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ORFIN: AN ELECTRIC UTILITY FINANCIAL AND PRODUCTION SIMULATOR

Stanton W. Hadley

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LOCKHEED MARTIN ENERGY SYSTEMS, INC.
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

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ENERGY DIVISION

ORFIN: AN ELECTRIC UTILITY FINANCIAL AND PRODUCTION SIMULATOR

STANTON W. HADLEY

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OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831
managed by
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SUMMARY

With the coming changes in the electrical industry, there is a broad need to understand the impacts of restructuring on customers, existing utilities, and other stakeholders. Retail wheeling; performance-based regulation; unbundling of generation, transmission, and distribution; and the impact of stranded commitments are all key issues in the discussions of the future of the industry. To quantify these issues, financial and production cost models are required.

We have created a smaller and faster finance and operations model called the Oak Ridge Financial Model (ORFIN) to help analyze the ramifications of the issues identified above. It combines detailed pricing and financial analysis with an economic dispatch model over a multi-year period. Several types of ratemaking are modeled, as well as the wholesale market and retail wheeling. Multiple plants and purchased power contracts are modeled for economic dispatch, and separate financial accounts are kept for each. Transmission, distribution, and other functions are also broken out. Regulatory assets such as deferred tax credits and demand-side management (DSM) programs are also included in the income statement and balance sheet.

This report describes some of the key features of the model. Examples of the financial reports are shown, with a description of their formulation. Some of the ways these results can be used in analyzing various issues are provided. Price calculation methods are described in Chapter 3, including cost functionalization, classification, and allocation. Examples of the effect of different methods for pricing are shown. The economic plant dispatch model (described in Chapter 4) is a complex balancing of production and demands. It must take into account the probabilistic nature of forced outages, and recognize the availability of a broader wholesale market for both additional purchases and sales. Changes in customer demands due to customers' switching to retail wheeling are described in Chapter 5. They include not just the loss of customers but a transformation from full-service to transmission and distribution (T&D) service only. The appendix includes a detailed description of the inputs required for the model's operation.

We are using this model to study various types of performance-based rates, stranded commitments recovery, and retail wheeling options. By varying the performance of the modeled utility, we can observe the consequences of various performance-based ratemaking algorithms on prices and profitability. Modeling individual high-cost assets, as well as T&D assets, and modifying their accounting allows us to compare some of the proposed stranded cost recovery methods, as well as ways to mitigate the impact. Including the wholesale market (purchases and sales) in the dispatch model helps us to study the effects of retail wheeling.

Previously the model was used in an analysis of the price impacts of DSM (ORNL/CON-402), the effects of different types of resource acquisition on shareholders (ORNL/CON-387), and the effect on stranded commitments depending on whether the utility lost their customers or kept them but had to offer market prices (ORNL/CON-424). In addition, an early version was translated into Russian and provided to Russian utility executives as a tool to understand American planning and accounting.

ACRONYMS

AFUDC	Allowance for Funds Used During Construction
C/I	Commercial/Industrial
CWIP	Construction Work in Progress
DSM	Demand-Side Management
ELDC	Equivalent Load Duration Curve
FAC	Fuel Adjustment Clause
G&A	General & Administrative
LDC	Load Duration Curve
LOLP	Loss of Load Probability
O&M	Operations and Maintenance
ORFIN	Oak Ridge Financial Model
PBR	Performance-Based Rates
ROE	Return on Equity
T&D	Transmission & Distribution

1. INTRODUCTION

With the coming changes in the electrical industry, there is a broad need to understand the impacts of future options on the customer, existing utility, and other stakeholders. Retail wheeling, performance-based rates, unbundling of generation, transmission, and distribution, and the impact of stranded commitments are all key issues in the discussions of the future of the industry. While utilities have detailed operational and financial models of their existing structure, these are often very large, complex, and slow. Examples of these models are PROMOD, SAFEPLAN, EGEAS, ELFIN, and MIDAS.

We have created a smaller and faster finance and operations model called the Oak Ridge Financial Model (ORFIN) to help understand the ramifications of the different options. It combines detailed pricing and financial analysis with an economic dispatch model and wholesale market interactions. Several types of ratemaking are modeled, as well as unregulated sales through retail competition. Multiple plants and purchased power contracts are modeled for economic dispatch, and separate financial accounts are kept for each. Transmission, distribution, and other functions are also broken out. Regulatory assets such as deferred tax credits and demand side management (DSM) programs are also included in the income statement and balance sheet.

We are using this model to study various types of performance-based rates (PBR), recovery of stranded commitments, and retail wheeling options. By varying the performance of the modeled utility we can observe the consequences of various PBR algorithms on prices and profitability. Modelling individual high-cost assets, as well as transmission and distribution (T&D) assets, and modifying their accounting allows us to compare some of the proposed stranded cost recovery methods. Including the external market as a supply or demand in the dispatch model allows us to study the effects of retail wheeling. The model has been used previously in an analysis of the price impacts of DSM (ORNL/CON-402) and the effects of different types of resource acquisition on shareholders (ORNL/CON-387). The results from these past and ongoing studies will be presented to illustrate the uses of the model.

The earliest version of ORFIN was developed in preparation for studies on the impact of DSM and other resources on utility shareholders. In the spring of 1994 it was upgraded to better calculate taxes, ratemaking, and other financial factors in accord with utility practice. It was used for the study on shareholder impacts and price impacts of DSM referenced above. In the fall of 1994 ORFIN was translated into Russian for use as a training tool for Russian utility executives. The latest version (described below) was developed in the spring and summer of 1995. Its main modification was the inclusion of economic load dispatching of up to ten power sources as well as wholesale power purchases and sales based on available capacity and relative costs.

Residential retail wheeling was also added. A report on the methods for calculating stranded commitments in the face of retail wheeling (ORNL/CON-424) has been published and other reports on mitigation and customer impacts are underway.

ORFIN is an Excel Version 5.0 workbook. It can run on Macintosh or Windows computers and takes about 30 seconds to run on a Pentium 90 machine. Although the entire workbook is approximately 1.4 Mbytes in size, the inputs for a specific case can be stored separately in a smaller file. It uses multiple worksheets to separate the various calculations, input, and output. These worksheets are: Input, Finance, Plants, Dispatch, Charts, Dispatch Macros, and Other Macros (Figure 1).

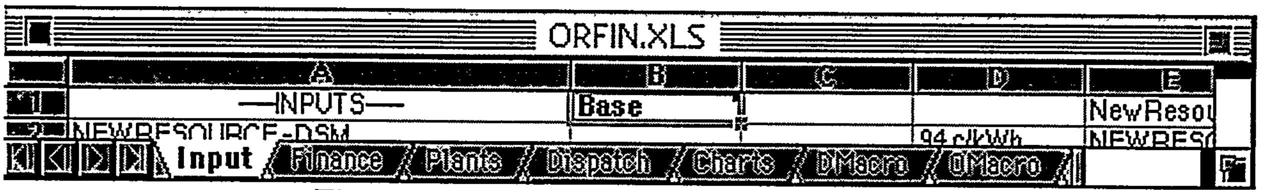

Figure 1. Worksheet modules inside ORFIN.

ORFIN has a wide variety of inputs that allow it to simulate and analyze a number of factors concerning electric utilities. The user enters both initial conditions for the utility and yearly values for escalation rates, prices, construction costs, and other variables. The key inputs are summarized in Table 1 and a more detailed description is provided in the appendix.

Rather than a complete description of all calculations, we will describe some of the key aspects of ORFIN that makes it a useful tool for analyzing electric-utility issues. These include the details of financial reporting with separation of assets into various components including generating plants, transmission, distribution, and general facilities (Chapter 2), calculation of rates using several different methods (Chapter 3), economic load dispatch of the generation plants using forced outages, equivalent load duration calculations, and wholesale trading (Chapter 4), and allowance for either of the two customer classes to switch to retail wheeling at different rates over time (Chapter 5). There are numerous other features of ORFIN that are not discussed, such as DSM program additions and incentives and new plant construction. The report closes with a summary and discussion of possible uses and improvements in Chapter 6. The Appendix includes an example of the input worksheet and descriptions of the input variables used in the model.

Table 1. Summary of key ORFIN inputs

Non-generation operating costs
transmission, distribution, customer service, and G&A O&M costs ($/year), social program costs ($/year), O&M cost escalation (%/year)

Non-generation capital costs
transmission, distribution, general capital costs ($/year, $/customer, $/ kW)

Purchase-power contracts
capacity (MW), off-line date (year), forced and planned outage rates (%), fixed costs ($/kW-year), variable costs (¢/kWh)

Utility-owned generating units
capacity (MW), initial cost ($/kW), start and off-line dates (year), tax and book depreciation lives (years), forced and planned outage rates (%), fixed O&M cost ($/kW-year), variable O&M cost (¢/kWh), O&M escalation rate (%/year), heat rate (Btu/kWh), fuel type, fuel prices ($/MBtu) by year

Wholesale-market prices
prices (¢/kWh) by time period (% of year), escalation rates (%/year), difference between wholesale purchase and sale price (¢/kWh), transmission capacity (MW)

Customers
by class: number of customers, consumption (kWh/customer-month), load factor, growth rates (%/year) in number of customers and in per-customer consumption, T&D energy and demand losses; by season: system load duration curve

Retail wheeling
percentage of customers from each class that wheel by year, percentage of G&A costs paid by wheelers, ancillary service cost adder (¢/kWh)

Finances
long-term bonds and common equity (% of total capitalization and return in %/year), inflation rate (%/year), federal/state income tax rate (%), revenue-sensitive tax rate (%), property tax rate (%), frequency and type (historic vs future test year) of rate cases, regulatory asset

2. FULL FINANCIAL REPORTS

ORFIN provides a complete set of financial statements for each year that it covers. The number of years is currently set at twelve but can be expanded or condensed based on the nature of the study. The Income Statement, Balance Sheet, and Sources and Uses of Funds all are standard reporting forms for electric utilities. The parameters in each inter-relate to provide a more complete picture of the utility's financial status at a given time. In order to generate these reports, more detailed calculations are done elsewhere in the model. Depreciation, capital expenditures, escalation of operating costs, customer sales, and other parameters have separate sections within the spreadsheet that contribute to the final results, and can be viewed by the user. Two of the sources used to determine the proper calculational methods were *Principles of Public Utility Rates* (Bonbright, 1988) and *Introduction to Public Utility Accounting* (Reeser, 1992).

In the Income Statement (Table 2), total revenues include revenues from the rate base calculation, the fuel adjustment clause (FAC), demand-side management (DSM) incentives, and construction work in progress (CWIP) allowances. Production expenses include the fuel costs and operating and maintenance (O&M) costs for each plant, power purchases through contracts, and power purchases less sales from the wholesale market. Non-production costs are the O&M costs for transmission, distribution, customer service, and general and administrative (G&A) functions. Depreciation is calculated for each asset, including an input "regulatory asset." Sales, property, and income taxes are calculated, with the income taxes based on accelerated depreciation for the generating assets, thereby creating deferred and current taxes. Interest payments are calculated on the average amount of long-term debt for the year. If CWIP is not allowed then an allowance for funds used during construction (AFUDC) is created, deferring the expense until a new plant defined by the user is put into the rate base. After writing off any disallowances, the net income is calculated by subtracting expenses from revenues. Dividends are paid and the remainder added to retained earnings.

The Balance Sheet (Table 3) identifies the assets, liabilities, and equity position of the utility as of the end of each year. The assets include the eight modeled power plants, transmission, distribution, and the customer service and general facilities. Construction Work in Progress (CWIP) is separately accounted for and the regulatory asset mentioned above also has a separate line. Current assets and liabilities are modeled by multiplying the total revenues by a fixed ratio to determine the *net* current assets (assets minus liabilities). Long-term debt is defined as a fixed percentage of the total assets, called the debt ratio. The other major liability is the accumulated credit for deferred taxes on production plant. Since the start date for each plant is input, the accelerated and book depreciation can be calculated for all historical years. This allows the initial

Table 2. Example Income Statement from ORFIN

INCOME STATEMENT (million$)	1994	1995	1996	1997	1998	1999	2000
Base revenues	1758	1792	1816	1841	1944	1971	1997
Fuel adjust clause+ Prod. Incent		0	20	42	0	22	45
CWIP adjustment		0	0	0	0	0	0
DSM Sales and Adjustments		0	0	0	0	0	0
Revenues, total	1758	1792	1836	1883	1944	1992	2042
EXPENSES							
Fuel	303	314	324	335	427	442	458
Purchase-power contracts	186	191	196	201	194	200	205
Spot purchases	84	91	100	108	60	66	72
Spot sales	-79	-77	-75	-72	-124	-123	-120
Purchased power - total	191	205	221	237	130	143	157
O&M, fixed + variable	238	245	253	261	274	283	292
Production expenses - total	732	764	798	833	831	868	906
Nonproduction & DSM expenses	256	264	271	279	287	296	304
Book depreciation	143	144	146	147	164	165	167
Deprec. of Regulatory Asset	8	8	8	8	8	8	8
Revenue sensitive taxes	123	125	129	132	136	139	143
Property taxes	76	76	75	74	77	80	79
Federal income taxes - current	73	71	70	67	78	78	78
Federal income taxes - deferred	11	10	10	10	10	10	10
Expenses - total	1423	1463	1506	1551	1592	1644	1696
Operating income	335	329	330	332	352	348	346
AFUDC (noncash)		4	14	28	0	0	0
Interest expense	186	186	189	194	196	193	190
Extraordinary item (disallowed)		0	0	0	0	0	0
Net Income w/AFUDC,Disallow.	149	148	155	165	156	155	156
Dividends	112	111	116	124	117	116	117
Additions to retained earnings	37	37	39	41	39	39	39

amount of deferred taxes to be calculated. Total equity is defined as assets minus liabilities, so this value can be calculated from the above figures. It is broken into two sections: retained earnings and shareholder investment. The model does not include preferred stock; it only models common stock.

The Sources and Uses of Funds sheet (Table 4) shows the cash flow of the utility. It starts with the net income from the income statement, adds those expenses that are non-cash (such as depreciation), and subtracts the non-cash revenues (such as AFUDC). Other sources are any new debt issued or the sale of stock. Uses of the funds include dividends, capital expenditures, debt retirement, and the buy-back of any stock because of an excess of cash. The model does not keep a separate balance of cash from year to year; instead, it distributes any excess at the end of each year through dividends or stock purchases.

Table 3. Example Balance Sheet from ORFIN

BALANCE SHEET - end of year	1994	1995	1996	1997	1998	1999	2000
Gross - Production Plant	4,005	4,005	4,005	4,005	4,451	4,451	4,451
- Transmission	619	647	676	706	737	770	803
- Distribution	1,389	1,449	1,511	1,575	1,642	1,711	1,782
- General Plant	107	114	121	128	136	144	152
Total	6,119	6,214	6,313	6,414	6,966	7,075	7,188
Accumulated depreciation	2,326	2,470	2,616	2,763	2,927	3,092	3,258
Net Plant	3,793	3,744	3,697	3,651	4,039	3,983	3,930
CWIP	0	101	234	446	0	0	0
Regulatory Assets	92	83	75	67	58	50	42
Net current assets	18	19	20	20	21	22	23
ASSETS, total	3,903	3,947	4,025	4,185	4,119	4,056	3,994
Long-term debt	2,147	2,171	2,214	2,302	2,265	2,231	2,197
Accumulated deferred income tax	478	488	498	508	518	528	538
Common equity	1,279	1,288	1,313	1,375	1,335	1,297	1,259
Common stock	1,234	1,207	1,193	1,214	1,135	1,058	981
Retained earnings	44	81	120	161	200	239	278
LIABILITIES and EQUITY, total	3,903	3,947	4,025	4,185	4,119	4,056	3,994

Table 4. Example Sources and Uses of Funds Statement from ORFIN

SOURCES AND USES OF FUNDS	1994	1995	1996	1997	1998	1999	2000
SOURCES: Net Income		148	155	165	156	155	156
Depreciation		153	154	155	170	172	174
- AFUDC		-4	-14	-28	0	0	0
+ Depreciation of AFUDC		0	0	0	2	2	2
Provision for Deferred Taxes		10	10	10	10	10	10
Disallowance		0	0	0	0	0	0
Cash from Operations		306	306	303	338	338	341
Debt Issued		24	43	88	0	0	0
Common Stock Issued		0	0	20	0	0	0
Total		330	349	411	338	338	341
USES: dividends		111	116	124	117	116	117
Capital Expenditures		192	218	286	105	109	113
Increase in Current Assets		1	1	1	1	1	1
Debt Retirement		0	0	0	36	35	34
Common Stock Repurchase		27	14	0	79	77	77
Total		330	349	411	338	338	341

With the information from the full financial reports available, a researcher can clearly see the effects of different policies or technologies on a utility. For example, our base case includes building a gas powered plant that starts operating in 1998. What happens if we have the same amount of power provided through a long-term contract at the same levelized cost? As shown in Figure 2, the return on equity declines faster in the non-rate case years with the purchase contract. One major reason is that in this example the FAC only applied to fuel cost increases, not purchase-contract-cost increases. Of course, varying other parameters such as including contract costs in the FAC or not having contract variable costs rise with inflation would give different results. The point is, that with detailed financial reports and a spreadsheet methodology that allows easy alterations, these factors can be studied easily.

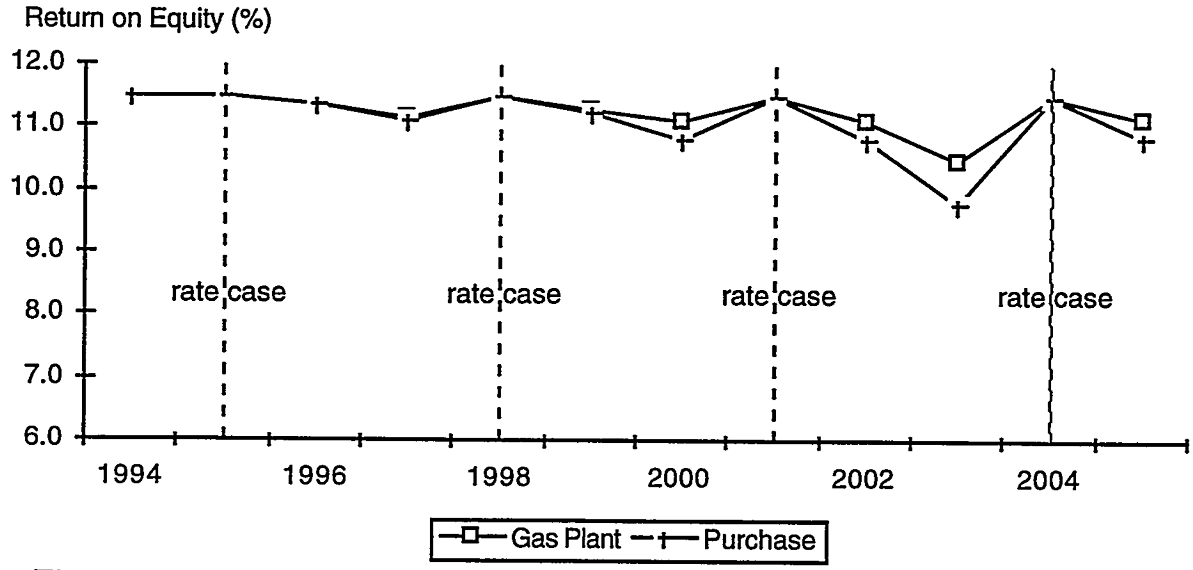

Figure 2. ROE for cases with a new gas plant or purchase contract added in 1998

Numerous other factors can be studied as well. Two of the ORNL studies mentioned earlier used ORFIN to study price impacts of DSM programs and resource acquisition impacts on utility shareholders.

3. RATE CALCULATION METHODS

To properly model electric utility finances, one must be able to determine prices that the utility will charge for electricity. These charges must fairly allocate the between the various classes of customers the utility has. ORFIN has several mechanisms for setting the rates. Traditionally, utilities have used periodic rate cases before the state public utility commission where historical or projected costs and sales are calculated. The costs are first classified by different function (e.g., generation, transmission, distribution, or general service), then categorized based on the relation of the cost to the type of service provided (e.g., capacity, energy, or customer service), and finally allocated to customer classes (e.g., residential, commercial, industrial, or wheeling). Prices for the different customer classes can then be determined. The model offers these same methods, either with historical or future test year costs. Production costs, non-production costs, depreciation, taxes, interest, and allowed return on equity are all summed to determine the required revenue.

Costs are assigned to energy, capacity, or customer service based on user input. Those costs that are a function of cost per unit of energy (¢/kWh) are assigned to energy costs, those based on $/kW are assigned to demand, and those based on $/customer are assigned to the customer charge. Costs that are not calculated based on any of these factors, such as depreciation, return on investment, taxes, as well as inputs based on a fixed dollar amount, are treated as fixed costs. The user can assign these costs to demand, energy, or customer charges or a mixture of the three.

Similarly, ORFIN attributes all costs to generation, transmission, distribution, and general services. Care is taken to allocate these costs to each customer class based on the customer's relative contribution to the cost. ORFIN contains three customer classes: a residential class which only pays an energy charge and customer charge; a combined commercial/industrial (C/I) class that pays an energy charge, demand (or capacity) charge, and customer charge; and wheeling class for those customers that do not pay for generation services. This last class will generally only have a demand charge and customer charge, but could have a small energy charge if T&D costs are a function of the energy use. Wheeling customers are made up of both residential and/or C/I customers, so can have T&D cost profiles similar to the respective full-service classes. The user may specify that only a fraction of C/I customers use distribution services so a higher proportion of the distribution-related costs are allocated to residential customers.

Table 5 shows how the total revenue requirement is allocated across customer classes and rate components. Values within a scenario are dependent on the inputs and will vary between years. The sum of the table is 100%. Although we show a percentage of demand-related costs to residential customers, these costs are eventually combined with the energy-related costs so that residential customers pay only energy and customer charges. Multiplying the revenue requirement by these percentages and dividing by the appropriate factor (kWh consumed, peak MW demand, or number of customers) determines the rates for each customer class.

Table 5. Percentage allocation of cost categories between customer classes

	Residential	Comm/Industrial	Retail Wheel
Customer Service	5.2%	0.7%	0.7%
Demand Charge	22.2%	37.4%	2.4%
Energy Charge	9.9%	21.6%	0.0%

A utility does not necessarily have a rate case every year. ORFIN allows the user to establish the frequency of rate cases. In the intervening years, a fuel adjustment clause can adjust the prices because of changes in fuel prices from the initial year. Also, CWIP adjustments and DSM incentives can change the amount of required revenue from year to year.

Another method for rate determination is through performance-based rates. These are rates that are initially set and then raised or lowered each year based on predetermined inflation and productivity indices. Two forms that have been proposed are price caps and revenue caps. Under price caps, a ceiling price is established and then raised or lowered each year. With revenue caps, the overall revenue is capped, allowing prices to rise if sales go down or decline if sales go up. Limits can be set on utility earnings to avoid excessive profits or losses. Periodic cost-based rate calculations (historical-test or future test years) can "true-up" the rates to the allowed return on equity. So it is only in the years between rate cases that the effect of PBR is visible. However, most PBR plans also expect longer time periods between rate cases.

A user can also directly set the prices to be used. Because the model has three customer types (residential, commercial/industrial, and retail wheeling) and three price components (demand, energy, and customer) there are eight prices defined for each year (residential customers have their energy and demand rates combined into an energy-based rate.) A base case can be set and its resulting prices can be frozen such that other cases can be run using the same prices as the base case.

Figure 3 shows an example of the calculated energy and capacity prices in real dollars for residential, commercial/industrial, and retail wheeling customers. In this example, rates are adjusted every three years beginning in 1995. In addition, the fuel adjustment clause affects prices in the intervening years. Notice that retail wheelers have no energy-related price but only a capacity payment for the transmission, distribution, and portion of the general plant. Not shown is the customer payment for each class which slowly declines from a base amount of $120 per customer per year.

Combining the residential and C/I demands and revenues, one can determine a system average price. These can be compared between cases to determine the effects of different actions on the utility's customers. For example, consider the effect of price caps every five years versus a traditional historical-test-year rate case every three years. Overall system prices to customers are shown in Figure 4.

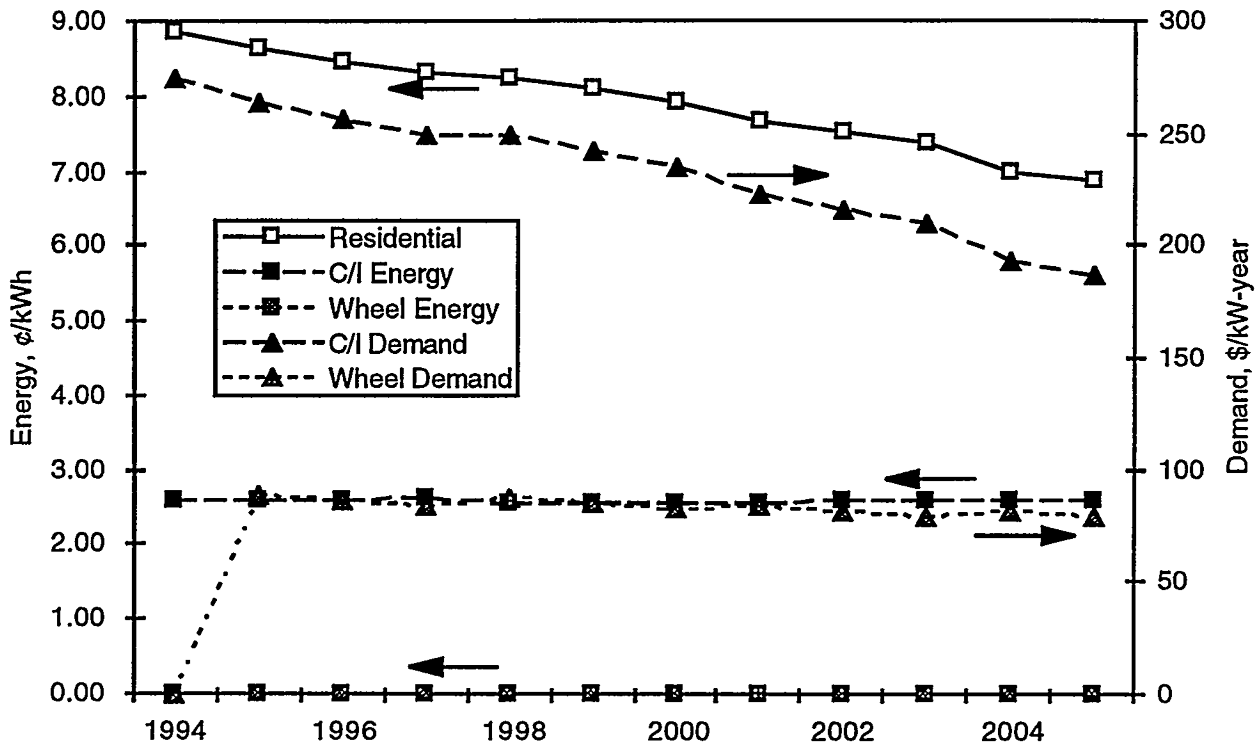

Figure 3. Energy and capacity prices for residential, C/I, and wheeling customers

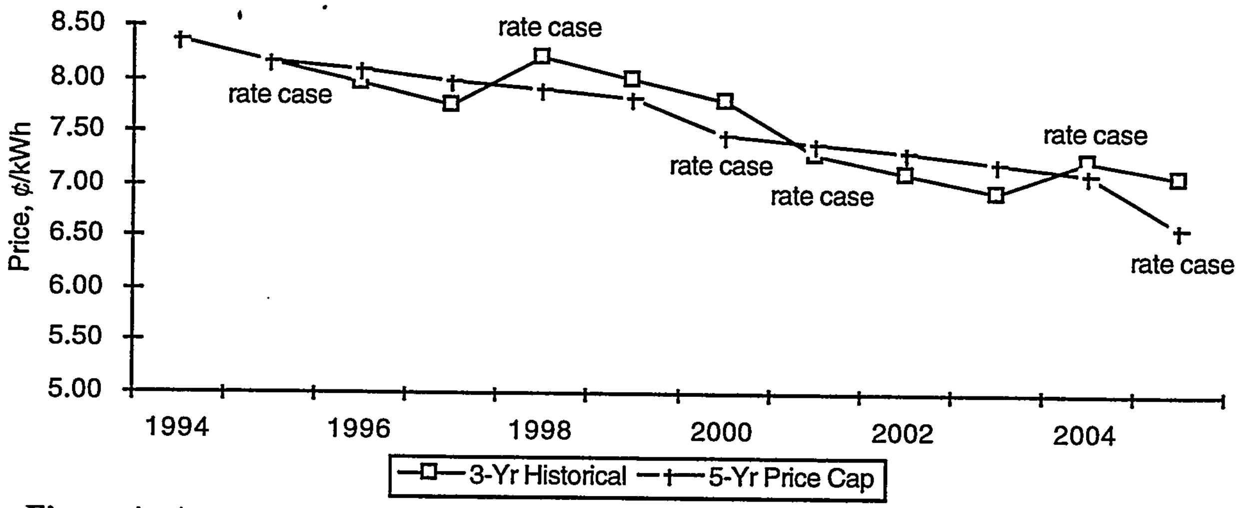

Figure 4. Average system price using historical-test-year rate case every 3 years and a price cap with reevaluation every 5 years.

4. ECONOMIC LOAD DISPATCH WITH WHOLESALE MARKET

Because the costs of a utility are typically dominated by the cost of the power plants and contracts it uses to provide electricity, we modeled these in more detail than other financial models. ORFIN can model six pre-existing plants (already on-line in initial year of simulation) and two pre-existing contracts; a new resource that can be a power plant, contract, or DSM program; and additional capacity added on a yearly basis to meet minimum reserve margin requirements. We also include an external wholesale power market with tiered prices based on customer loads. Detailed information on the operation and costs of these resources is provided to allow a closer representation of actual utilities. However, we do not model production costing as completely as the more detailed utility models mentioned earlier. For our purposes, this is an advantage because it reduces the amount of detailed information needed and the time required for running the model.

In the real world, utilities must be prepared to provide for customer demands every second with the lowest-cost source. ORFIN has separate demands for residential and C/I customers. After losses in the T&D system are taken into account, the demands are combined to provide a system load duration curve (LDC) at the generator level. ORFIN uses two curves for each year: an on-peak season (where no maintenance is done on plants) and an off-peak season (where plants are derated for maintenance outages.) Flexibility is allowed in defining these demand curves while maintaining consistency with overall demands.

Because plants are not available 100% of the time, we also model forced outages on a probabilistic basis. Plants are first put in an economic dispatching order by the model. (These can be over-ridden by the user so that plants can be put anywhere in the loading order. For example, must-run plants can be placed at the bottom of the order.) They are then matched up against the LDC for each season. The higher-cost plants will see demands not only from customers, but "equivalent demands" based on the probability of lower plants undergoing a forced outage. This creates an "equivalent load duration curve" (ELDC) for each plant, extending the percentage of time that the plant would be needed for the season. This methodology is described in more detail by Vardi and Avi-Itzhak (Vardi, 1981).

Examples of the dispatch for the peak and off-peak seasons are shown in Figures 5 and 6. Note that the base LDC for the off-peak season is both lower and flatter than for the peak season. Each plant's capacity is also lower, to simulate maintenance during this time. For the entire year, availability is equal to 1 – planned outages – forced outages.

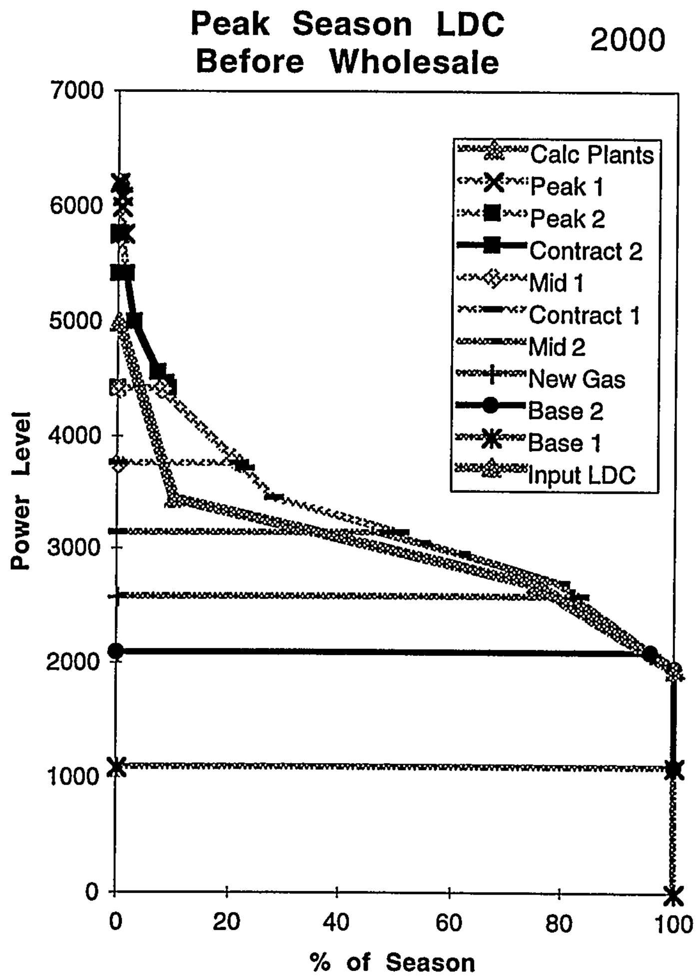

Figure 5. Load duration curve during the peak season

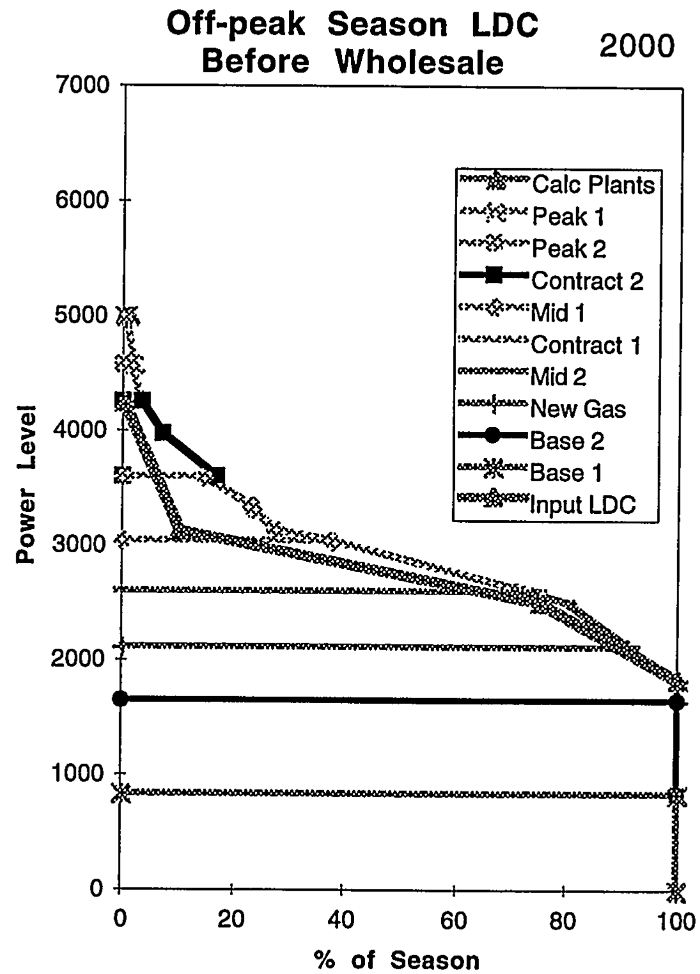

Figure 6. Load duration curve during the off-peak season

The peak of the ELDC is cut off where all the plants are at maximum capacity. The percentage of time at which this occurs is the loss-of-load probability (LOLP). In these figures the value is less than 1%, but with higher forced outage rates or lower reserve margins the value can be higher. Because we model plants as a whole rather than individual units or with partial outages, the LOLP calculated is generally larger than what more detailed production models would show for the same reserve margin.

The wholesale power market is becoming more important to utilities as both a source of needed energy and a market for excess power. ORFIN treats the market not as a single average price, but as four different prices for different portions of the load duration (Figure 7). In times of low demand, a low price for the wholesale market can be used. As the load increases, higher prices can be applied to the wholesale market. This is to simulate that as demand increases for the utility, the regional power market will likewise be facing higher demands and have higher cost plants as the marginal producers. We allow a price differential between the price at which the utility may buy and sell. We also have a transmission constraint option that can limit how much power the utility can buy or sell during each of the four wholesale price periods.

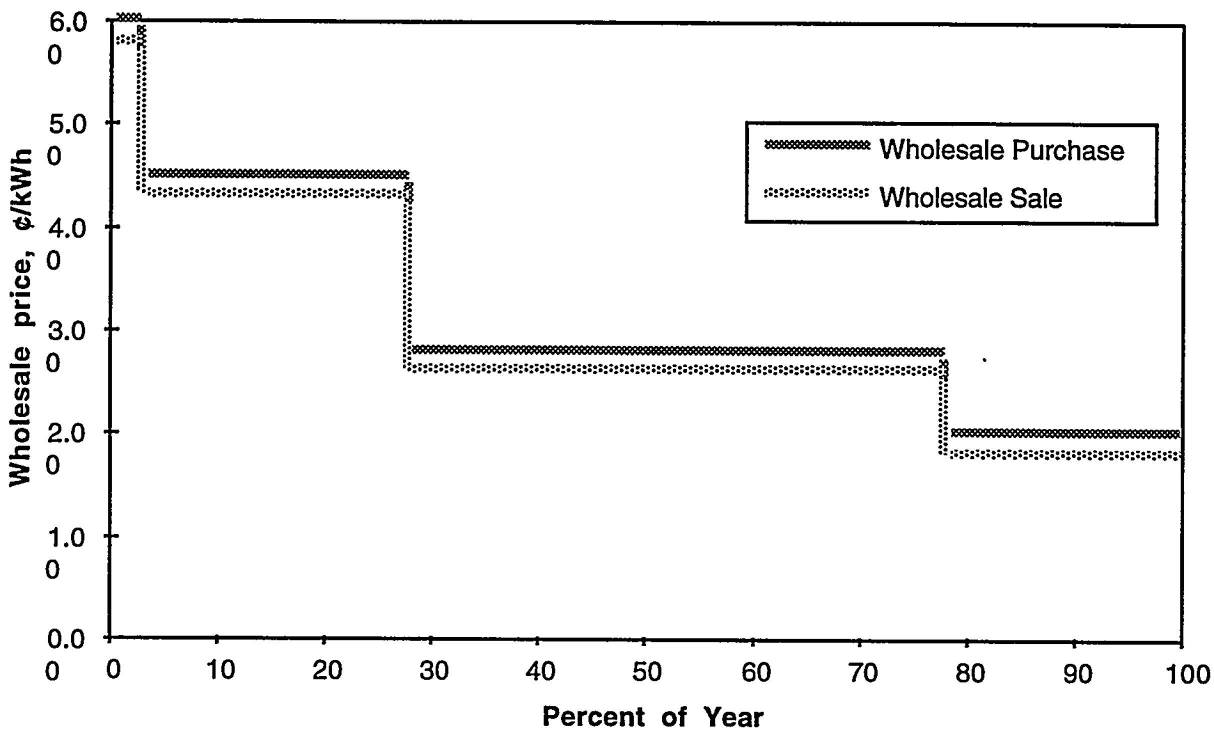

Figure 7. Wholesale power cost distribution

Once each plant has been dispatched to meet demand, its marginal cost is compared to the wholesale purchase and sale prices in each price period. Figure 8 shows an example of the marginal cost for the utility's production versus the wholesale prices at the same points in time. There are times when a higher cost plant is dispatched because of the forced outages of the lower cost plants. This can result in the high-cost plant being on the margin in a low-cost wholesale time while the lower-cost plant is on the margin for part of the higher-cost wholesale period. This shows up in Figure 8 as peaks or valleys in the wholesale price curves that are coincident with the marginal cost curves.

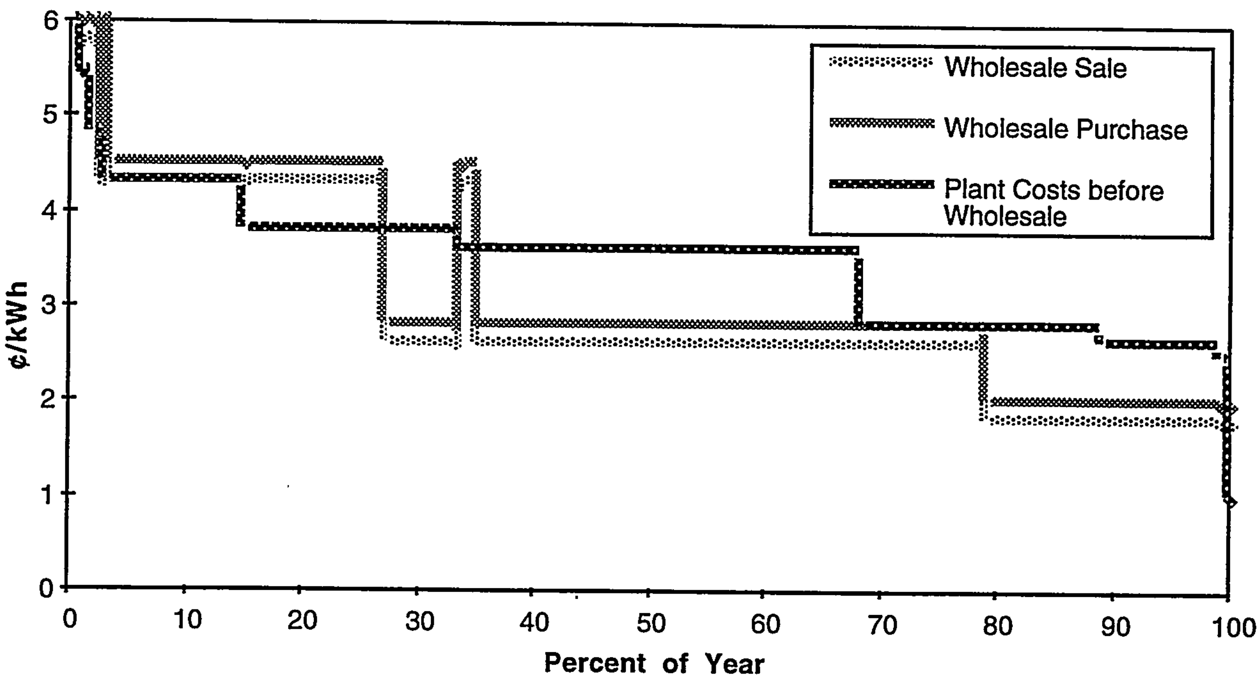

Figure 8. Utility marginal costs and wholesale prices

If the plant cost is lower than the wholesale sale price for the period, and there is transmission capacity available, ORFIN will have the plant generate extra power for sale on the wholesale market in that period. If the plant is more expensive than the wholesale purchase price, then it will be backed down and wholesale power will replace its production. Figure 9 shows the impact of these changes on the economic dispatch for the peak season. Notice that for the second plant (Base 2) transmission constraints keep it from dropping back to zero power level in the lowest cost wholesale time period, even though its cost is above the wholesale market. The model will displace the most expensive generation with purchases before it will back down less expensive plants. Similarly, the least expensive plants will sell into the wholesale market first.

In the upper left of the figure (barely visible) is the wholesale power purchased in the peak period to cover the unserved energy due to lack of capacity. If reserve margins decline or forced outage rates increase, the LOLP will increase and more power will need to be purchased solely to meet demand. If the LOLP increases to larger than the highest cost wholesale power, then power will also be bought at the lower wholesale costs for the portion of demand in that region. ORFIN can even be run with a distribution-only utility where all power is purchased on the wholesale market.

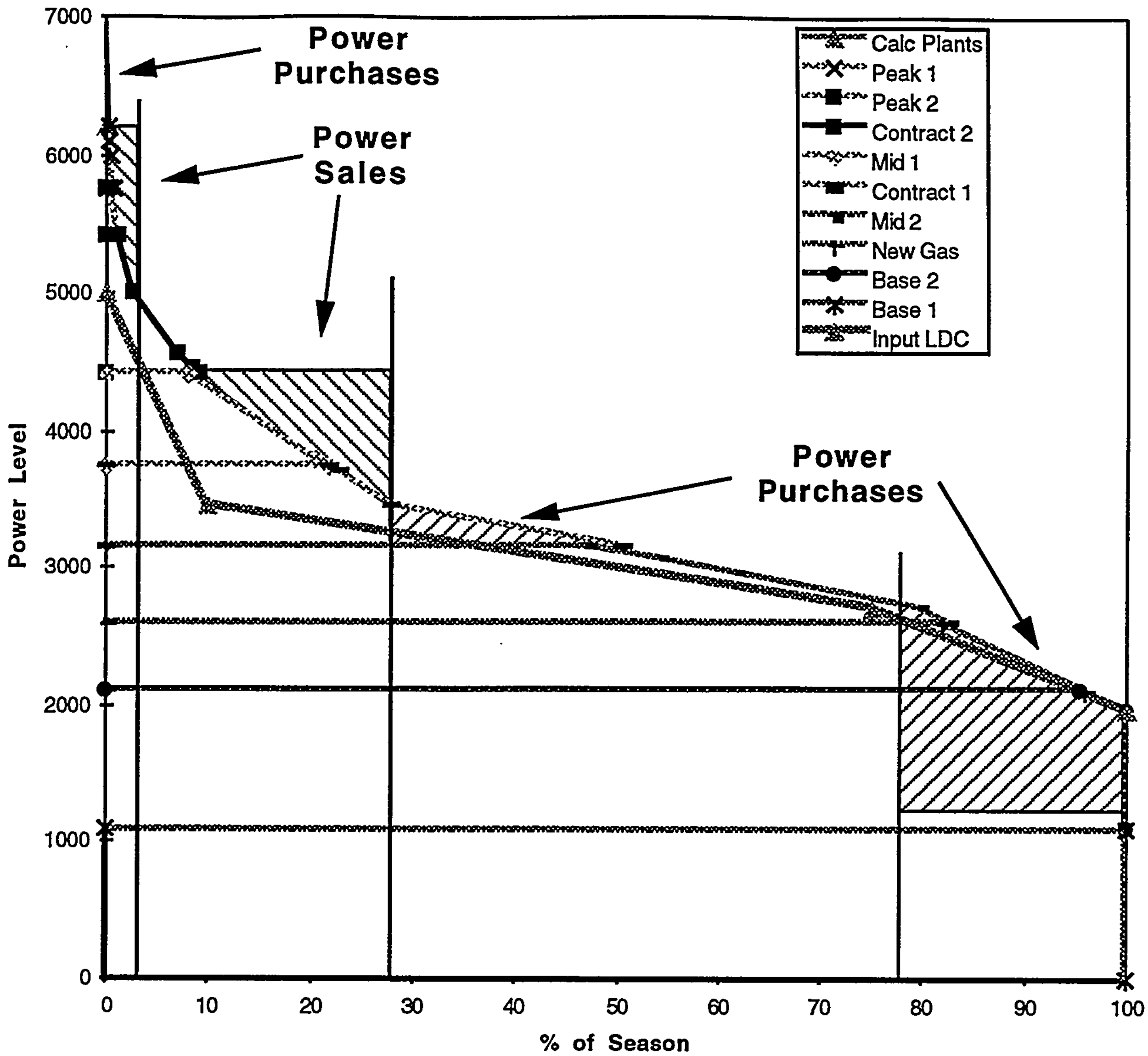

Figure 9. Peak-season load duration curve after wholesale transactions

As a consequence of the wholesale market, without any transmission constraints a plant (or contract) will operate for the percentage of time its cost is lower than the wholesale market. Its capacity factor will be that percentage times (1– planned outage rate – forced outage rate). Figure 10 shows the capacity factors for the plants in the example case over the entire study period. Figure 11 shows the amount of generation by each plant in megawatt-years. From this you can see the impact of new plants beginning operation or others shutting down on the other plants or wholesale market. Notice that the chart shows only net wholesale transactions at the top. In this case, there were more purchases than sales in every year, although the amount changed between years.

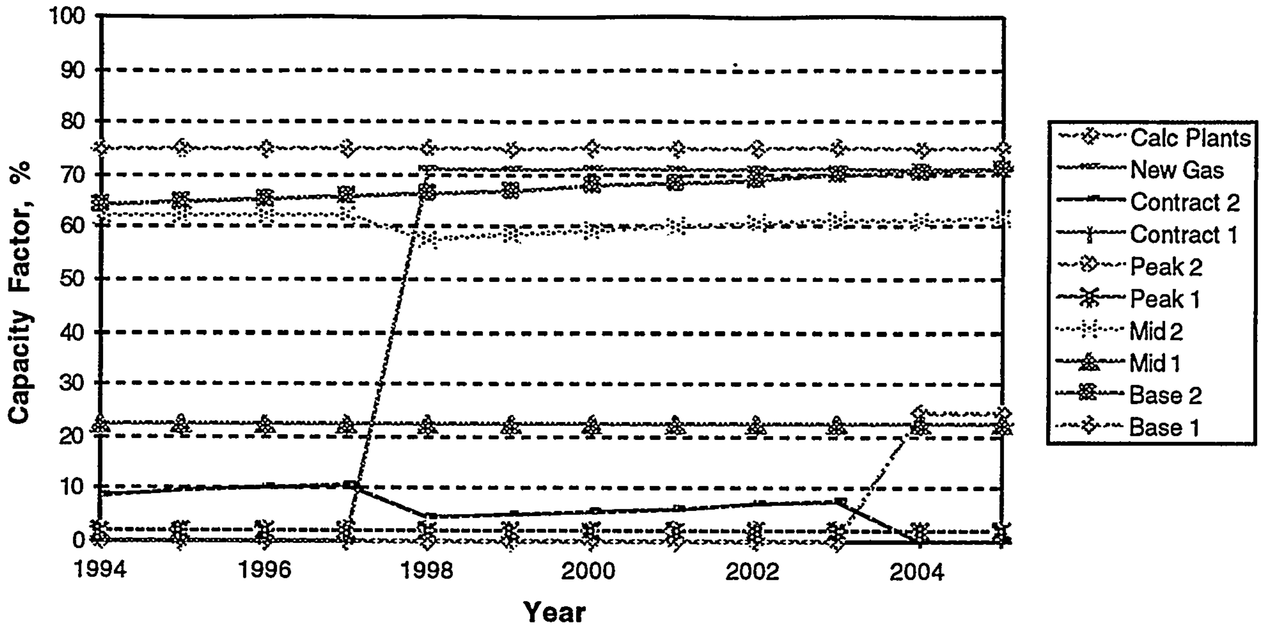

Figure 10. Capacity factors from 1994 to 2005

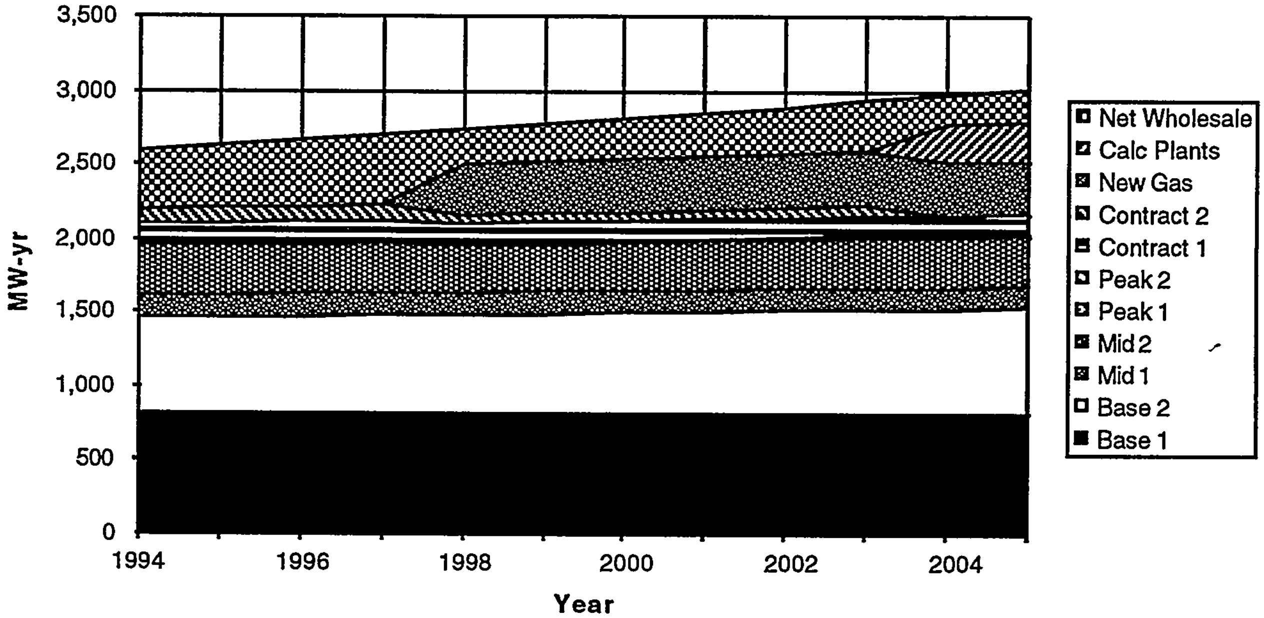

Figure 11. Generation amounts from 1994 to 2005

5. RETAIL WHEELING

The future of the electric power industry may involve customers purchasing their electricity from alternative suppliers and only using the local utility for transmission and distribution of that power. Sales, prices, production, capital expenditures, wholesale interactions, transmission capacity, and ultimately profits are affected by the change in customer status. Because this is a critical issue for the industry, ORFIN was expanded to assess the effects of retail wheeling on utility finances and customer rates.

The user can define what fraction of the residential and C/I customers switch to retail wheeling. Currently, ORFIN models this by having the percentage of customers who are retail wheelers ramping up over time and then leveling off at a certain percentage. The user inputs the first year for wheeling with the associated percentage and the year of plateau with its associated percentage. Separate dates and percentages can be set for residential and C/I customers.

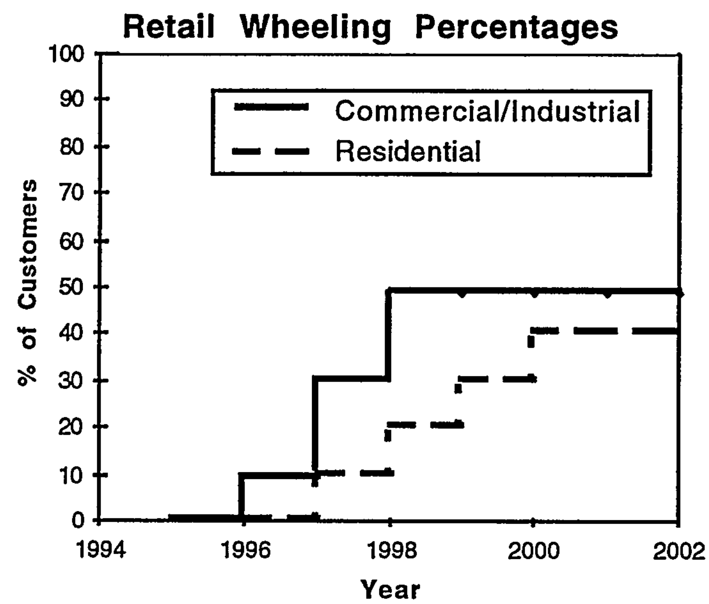

Figure 12. ORFIN treatment of customers switching to retail wheeling.

Figure 12 gives an example where 10% of C/I customers leave in 1996, and an additional 20% in 1997 and 1998. Residential customers begin leaving in 1997, with 10% in 1997, 1998, 1999, and 2000. ORFIN keeps track of the number of customers who have left the system and change the demands and LDC accordingly for each year. If more C/I customers have left in a given year (e.g., 1998 in the example), and they have a higher load factor than residential customers, then the overall system load factor will go down to reflect the higher proportion of residential customers.

Prices can be calculated for each of the three types of customer (using any of the methods described above and with wheeling customers only paying for their reduced requirements) or prices from earlier cases can be used so that the impacts of changing demands are borne by the utility rather than remaining retail customers. Generally, wheelers would only pay a demand ($/kW) and customer

($/yr) charge, with no energy (¢/kWh) charge. However, if some T&D costs are a function of energy use rather than peak demand, or if some of the fixed costs for T&D or general services have been classified as energy-related, then there will be a small energy charge unrelated to generation costs.

If retail wheeling occurs, then the utility has more capacity available to sell and less need to purchase on the wholesale market. This is shown in Figure 13, which shows the difference in amount of wholesale purchases and sales before and after retail wheeling. The amount of change for a given year is based on the relative costs of the available capacity. In this example, a new plant is added in 1998 and a contract expires in 2004. A new balance is struck between cost-effective capacity and the wholesale market as customer demands and production capacity change. Transmission constraints will also limit how much the utility can sell.

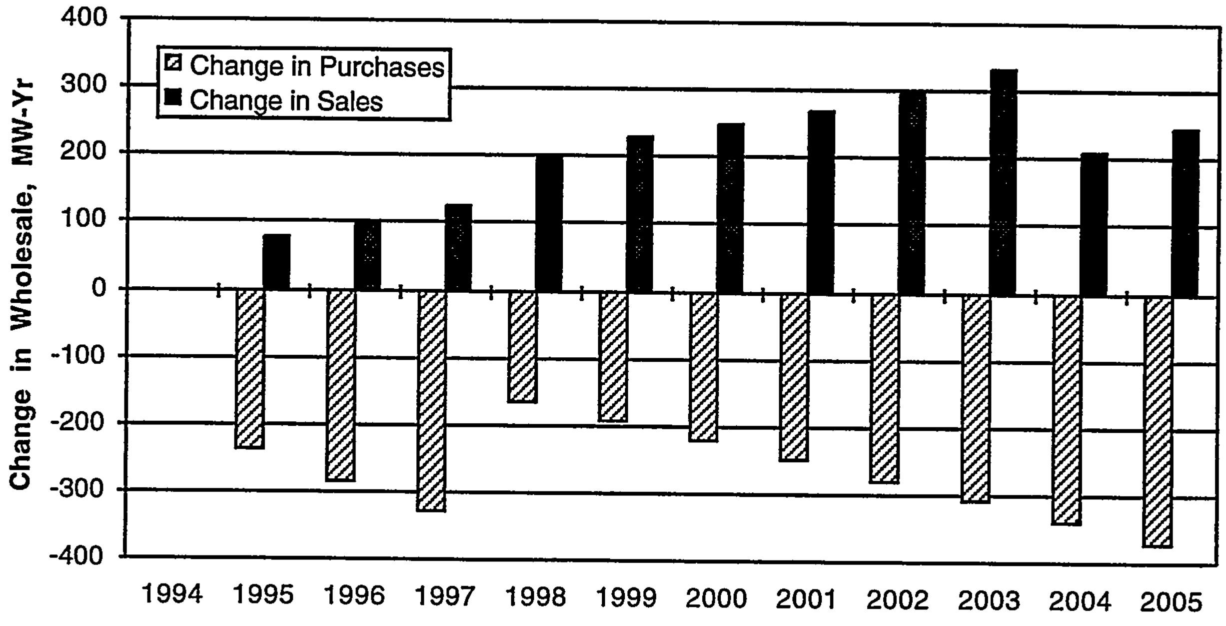

Figure 13. Change in wholesale purchases and sales with retail wheeling

Several studies on retail wheeling are ongoing at ORNL. We have completed a report on methods to estimate stranded commitments (ORNL/CON-424) and are working on a study on the effects of various mitigation strategies to reduce stranded commitments. These both use ORFIN. In the first we analyzed the accuracy of calculating stranded costs by using the average production costs and wholesale prices (top-down method) versus the amount of losses based on actual changes in net income for the utility (bottom-up method). We also analyzed the difference in stranded costs depending on whether the utility kept the customer by reducing prices to the wholesale price, or lost the sale and instead sold on the wholesale market when economically feasible.

Mitigation can involve reducing costs or shifting the cost burdens among the various stakeholders of wheeling customers, remaining customers, shareholders, bondholders, suppliers, and taxpayers. Strategies can involve changing depreciation of plants and T&D assets, more aggressively reducing operating costs, limiting social expenditures, setting exit fees, spinning off assets, as well as numerous other methods.

6. CONCLUSIONS

ORFIN is a useful in analyzing various scenarios for the future U.S. electric industry. It has the detail necessary to allow numerous parameters to be examined realistically yet quickly. It has the flexibility to be modified or expanded easily as new situations arise. And it has the transparency afforded by a spreadsheet system to allow the individual user to examine the specifics behind the overall results. The detailed financial reporting provides comprehensive information on the ramifications of different operating structures for a utility.

ORFIN should continue in its role as an analytical tool for ORNL and other researchers. Enhancements could be made in several areas. Customer switching to retail wheeling is currently an exogenous input. We have had some discussion of adding the capability to make this an endogenous function of the utility prices and the wholesale market price. Details on this type of mechanism have not been determined.

One of the initial reasons that production modeling was added was the need to study the economics of individual plants within a utility system. By pricing a plant's output at the system price applicable during its operation, each plant can be set up as a profit center and its overall profitability measured. Some plants will likely show a net loss by never recovering their fixed costs (depreciation, fixed O&M, etc.). In a more extreme case, some may not recover their cash fixed costs, meaning that they are a net drain on the utility and should be retired. A future addition to ORFIN will examine the individual plants as profit centers to determine their individual contribution to the utility. This will have ramifications in stranded cost analysis and the feasibility of spinning off generation to separate companies.

Other effects of the transition to a deregulated market could be examined. Early sell-off of generating assets is not allowed in the model, although it does have the capability to write-down plants in a shortened time period. The wholesale market could be defined in more detail such as multiple prices within a period, separate pricing for peak and off-peak seasons, or capacity constraints that differ for each price. While useful, these changes have not been determined to be worth the extra programming, data requirements, and run-time that they would entail.

Those interested in the application of ORFIN should contact the author. Although an ongoing research tool for analysts here at ORNL rather than a finished stand-alone product, ORFIN may prove useful to others as an adjunct to their own studies.

ACKNOWLEDGEMENTS

I thank Eric Hirst for his enormous contribution to the development of ORFIN, from development of the initial version to debugging of subsequent releases to suggestions for improvements to additions of output for use during specific studies. I also appreciate his many comments to this report to improve its readability. Without him this model would not have been developed. I also thank Les Baxter for his suggestions and comments on how to make both the model and this report better, and Larry Hill for his knowledge on utility financial structures.

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I. INPUT SHEET SECTIONS

The Input sheet contains all the data needed to run a single case. Cell B1 is where a title can be put to identify a case. All other data are segregated into a number of "modules" that have data specific to different aspects of the modeled utility. These are described below, with each module designated by its location on the spreadsheet. Table A-1 and A-2 show a sample of the Input spreadsheet. The items that are in bold print are input by the user; those in plain print are labels or calculated within the model.

A. One New Resource of Different Types

ORFIN currently models a utility over a twelve year time period. During this time it can model the addition of a new resource (plant, power purchase contract, or DSM) in extensive detail. This allows the user to analyze the impact of a single resource addition to the utility. The data needed to model the new resource is in rows 1-19 of Input, with each type taking a different region within these rows and one module containing data used by each of the types of new resources. Cell H1 is where the user specifies which type of new resource to use: "DSM", "Purchase", "None", or a label showing the type of fuel used in the power plant. If the cell does not contain one of the words in quotation marks, then the model uses the data in the Utility Plant module for adding a new resource.

Demand-Side Management program

DSM data is contained in cells A2 to D14, with an implementation schedule in row 15. The initial cost is the $/kW in first-year dollars for the DSM program. The percent of cost goal is simply an exogenous number used to determine how much performance bonus or shared savings to provide (explained in section III.C.13). The capacity factor is the ratio of actual energy saved per kW of capacity relative to 8760 kWh per kWyr.

Various types of DSM incentives are modeled. The premium ROE is the percentage amount of extra return on equity investment given to any DSM investment. For this to work, the DSM must be rate based. The performance bonus surcharge is a ¢/kWh surcharge on all kWh saved by DSM. The shared savings provides a percentage of the difference between the cost of the DSM measure and the NPV of the avoided cost over its life. The avoided cost includes the capacity and energy cost of purchased power plus an input fraction (e.g. 80%) of the avoided transmission and distribution costs. The Net Loss Revenue Adjustment flag tells the model whether the to add a surcharge based on the lost revenues from DSM.

Table A-1. Input Data

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	-----INPUTS-----	Base			New Resource to Use			None					
2	NEW RESOURCE - DSM			¢/kWh	NEW RESOURCE - UTILITY PLANT					New Resource lifetimes		Years	
3	Initial cost, $/kW =	2,000	Level cost	1.28	O'night capital cost, 1994-$/kW			750		Operating Life		30	
4	Percent of Cost Goal	100	Initial cost	38.1	Fuel type			Gas		Book depreciation		30	
5	Capacity factor	0.6			Heat Rate, BTU/kWh			8100		Tax depreciation	Book		Factor
6	Premium ROE on DSM Investment, %	0			O&M cost, 1994-c/kWh			0.2		Capacity added, MW		500	
7	Performance Bonus @ % Goals	40%	100%		NEW RESOURCE - PURCHASE POWER					Forced Outage Rate		5%	
8	1994 c/kWh from DSM	0.0	0	0.00	Fixed cost, 1994 -$/kW-year			133		Planned Outage Rate		10%	
9	Shared Savings % at 100% of Goal	0	Zero point	50	Operating cost, 1994 -c/kWh			2.3		Dispatch Price, 1994 ¢/kWh or 'OP'			OP
10	Ratebase (=1) or Expense (=0) =	1			Contract Start Year			2006	2030	% Investment or Purch allowed			100
11	Net Lost Revn Adj (0=no, 1=yes)	1			Nominal Escal in fixed cost after start, %/yr			0	0	Normalize (1) or flowthru (0) FIT			1
12	Percent of T&D Avoided by DSM	100	1		Real esc in operating cost, %/yr			2	0.02	CWIP (1) or AFUDC (0)			0
13	Percent of DSM to Residential	33	0.33		% of NPV of Fixed Charge = Debt			0					
14	Percent of DSM Cost to Demand Chge	50											
15	% DSM additions by year if new DSM used	0	0	20	30	50	0	0	0	0	0	0	0
16	Actual Cum. % spent on DSM	0	0	0	0	0	0	0	0	0	0	0	0
17	% constr cost by year if Power Plant used	0	25	30	45	0	0	0	0	0	0	0	0
18	Actual cum. construction cost %	0	0	0	0	0	0	0	0	0	0	0	0
19	year	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
20													
21	OPERATING COST COEF.	1994 MM$	$/kW	¢/kWh	SALES INFORMATION			Residential	Comm/Ind	REVENUE PARAMETERS			
22	Transmission O&M Costs	0	5.1	0	1994 Thousands of Customers			750	100	Rate Calculation Method			6
23	Distribution O&M Costs	0	7.6	0	1994 Avg. Monthly kWh/Customer			750	12000	1=Hist, 2=Fut, 3=Exog. Price, 4=Rev Cap, 5=Price Cap			
24	G&A Expenses, 1994 MM$	80			Class Load factor			0.50	0.65	Frequency of Rate Cases			1
25		Resid.	Com/Ind	Wheel	Customer Growth, %/yr			1.4	1	First Year for Rate Case (besides year2)			1995
26	Distribution, $/Customer	36	36	36	Load growth/Customer, %/yr			-0.3	0.5	Year to Begin Marg E/D Pricing			2030
27	Cust. Service, $/Customer	75	75	75	Total Energy Growth, %/yr			1.010958	1.01505	Productivity Factor for PB Rates, %			1
28		Non-product.	Fixed Product.	Vari. Product.				Capacity	Energy	Deadband Points for PB Rates			200
29	Real O&M cost escal, %/yr	-1	0	0	Transmission Losses, %			4	3	Shared Savings past Deadband, %			50
30	CAPITAL COST COEF.	1994 MM$	$/ΔkW		Distribution Losses, %			8	4	Real Exog Electricity price			8
31	Transmission Capital Costs	18	150		Wholesale transmission capacity, MW			1000		Real Exog DSM price(1994 c/kWh)			6
32	Distribution Capital Costs	34	250		Emergency capacity, MW			400		Real Exog Wheeling Price, $/kW			50
33	General Plant	5			%of C/I Cust. using Dist. System			100	1	Real Exog Prices Escalation Rate, %			0
34		Resid.	Com/Ind	Wheel	Allocated Cost to Demand Charge, %			100	1	Deadband Percent for 100% FAC			0
35	Distribution, $/ΔCustomer	800	800	800	Allocated Cost to Customer Charge, %			0	0	FAC Outside Deadband, %			100
36	General Plant, $/ΔCustomer	150	150	150						Costs Included in FAC Calculation			0
37					COMMERCIAL/INDUSTRIAL WHEELING					1=Fuel,2=Fuel+PurchEnergy,3=Fuel+Purch			
38	INITIAL PLANT INVESTMENT	Gross	Cum Dep.	Life	Start/End years of switch to wheeling			1996	2005				
39	Transmission	591.6	207.6	50	C/I switch to retail wheeling, %			0.0001	0.0001	CAPITAL STRUCTURE		LT Bonds	Equity
40	Distribution	1331.1	467.1	50	RESIDENTIAL WHEELING					% of Assets		55	45
41	General Plant	100	35	40	Start/End years of switch to wheeling			1996	2005	Initial Rate		8.6	11.50
42	Total Non-Generating	2022.7	709.7		Residential switch to retail wheeling, %			0.0001	0.0001	Future Rate		8.6	11.50
43	Regulatory Asset	100		12	% Wheeling requiring transmission			0		Ratio-Net Current assets/Revenue			0.01
44					% General Plant&Admin Costs paid by Wheelers			45	0.45	Initial Retained earnings, MM$			7
45	PURCHASE CONTRACT	Contract 1	Contract 2		Wheeling ancillary cost adder, 1994 $/kW-yr			0		Dividend payout ratio, %			75
46	Amount, MW	600	1000							Inflation rate, %/yr			3
47	Final Year	2015	2003		ADDED PRODUCTION			Calc Plants					
48	Forced Outage Rate	0	0		Minimum Reserve Margin, %			5	1.05	TAX RATES			
49	Planned Outage Rate	0.2	0.25		First Year for Calc Plants			2005		Income tax rate, %			36
50	Fixed cost, Nominal $/kW-yr	35	40		Forced Outage Rate			0		Revenue sensitive tax rate, %			7
51	Variable cost,1994-¢/kWh	3.6	4.3		Planned Outage Rate			0.1		Base Property tax rate, %			2
52	Variable cost escal rate, %	0	0		Dispatch Price,1994 ¢/kWh or 'OP'			OP		New Resource Property tax rate, %			2
53	Dispatch Price,1994 ¢/kWh or 'OP'	OP	OP		Depreciation Life			30		New Resource Investment tax credit, %			0
54													

Table A-2. Input Data (cont.)

	A	B	C	D	E	F	G	H	I	J	K	L	M
55	EXISTING GENERATING PLANTS	Base 1	Base 2	Mid 1	Mid 2	Peak 1	Peak 2	LOAD CURVE TEMPLATES					
56	Capacity, MW	1100	1000	660	550	450	350	PEAK SEASON		Min (100%)	Shoulder 1	Shoulder 2	Peak (0%)
57	Cost/kW in startyear dollars	1700	700	1100	550	670	300	Cum fraction of Season, %		100	75	10	0
58	Year start	1982	1984	1971	1966	1988	1970	Percentage of Peak		40%	55%	70%	100%
59	Operating life	45	50	45	45	45	45						
60	Original Depreciation Life	40	40	40	40	40	40	OFF-PEAK SEASON					
61	New "Full Depreciation" Date	2022	2024	2011	2006	2028	2010	Cum fraction of Season, %		100	75	10	0
62	Tax Life	20	20	20	20	20	20	Percent of Off-peak Peak		44%	60%	75%	100%
63	Tax depreciation factor	1.5	1.5	1.5	1.5	1.5	1.5			0.374	0.51	0.6375	0.85
64	Forced Outage Rate	8%	8%	10%	10%	25%	25%	Ratio of Off-peak season peak					
65	Maint Outage Rate	17%	12%	10%	10%	5%	5%	to Peak season peak		85%			
66	Vari. O&M Cost,1994¢/kWh	0	0.5	0.5	0.8	2	1	Peak season percent of year		25%	75%		
67	Fixed Oper cost,1994 $/kW-year	150	3	3	3	3	3						
68	Fuel Type	Nuclear	Coal	Gas	Coal	Gas	Oil	WHOLESALE DATA		Lowest (#1)	Next (#2)	Next (#3)	Highest (#4)
69	Heat Rate, BTU/kWh	17000	10000	11000	10000	11500	9500	% Year each Available		20	50	25	5
70	Dispatch Price,1994 ¢/kWh or 'OP'	OP	OP	OP	OP	OP	OP	Escalation factor		coal	coal	gas	gas
71													
72	MISCELLANEOUS COSTS	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
73	Added Production Capital Cost 1994 $/kW	1	1	1	1	1	1	1	1	1	1	1	1
74	Added Production Energy Cost, 1994 ¢/kWh	4	4	4	4	4	4	4	4	4	4	4	4
75	Avoided Capital Cost for DSM, 1994-$/kW-yr	25	25	50	75	75	75	75	75	75	75	75	75
76	Avoided Energy Cost for DSM, 1994-c/kWh	2.1	2.1	2.2	2.3	2.4	2.8	3.2	3.6	4	4	4	4
77	Social Programs Oper Cost, 1994 M$	25	25	25	25	25	25	25	25	25	25	25	25
78													
79	WHOLESALE PURCHASE PRICES, 1994 ¢/kWh												
80	Lowest Cost (#1), 20% of time, coal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
81	Next Lowest (#2), 50% of time, coal	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80
82	Next Lowest (#3), 25% of time, gas	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
83	Highest (#4), 5% of time, gas	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
84	Purchase Price - Sale Price, ¢/kWh	0.20											
85	WHOLESALE SALE PRICES,1994 ¢/kWh												
86	Lowest Cost (#1), 20% of time	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
87	Next Lowest (#2), 50% of time	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60
88	Next Lowest (#3), 25% of time	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80
89	Highest (#4), 5% of time	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80
90													
91	FUEL COST ESCALATED PRICES	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
92	Gas Price Real Escalation Rate, %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
93	Coal Price Real Escalation Rate, %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94	Oil Price Real Escalation Rate, %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	Nuclear Price Real Escalation Rate, %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	Other Price Real Escalation Rate, %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
97													
98	Gas Prices, 1994 $/MMBTU	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
99	Coal Prices, 1994 $/MMBTU	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
100	Oil Prices, 1994 $/MMBTU	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
101	Nuclear Fuel Prices, 1994 $/MMBTU	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
102	Other Plant Types Fuel,1994 ¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103													
104	INPUT REAL SALES PRICES, IF OPTION 6												
105	Residential, ¢/kWh	10.02	10.95	10.80	10.65	10.51	10.37	10.24	10.12	10.00	9.89	9.74	9.69
106	C/I Energy, ¢/kWh	3.00	3.87	3.88	3.89	3.91	3.92	3.93	3.94	3.95	3.96	3.92	3.95
107	Wheel Energy, ¢/kWh	0.00	0.00	0.35	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
108	C/I Demand, $/kW-yr	329	332	322	312	303	295	286	278	271	264	258	253
109	Wheel Demand, $/kW-yr	0	0	139	160	160	160	160	160	160	160	160	159
110	Res Customer Charge, $/yr	102	102	102	102	102	102	102	102	102	102	102	102
111	C/I Customer Charge, $/yr	102	102	102	102	102	102	102	102	102	102	102	102
112	Wheel Customer Charge, $/yr	102	102	102	102	102	102	102	102	102	102	102	102

The percent of DSM to residential tells what fraction of both the cost and savings of DSM should be assigned to residential customers. This will be reflected in both residential and C/I sales amounts and rates. The percent of DSM to demand charges represents how much of the surcharges for DSM (incentives and NLRA) are captured in the commercial/industrial demand charge versus their energy charge.

New generating plant

The power plant as a new resource input is in cells E2 to H6, with the construction schedule in Row 17. The overnight capital cost input is in first-year $/kW and represents the cost of actual construction with no interest and no inflation during construction. A fuel type and heat rate are entered. Later in the Input worksheet (rows 91 to 102) are the cost of the fuel types in $/mmBTU. The O&M cost in first-year ¢/kWh is also input.

New purchase

The Purchase Power resource is a long-term contract for power with separate fixed cost in first-year $/kW-year and a variable cost in first-year ¢/kWh. It is in cells E7 to H13. The contract begins in the year input. The fixed cost is escalated using general inflation until the contract begins and then uses the input escalation rate instead of general inflation. This gives the option that the fixed cost is static in nominal dollars or increases at a different rate than inflation. The variable cost is escalated at the general inflation rate plus the input real escalation rate.

The model allows that the net present value of the fixed cost of the long-term contract be considered as equivalent to debt when calculating the debt to total capital ratio. The input assigns a relative equivalence (0% – 100%). To calculate the effect, the present value of the remaining capacity charge is multiplied by the input fraction to find its debt equivalence. This is added to the total assets. This adjusted total asset value is multiplied by the input debt ratio to find the total allowed debt plus debt equivalence. Subtracting the debt equivalence determines the allowed amount of debt. The effect is a lowering of the amount of debt that the utility can carry when the contract is signed. This alters the cost of capital as well as causes the utility to replace some of their existing debt with equity.

Common new resource data

In cells J2 to M12 are various data that apply to more than one of the new resource types. There are three types of lives recognized in the model: the operating life (which determines how long the resource will provide power), the book depreciation life (which specifies how long for the plant to be depreciated), and the tax depreciation life (which uses accelerated depreciation to calculate the deferred taxes). If the word "book" is used for the tax depreciation then the depreciation will match the book depreciation schedule and there will be no deferred taxes.

The actual capacity of the new resource in megawatts is entered in cell L6. A forced outage rate and planned outage rate are entered for use during dispatch of the new plant or new contract (but not DSM). The dispatch price is the variable cost used to determine the load order when calculating the economic dispatch. If the word "OP" is entered then the model will used the variable operating costs, including fuel costs.

Schedules

If a power plant or DSM program is added then a schedule is used to show what percentage of the capital cost is spent in each year. These are in rows 15-19. Actually, the construction profiles can be put in but are not used unless the label in cell H1 has "DSM" (for the DSM resource) or something other than "None" or "Purchase" (for the new plant resource). This allows the user the quickly switch between different technologies for new resources.

B. T&D and General Plant

ORFIN calculates separately the cost of transmission, distribution, and general facilities. Capital and Operations & Maintenance (O&M) costs are tracked and allocated to the different customer classes.

Operating costs

The O&M costs inputs are defined in cells A21 to D29. Costs for transmission and distribution can be entered in millions of dollars, $/kW, and/or ¢/kWh. General administrative (G&A) costs are entered in millions of dollars. (All are in first-year dollars). In addition, distribution costs and customer service costs can be defined as a function of $/customer. Different values can be set for each customer type: residential, commercial/industrial, and wheeling. All of the costs calculated by these components are inflated by the general inflation rate and the input nonproduction cost escalation rate. Using a negative value reflects that productivity gains slow the increase below inflation.

Capital costs

Capital expenditures for T&D and general plant are calculated using input fixed amounts per year and/or changes in demand or number of customers from the previous year. These costs are multiplied by the appropriate variables and escalated solely by general inflation. If change in demand or customers is negative, then no capital is spent, not negative amounts. One note, the values for changes in wheeling customers is offset by any reduction in full service customers to reflect net additions rather than just conversions from full service to wheeling.

Initial investment

The initial plant investment module shows the gross investment and accumulated depreciation for T&D and general plant assets as of the beginning of the study. Each of the asset types may have separate book lifetimes. Tax depreciation is not calculated separately on these assets, so tax calculations use the same depreciation schedule as book depreciation.

Regulatory assets represent costs that normally would have been expensed earlier, but instead were capitalized for recovery later through the ratemaking process. Examples include a deferral in applying depreciation of a new plant to avoid rate shock or DSM investments that are to be included in future rates. An amount as of the beginning of the study and a depreciation life is entered in Row 43. The asset is depreciated on a straight line over this time period and the costs associated with it are included in the rate calculation and financial reports.

C. Sales

Residential and Commercial/Industrial customer size is calculated with these input values. Initial numbers of customers, energy use per month, and load factor are used to calculate the total demand for capacity and energy. The growth rates for number of customers per year and energy use per customer then are used to calculate unadjusted growth in demand. (The following line shows the total growth rate for each customer type, but is not an input.) DSM programs will lower the net sales by each category, and wheeling will reduce the number of full service customers.

Transmission losses and distribution losses affect the capacity and energy delivered separately. The values input here are used to increase the amount of capacity and energy that must enter the distribution system, transmission system, and ultimately, be generated. They affect the residential and C/I customers differently based upon the next variable, percent of C/I customers that use the distribution system. Transmission-only power losses are not as great as transmission and distribution combined, so those C/I customers that use just transmission do not face as much generating cost per unit of purchase. Only the residential customers and the input percentage of C/I customers are charged for the distribution system costs. If no C/I customers use the distribution system, then residential customers bear the full cost.

Transmission capacity is made available to the utility to purchase or sell power on the wholesale market. ORFIN has two capacities defined. The first is that available to the utility to buy or sell based on a cost difference between its locally-owned capacity and the power available on the wholesale market, as well as to meet unserved demand. The second, emergency capacity, is available only to meet unserved demand and is priced at the most expensive wholesale purchase price. Its main purpose is to handle the top tail of the equivalent load duration due to forced outages and to cover any round-off error in the dispatch calculations.

Fixed costs in the price calculation include the input costs that are not a function of customers, demand or energy: depreciation, property taxes, income taxes, interest, and allowed ROE. These can be allocated between customer service, demand and energy charges in the rate calculation. While generally these would be allocated to demand, some fraction can be assigned to be recovered in the customer and/or energy charge. (The amount charged to energy is 100% minus the two input numbers for demand and customer allocations.) Changing these factors will change the relative prices between customer types based on their load factors.

D. Retail Wheeling

The model calculates the number of C/I and/or residential customers going to wheeling through an exogenous ramp up. In the input start year the percentage below it switches. This percentage increases linearly to reach the final percentage in the end year. It then remains constant at the final percentage. Separate ramp-ups are allowed for residential and C/I customers.

Wheeling customers may be purchasing power from distributed generation within the service territory or from outside the region. If it is from outside then they would be taking up some of the available transmission capacity that the utility otherwise would use for wholesale purchases and sales. To allow flexibility in this, the percentage of wheelers requiring transmission capacity is input. The amount of wholesale energy available to the utility is reduced by this fraction of the wheelers' energy requirements. The calculation takes into account the load shape of the wheelers such that the transmission capacity at wholesale price #1 is not as reduced as much as that at wholesale price #4.

To study the impact of not requiring wheeling customers to pay for fixed charges other than those associated with T&D, an input percentage of fixed charges for general plant can be allocated to wheeling customers. At 100%, they are allocated their proportional amount of G&A based on the kW demand. At 0%, they only pay their portion of the fixed T&D costs (based on kW demand) and no G&A fixed costs. Of course, in no circumstance are they charged for the fixed costs associated with generation. In Cell H45 is an adder to the wheeling demand charge to represent recovery of ancillary costs that are not recovered in the normal calculations.

E. Pricing

The rate calculation method has six options. Historical Test year calculates prices based on the previous year's costs and sales (with some adjustments to use this year's depreciation and a few other things). Future Test year uses this year's costs and sales to calculate prices. The user enters how frequently the rate cases occur and the first year they occur (besides the first and second year). For the first year, the model uses future test year. For the second, unless the user chooses historical test year or sets the first year of the rate case sequence to this year, the model will use future test year.

Under Option 3, the required revenue is based on the exogenous prices in M30 to M33. It is set up so that the combined residential and full service C/I customers will pay a total average price equal to the exogenous price. However, their individual price components will still be calculated using the embedded (or marginal) costs so that the price for each may be different. The wheeling customers will pay the exogenous demand price for wheeling and any DSM customers will pay the exogenous energy price entered. Under Option 6, the model will use the prices in Rows 105 to 112.

Performance based rates in the form of a revenue cap (Options 4) use the previous year's revenue requirement, adjust it upward for increase in number of customers and inflation and decrease it based on the input productivity factor. In addition, a deadband is placed around the authorized return on equity (ROE). If in the previous year the actual ROE (including AFUDC and deferred taxes) is above the authorized plus the deadband points (e.g. 200 points), then the input percentage (50%) of the amount over the deadband is refunded to customers. If the ROE is below the deadband, then customers pay a surcharge. Option 5 (price cap) is calculated similarly but instead of adjusting the required revenues for the increase in number of customers, it adjusts it based on the increase in sales. This in effect keeps the price constant except for changes in inflation and the productivity factor.

The Marginal Energy/Demand Pricing option changes the relative contribution of demand-related costs to energy-related costs such that the ratio of demand price to energy price for C/I customers is equal to the ratio of avoided purchased power. (T&D avoided costs are not included because they will vary depending on the customer type and the relative amount of distribution used.) The total revenue required and customer service charge are kept constant. Within the demand and energy charge calculations, the percentages from residential, C/I, and wheeling remain the same.

The fuel adjustment charge is calculated on the entire utility's fuel (and purchased power) costs; it does not separate the new plant from the rest of the utility. The model compares the cost per kWh for a given year and compares it to the cost per kWh in the most recent rate calculation. If the actual cost per kWh is within the deadband percentage (e.g., 10%) of the authorized, then 100% of the difference is included in the FAC. If the percentage is higher than the deadband percentage, then only a fraction of the amount above the deadband is recovered through the FAC. For example, if actual fuel cost is 4¢/kWh, the amount in the last rate case was 3.5¢/kWh, and FAC outside of the deadband is only 50%, then the utility would recover in the FAC:

100% x 3.5¢/kWh x 10% + 50% x (4¢/kWh-3.5¢/kWh x(110%) = 0.425¢/kWh

If fuel cost per kWh went down, then the utility would similarly only have to refund part of the savings.

The FAC can be applied to just fuel used in the utility's power plants, fuel plus the energy portion of any power purchases, or fuel plus all costs of power purchases.

F. Capital Structure

The capital structure indicates the relative make-up of the investment between debt and equity. The amount of debt is defined by an input percentage of assets. This is held constant during the entire time period, unless the new resource purchase contract is considered equivalent to debt. The debt has an input initial interest rate that applies to a debt level existing at the beginning of the study. A separate interest rate is input for all new debt.

The equity ratio is one minus the debt ratio, so is calculated in the model. The Equity ROE is input both for the first year and for all years after. Separately, the model calculates an after-tax cost of capital and a real after-tax cost of capital for use in present valuing various cost streams.

The ratio of net current assets to revenues represents the current assets on the books minus the current liabilities. We define it as a function of revenues so it will follow growth in sales. According to the recent EIA data, the total net current assets (combined with other non-plant assets and non-capital liabilities) is relatively small. Initial retained earnings simply establishes for the balance sheet how much of initial equity funds is from retained earnings as opposed to stock issuance. The dividend payout ratio says how much the utility will pay to stockholders as a function of the net income. Since the model keeps the debt ratio constant and does not retain surplus cash, this parameter only becomes meaningful if there is insufficient cash since the utility will issue stock to cover the dividend or buy back stock if there is excess.

The inflation rate is input in this table and applies to all future years.

G. Taxes

The income tax rate applies to the net income of the utility, adjusted for tax depreciation. The revenue-sensitive rate applies to all revenues of the utility. Many of the revenue surcharges are increased to collect the sales tax that would apply to them. Separate property taxes rates are allowed on the base plant and the new resource. This is charged on the net book value of the plant. The investment tax credit provides a tax credit for construction of the new resource. It does not apply to the other production plant added or other capital additions.

H. Base Contracts

ORFIN models two existing long-term power purchase contracts as resources available for dispatch. Variables include the capacity, final year, forced and planned outage rates, and fixed and variable costs. Variable costs are allowed to escalate over inflation at an input fixed rate, while fixed cost will stay constant regardless of inflation. A dispatch price (or "OP") is input for use by the dispatch spreadsheet. This is the same as with the new resource, where a zero price creates a "must-run" plant, while "OP" means to use the variable operating cost.

I. Added Plants

Based on the minimum reserve margin input in cell H48, additional plants will be constructed. However, this reserve margin is not applied until the year specified in cell H49. These plants are assumed to be built in a single year and have costs and operating characteristics as shown in rows 73 and 74. A name for the plants can be put in cell H47; the other variables operate similarly to those of the base plants.

J. Base Plants

There are six base plants defined within ORFIN in cells A55 to G70. A name can be entered for each in row 55 and their capacity is in row 56. The cost per kW of row 57 should be the initial plant cost in the year it started up (row 58). Rows 59, 60, and 62 are the operating life, book life and tax life, respectively. These define, as with the new resource, how long it actually operates, its book depreciation, and its tax depreciation. With a plant starting sometime in the past, the result can be a significant amount of deferred taxes due to the difference in book and tax depreciation as of the start of the study period. Row 61, "New Full Depreciation Date" allows the user to model a change in the depreciation life of the plant as of 1995. This was added to analyze the effect of accelerating depreciation of certain assets to change the stranded investment due to retail competition.

The forced and planned outage rates (rows 64 and 65) are used during dispatch of the plants. The variable O&M cost is a function of the energy generation of the plant and is a factor in its economic dispatch. The fixed O&M cost is based on the plant's capacity and allocated to the demand charge. The fuel type tells the model which fuel cost to use, and the heat rate provides the factor to convert the fuel cost into ¢/kWh.

K. Load Curves

Two sets of load duration curves are input in cells H55 to M66: one for the peak season and one for the off-peak season. The load duration curve shows the percent of time that demand equals or exceeds the specified demand (Figure A-1). The input data represents the curve as a percent of the peak demand for the period. To relate the two curves, the user inputs the ratio of the system peak during the off-peak season to the system peak during the peak season in cell J65. Also, the user enters the fraction of the year that is represented by the peak season in J66.

Each curve has two points along the X-axis (besides the end-points) where the curve changes its slope. These two points are input by the user. The user specifies the ratio of demand at these points to the peak for the season, as well as the minimum ratio that is required 100% of the time.

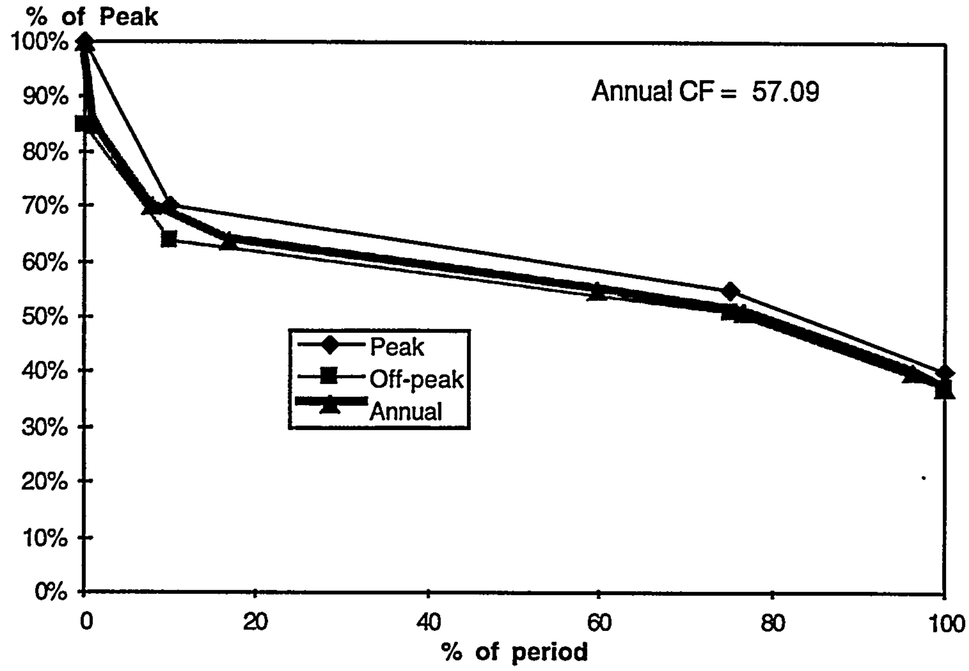

Figure A-1. Load Duration Curve Templates

To get an understanding of the resultant load duration curves, a small chart is on the input sheet (Figure A-1). It shows the percent of time that demand meets or exceeds the given capacity. However, it should be pointed out that these curves are only templates for each year's actual load duration curves. The load factor of demand for a given year might be different based on the relative demands from residential and C/I customers. The combined load factor might not match the load factor as calculated using these curves.The model modifies these curves by raising or lowering the curve so that the curves' load factor matches the actual for the year.

L. Miscellaneous Costs

There are several annual costs in this module. The first shows the capital cost for any of the calculated plants added to meet the required reserve margin. The second line shows the fuel and operating cost for that plant in first-year ¢/kWh. For simplicity, only the first-year price needs to be entered; the model will then escalate that for future years based on the escalation rate for natural gas (see below). Next, the avoided cost of power for use in calculating DSM incentives is entered, both annual capital and annual operating. Finally, a schedule for non-production operating cost related to "social programs" is entered in first-year millions of dollars. This is to allow modeling of extra costs for the utility such as low-income subsidies.

M. Wholesale Power Costs

After ORFIN has dispatched the available plants to meet demand, it checks to see if there is economic wholesale power that it could purchase to displace generation, or excess capacity that it could sell on the wholesale market. The model uses four different wholesale power categories, each available for an input fraction of the full year (in cells J69 through M69). Rather than enter a price for each year, prices are only entered for the first year and then escalated based on the fuel type that is assigned to that wholesale power in J70 through M70.

Purchase prices are input in rows 80 through 83. Column B is input and column C through M show the amounts escalated based on the fuel type. The model has separate prices for the sale of wholesale power as opposed to the purchase. The difference in price is input in cell B84. This amount is used to represent potential wheeling charges if the utility were to sell to others.

N. Fuel Costs

The base plants and new resource may use one of five types of fuel. The user inputs a price in $/mmBTU in the first year for coal, gas, oil, and nuclear in cells B98 to B102. The model uses these in conjunction with the heat rates to determine the fuel price in ¢/kWh. The fifth fuel cost is for any other type of fuel and is entered directly in ¢/kWh. It can be used to model renewable fuels. Real escalation rates are input for each fuel type for each year in cells B92 to M96. Constant values for each year can be used, or a price spike can be modeled.

O. Input Prices

If the user wishes to enter exogenous prices, or use the same prices as from a previous case, he may enter these prices in cells A105 to M112. Residential, C/I, and wheeling prices are entered in first-year ¢/kWh, $/kW-year, and $/customer.

II. Operational Macros

To operate the model, all that is necessary is to enter the desired values for the inputs and calculate using Cntl-A. ORFIN uses the macro Cntl-A to do a full recalculation that includes redispatching of the plants, if necessary. If inputs have not changed to where a redispatch is needed, then none will be done.

A number of macros have been developed to assist in the model's operation. Some of these macros are:

- Cntl-A — Run the full case including dispatching of the plants if needed.

- Cntl-B — set the current case as the "base" case for comparisons. (Note: this has been changed to so that retail wheeling is set to zero, prices are set through an annual future test year, the results are stored as the base case, calculated prices are copied to the input sheet, and the price calculation method is changed to use these prices.)

- Cntl-L — Run the Coal plant as the new resource. (Values for capital cost, fuel cost, and escalation are in the macro file.)

- Cntl-D — Run the DSM program as the new resource. (Value for capital cost is in the macro file.)

- Cntl-R — Run the Renewable plant as the new resource. (Values for capital cost and escalation are in the macro file.)

- Cntl-G — Run the Gas plant as the new resource. (Values for capital cost, fuel cost, and escalation are in the macro file.)

- Cntl-N — Run the model with no new resource.

- Cntl-U — Run the Power Purchase contract as the new resource. (Values for fixed and variable cost, and start year are in the macro file.)

- Cntl-T — Copy the output prices to the input sheet.

- Cntl-W — Run a case with no wheeling, store its values as a base case, copy its prices to the input worksheet, and reset the price option to "6" so it will use those prices in the next run.

- Cntl-E — Copy the dispatch data for a specific year into the dispatch sheet and run the dispatch model. This does not copy the results back into financial calculations.

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