The Contribution of Energy and Ancillary Services to Net Income of Generating Units in the U.S. Power System

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Electric Power Research Institute (EPRI) by

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Executive Summary

In a restructured electricity market, power plants earn revenue from both energy and ancillary service (A/S) markets, and profits are maximized through an optimal allocation of scarce capacity between energy and A/S sales. New participants considering entering competitive operations have little information to help them understand how much additional revenue ancillary services can contribute to their income or how they might consider operating their units.

An analysis of energy and A/S contribution to profits has been performed on representative base-load, mid-merit, and peaker plants in four restructured U.S. power markets: New York, New England, Electric Reliability Council of Texas (ERCOT), and California. Information on the respective contributions of energy and A/S markets to a plant's profits is crucial to short-term operational objectives as well as to long-term investment plans.

The methodology is based on an ex-post assessment of opportunity cost of a generator seeking to allocate two blocks of capacity. Using historical price data, an analysis was performed to determine the best use of a unit in the energy and ancillary services markets to maximize income. The purpose of this approach is to illustrate that the opportunity to participate in multiple markets offers significant returns to generators if their units are optimally operated in each market. Having done that, a supplier will seek to determine the optimal bidding strategies and unit operations in the future, when prices are not known in advance. A proper analysis of the future prices and unit operations can be performed using UPLAN, an LCG proprietary model, which can find rational expectations Nash equilibria for multiple players, commodities, and markets across space and time.

A/S is a significant source of income for base-load and mid-merit plants, assuming they are correctly bid into these markets (see Summary Table below). Base-load units capable of regulation or spin may earn up to 40% of their income from A/S. Mid-merit units capable of regulation or spin may earn up to three-fourths of their income from A/S. Peaker units capable of ten-minute non-spinning reserve may earn up to 48% of their income from A/S.

Summary Table

Plants		Markets	NYISO	NEISO	ERCOT	CA
Base-load	With Regulation	Energy	63%	95%	88%	28%
		A/S	37%	5%	12%	72%
	No Regulation	Energy	76%	99%	91%	90%
		A/S	24%	1%	9%	10%
Mid-merit	With Regulation	Energy	28%	61%	50%	14%
		A/S	72%	39%	50%	86%
	No Regulation	Energy	47%	75%	50%	73%
		A/S	53%	25%	50%	27%
Peaker (No Regulation)		Energy	52%	79%	53%	53%
		A/S	48%	21%	47%	47%

1. Aim, Rationale, and Scope of the Study

The aim of the study is to calculate the contribution of energy and ancillary services (A/S) to the profits of representative base-load, mid-merit, and peaker plants in the U.S. power system. In a restructured electricity industry, markets govern the operation and expansion of electricity generation, and power plants make money from markets for energy and A/S. Maximum profits are achieved not only through correctly bidding a plant's opportunity cost[1] but also through the optimal allocation of its output between energy and the various A/S, such as regulation up, regulation down, spin, non-spin, and replacement. As a consequence, the shares of energy and A/S to total profits of a power plant are key pieces of information guiding a plant's operations and indicating the expected profitability of potential generator entry.

The restructured markets under study are four of the five U.S. power systems under the control of an independent system operator (ISO): New York, New England, Electric Reliability Council of Texas (ERCOT), and California (The fifth one, excluded in this study, is the Mid-Atlantic system comprising the Pennsylvania-New Jersey-Maryland area, or PJM, which is primarily cost based with operating reserves reimbursed as compensation for being provided. Thus, the ramifications of this study would apply differently to entrants in that market.) Except for ERCOT, the focus is on a historical retrospective for the year 2000, to see how typical units might have operated, given the price outcomes. ERCOT did not have ancillary service prices available until beginning in August 2001, and as such, ERCOT has been studied for September and October 2001.

2. Energy and Ancillary Service Markets in the Restructured U.S. Power Industry

A restructured electricity market is usually composed of forward and spot markets. The forward market may have bilateral contracts, futures, options, day-ahead and hour-ahead energy markets, and in some areas, A/S markets. In the spot (or real-time) market, only energy is traded. A large number of factors affect the behavior of these markets, such as the institutional arrangements of the market, physical features of the grid, environmental restrictions, psychology and expectations, weather, hydrological conditions, load growth, entry, and volatility.[2] Volatility exposes market players to locational basis risk, arising from price differences across geographic regions, as well as to forward/spot basis risk, arising from the difference between the future price and cash value of the underlying commodity. The most fundamental instruments for hedging risk are bilateral contracts and futures. A related strategy is the purchase of options on futures.[3]

Reliability services, such as short- and long-term reserves, have been unbundled into several A/S. Customers of the transmission grid purchase A/S from the market in order to secure the amount and quality of their electricity requirements. Energy and A/S are generally organized into several markets: forward, regulation, operating reserve, replacement reserve, capacity, and balancing. In forward markets, a buyer and seller of energy agree on delivery at a pre-determined price and future time. In the regulation market, a plant under automatic generation control (AGC) is used to maintain balance between load and resources. In the reserve market, energy is delivered within a specified time period, usually ten minutes. Spinning reserves are on-line and synchronized and provide simultaneous frequency and/or voltage support. Non-spinning reserves are not necessarily in operation but must be capable of synchronization and ramping within a specified time period. In the market for replacement reserves, units previously dispatched as operating reserves may be

[1] Defined as the greater of marginal production cost and the expected prices in the different markets to which a plant could sell. See Rajat K. Deb, Pushkar Wagle, & Rafael Emmanuel A. Macatangay, *Generation and Transmission Investments in Restructured Electricity Markets*, Environmental Monitor (forthcoming). Also see Rajat K. Deb, *Analyzing Multiple-Product Power Markets: Simulation of Energy and Ancillary Services Prices and System Adequacy*, EPRI, Palo Alto, and LCG Consulting, Los Altos (2000).
[2] See Rajat K. Deb, Pushkar Wagle, & Rafael Emmanuel A. Macatangay, *Supra* Note 1.
[3] Details are in Rajat K. Deb, *Supra* Note 1.

backed down and form part of replacement, a "slow" reserve product. In the capacity market, a particular portion of operable capacity is made available to provide energy and/or operating reserves. Finally, in the balancing market, a real-time balance between load and resources, and the satisfaction of NERC operating criteria, are achieved.

Revenues from energy and A/S are important components of a generator's financial stability. In maximizing its profits, a power plant has to bid its opportunity cost, and to achieve an optimal allocation of its capacity between energy and A/S. Energy and A/S market clearing prices (MCPs) interact in a variety of ways. For example, payments for A/S reserve capacity are similar to insurance revenues: the seller of A/S is insuring energy users against contingencies in the energy market. Under some circumstances, however, A/S provides little insurance, and the long-run price of A/S reserve capacity is close to zero. One reason for the "limited insurance" is that a dispatched generator receives a high price in the event the contingencies requiring dispatch do indeed occur. In such a situation, the probabilistic revenues from real-time dispatch replace the revenues from capacity sales, and the generator chooses to participate in the energy market, which is the most profitable market it faces.

There are other commercial concerns regarding energy and A/S markets. In view of the small operating costs of providing A/S, the relevant cost of A/S is the revenue foregone from energy sales. Reserves located near loads may earn a higher capacity price than those isolated by transmission constraints. For a hydroelectric plant, A/S may be provided in off-peak hours, but the reservation price for dispatch is the expected energy price in peak hours, in the event generation off-peak reduces available generation at the peak. For a thermal plant, the potential earnings from energy and A/S affect the decision to start the unit. In essence, therefore, energy and A/S are typically substitutes, and the expected earnings from A/S are significant. Indeed both energy and A/S revenues contribute to the recovery of investment. The relative shares of energy and A/S revenues depend on institutional arrangements, payments mechanisms, and volatility.[4]

3. Four U.S. Control Areas

The four ISOs under study are New York (NYISO), New England (NEISO), California (CAISO), and ERCOT. NEISO and NYISO exercise tight control over location dispatch but have markets for A/S. CAISO has an auction for real-time energy and, prior to the closure of the Power Exchange (PX), used to have one for A/S. ERCOT, which began to report A/S prices only in September 2001, is the residual manager of bilateral contracts arranged among market players. A discussion of each of the four ISOs, including the representative plants employed in the revenue contribution analysis involving energy and A/S follows in the next four sub-sections.

New York

The NYISO operates day-ahead, hour-ahead, and real-time energy markets as well as multiple ancillary service markets. Energy market participants may submit bids on a day-ahead and/or hour-ahead basis for generation, load, and bilateral transactions. During day-ahead processing, the NYISO uses day-ahead capacity bids and seven-day load forecasts to designate

[4] *Ibid.*

which generators will be available for dispatch the following day. The ISO also establishes locational-based marginal energy prices (LBMPs) and schedules a variety of ancillary services. Ancillary services in the NY control area include, but are not limited to, regulation (REG), ten minute spinning reserve (TMSR), ten-minute non-synchronized reserve (TMNSR), and 30-minute reserve (30M RES). Ancillary services for the 11 zones within the NY control area are purchased through the NYISO (*i.e.* single price for each service) and are used to maintain reliable operation of the NY power system. Following the close of the day-ahead market, the ISO uses hour-ahead capacity bids to meet changing loads and to respond to generation and transmission outages. This new set of LBMPs is applied to transactions in the real-time energy market. The NYISO guarantees coverage of start-up and minimum-run costs for dispatched generators; generators that provide operating reserves and whose energy bids are below the relevant LBMP receive an opportunity cost payment.

Analyses were carried out on three plants located in the Hudson Valley load zone: a 234 MW coal-fired base-load unit, a 610 MW natural gas-fired mid-merit unit (*i.e.* steam turbine), and a 40 MW natural gas-fired peaking unit (*i.e.* combustion turbine). The units became operational in 1967, 1972, and 1993, respectively.

New England

NEISO uses locational pricing for energy. Its A/S markets are AGC, ten-minute spinning reserve, ten-minute non-spinning reserve, and thirty-minute operating reserve. A participant sells into the energy market the amount unused by its native load. In order to mitigate market power, a player has to bid any capacity that is not self-scheduled for meeting native load or sold through a bilateral transaction. Every five minutes, NEISO calculates an energy MCP equal to the cheapest MW supply increment that was not called for dispatch. The price to sellers is the weighted average, over an hour, of the five-minute MCPs.

An analysis of energy and A/S market net income was performed on three thermal plants in Massachusetts: a 255 MW coal-fired base-load unit, a 380 MW gas-fired mid-merit unit (i.e. steam turbine), and a 270 MW gas-fired peaking plant (i.e. combustion turbine).

California

The two key institutions in California's wholesale power market are the Power Exchange (PX) and the ISO. The PX, which closed on 31st January 2001, administers the forward energy markets. It was a scheduling coordinator (SC), one of the many certified by the ISO. It used to be responsible for sending preferred schedules and adjustment bids to the ISO that, in turn, calculates zonal market clearing prices (MCPs) and uses them in congestion management and settlements. The ISO is responsible for overall grid security. It manages ancillary services through market operations as well as through contracts, such as reliability must-run (RMR) contracts. It also oversees the real-time imbalance energy market as well as transmission congestion protocols involving the minimization of redispatch costs calculated from "inc" and "dec" generator bids. The CAISO territory is divided in three zones: north, south, and central, corresponding to three hourly zonal MCPs for energy and A/S.

The three plants selected for this control area are all natural gas-fired. They include a 739 MW base-load unit, a 338 MW mid-merit unit, and a 53 MW peaking unit with operational dates of

1968, 1963, and 1986, respectively. The base-load and peaking plants are located in northern CA and the mid-merit plant is located in central CA.

ERCOT

ERCOT has relied on bilateral contracts that must be backed up by adequate operating reserves (*i.e.* firm) and supported by transmission capacity (*i.e.* feasible). However, ERCOT began reporting A/S prices beginning in August 2001. Previously, the task of energy dispatch was left to control area operators. ERCOT made sure that submitted schedules are feasible and have sufficient operating reserves meeting ERCOT reliability standards. The energy and A/S markets to be controlled by ERCOT are now under development and are expected to be fully in place by January 2002. The review of how suppliers might have operated in the markets was done for September and October 2001 based on recorded prices.

Three units were selected for this analysis: a 555 MW coal-fired base-load plant, a 390 MW natural gas-fired mid-merit plant, and an 80 MW natural gas-fired CT peaking plant.

4. Methodology

The methodology is based on an assessment of opportunity cost and rational expectations decision-making in restructured power markets in the U.S. We used publicly available ISO energy and A/S market MCPs for the year 2000 to conduct an ex-post analysis of the contributions of energy and A/S net income to total net income. Using hourly MCPs in conjunction with unit specific data such as heat rate, fuel costs, and variable O&M costs, we can estimate the optimum allocation of capacity between energy and A/S markets.

For the base-load and mid-merit units, we consider two scenarios. In the first scenario, the units can participate in the energy market and either the regulation or ten minute spinning reserve A/S markets. In the second, units can participate in the energy and ten minute spinning reserve A/S markets (i.e. no AGC equipment installed). For the peaking unit, we consider a single scenario in which the unit can participate in the energy market and either the ten-minute non-synchronized reserve or thirty-minute reserve A/S markets. The net income from each market is calculated using the set of decision rules outlined below.

A generator has to allocate two blocks of capacity, Block 1 with marginal cost MC_{min}, and Block 2, MC_{max}, to two markets, energy and A/S, whose market clearing prices MCP_e and $MCP_{A/S}$ are known. MCP_e is typically greater than $MCP_{A/S}$. There are two general cases, and two sub-cases under each.

- If $MC_{\min} < MCP_e$ (see Figure 1), then run Block 1 in the energy market, and assess:
    - If $(MCP_e - MC_{\max}) > (MCP_{A/S})$, then run Block 2 in the energy market. This condition simplifies to $(MCP_e - MCP_{A/S}) > (MC_{\max})$. Running both blocks in the energy market brings the most profit.

- If $(MCP_e - MC_{\max}) < (MCP_{A/S})$, then run Block 2 in the A/S market. This condition simplifies to $(MCP_e - MCP_{A/S}) < (MC_{\max})$. Running Block 2 in the A/S market brings more profit than running it in the energy market.

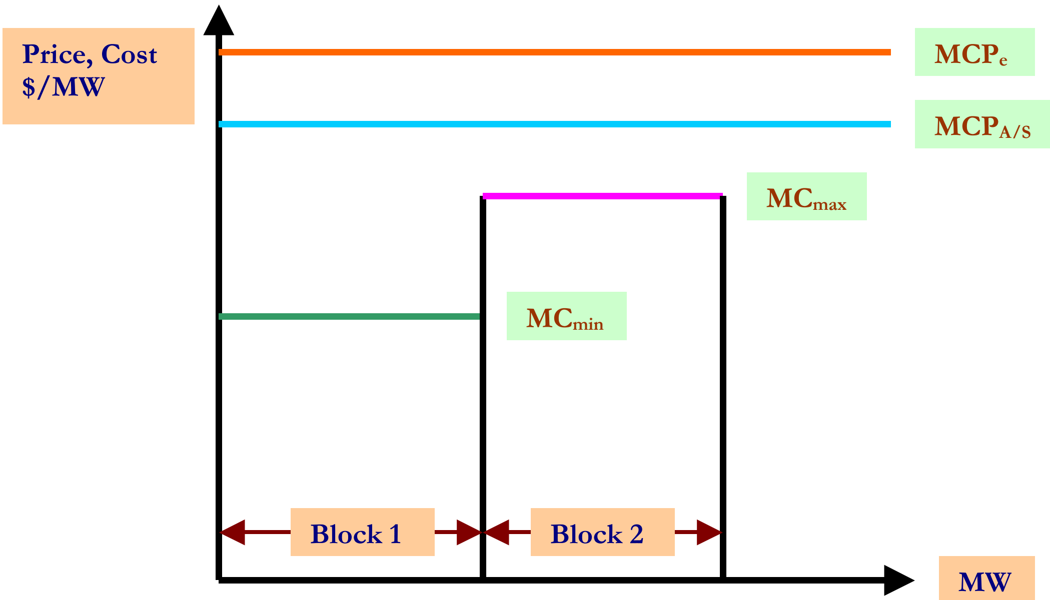

Figure 1. MC of Block 1 is Below Energy MCP

➢ If, however, $MC_{\min} > MCP_e$ (see Figure 2), then assess: If $(MCP_{A/S}) * (Block2) > (MC_{\min} - MCP_e) * (Block1)$, then run Block 1 in the energy market and Block 2 in the A/S market. The loss in running Block 1 in the energy market is more than offset by the gain in running Block 2 in the A/S market.

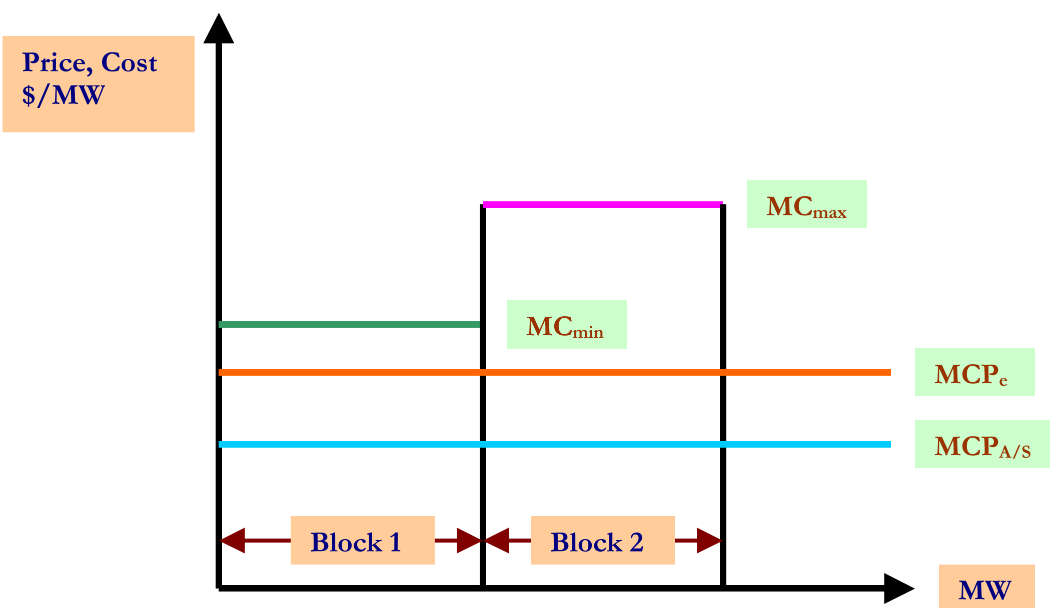

Figure 2. MC of Block 1 is Above Energy MCP

The methodology is illustrative and inevitably has a number of limitations. First, the plant's decision to allocate capacity is based solely on a static evaluation of known MCPs. A complete assessment, however, involves a simulation of the dynamic and iterative processes involved in multi-commodity, multi-player games. A bid in one market reflects the opportunity cost of that in another. In the presence of many players, the solution to the game is found through an iteration of best-response functions for each player across all markets. All arbitrage opportunities are exhausted. UPLAN, our proprietary engineering economy model of the U.S. power system, is capable of modeling the multi-commodity, multi-player games played in power markets.

The second limitation of the methodology is that fundamental drivers of the market are not represented. A proper analysis, however, has to account for the fundamental factors driving market outcomes. In UPLAN, each player is modeled to understand the key factors underlying the different spatial and temporal markets in restructured power markets (see Figure 3). The resulting Nash equilibrium is therefore generated through rational expectations. The third, but by no means final, limitation is that transmission constraints are ignored. However, a rigorous representation of the grid is needed for a proper evaluation of imports, a prime determinant of the intensity of competition in, and thus the profitability of, a geographic market.

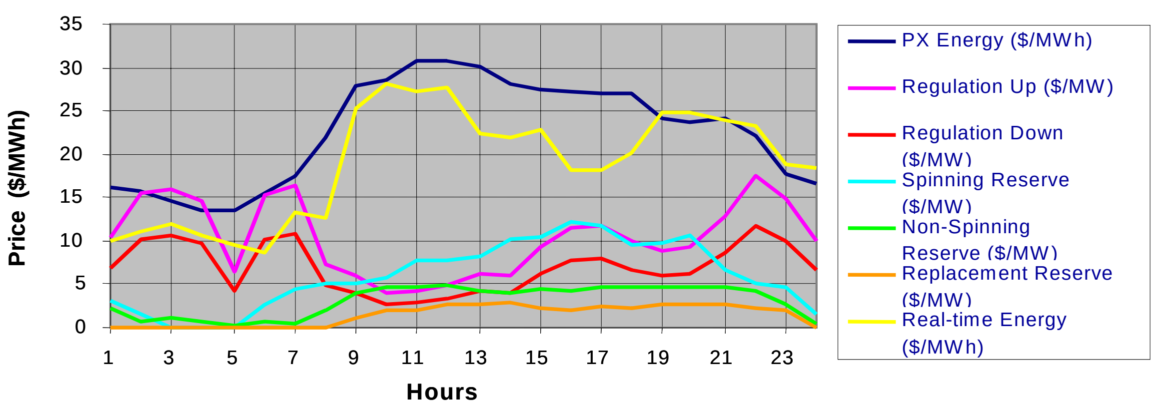

Figure 3. Energy and A/S MCPs Generated by a UPLAN Simulation

In short, in a restructured electricity industry, the market realities are exceedingly complex, and price is determined by a confluence of a large number of different events and factors.[5] Supply and demand are just one set of factors. All possible market design loopholes and legal inconsistencies are exploited for profit. The status-quo pattern of transmission constraints is usually beneficial to some generation and transmission owners but detrimental to others. Any proposed alteration of the network implies a redistribution of rents, a change in bidding strategies, and, depending on the location of the players, a realignment of alliances. The potential for earning capacity payments in the ancillary service markets, as in California, is a powerful incentive to withdraw capacity from the energy market, in which payments are purely on energy. Expectations of drought and unfavorable changes in weather patterns increase the scarcity value of water and worsen any strategic behavior exercised by the hydro unit. Thus, many interacting factors are at work, and any market analysis of generator operation and investment quickly becomes intractable.

[5] See Rajat K. Deb, Pushkar Wagle, and Rafael Emmanuel A. Macatangay, *Supra* Note 1.

5. Results

NYISO

Table 1 shows the contributions of energy and A/S net income to total monthly unit net income for the year 2000. In some instances, units loose money in the energy market, and this is shown as negative values in Table 1. For the base-load plant capable of providing regulation (REG) or ten minute spinning reserve (TMSR), A/S net income is significantly larger than energy net income from January through April (see Table 1 and Figure 4). Beginning in May, this pattern reverses, with energy income becoming an increasingly dominant fraction of total net income. A similar pattern can be observed for the base-load plant capable of TMSR only (see Figure 5). Not surprisingly, energy income is an even larger fraction of total net income when the base-load unit is unable to participate in the regulation market. The mid-merit plant shows a somewhat different monthly income pattern. For the mid-merit plant capable of providing REG or TMSR, A/S income is much larger than energy income from January through May, but shows no consistent pattern thereafter (see Figure 6). As is the case with the base-load unit, when the mid-merit plant is unable to provide REG, a larger fraction of total net income comes from the energy market (see Figure 7). For the peaking unit capable of providing either ten minute non-synchronized (TMNSR) or 30 minute (30M RES) reserves, the pattern is somewhat similar to what is observed for the base-load unit, with A/S income dominating energy income early in the year, and energy income dominating A/S income from April through December (see Figure 8). In relative and absolute terms, A/S income for all units tends to be greatest from January through March, reflecting the seasonal peak in A/S market prices (see Figure 9).

Examining the contributions of energy and A/S income to annual net income is also quite interesting. Energy market net income accounts for 76% of total revenue for the base-load unit without REG, 63% for the base-load unit with REG, 52% for the peaking unit, 47% for the mid-merit unit without REG, and 28% for the mid-merit unit with REG. Despite a higher heat rate, the base-load unit's marginal production cost is low because it burns coal, a relatively inexpensive fuel. It would thus be expected to be a more frequent participant in the energy market. The mid-merit unit burns natural gas and thus has a higher production cost. As marginal cost approaches the MCP for energy, energy revenue falls, and participation in A/S markets becomes a more attractive option. For base-load and mid-merit units that cannot participate in the REG market, a larger fraction of total revenue will come from the energy market because the MCP for TMSR is typically much lower than the MCP for REG. Interestingly, the peaking unit obtains a greater share of its annual revenue from the energy market than does the mid-merit unit. This may occur for two reasons. First, although the natural gas-fired peaking plant also has high fuel costs, it has a significantly lower heat rate. Its production costs are thus intermediate between the base-load and mid-merit unit production costs. Second, and perhaps more importantly, the peaking unit can only participate in the TMNSR and 30M RES A/S markets, both of which tend to yield low premiums.

Table 1. Percentage Contributions of Energy and Ancillary Services for Selected Plants in NYISO

	Coal-fired Unit with AGC		Coal-fired Unit w/o AGC		Natural Gas-fired Unit with AGC		Natural Gas-fired without AGC		Natural Gas-fired Combustion Turbine	
	REG/TMSR		TMSR Only		REG/TMSR		TMSR Only		TMNSR/30M Reserve	
Month	Energy %	A/S %	Energy %	A/S %	Energy %	A/S %	Energy %	A/S %	Energy %	A/S %
JAN	17.1	82.9	47.2	52.8	13.4	86.6	30.1	69.9	48.4	51.6
FEB	5.3	94.7	5.4	94.6	1.4	98.6	1.5	98.5	0.0	100.0
MAR	6.4	93.6	14.2	85.8	-1.5	101.5	-0.5	100.5	4.5	95.5
APR	29.4	70.6	89.4	10.6	-4.5	104.5	31.4	68.6	81.2	18.8
MAY	67.4	32.6	96.2	3.8	38.9	61.1	90.2	9.8	93.3	6.7
JUN	90.4	9.6	99.6	0.4	76.3	23.7	98.1	1.9	99.0	1.0
JUL	82.0	18.0	98.7	1.3	30.5	69.5	83.3	16.7	92.6	7.4
AUG	93.6	6.4	99.1	0.9	82.6	17.4	96.8	3.2	97.6	2.4
SEP	91.3	8.7	98.6	1.4	21.3	78.7	59.7	40.3	92.1	7.9
OCT	96.9	3.1	99.1	0.9	-3.8	103.8	16.5	83.5	90.6	9.4
NOV	96.4	3.6	99.8	0.2	58.1	41.9	88.6	11.4	94.9	5.1
DEC	98.3	1.7	100.0	0.0	NA	NA	NA	NA	81.9	18.1
Annual	63.0	37.0	76.2	23.8	27.6	72.4	46.6	53.4	52.1	47.9

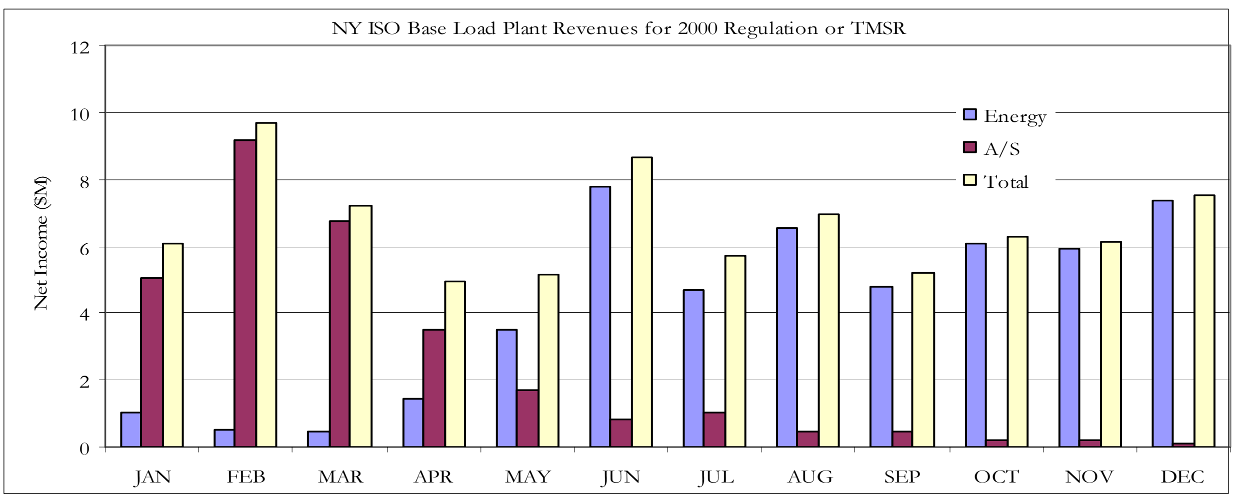

Figure 4. NYISO Coal-fired Plant with AGC: Simulated Net Income

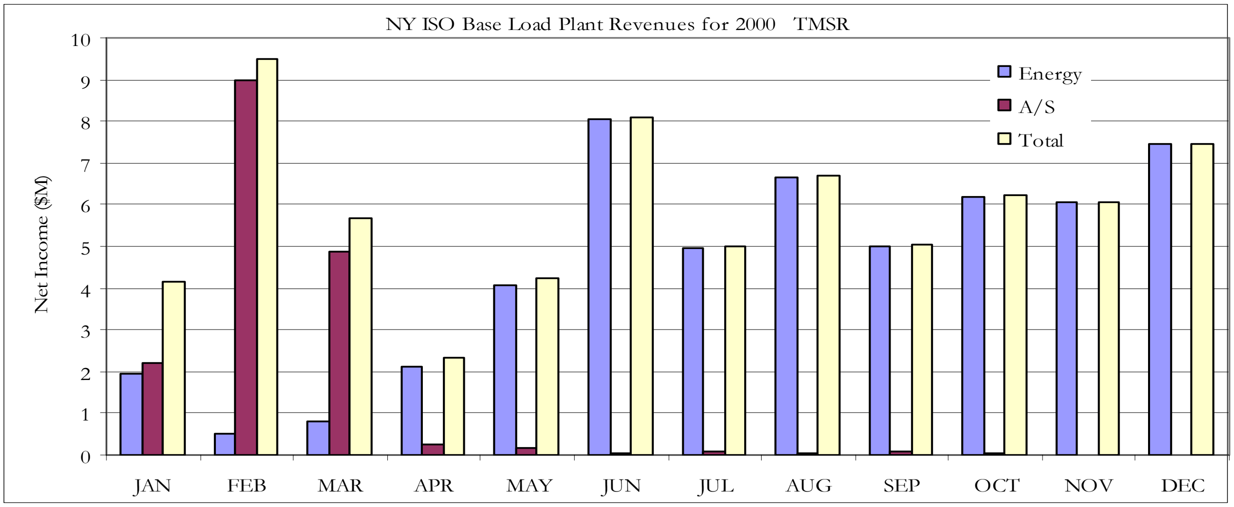

Figure 5. NYISO Coal-fired Plant without AGC: Simulated Net Income

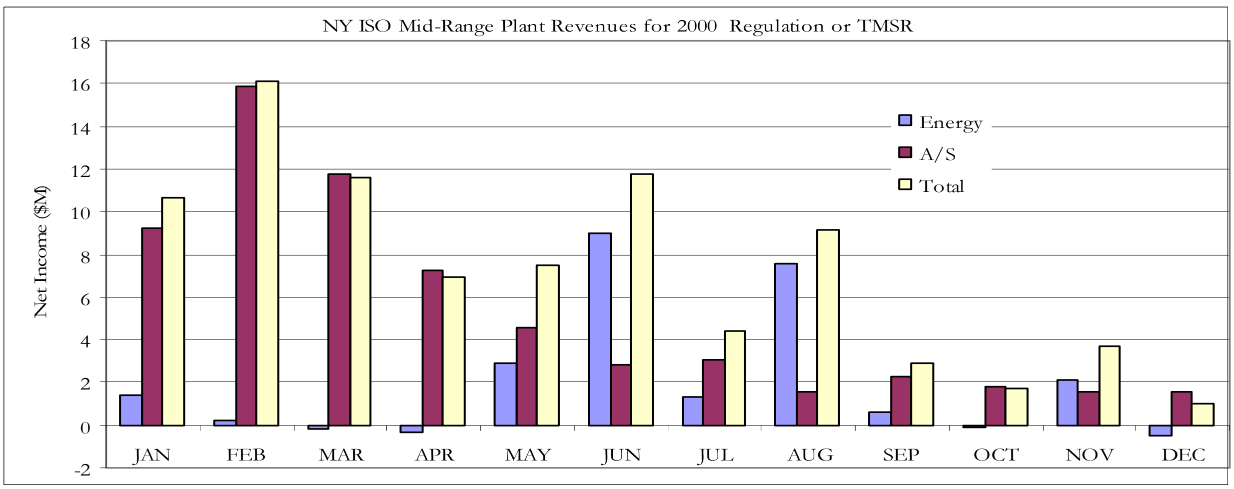

Figure 6. NYISO Natural Gas-fired Plant with AGC: Simulated Net Income

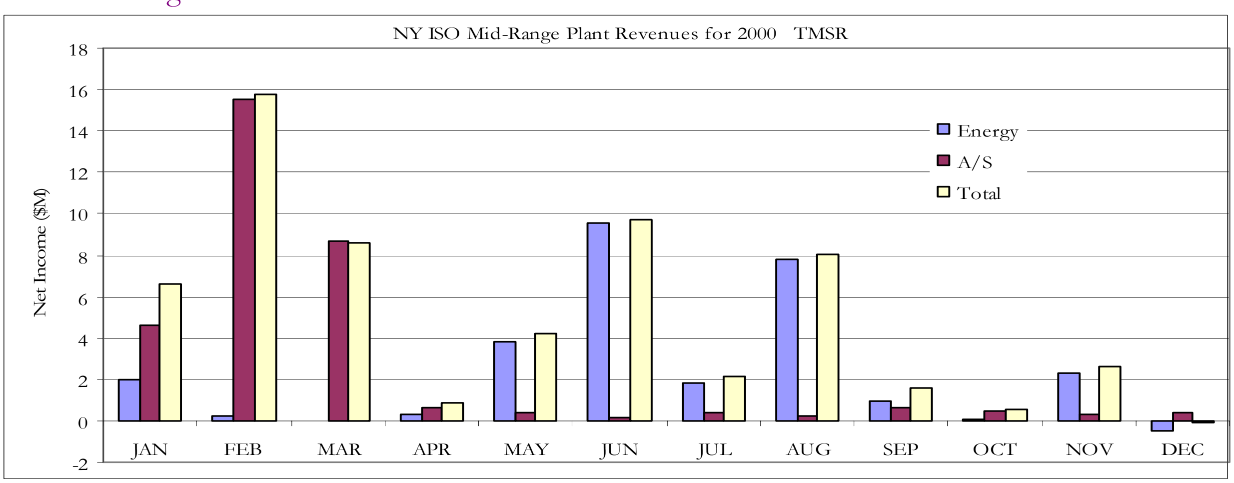

Figure 7. NYISO Natural Gas-fired Plant without AGC: Simulated Net Income

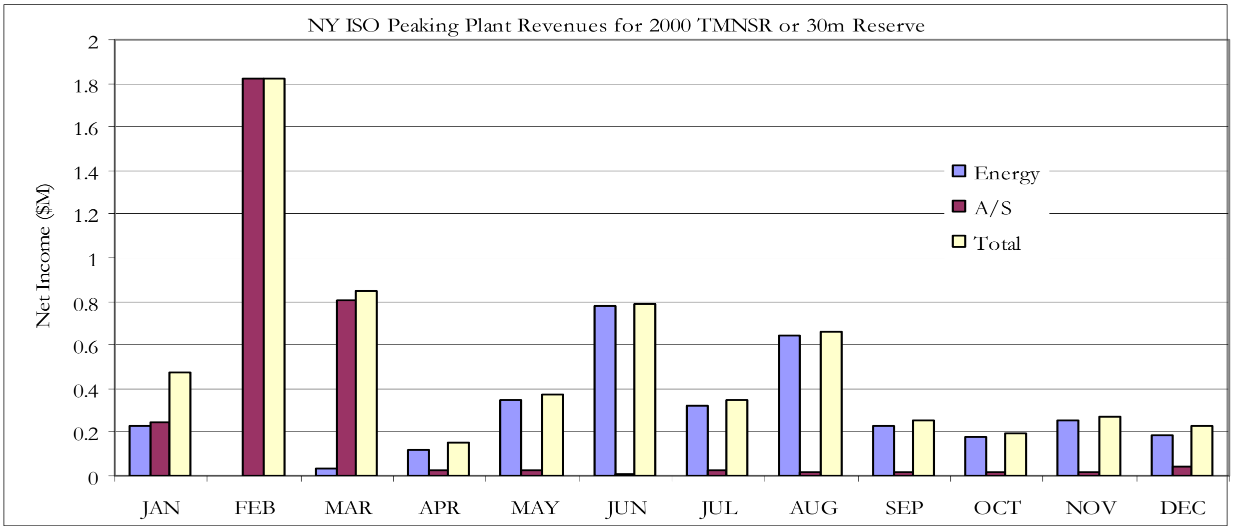

Figure 8. NYISO Natural Gas-fired Combustion Turbine: Simulated Net Income

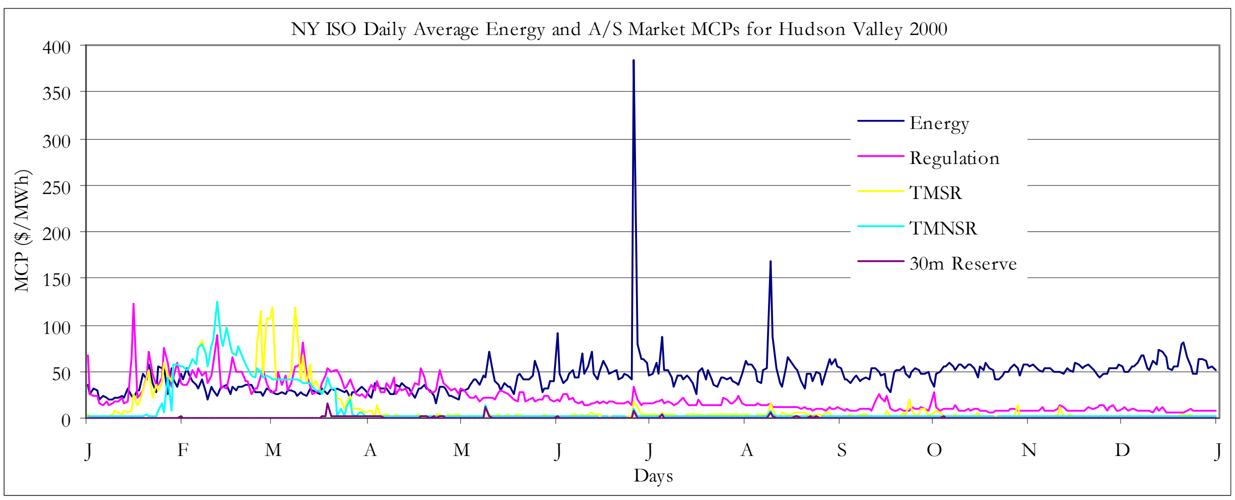

Figure 9. NYISO Daily Average Energy and A/S Market-Clearing Prices

NEISO

The base-loaded coal plant has low variable operating costs, and thus is more competitive than the marginal plants and can earn significant profits in peak hours. Ancillary services nonetheless contribute to its profits (see Table 2 and Figures 10 and 11). In April, this particular base load, if capable of regulation, can earn nearly half of the month's revenues by offering this ancillary service. If the plant is not capable of regulation, its earnings from ancillary services (spinning reserves are the best alternative to regulation) are somewhat lower in all months.

The mid-merit plant had distinctly different results in terms of its energy revenue, relative to the baseloaded plant (see also Table 2 and Figures 12 and 13). Due to its fuel costs from natural gas, and its mediocre efficiency, its energy revenues were much lower than those of the baseloaded plant. Note that in some months, the percentages concerning the mid-merit plant show 100% contribution from A/S, and 0% from energy. This indicates that while revenue was earned from energy, net income from providing the energy was negative. In eight months, its net revenue from energy was found to be negative, while May produced more revenue from energy than all other months combined. Assuming that it was capable of regulation, this plant could earn revenue from ancillary services to offset its poor performance in the energy market. In fact, even if energy revenues from the month of May were excluded, ancillary service earnings would allow the plant to earn a profit. Regulation would produce greater net revenue than spinning reserves.

The peaking plant would be expected to earn most of its revenues from energy in peak hours, regardless of whether it sold ancillary services (see again Table 2 and Figure 14). Thus, it would have a low capacity factor to begin with. The analysis performed showed that in most hours, the ancillary service market for non-spinning reserve or operating reserves would be more profitable than the energy market. Thus, the peaking plant would be expected to earn the highest percentage of its revenues from ancillary services. The analysis showed that twenty percent of revenue could be earned in the ancillary service markets.

Table 2. Percentage Contributions of Energy and Ancillary Services for Selected Plants in NEISO

Month	Coal-fired Unit with AGC		Coal-fired Unit w/o AGC		Natural Gas-fired Unit with AGC		Natural Gas-fired Unit w/o AGC		Natural Gas-fired Combustion Turbine	
	REG/TMSR		TMSR Only		REG/TMSR		TMSR Only		TMNSR/30M Reserve	
	Energy %	A/S %	Energy %	A/S %	Energy %	A/S %	Energy %	A/S %	Energy %	A/S %
JAN	95.3	4.7	96.7	3.3	90.3	9.7	91.6	8.4	86.8	13.2
FEB	97.5	2.5	99.7	0.3	0.0	100.0	0.0	100.0	68.2	31.8
MAR	82.7	17.3	92.0	8.0	0.0	100.0	0.0	100.0	44.3	55.7
APR	55.9	44.1	58.4	41.6	0.0	100.0	0.0	100.0	12.8	87.2
MAY	94.3	5.7	95.1	4.9	96.4	3.6	93.6	6.4	91.0	9.0
JUN	91.6	8.4	92.9	7.1	0.0	100.0	0.0	100.0	44.3	55.7
JUL	97.1	2.9	99.9	0.1	0.0	100.0	0.0	100.0	80.3	19.7
AUG	98.2	1.8	100.0	0.0	66.2	33.8	97.1	2.9	97.2	2.8
SEP	98.8	1.2	99.8	0.2	0.0	100.0	0.0	100.0	91.5	8.5
OCT	99.7	0.3	100.0	0.0	0.0	100.0	0.0	100.0	90.3	9.7
NOV	99.9	0.1	100.0	0.0	11.3	88.7	92.8	7.2	95.9	4.1
DEC	99.2	0.8	99.4	0.6	0.0	100.0	0.0	100.0	87.3	12.7
Annual	95.1	4.9	99.5	0.5	61.1	38.9	74.6	25.4	79.3	20.7

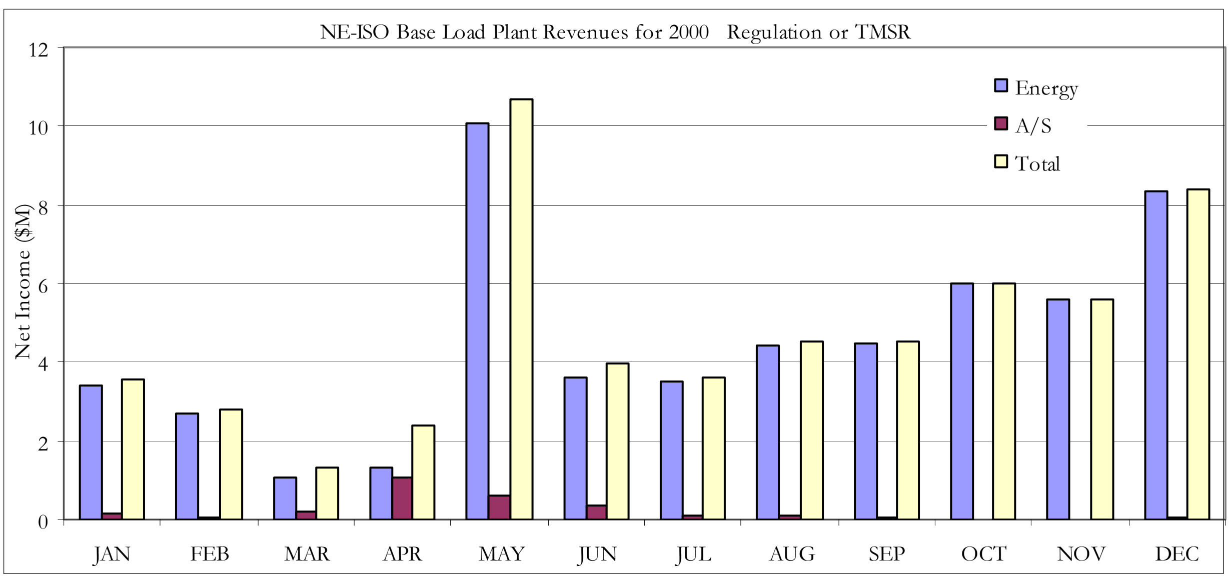

Figure 10. NEISO Coal-fired Plant with AGC: Simulated Net Income

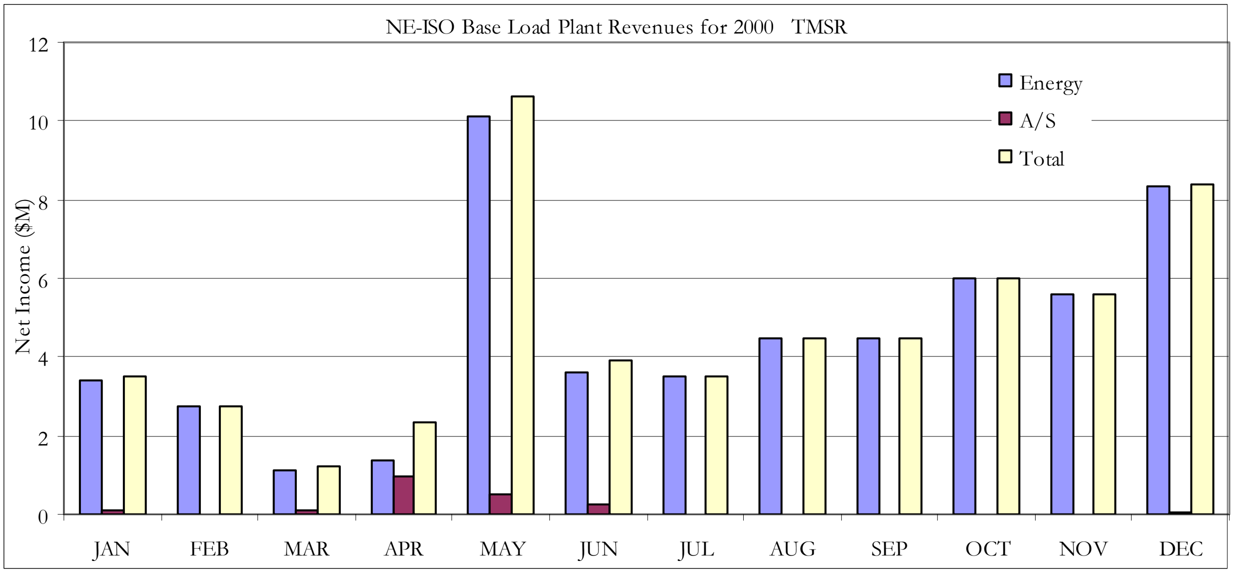

Figure 11. NEISO Coal-fired Plant without AGC: Simulated Net Income

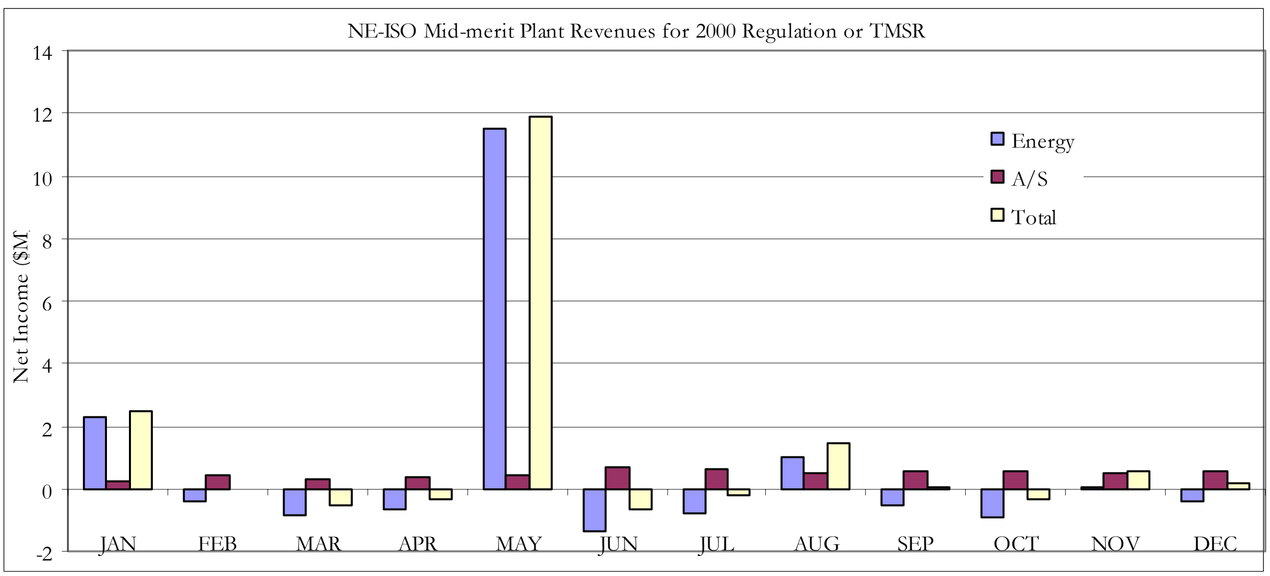

Figure 12. Natural Gas-fired Plant with AGC: Simulated Net Income

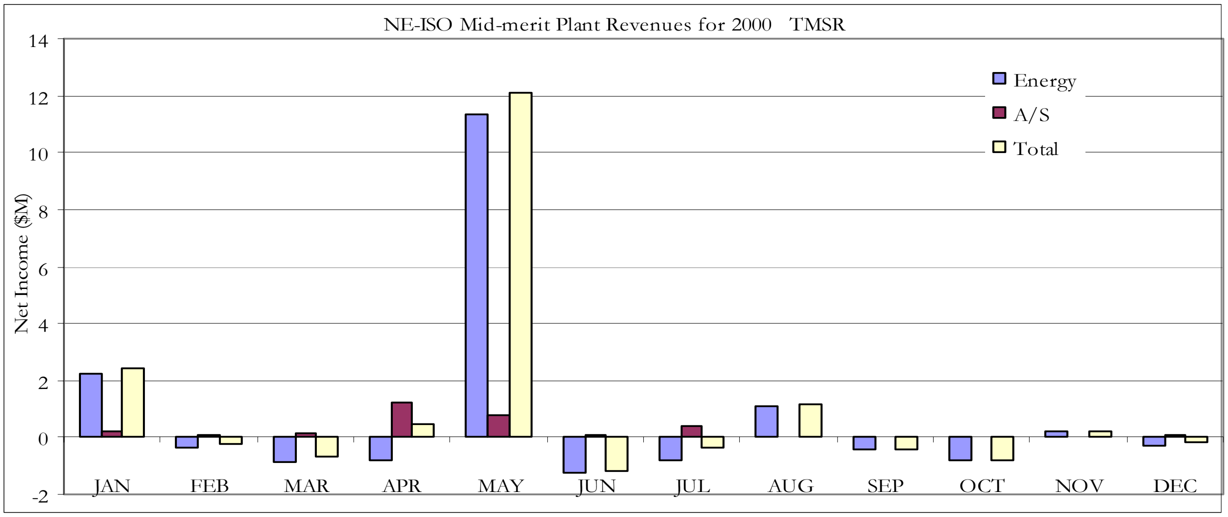

Figure 13. Natural Gas-fired Plant without AGC: Simulated Net Income

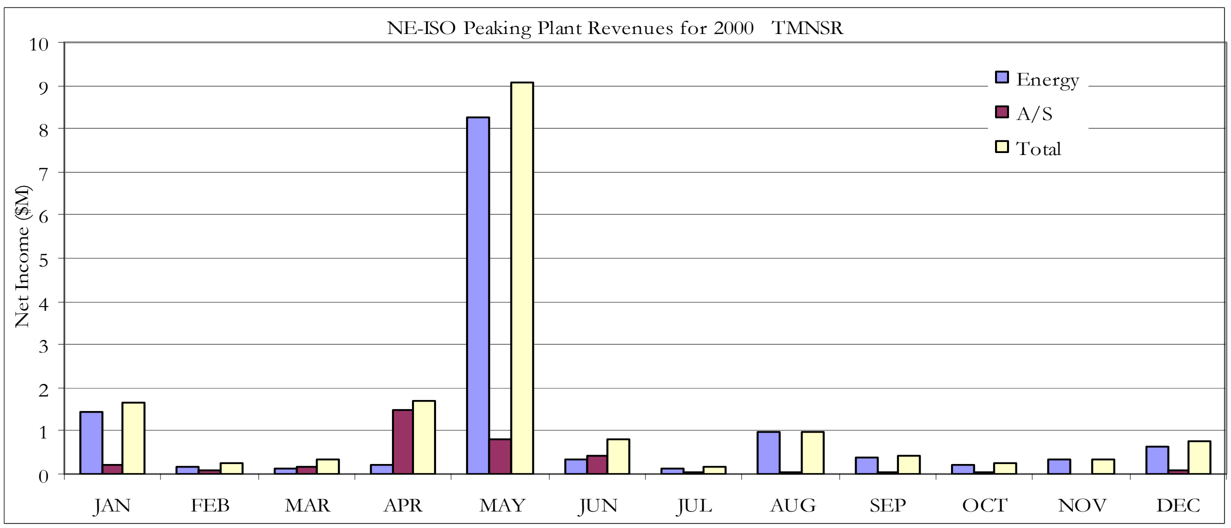

Figure 14. Natural Gas-fired Combustion Turbine: Simulated Net Income

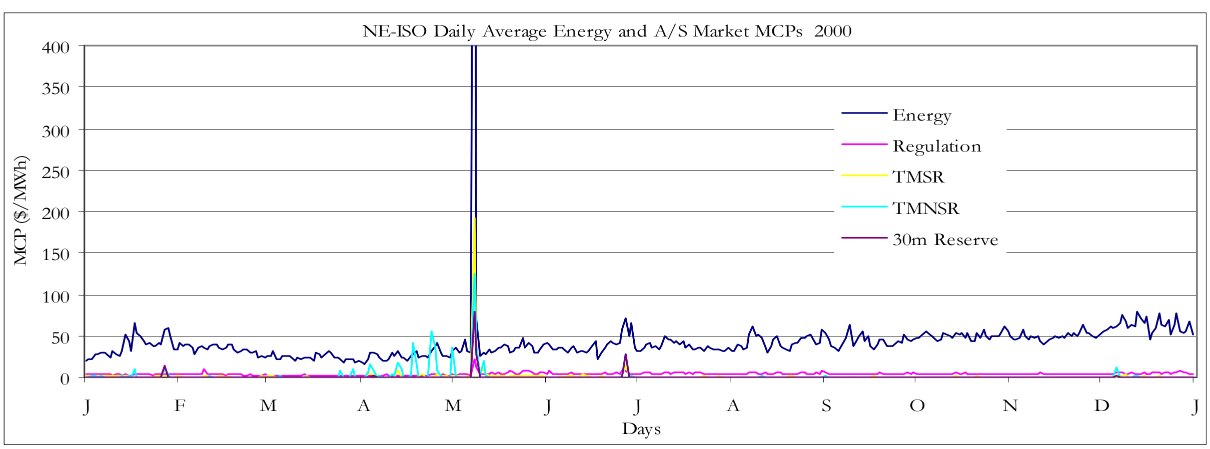

Figure 15. NEISO Daily Average Energy and A/S Market Market-Clearing Prices

CAISO

For base-load and mid-merit plants in CA, the capability for regulation is a prime source of profit (see Table 3) (In some instances, the percentage for energy is negative, reflecting the situation that the net income from energy is negative. Note that as with New England results, in some months, the percentages show 100% contribution from A/S, and 0% from energy. Again, while revenue was earned from energy, net income from providing the energy was negative.). In most months, assuming the plant can provide regulation, A/S has a much larger contribution to profits than energy. On an annual basis, the share of A/S is 72% for base-load and 86% for mid-merit. Without regulation, however, energy is the dominant source of profit. On an annual basis, the share of A/S is 10% for base-load and 27% for mid-merit. By contrast, the bulk of profits of a peaker plant come from energy (see also Table 3). From February to June, most profits are from replacement, but in January and from July to November, most profits are from energy. Non-spin provides 59% of profits in December. On an annual basis, the share of energy is 53%, non-spin, 33%, and replacement, 14%.

As in the other ISO areas, the conclusions on the percentage shares have to be combined with an assessment of the levels (see Figures 16 to 22). Movements in levels are uncorrelated to those in MCPs. For example, for a base-load plant capable of regulation, A/S has a share of 85% in July, and its average value is $30.29M. In December, its share is down to 57%, but its value is $57.53M (see Figure 16), even though A/S prices are not noticeably different between July and December (see Figure 18).

Table 3. Percentage Contributions of Energy and Ancillary Service for Selected Plants in California

	Base-load				Mid-merit				Peaking		
	Coal-fired Unit with AGC		Coal-fired Unit without AGC		Natural gas-fired Unit with AGC		Natural gas-fired Unit without AGC		Natural gas-fired Combustion Turbine without AGC		
Month	**Energy**	**A/S**	**Energy**	**A/S**	**Energy**	**A/S**	**Energy**	**A/S**	**Energy**	**NonSpin**	**Replace**
Jan	48%	52%	0%	100%	36%	64%	0%	100%	79%	10%	11%
Feb	30%	70%	95%	5%	13%	87%	90%	10%	1%	39%	60%
Mar	0%	100%	0%	100%	-13%	113%	0%	100%	2%	47%	50%
Apr	-27%	127%	44%	56%	-33%	133%	46%	54%	0%	7%	93%
May	13%	87%	86%	14%	15%	85%	16%	84%	37%	17%	45%
Jun	28%	72%	0%	100%	12%	88%	77%	23%	33%	23%	44%
Jul	15%	85%	25%	75%	8%	92%	0%	100%	64%	26%	10%
Aug	32%	68%	84%	16%	24%	76%	80%	20%	66%	30%	4%
Sep	12%	88%	51%	49%	9%	91%	81%	19%	63%	27%	10%
Oct	55%	45%	97%	3%	26%	74%	48%	52%	76%	22%	3%
Nov	82%	18%	96%	4%	56%	44%	0%	100%	91%	8%	1%
Dec	43%	57%	56%	44%	11%	89%	12%	88%	33%	59%	8%
Average	28%	72%	90%	10%	14%	86%	73%	27%	53%	33%	14%

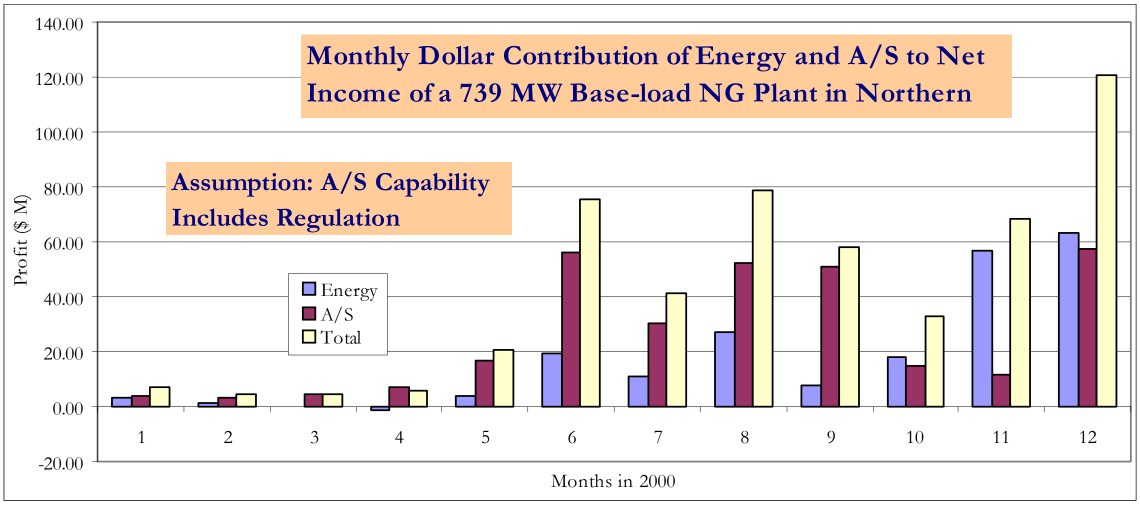

Figure 16. Northern California Coal-fired Plant with AGC: Simulated Net Income

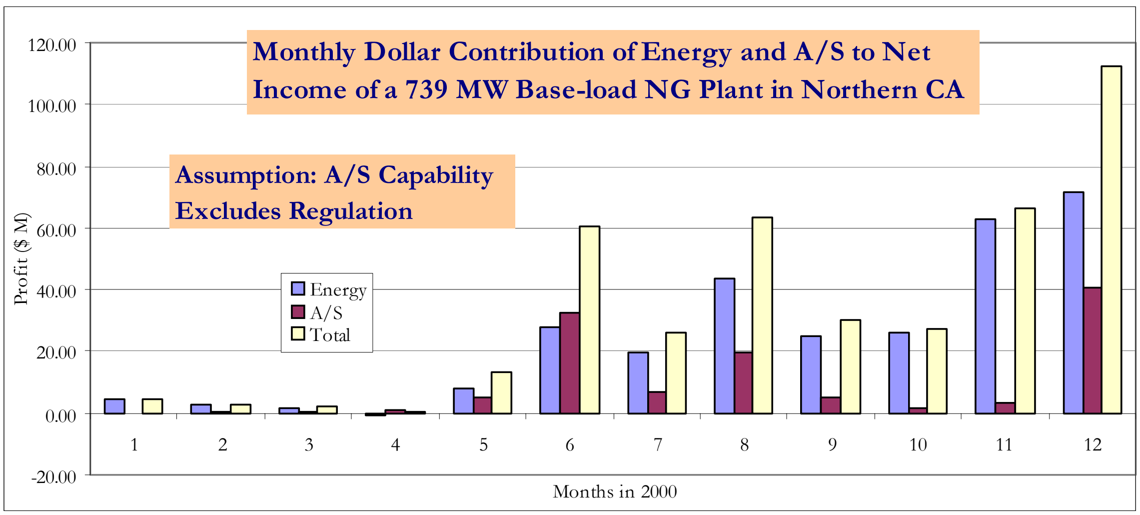

Figure 17. Northern California Coal-fired Plant without AGC: Simulated Net Income

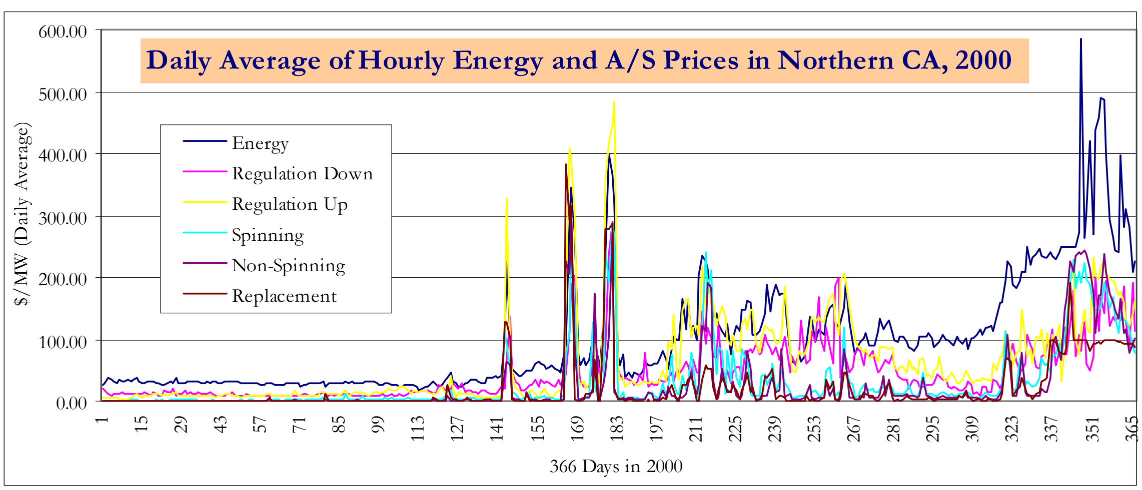

Figure 18. Northern California Energy and Ancillary Services Market Clearing Prices

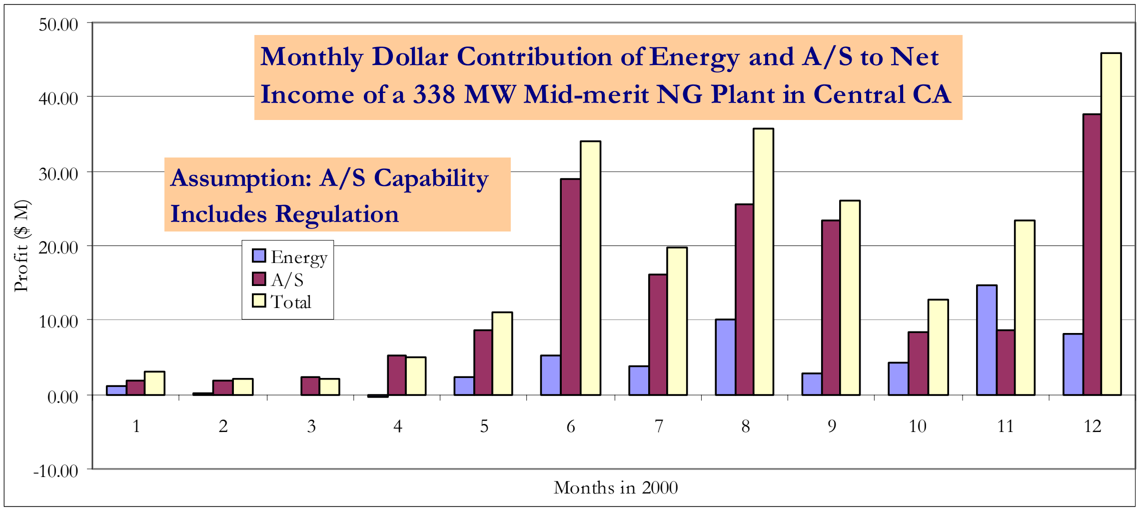

Figure 19. Central California Gas-fired Plant with AGC: Simulated Net Income

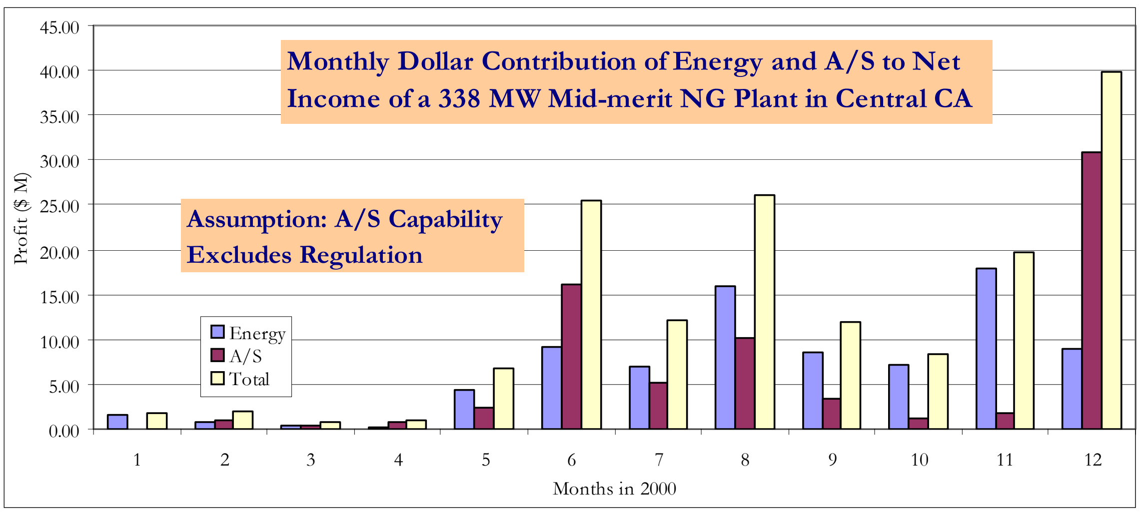

Figure 20. Central California Gas-fired Plant without AGC: Simulated Net Income

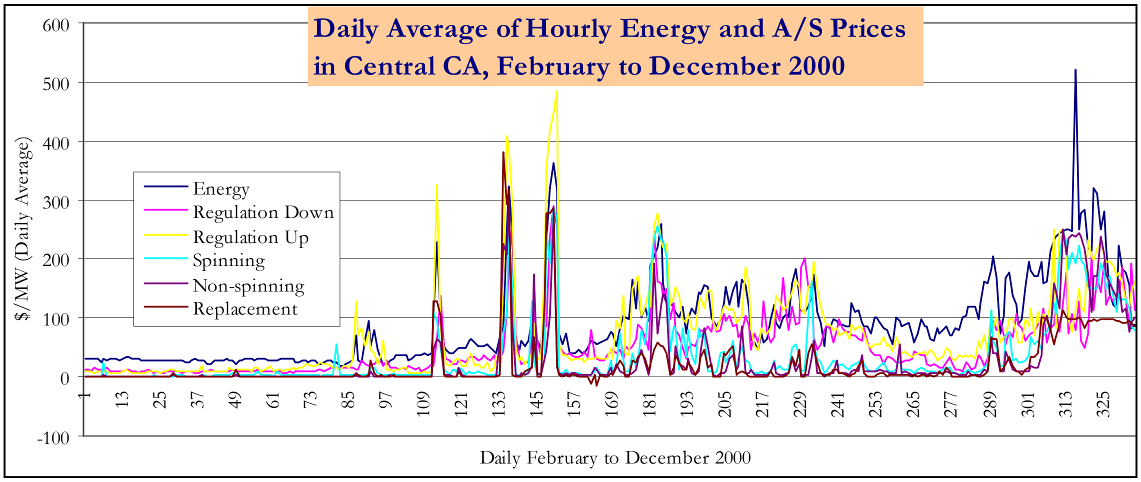

Figure 21. Central California Energy and Ancillary Services Market-Clearing Prices

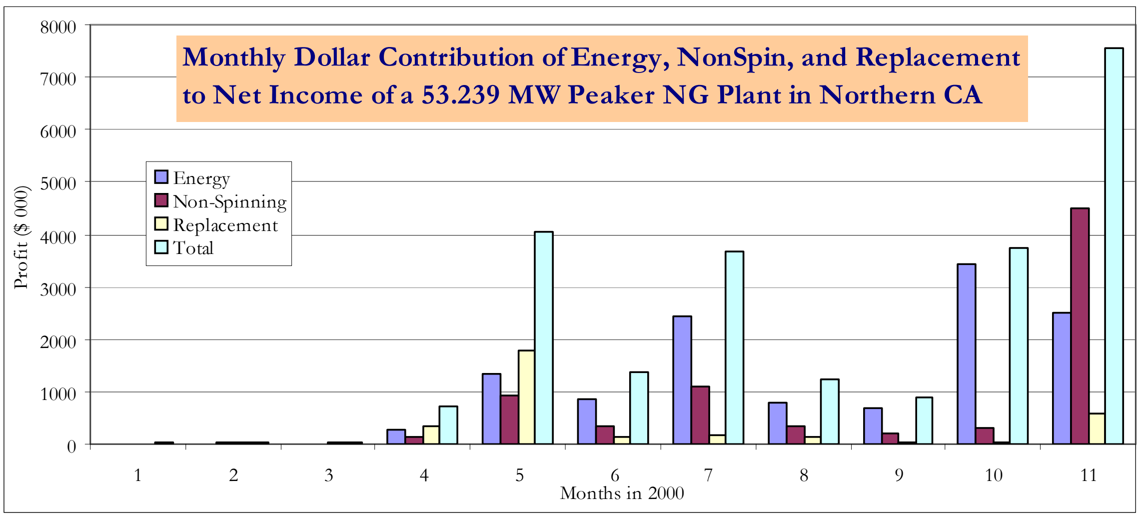

Figure 22. Northern California Gas-fired Combustion Turbine: Simulated Net Income

ERCOT

A/S markets are most important for mid-merit and peaker plants in ERCOT (see Table 4). A base-load unit earns only up to 20% of income from A/S. However, a mid-merit plant and a peaker earn up to half of their income from A/S. In September, for example, the mid-merit plant earns 49% from A/S, the peaker, 67%. Apart from a few spikes, energy and A/S prices were fairly stable over the sample period covering September to October 2000 (see Figures 23 and 24).

Table 4. Percentage Contributions of Energy and Ancillary Services for Selected Plants in ERCOT

Month	Base		Mid		Peak	
	Energy	A/S	Energy	A/S	Energy	A/S
September	83%	17%	51%	49%	33%	67%
October	90%	10%	49%	51%	100%	0%
Total	88%	12%	50%	50%	53%	47%

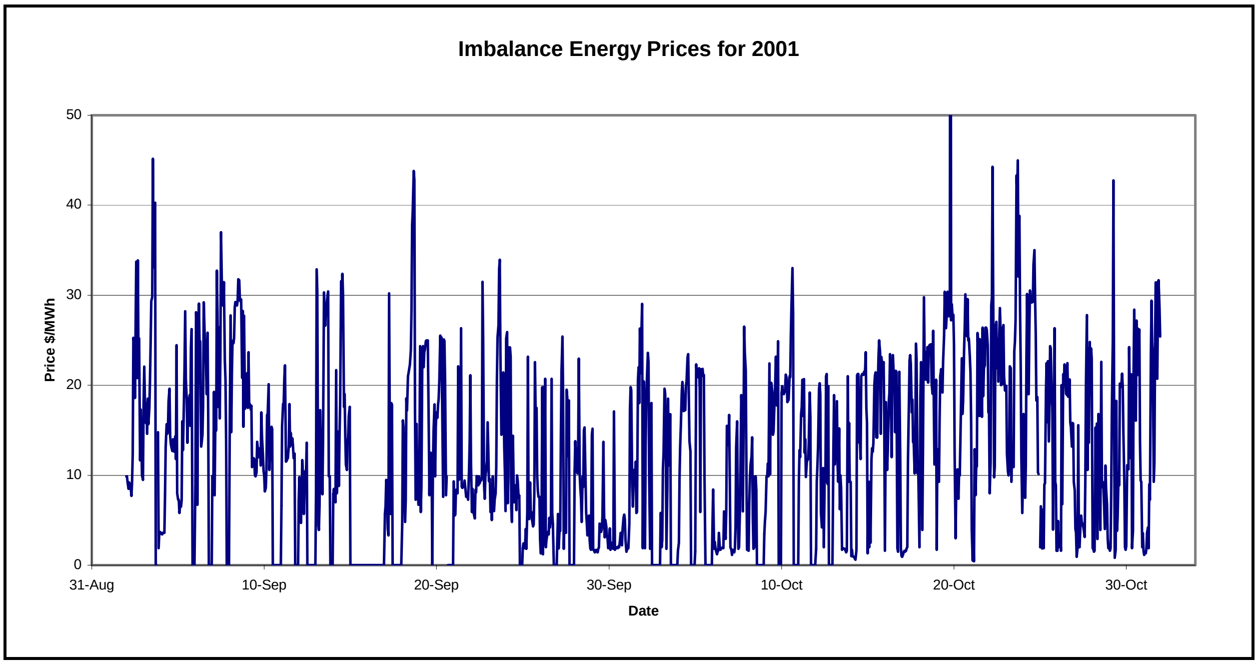

Figure 23. Imbalance Energy Prices for ERCOT

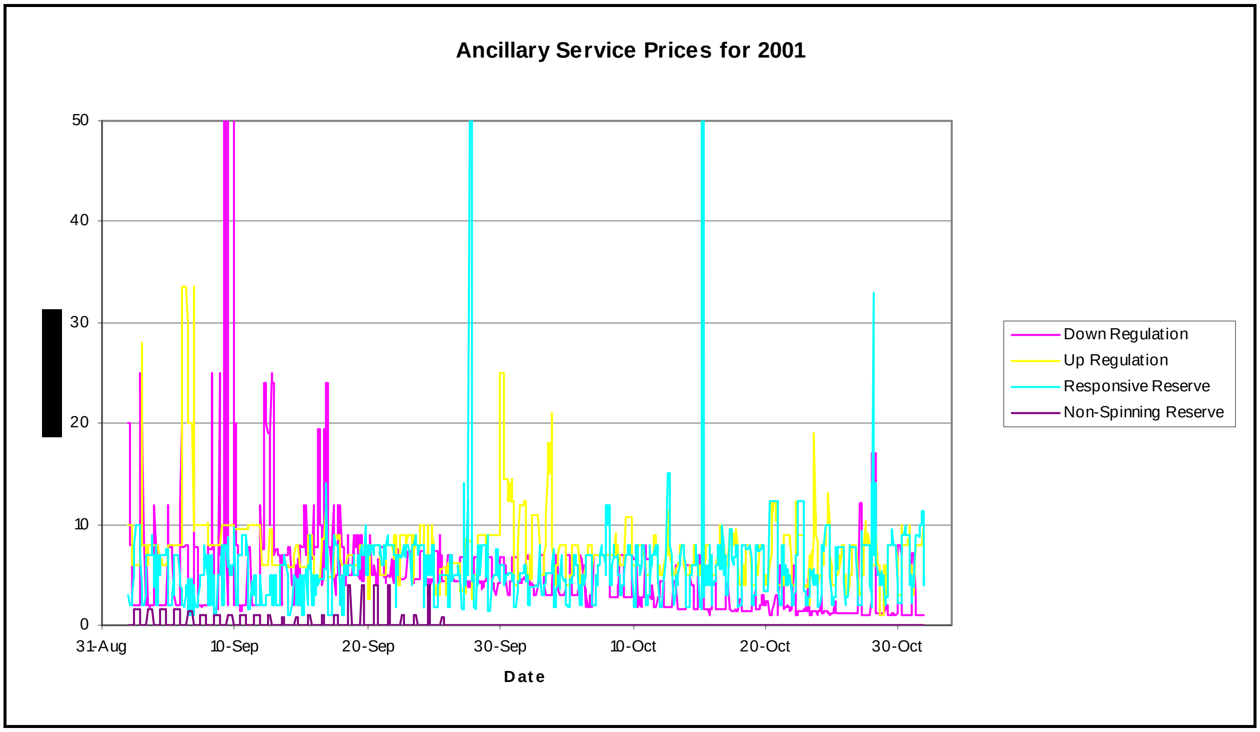

Figure 24. Ancillary Service Prices for ERCOT