of simplicity.

[10]For example, generic combined cycle plants in Southern California operate for about 7000 hours at a heat rate of 7600 Btu/kWh.

[11]This is calculated at the project's average capacity, rather than the minimum capacity calculation cited in the reference.

which influence siting decisions. This regional problem has been addressed in the past using a long range optimization approach (Decision Focus, 1990). Here we adopt a somewhat more short run view and rely on the simulations for guidance in the quantification.

General Conditions

The regional siting decision involves a trade-off between lower fuel prices associated with remote siting, versus wheeling costs to bring the power to the high valued load center. The question is simply whether it is cheaper to move fuel or transmit electricity. Let

G_R = the price of gas purchased at a remote location, and
Wr = the wheeling rate.

If we assume that the entrant would build the same plant with the same efficiency in either the local or the remote location, then the remote site would be favored if

$$\{[G_L - G_R]*HR\}*O > Wr.$$

This relation assumes that the plant would operate at the same level in either location.[12] We neglect the effects of losses, congestion and local area control services, all of which would favor local area generation.

Parameter Estimates

For convenience we refer to $G_L - G_R$ as ΔG; in the natural gas industry such regional differences are called basis differentials. The largest value of ΔG is found between Alberta and Northern California, where it is about $\$0.90/10^6$ Btu. A new combined cycle plant, however, would operate for only 4200 hours in Northern California, as opposed to 7000 hours in Southern California. In the Southern California market, ΔG is closer to $\$0.70/10^6$ Btu. At the latter value then, the siting trade-off amounts to

$$\$0.70/10^6 \text{ Btu} * 7000 \text{ Btu/kWh} = 4.9 \text{ mills/kWh} > Wr.$$

Focusing on the Case 1 transmission pricing assumptions, the wheeling rate from Alberta is likely to be in excess of 4 mills/kWh. Lower wheeling rates require siting closer to California, in either Arizona or the Northwest. In which case ΔG is likely to be closer to $\$0.30/10^6$ Btu. In this case the siting trade-off amounts to

$$\$0.30/10^6 \text{ Btu} * 7000 \text{ Btu/kWh} = 2.1 \text{ mills/kWh} > Wr.$$

[12]This assumption is not particularly plausible in light of simulation results showing the Hermiston plant in the Northwest operating only about 4000 hours at a HR of 8000 Btu/kWh and the Ft. St.Vrain plant in the Utah transmission area operating 5200 hours at a HR of 7800 Btu/kWh.

In both cases, the fuel price economies are nearly equal to wheeling rates. This suggests that the crucial factor will be operating hours.

The evidence from the simulations is ambiguous about whether a highly efficient new combined cycle plant will operate the same number of hours in California as in other WSCC locations. The raw data suggests that there will not be equality. Operating hours will be greater in California than elsewhere (see note 11). What is not clear, however, is whether this result is an artifact of the model logic, current market conditions, or whether it represents the least cost outcome. The unit commitment in each transmission area would have to examine the potential for export sales from these units if the full inter-regional benefit from their operation were to be realized. While MULTISYM takes such factors into account in a limited way, it does not make the full economic assessment. This appears consistent with current market behavior. Another interpretation of this situation is that a new entrant who chose a remote site would contract with a Southern California buyer so that the new plant would operate 7000 hours as a scheduled transaction. The uncertainties of entry would be mitigated by such a contract, and it could result in greater efficiency than the market mechanism modeled here.

Finally, we have modeled gas rates throughout this discussion on an average cost basis, when in reality they typically have a two-part tariff structure. Gas rate design can have a significant effect on the kinds of trade-offs analyzed here, and ought to be taken into account in a more sophisticated assessment.

8.0 Conclusions

This modeling exercise represents the beginning of efforts to understand California electricity restructuring quantitatively. We expect that further refinements of data and modeling technique will ensue. We enumerate briefly the lessons of this exercise and comment on further research needs.

1. Pooling economies appear small in the short run. Table 3 shows quite modest operational savings from pooling.

2. Regional dependence for imports will increase. This conclusion is an obvious consequence of the geographical distribution of resources in the WSCC, but also results from commitment economies.

3. Congestion increases, but its costs are small. Given the low level of resolution in our analysis, the conclusion concerning congestion costs may well be revised with more careful attention.

4. Unit commitment effects on the production of individual plants can be relatively large. The operation of pool markets will require considerable detailed attention to exactly how commitment is handled. The impacts of these decisions are significant for particular actors, and the decision logic at the pool level is hard to make transparent.

5. Rents from marginal cost pricing may not offset fixed O&M costs for some generators. Large rents may accrue to hydroelectric endowments and contracts.

6. Siting tradeoffs do not reveal a dominant strategy. If transmission into California is cheap enough, remote siting is desirable. But simulation results show that remotely sited projects may not be dispatched as much as more local generation. More careful modeling of local control area benefits is important to this tradeoff.

7. Additional study of modeling tools will be required. It is important to emphasize once again the preliminary nature of these results. Both data and modeling uncertainties will require attention.

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