UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Congestion on the	)	Docket No. PA03-12-000
Delmarva Peninsula	)	

SUMMARY OF
TESTIMONY OF
FRANK WOLAK
ON BEHALF OF
OLD DOMINION ELECTRIC COOPERATIVE

In his testimony, Dr. Frank A. Wolak addresses the following main points: (1) the historical extent of congestion in the DPL Zone from January 1, 1998 to the present, (2) the historical distribution of congestion costs among load-serving entities ("LSEs") in the DPL Zone from January 1, 1998 to the present, (3) the current and historical causes of congestion in the DPL Zone, and (4) market rule changes that will more efficiently allocate these congestion costs among market participants and reduce the incentives that suppliers have to cause congestion in the DPL Zone. His analysis establishes that Old Dominion Electric Cooperative (ODEC) disproportionately bears the burden of congestion charges in the DPL Zone. Dr. Wolak further provides strong evidence that local market power exists in the DPL Zone as a significant current and historical cause of congestion. Dr. Wolak's testimony identifies several methods of exercising local market power, including: (1) scheduling and bidding by generation unit owners without Financial Transmission Rights ("FTRs") to raise energy prices, and (2) scheduling and bidding of generation units owned or controlled by load serving entities that have substantial FTR holdings in order to cause congestion and earn congestion revenue payments from their FTRs. In addition to other witnesses on behalf of ODEC, Dr. Wolak recommends various solutions for the problem of congestion in the DPL Zone, including mitigating against local market power.

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Q. Please state your name and business address

A. My name is Frank A. Wolak. My business is the Department of Economics, Stanford University, Stanford, California 94305-6072

Q. Please state your educational and professional background.

A. I am a Professor of Economics at Stanford University. I began my work on energy and environmental issues at the Los Alamos National Laboratory (LANL) in 1980. The following year I entered graduate school at Harvard University, where I received an S.M. in Applied Mathematics and Ph.D in Economics. For the past fifteen years, I have been engaged in a research program studying privatization, competition, and regulation in network industries such as electricity and natural gas. A major focus of my academic research is the empirical analysis of market power and, more generally, market design issues in newly restructured electricity markets. I have studied the design and operation of the PJM (The Pennsylvania, New Jersey, and Maryland Interconnection), New York, New England and California electricity markets, as well as virtually all restructured electricity markets currently operating around the world. I have advised governments in Australia, Columbia, Brazil, New Zealand, and Spain, and the regulatory bodies in a number of other countries on issues relating to electricity market design and monitoring. Since April 1, 1998, I have been the Chairman of the Market Surveillance Committee (MSC) for the Independent System Operator (ISO) of California's electricity supply industry.

Q. What regions does the Commission's May 12 order establishing this fact finding proceeding address?

A. The Federal Energy Regulatory Commission's ("FERC's") May 12 Order in this docket directs an inquiry into the facts and solutions concerning congestion on the "Delmarva Peninsula."

Q. What do you understand the phrase "Delmarva Peninsula" to mean in your testimony?

A. I reference the "Delmarva Peninsula" to include (but not exclusively comprise) the service territory of Delmarva Power and Light ("DP&L") that is physically located south of the Delaware and Chesapeake Canal ("Canal") on the Delmarva Peninsula and, electrically, south of the Keeney interconnection of DP&L. DP&L's Peninsula service territory is defined as "DPL Zone," which is comprised of two separate aggregates: "DPL South" (where all of Old Dominion Electric Cooperative's ("ODEC's") member loads on the Peninsula are located) and "DPL North." The term "DPL South" covers the geographic service territory of DP&L south of the Canal. "DPL North" covers the geographic service area north of the Canal.

Q. What is the purpose of your testimony?

A. My testimony addresses four issues: (1) the extent of congestion in the DPL Zone since January 1, 1998 to the present, (2) the distribution of congestion costs among load-serving entities ("LSEs") in the DPL Zone since January 1, 1998 to the present, (3) the causes of congestion in the DPL Zone, and (4) market rule changes that will more efficiently allocate these congestion costs among market participants and reduce the incentives suppliers have to cause congestion in the DPL Zone.

Q. What general conclusions do you draw from this analysis?

A. My analysis provides strong evidence in favor of designing and implementing a comprehensive solution to congestion in the DPL Zone that recognizes the exercise of local market power as a significant cause of congestion. My testimony identifies two major avenues for the exercise of local market power: (1) scheduling and bidding by generation unit owners without Financial Transmission Rights ("FTRs") to raise energy prices, and (2) scheduling and bidding of generation units owned or controlled by LSEs that have substantial FTR holdings in order to cause congestion and earn congestion revenue payments from their FTRs.

My testimony demonstrates that congestion in the DPL Zone is an ongoing problem that has continued unabated for more than four years, in spite of a number of remedies implemented by PJM Interconnection, L.L.C. ("PJM"), DP&L and ODEC. It shows that the burden of these congestion charges is disproportionately borne by ODEC because the mechanism currently used by PJM to allocate FTRs fails to recognize fully the extent that local ownership of generation by an LSE can provide a hedge against congestion charges.

My analysis strongly supports the conclusion that the current PJM mechanism for allocating FTRs and mitigating local market power in the DPL Zone is detrimental to market efficiency because it provides incentives for suppliers to increase the frequency and magnitude of congestion in the DPL Zone. For this reason, high levels of congestion are likely to continue to occur in the DPL Zone unless remedies that directly address its causes are approved by FERC and implemented by PJM and DP&L.

For the case of PJM, these remedies take the form of the market rule changes outlined later in my testimony. For the case of DP&L, these remedies take the form of a PJM mechanism for allocating the costs of planned and unplanned transmission outages that limits the incentive and ability of generation units owned by DP&L to cause congestion on the DPL Zone. Finally, the joint remedy between PJM and DP&L is a mechanism that ensures all economically viable transmission expansions that pass the cost-benefit test are undertaken in a timely manner

My testimony also provides suggestions for additional studies of the performance of the PJM market in the DPL Zone that would provide useful input to the process of implementing the specifics of my proposed remedies. These studies could not be performed because of time constraints and lack of data availability. However, the results presented here provide sufficient evidence that there are substantial inefficiencies associated with the congestion management, transmission operation, and transmission upgrade mechanisms in the DPL Zone to merit the further study necessary to craft a permanent solution.

Q. Please provide historical context as background to your testimony.

A. A wholesale market with Locational Marginal Pricing ("LMP") is very different from the dominant historical industry structure where a single firm owned and operated both the transmission network and virtually all of the generation units in its control area. Under the new wholesale market regime, the operator of the transmission network is financially separate from all generation owners. Under the prior industry structure, state public utilities commissions fixed the retail price paid to the vertically-integrated, investor-owned utility for all of the energy it sold. In contrast, under the new wholesale market regime, competitive forces determine the prices power producers receive for their electricity.

Because of the vertically integrated investor-owned utilities' prior transmission and generation construction decisions, in many areas of the U.S., the existing transmission network may have inadequate transfer capacity to face every generation unit owner with enough competition from distant generation unit owners to elicit competitive behavior from the firm at each location in the transmission network that it serves for the vast majority of hours of the year. Instead, a firm owning a substantial fraction of the generation capacity in and around a geographic area with inadequate transmission capacity to serve local demand has an incentive to withhold energy from the market--either by bidding very high prices or by refusing to operate some of its units--to increase the prices paid for the energy it does supply. This is the circumstance on the DPL Zone.

The combination of a transmission network designed for an industry structure that no longer exists and the resulting perverse incentives for profit-maximizing behavior by dominant generators in a wholesale market regime like that described above implies that at many locations in the transmission network of all existing and proposed ISOs in the U.S., there are a substantial number of hours of the year when only one firm or a small number of firms can meet a local energy need. This creates substantial opportunities for firms to exercise market power.

This logic also implies that there is virtually no limit on the price that consumers located in this area would have to pay for electricity because they happen to live in an area that the former vertically integrated investor-owned utility found least-cost to serve with a combination of local generation and transmission capacity. In any transition to such a new wholesale market regime, consumers of electricity should not be punished or rewarded for their location in a transmission network or for the cost characteristics of local generation units built to serve an industry structure that no longer exists. Consumers should also not be subject to substantial market power in the prices they pay for electricity because of their location in a transmission network built to serve an industry structure that no longer exists or because of the generation capacity divestiture decisions of the formerly vertically integrated utility.

Market Power and Congestion Pricing

Q. Please define the exercise of market power.

A. A supplier possesses market power if it has: (1) the ability to raise the price it is paid by how it bids or schedules its generation units and (2) the ability to profit from this price increase. Suppliers exercise market power by bidding their willingness to supply additional energy from a generation unit in excess of the variable costs of operating the unit at that level of output. Suppliers can also exercise market power by withholding generation capacity from the market. This is equivalent to the supplier being unwilling to supply energy at any positive price below the price cap in the market.

Q. Please define local market power.

A. A supplier possesses local market power if it has the ability to exercise market power over a smaller geographic market because of transmission constraints, the level of local demand and the operating behavior and distribution of ownership of generation units in this geographic area. The distinction between local market power and system-wide market power is that transmission constraints limit the ability of suppliers outside of a geographic region to compete with local generation owners at all levels of local demand, specifically the higher levels of local demand.

Therefore, the extent of local market power possessed by a supplier depends on the level of demand local to its generation units, the capacity of other local generation units and the number of independent suppliers that own them, and the amount of available transmission capacity into the region. Consequently, depending on the level of local demand, the amount of available transmission capacity into the region, and the operating condition of other units in this geographic area, virtually any supplier can possess substantial local market power.

Q. Please define substantial local market power.

A. Although there is some disagreement over the necessary conditions for a supplier to possess substantial local market power, a sufficient condition is that the supplier is pivotal in meeting the local demand. A supplier is pivotal in meeting local demand if after subtracting the maximum available imports into the region and the maximum available supply from other suppliers in this region during that hour from the level of local demand in that hour, some capacity from this supplier is needed to meet demand. For example, if demand in a local area is 100 MW and the amount of available import transmission capacity into the region is 40 MW and there are two suppliers local to the demand, each of which owns 50 MW of capacity, then each supplier is pivotal for 10 MW = (100 MW – 40 MW – 50 MW) of capacity. This means that even if 40 MW of imports is supplied into the region and the other firm supplies 50 MW, the firm under consideration would still be required to supply 10 MW or a portion of the 100 MW of demand would go unmet. Under these circumstances, there is no limit to the amount a pivotal supplier can bid for this pivotal quantity of energy, if the hourly demand for energy does not depend on the hourly wholesale price. This is why all ISOs currently operating in the U.S. have local market power mitigation mechanisms integrated into their dispatch and price-setting processes.

Q. Please describe why a local market power mitigation mechanism is necessary.

A. An analogy to geographically-dispersed markets is useful for illustrating the need for a local market power mitigation mechanism. Before the U.S. interstate highway system became ubiquitous, transporting goods between U.S. cities was considerably more expensive, and in many cases prohibitively expensive. Consequently, each city had to produce locally a large fraction of the goods it consumed, because of the high cost of importing goods from distant locations. Under these circumstances, local firms could often exercise significant market power through prices they charged to local consumers. The cost of entry was sufficiently high relative to the potential profits that a new supplier could expect to earn, because of transportation costs into the area and the limited revenue potential of the small local market that such market power was sustainable over time.

As the demand for goods in certain areas grew, expanding the capacity of the transportation links between these areas became economic. These enhanced transportation links, in turn, limited the ability of producers in these regions to exercise local market power, because they now faced significant competition from distant producers. Moreover, the growing size of these markets implied significantly greater potential revenues from entry, particularly in the largest and fastest growing areas.

The self-reinforcing mechanism described above also implies that regions with little economic activity or prospects for growth will continue to face significant local market power problems. Unless the local market power problem is extreme, it makes very little economic sense to invest in significant new transportation capacity into a small locality with little prospect of significant growth. Consequently, these local market power problems could persist for the foreseeable future.

This analogy and the self-reinforcing mechanism of growth in local economic activity providing the economic justification for expanding the transportation infrastructure between these areas, have important implications for electricity networks. The pre-interstate highway system is analogous to the vertically-integrated utility regime when there was little electricity trading across control areas, because these transmission networks were designed to serve the utility's service area, not to facilitate trade. Any local market power problems associated with these transmission networks were solved by state-level, cost-based regulation of the retail prices of electricity sold by these vertically-integrated utilities.

Throughout the U.S., the legacy of the vertically-integrated utility regime is a transmission network that provides significant opportunities for firms to exercise local market power. The least-cost network design and geographic location of generation units used by a former vertically-integrated utility now creates system conditions where certain wholesale power producers face insufficient competition from distant generation to cause their expected profit-maximizing generation unit bid curve to be very close to the unit's marginal cost curve.

Because of these initial conditions in transmission networks throughout the U.S., even for large load centers or load centers expected to experience significant growth, a local market power mitigation mechanism is necessary to protect end-use customers during the transition period during which new transmission capacity is built to provide all generation units in these areas with sufficient competition from distant generation units to cause these firms to bid close to their minimum variable cost of production from their units.

Q. Can a local market power mitigation measure completely insulate consumers from the exercise of local market power?

A. No. This would imply the existence of a perfect regulatory process. The ISO would need to know each supplier's minimum cost of producing power. It could then dispatch suppliers based on their minimum cost of producing power. However, if such a regulatory process existed there would be little need to introduce a competitive market because, by assumption, a lower average cost of supplying power to consumers could be achieved by paying suppliers only their minimum cost of production, rather than the market-clearing price set through a process where all suppliers were bidding to maximize their expected profits for all of the energy they produce.

Consequently, any local market power mitigation measure is necessarily imperfect in the sense of being unable to protect consumers from the exercise of all local market power. Moreover, there are some local market power mitigation mechanisms that provide a greater level of protection to consumers from the exercise of local market power.

Q. How well does the PJM mechanism protect consumers from the exercise of local market power?

A. The PJM local market power mitigation mechanism is one of the better local market power mitigation mechanisms that exists among the currently operating U.S. ISOs. However, there are a number of shortcomings that significantly enhance the opportunities for suppliers to exercise local market power in areas such as the DPL Zone.

Q. What structural features of the DPL Zone make it susceptible to the exercise of significant local market power?

A. The DPL Zone is a region where a small number of suppliers possess substantial local market power a large fraction of the hours of the year. In particular, there are geographic areas where the current configuration of the transmission network precludes access to enough independent suppliers from outside the area to meet local demand a significant fraction of the hours of the year. There is also insufficient competition among generation unit owners to meet the remaining demand within the region not supplied by imports to allow bids to set the prices paid for energy in this region a substantial fraction of the hours of the year. In other words, one or more local suppliers are pivotal a significant fraction of the hours of the years. For the purposes of my testimony, I will refer to a region where a small number of suppliers possess substantial local market power a large fraction of the hours of the year as a "load pocket."

Q. Is the DPL Zone a load pocket?

A. Yes. The amount of available transmission capacity for imports into the DPL Zone is less than local demand a large fraction of the hours of the year. Second, from the start of the PJM market to the date of transfer of slightly less than 1,000 MW of generation assets from DP&L to NRG Power and Marketing ("NRG"), DP&L owned more than 1,000 MW in DPL South and almost 2,000 MW in DPL North, so that it was a pivotal supplier in the DPL Zone the vast majority of hours of the year. After the transfer of assets from DP&L, NRG became a pivotal supplier in the DPL Zone a significant fraction of the hours of the year.

Q. What other features of the DPL Zone make the PJM local market power mitigation mechanism provide such limited protection for consumers from local market power?

A. The presence of a number of high variable cost units in the DPL Zone in the hands of NRG and DP&L significantly enhances the ability of these suppliers to exercise local market power, in spite of the existence of the PJM local market power mitigation mechanism. As noted in Wolak (2002), attached as Exh. ODC-24 to my testimony, under the PJM market rules, when a generating unit is determined to possess significant local market power, the ISO automatically mitigates the bids of the unit to one of the following levels: (1) a regulated variable cost of production for the unit plus a ten percent adder, (2) an average of the accepted bids from that unit when it was known not to possess local market power, or (3) a level mutually agreed upon by the market participant and the ISO.[1] In practice, the mechanism that replaces the firm's bid with the unit's regulated variable cost plus a 10% adder is used the vast majority of the time. This mitigated bid is

[1] Affidavit of Frank A. Wolak on behalf of the Electricity Consumer Resource Council, The Transmission Dependent Utility Systems, Buckeye Power, Inc., Great River Energy, Wolverine Power Supply Cooperative, Inc., and East Texas Electric Cooperative, Inc." filed at Federal Regulatory Commission in

applied to the entire capacity of the unit and the LMP algorithm is then run, with all mitigated bids in place of the actual bids submitted. All units are paid the resulting price at their location for all of the energy they supply to the day-ahead market.

In preparing my testimony, I analyzed the confidential PJM bid data which included both the market-based bids and the cost-based bids for units with market-based pricing authority and the cost-based bids for units without market-based pricing authority located in the DPL Zone. I also collected historical information from the U.S. Energy Information Administration (EIA) on the heat rates and variable operating and maintenance costs of these units. For the sample period of the PJM bid data I also collected information on the prices of natural gas, diesel fuel, fuel oil and coal delivered to the DPL Zone. Comparing the cost-based bids in the confidential PJM data to the estimates of the variable cost of each unit (computed using the unit's heat rate times the relevant fuel cost plus the unit's variable operating and maintenance cost) yielded large positive differences for several bid increments for a number of generation units. This analysis suggests that PJM should establish and enforce uniform standards for determining the regulated variable costs of units to limit the ability of generation owners to raise these regulated costs above levels that can be justified based on the unit's heat rate multiplied by the input fuel costs plus the unit's demonstrable variable operating and maintenance costs.

These implausibly high cost-based bids for units located in the DPL Zone enhance the profitability of withholding lower cost units during hours when congestion in DPL South or DPL North is likely to occur. Specifically, withholding capacity to allow a cost-based bid of $100/MWh to set the local price paid for all energy is substantially more profitable for a supplier with significant capacity in the DPL Zone than withholding the same amount of capacity to allow a cost-based bid of $50/MWh to set the price. The addition of a 10 percent adder to this cost-based bid only makes this strategy even more attractive to suppliers in the DPL Zone.

Q. Can you describe the difference between local scarcity pricing and the exercise of local market power?

Docket No. RM01-12-000, November 11, 2002, available from http://www.stanford.edu/~wolak [hereafter referred to as "Wolak (2002)" and attached as Exhibit ODEC-FAW-1].

A. Returning to the example of a local area with two suppliers that own 50 MW of generation and 40 MW of import capacity into the region, suppose that the level of demand is 85 MW. Under these conditions, neither of the suppliers is pivotal. All demand can be met from the 40 MW of imports and 50 MW from one of the local suppliers. However, at local demand levels at or above 91 MW and available transmission capacity equal to 40 MW, one local supplier is pivotal for at least 1 MW. For every 1 MW reduction in the amount of available transmission capacity into the region, the level of demand at which one of the local suppliers is pivotal falls by 1 MW. However, even if the amount of available transmission into the region is zero, there still is no shortage of generation to serve up to 100 MW of demand for energy, because the total amount of local capacity available is 100 MW. However, there is an enormous local market power problem, because at this level of demand, each supplier is pivotal for their entire capacity of 50 MW.

The only time there should be local scarcity pricing is when there is a true scarcity of generation available to meet demand. In our original example, this would be at a level of demand greater than 140 MW, because we have 40 MW import transmission capacity and 50 MW from each local supplier. Assuming that final demand does not depend on the wholesale price, if it is above 140 MW, the price of energy should rise to the level of the price cap. There is a true scarcity of energy to serve local demand and some demand must be curtailed because there is only 140 MW of energy that can be supplied. This is the only instance when scarcity pricing should occur for the case of an inelastic local demand, because at all levels of local demand at or below 140 MW there is no scarcity of energy to meet demand. There still is the potential for substantial local market power, particularly for demand levels above 90 MW, as noted above. Given the annual distribution of hourly demand in the DPL Zone, the amount of available transmission capacity into the region and the amount of local generation capacity, it is extremely unlikely that system conditions requiring true scarcity pricing should ever occur. According to Table PHI-T-1, the peak demand in the DPL Zone is 3,758 MW and the amount of local generation plus import capability is 5,206 MW.

There are a number of factors which complicate the process of setting true scarcity prices. This is the same problem as the impossibility of perfect regulation described above. Specifically, if we introduce the possibility of forced outages of generation capacity, and assume the ISO sets scarcity prices when there is insufficient capacity declared available to meet local demand, then suppliers with local market power have an extremely strong incentive to declare a substantial amount of capacity out to cause an apparent shortage of generation capacity available to produce energy to meet demand. Moreover, if the large local supplier is also affiliated with the owner of the import transmission capacity, the transmission owner may also have an incentive to reduce the amount of available import capacity to increase the likelihood of a period of scarcity pricing. Consequently, just as it is impossible for the ISO to determine the true minimum cost of supplying energy from a given generation unit, it is also impossible for the ISO to determine if a generation unit is truly able to operate. This, in turn, implies that it is impossible for the ISO to determine without substantial error when scarcity pricing should occur.

Fortunately, there is a straightforward way to reduce the probability and magnitude of these potential errors. Actively involving final demand in the wholesale price-setting process can limit the ability of suppliers to exercise local market power. With an active demand side of the market, when the market price rises, the amount of energy demanded is expected to fall. This reduced demand at higher prices implies that if a supplier attempts to raise the market price, it will make less energy sales at this higher price. If final demand is sufficiently responsive to prices, then suppliers will lose sufficient sales to find it unprofitable to withhold energy by bidding in excess of their variable operating costs or by declaring their plants unable to operate. Unfortunately, there are few examples of successful programs for actively involving final demand in any of the wholesale markets currently operating in the U.S. Moreover, there are no programs that I am aware for actively involving final demand from residential and small business customers. These customers consume the majority of ODEC's load in the DPL Zone.

Q. Are there any structural solutions to this local market power problem?

A. By divesting the local generation capacity into a larger number of independent suppliers, the frequency that any supplier possesses substantial local market power at a given demand level can be limited. For example, if the two 50 MW local generators in my previous example are each required to divest half of their capacity into an independent supplier, then none of the four local suppliers is pivotal, until the level of demand rises to 115 MW = 40 MW + 75 MW. That is because the entire demand can be met by imports and 3 of the 25 MW suppliers. Recall that with two local suppliers, 90 MW is the level of demand when each local supplier is pivotal. Continuing further, if there are 10 independent suppliers, each of which owns 10 MW of local generation, then 130 MW is the level of demand at which one supplier is pivotal. To illustrate the point that high prices at levels of demand very close to the maximum amount of available energy reflect the exercise of local market power, not scarcity pricing, consider the case of 140 independent local generation unit owners, each of which owns 1 MW of capacity. Under these conditions, 139 MW is the level of demand at which one supplier becomes pivotal. Moreover, these unconcentrated structural conditions imply extremely competitive market outcomes, even at very high levels of demand, even though these levels of demand vastly exceed the levels of demand at which severe local market power problems show up in a market with two independent suppliers that each own 50 MW of capacity. Consequently, the same capacity distributed over a far larger number of independent suppliers eliminates local market power problems at all demand levels very close to the total amount of energy available.

Q. Are there any other structural factors that are important determinants of the extent of local market power that can be exercised?

A. The distribution of capacity ownership is also a very important determinant of the level of local demand where significant local market power arises. For example, consider the case in which the 100 MW of total generation capacity is distributed among the two local suppliers as 90 MW and 10 MW, instead of as 50 MW for each supplier. With this skewed distribution of capacity ownership shares, the larger supplier is pivotal at a level of demand of 50 MW, because subtracting the 40 MW of import capacity and 10 MW from the small local supplier from the 100 MW of demand leaves 50 MW that must be supplied from the large local generator. In contrast, for the case in which the small 100 MW of local generation is divided equally among the two local suppliers, a pivotal supplier does not occur until demand exceeds, 90 MW. Consequently, substantial local market power problems don't arise until the level of demand is almost twice as large if the local generation capacity is shared equally among the two local suppliers versus being primarily owned by one firm. Unfortunately, this skewed distribution of capacity ownership is precisely the case for the DPL Zone before DP&L transferred its generation assets to NRG. After the asset transfer there is a very highly skewed distribution of generation ownership in DPL North and DPL South. These features of the distribution of generation capacity ownership in the DPL Zone increase the severity of the DPL Zone's local market power problems.

Q. Are there other aspects of the market structure in the DPL Zone that exacerbate local market power problems?

A. DP&L and its affiliates own both the transmission facilities and all of the generation assets of the former vertically integrated utility DP&L (that have not been sold to NRG) in the DPL Zone. In addition, DP&L is still the largest retailer in the DPL Zone. For the remainder of this testimony, I will refer to DP&L as the collection of its affiliates that own the transmission and generation assets and the load-serving entity. In spite of this ownership structure, different from the former vertically integrated regime, DP&L no longer dispatches units or operates the transmission network on the DPL Zone. The PJM ISO performs both of these functions based on bids submitted by market participants to the day-ahead and real-time markets.

This separation of ownership from joint control of the transmission and generation assets during the wholesale market regime differs from the former vertically integrated regime when DP&L owned the vast majority of generation assets in the DPL Zone and operated them along with the DPL Zone transmission network to meet its retail load obligations. Under this regime, DP&L had an obligation to serve all demand at retail prices set by the relevant state public utilities commissions. The combination of fixed retail prices and the obligation to serve all demand at these prices implies a revenue stream that is largely independent of the operating decisions of DP&L generation assets. Consequently, in order to maximize profits over the time horizon these fixed retail prices are valid, DP&L should attempt to minimize the total costs of meeting its retail load obligations, which should also cause DP&L to choose the least cost mix of transmission and generation assets to meet its retail load obligations. For example, if DP&L found that the redispatch costs associated with managing congestion into a geographic area with more local demand than import transmission capacity exceeded the costs of expanding the transmission network to eliminate or reduce the frequency of this congestion, then the vertically integrated DP&L would have a strong incentive to undertake such an investment.

The wholesale market regime forgoes these potential economies of scope in jointly operating the transmission and generation assets for a given geographic area in order to allow competition among suppliers to determine the mix of generation capacity needed to serve demand given the existing transmission infrastructure. Different from the vertically-integrated regime, there is no market participant that is able to implement the least cost mix of transmission and generation investment to meet a given local energy need. The ISO operates the existing transmission network to meet demand, but it has little incentive to identify economically beneficial transmission upgrades, and it cannot undertake such upgrades, because it does not own the transmission network. In addition, PJM is neither financially benefited nor harmed by the frequency of congestion or its costs to market participants. Even if the costs to PJM of operating the system do increase as a result of greater congestion in the network, PJM can recover these costs through higher charges to market participants for its services because it is a non-profit entity.

Three types of market participants can benefit significantly from greater congestion into the DPL Zone under the wholesale market regime: (1) portfolio generation unit owners located in the DPL Zone, (2) LSEs located in the DPL Zone with significant FTR holdings that also own substantial local generation, and (3) LSEs located in the DPL Zone with significant FTR holdings and that own transmission network in the DPL Zone. All of these entities can profit from bidding and scheduling their generation units to cause congestion. A portfolio generation owner that manages to cause congestion and therefore raise the price of local energy will earn this higher price for all the energy it sells from its units. An LSE that manages to cause congestion by bidding or scheduling its local generation units can earn substantial revenues from its FTR holding. An LSE that manages to cause congestion by declaring outages on its transmission assets can earn significant revenues from its FTR holdings. The DPL Zone has all three of these types of market participants.

The only entity with an incentive to reduce congestion is an LSE with little if any local generation capacity and limited FTR holdings that does not own transmission assets. Unfortunately, this LSE can find it enormously costly to undertake the investments necessary to solve this congestion problem. First, this LSE would have to make enormous investment in generation capacity in order to limit the ability of the local portfolio generation owners and LSEs with significant generation holdings (that might also own the local transmission assets) to cause congestion. Second, this LSE cannot make transmission upgrades without the permission of PJM and the LSE that owns the transmission network. However, as discussed above, PJM is largely financially indifferent to the level of transmission congestion and the LSE that owns the transmission assets may not want to reduce congestion if it has substantial FTR holdings.

ODEC owns little local generation capacity in the DPL Zone and has a limited allocation of FTRs from PJM. NRG is a large portfolio generation unit owner in the DPL Zone. As discussed above, DP&L is the largest LSE in the DPL Zone and it owns the majority of generation in the DPL Zone and the transmission assets that serve the DPL Zone. Consequently, if the incentives to cause congestion described above for local portfolio generation owners and LSEs that own substantial local generation or local transmission capacity are applicable to the DPL Zone, then it is not surprising that significant congestion in the DPL Zone has persisted for so long. It is extremely profitable for two large market participants for this to be the case and unprofitable only for ODEC and other LSEs in the same circumstances.

A major goal of my testimony is to provide evidence that these incentives to cause congestion do, in fact, exist and are a significant factor causing the high levels of congestion the in DPL Zone. As noted above, given time and data constraints, it is not possible to perform a comprehensive analysis of this issue. Nevertheless, the results presented below are clearly consistent with the existence of these incentives. They also strongly argue in favor of more comprehensive analysis of this problem in order to formulate a solution that alters the incentives to cause congestion described above, and therefore remedy the problem.

Measuring Congestion Costs Borne by an LSE

Q. Is there other historical background you would like to provide before you present this analysis?

A. I would like to describe how to measure the explicit, implicit and total congestion costs borne by an LSE, as well as the net congestion costs. Following these definitions, I then present calculations of the congestion costs borne by ODEC from 1998 to the present time and characterize several features of congestion on the DPL Zone. Further detail on this historical background can be found in "ODEC's Historical Costs of Congestion in DPL Zone, prepared by Old Dominion Electric Cooperative," attached to this testimony as Exh. ODC-25, referred to henceforth as the "ODEC Analysis."

Quantifying the extent of congestion on DPL Zone is an extremely complex task. A first step in this process is determining what price an LSE on the DPL Zone would have paid for wholesale power had there not been congestion. The PJM settlement system accomplishes this by allowing each market participant to submit their bilateral contract quantities and delivery points as e-schedules. These e-schedules allow PJM to determine the source price and sink price for the purposes of computing the congestion charge borne by the LSE in the day-ahead market and real-time market. For example, if ODEC schedules 200 MWh in a bilateral contract at the Western Hub and schedules consumption of this energy at DPL South in the day-ahead market, the congestion charge in the day-ahead market for this energy is the difference between the day-ahead DPL South price and day-ahead Western Hub price multiplied by 200 MWh. This magnitude is what ODEC calls explicit congestion costs.

However, ODEC also pays an implicit congestion cost for any other energy it schedules or consumes during congested hours without an associated e-schedule. For example, if ODEC's only bilateral contract was the 200 MWh at the Western Hub and it scheduled 210 MWh in the day-ahead market at DPL South, this would mean that ODEC had purchased 10 MWh at DPL South without an associated bilateral delivery of power. Because there is a difference in the price at DPL South and the Western Hub, there is the implicit cost of congestion in this 10 MWh energy purchase relative to the Western Hub price. For energy not purchased under a bilateral contract, some assumption must be made about the source of this energy in order to compute this implicit cost of congestion.

Similar logic applies to the real-time market, unless ODEC submits e-schedules to tell PJM the source of this incremental real-time energy purchase. For example, suppose that ODEC consumes 225 MWh during the hour and there is congestion between the Western Hub and DPL South in the real-time market. This implies that ODEC purchased 15 MWh = 225 MWh – 210 MWh in the real-time market and paid an implicit congestion cost relative to the Western Hub of difference between the DPL South price and the Western Hub price multiplied by 15 MWh.

Assuming that available transmission capacity into DPL South is fully scheduled in the day-ahead market, meaning that there is congestion, energy without an explicit source specified in the PJM e-schedule system is supplied from units located in the DPL Zone. However, because of this congestion, the energy is higher priced than energy outside of the DPL Zone, and the units inside the DPL Zone set the LMPs at the buses in the DPL Zone. Nevertheless, this higher local energy price is the source of what ODEC calls implicit congestion.

The sum of explicit and implicit congestion is what ODEC calls gross congestion. ODEC's net congestion costs are computed by taking gross congestion costs and subtracting the credits that ODEC receives from PJM for its FTR holdings. Because FTRs issued by PJM are not always fully funded, the FTR credits ODEC receives are sometimes less than the quantity of FTRs ODEC has on a source and sink pair, multiplied by the price difference between the sink and source over sustained periods of time. This adds further complexities to computing net congestion costs.

Q. Could you summarize the behavior of ODEC's gross and net costs of congestion from 1998 to the present time according to the ODEC Analysis?

A. Table 1(a) and 1(b) in the ODEC Analysis presents the explicit and implicit costs of congestion and the hours of congestion each month of each year from 1998 through June 30, 2003. Also included in Table 1(a) is the gross and net costs of congestion for each year over this time period. The starkest conclusion that can be drawn from these tables is that the number of hours of congestion and the total and net cost of congestion to ODEC jumped dramatically from 1998 to 1999. Further analysis of the hours of congestion each month of the year show that a substantial increase in the hours of congestion occurred in the second half of 1999 after PJM took over operation of the low voltage facilities in the DPL Zone.

Although total congestion costs in 1999 were several orders of magnitude higher than in 1998, ODEC has consistently experienced gross annual congestion costs above 10 million dollars each year between 2000 and 2002, with 2000 and 2001 being more than $2 million higher than 2002. ODEC's net congestion costs were more than $12 million in 2000, but they fell to around $7 million in 2001 and were slightly higher in 2002 because ODEC was allocated FTRs in 2001 and 2002.

Although it is too early in the year to draw any definitive conclusions about 2003, extrapolating from the first six months of data, annual gross and net congestion costs will be significantly higher than the 1999 levels, indicating that congestion in the DPL Zone continues to be extremely costly to ODEC.

Q. According to the ODEC Analysis, how do average prices in DPL South and the DPL Zone reflect these congestion costs?

A. Table 2 of the ODEC Analysis presents the unweighted annual average day-ahead prices at the Western Hub, Keeney bus, DPL Zone and DPL South. This shows that in 2000, the annual average day-ahead DPL South price is 16% higher than the annual average day-ahead Western Hub price. In 2001, this DPL South average day-ahead price was 27% higher than the Western Hub average day-ahead price. In 2002, the average day-ahead price at DPL South was 13% higher than the average day-ahead price at the Western Hub.

Table 3 reports the PJM quantity-weighted day-ahead average price and the ODEC load-weighted average price at DPL South for 2000 to 2002. The ODEC load-weighted average day-ahead DPL South price is 18% higher than the PJM load-weighted average price in 2000, 26% higher in 2001, 10% higher in 2002.

Table 4 reports comparisons of annual average real-time prices at the Western Hub, Keeney bus, DPL Zone and DPL South. This table shows that DPL South average real-time prices are persistently and significantly higher across all years from 1998 to 2003.

Q. Please summarize the distribution of the costs of congestion in the DPL Zone, according to the ODEC Analysis?

A. The ODEC Analysis presents a simplified methodology for computing the distribution of congestion costs on the DPL Zone using day-ahead prices at DPL South and the Western Hub. This analysis shows that over the period June 1, 2000 to March 31, 2003 ODEC served approximately 10 percent of the load in the DPL Zone, however it paid approximately 15 percent of the total congestion costs. This significant difference between its share of total congestion costs and share of load served in the DPL Zone suggests that ODEC bears a disproportionate burden of the costs of congestion in the DPL Zone.

Q. Can you provide an example to show the difference in gross and net congestion costs for two identical LSEs that differ only because one owns local generation and the other does not?

A. Consider the following very simple example of two LSEs located at the end of a potentially congested transmission line with a capacity of 90 MW. Each LSE has 100 MWh of load to serve but one LSE owns 150 MW of generation and the other owns no local generation. Suppose the price outside of the region is $20/MWh, but because of congestion, the price inside the region is $50/MWh. This price is set by one of the high-cost units operated by the generation-owning LSE. Because the line is congested and the demand of the two LSEs is 200 MWh, the amount of energy supplied by the generation-owning LSE is 110 MWh = 200 MWh – 90 MWh. To make this example even more straightforward, I will assume no forward contracts for energy between any of the parties.

To understand the distribution of congestion costs among the two LSEs, it is important to recognize that total congestion charges equal $2,700 = ($50/MWh - $/20/MWh)*90 MWh, even though all 200 MWh energy must be purchased at $50/MWh. However, different from the LSE that owns no generation, the LSE that owns local generation does not pay $50/MWh for the energy it supplies to itself. It pays the total cost of producing the electricity that it sells to itself, not $50/MWh. That is because it sells the 110 MWh it produces at $50/MWh, but it also pays $50/MWh for 100 MWh of this energy as an LSE, which nets out to zero for the amount it purchases to serve its own load. Consequently, we can think of the LSE owning local generation as self-supplying its load of 100 MWh and then selling 10 MWh at a price of $50/MWh to the LSE that owns no local generation. I use this logic later in my testimony to formulate a procedure to estimate the distribution of gross congestion charges among LSEs on the DPL Zone.

Now introduce FTRs into this example to assess the distribution of net congestion charges across the LSEs. Suppose that each LSE receives its load-weighted share of the total FTRs available, which in this simple example is 90 MW, the capacity of the transmission line. Therefore, each LSE receives 45 MW of FTRs. This FTR allocation mechanism then implies that the LSE that owns no local generation is hedged against the high price of power in the region for only 45 MWh of its 100 MWh of load. In contrast, the LSE that owns local generation receives congestion revenue credits for 45 MWh of FTRs, even though it is completely hedged against the high local price of energy for all load because it owns 150 MWh local generation and supplies 110 MWh from its units.

Depending on the cost structure of the generation-owning LSE, this strategy of selling 110 MWh of energy, setting a local price of $50/MWh, and earning substantial revenues from its FTR holdings can be extremely profitable. Suppose that 120 MW of the LSE's generation capacity has a marginal cost of $20/MWh and the remaining 30 MW has a marginal cost of $50/MWh. Given this FTR allocation, the LSE would clearly prefer to supply no more than 109 MWh from the units with a marginal cost of $20/MWh and at least 1 MWh from the unit with a marginal cost of $50/MWh, because doing so sets the local price at $50/MWh and yields $1,350 = 45*($50 - $20) in FTR revenues. In contrast, if the LSE supplied 110 MWh from its units with a marginal cost of $20/MWh, the price in the local area would be $20/MWh and the congestion charge would be zero, and the LSE's FTR revenue would be zero and its overall profits from selling wholesale and retail energy would be far lower. Later in my testimony, I will assess the distribution of net congestion charges using this logic.

Q. What does this example say about the costs to consumers located in the DPL Zone of an inefficient allocation of FTRs across LSEs?

A. If the generation owning-LSE was allocated a significantly smaller amount of FTRs, then it would have less of an incentive to withhold supply from its low-cost local generation units in order to cause congestion in the DPL Zone. This withholding behavior introduces two additional costs that are not incurred if FTRs are efficiently allocated. First, the total cost of all of the energy produced in the DPL Zone is higher.

Second, consumers must pay a higher average price for all energy produced in the DPL Zone. With an efficient allocation of FTRs, the LSE that owns local generation would want to operate its units to limit the frequency and magnitude of congestion rather than to increase its revenue stream through congestion revenue credits from its FTR holdings.

Q. Can you show why the generation-owning LSE would find withholding low-cost units to cause congestion profit-maximizing?

A. Enriching the realism of the above example in the following manner emphasizes this point. Suppose the 30 MWh of \$50/MWh generation is composed of two 15 MW combustion turbine ("CT") facilities, and that each of these units must either be operated at full capacity or not at all. For simplicity, assume all units have zero start-up costs. Suppose that the retail price the LSE is able to charge does not vary with the hourly wholesale price. This assumption implies that the LSE cannot influence its retail revenue stream by how it operates its units. Under these circumstances, if the generation-owning LSE is allocated more than 15 MW of FTRs, it will find it profit-maximizing to withhold capacity from its \$20/MWh units in order to cause congestion, because its FTR credits are more than enough to compensate it for the increased costs of having to operate the \$50/MWh unit at 15 MWh. In other words, it is privately profitable for the generation-owning LSE to withhold lower cost units, even though this raises the LSE's total cost of producing energy, because the revenues the LSE receives from its FTRs more than compensates for these increased production costs.

This logic follows from the fact that at least 110 MWh of total demand must be met from local generation under either scenario. If the LSE withholds 15 MWh from the low cost units in order to operate the CT, it incurs total production costs equal to \$2650 = (95 MWh x \$20/MWh) + (15 MWh x \$50/MWh), but it receives Q(FTR) x (\$50 - \$20) in FTR credits, and \$500 for 10 MWh of wholesale energy sales at \$50/MWh, the CT sets the local price of energy. Therefore, its net wholesale energy production costs are \$2,150 = \$2,650 - \$500. In contrast, if the LSE supplies all 110 MWh from its low cost units, then its total production costs equal \$2,200 (110 MWh x \$20/MWh). The LSE earns \$200 from selling 10 MWh of energy in the wholesale market \$20/MWh, because the low cost units set the local price. In this case, its net wholesale energy production costs are \$2,000 = \$2,200 - \$200. If the FTR credits the LSE receives are sufficient to compensate it for the increased costs associated with operating the higher cost CT unit, the generation-owning LSE will find it profit-maximizing to schedule its units to cause rather than alleviate congestion. In this example, if the generation-owning LSE earns more than $150 = $2,150 – $2,000 from its FTRs, the LSE will find it profit-maximizing to cause rather than alleviate congestion through how it schedules its units. Because the cost of congestion in this example is $30/MWh = $50/MWh - $20/MWh, if the generation-owning LSE is given more than 5 MW of FTRs it will schedule its units to increase rather than decrease congestion.

Summarizing the results of this example, if the ISO inefficiently allocates more than 5 MW of the available 90 MW of FTRs to the generation-owning LSE, say 20 MW (less than half of the load-weighted share of FTRs available), then the total cost of producing the 110 MWh of locally supplied energy rises from $2,200 to $2,650. In addition, the amount customers of the LSE that owns no local generation pay for wholesale energy rises from $2,000 = (100 MWh x $20/MWh) to $2,900, if we assume this LSE received the remaining 70 MW of FTRs. The total wholesale energy purchases cost $5,000 = $50/MWh x 100 MWh, but the LSE receives $2100 = $30/MWh x 70 MW in FTR credits. This simple example shows that enormous costs can be imposed on consumers and significant deviations from least cost production because of an inefficient allocation of FTRs among LSEs.

Q. Is the generation-owning LSE required to submit market-based bids to be able to cause congestion to earn revenues from its FTR holdings?

A. No. The above example assumes that the generation-owning LSE always bids its units into the market at their variable costs. The only question is how much of the low cost unit the LSE makes available. Consequently, this example illustrates why the PJM local market power mitigation mechanism is not sufficient to prevent unit owners from causing rather than alleviating congestion in the manner described above. This mechanism caps the bids of units that it determines possess local market power at levels based on variable costs and then allows these mitigated bids to enter the pricing process. To the extent that this local market power mitigation mechanism sets a unit's mitigated bid above the unit's variable cost and allows this mitigated bid to enter the LMP mechanism, this creates further opportunities for suppliers to use FTRs to cause rather than alleviate congestion.

Q. What is the efficient allocation of FTRs for this example?

A. This example implies that the LSE with local generation should receive less than 5 MW of FTRs and the LSE without local generation should receive more than 85 MW of FTRs. This FTR allocation would still leave the LSE without local generation exposed to potentially high local energy prices for 15 MWh or less of its energy needs. However, because of the incentives for supplier behavior created by limiting the FTRs allocated to the generation-owning LSE, this LSE would not be subject to congestion charges for these MWh, because the LSE with local generation would find it profitable to operate only its low cost units to meet the local demand for energy. However, if more than 5 MW of FTRs were allocated to the generation-owning LSE, the other LSE would receive fewer FTRs and have to pay congestion charges on more than 15 MWh of its energy needs.

This example also illustrates the enormous market inefficiencies introduced by a load-weighted allocation of FTRs among LSEs, regardless of their local generation holdings. Allocating 45 MW of FTRs to each LSE would yield enormous profits from FTR credits to the LSE with local generation holdings and impose enormous harm on the LSE without local generation. How FTRs are allocated among LSEs can exert an enormous impact on the economic efficiency of market outcomes in terms of the frequency, magnitude and duration of congestion. As discussed in detail in Wolak (2002)(Exh. ODC-24), this logic implies that the PJM ISO should factor local generation holdings of the LSEs into the process of allocating FTRs.

<u>Empirical Analysis of Cost, Relative Burden and Causes of Congestion on DPL Zone</u>

Q. Please outline how you plan to analyze the determinants of congestion on the DPL Zone.

A. I will provide evidence that the exercise of local market power, in a manner similar to the above example, by a portfolio generation owner in the DPL Zone (in this case NRG) and the LSE with significant local generation and significant FTR holdings that owns the local transmission assets (in this case DP&L) can explain a significant portion of the congestion in the DPL Zone. I will also provide evidence that another explanatory factor is the transfer of control of the DP&L low voltage transmission assets to PJM in July, 1999.

This will be accomplished, in part, by distinguishing between three regimes in my analysis: (1) from the start of the market to the date that PJM took over operating the low voltage facilities in the DPL Zone (July 23, 1999), (2) from this date until the time NRG took over operating a number of units formerly owned by DP&L (June 25, 2001) in the DPL Zone, (3) from this date to the present time.

I distinguish between these three regimes because I would expect the operators of the generation units in the DPL Zone to face different incentives for causing congestion under each regime. Under the first regime suppliers in the DPL Zone should have very little incentive to cause congestion in the DPL Zone because virtually all of the generation capacity in the DPL Zone was owned by DP&L and the low voltage transmission facilities in the DPL Zone were operated by DP&L. In addition, throughout this time period, ODEC had a partial requirements contract from DP&L for the remainder of it energy requirements in the DPL Zone besides energy supplied by Public Service Electric & Gas ("PSE&G") of New Jersey. This contract expired in December of 1999, a few months after PJM took control of the low voltage facilities. Once these transmission facilities were turned over to PJM to operate and DP&L received a substantial fraction of the available FTRs into the DPL Zone and this partial requirements contract to ODEC expired, the incentives for DP&L to bid and schedule their units to cause congestion into the DPL Zone should have increased. Finally, after the vast majority of the generation capacity located in the DPL South zone formerly owned by DP&L was transferred to NRG, the incentives faced by these new owners to schedule and operate these DPL South units to cause congestion should differ from those faced by DP&L.

Q. Why do you believe the incentive for NRG to schedule the units in DPL South formerly owned by DP&L would be different from when DP&L owned them?

A. First, before this asset sale, DP&L faced no significant competition to supply energy in the DPL Zone. This sale of slightly less than 1,000 MW of capacity to NRG and NRG's decision to construct slightly less than 100 MW of new capacity in DPL South created a significant competitor to DP&L to supply incremental energy in the DPL Zone.

Second, different from DP&L, NRG did not receive any FTR allocation from PJM because it has no native load obligations to serve in the DPL Zone. Finally, to the extent that NRG does not have firm supply agreements with LSEs in DPL South, I would expect the likelihood to increase that these units are bid and scheduled to cause congestion into DPL South.

Q. Are you aware of any of the bilateral contracts NRG signed and how they might impact the scheduling and bidding behavior of NRG in the DPL Zone?

A. Exhibit G filed by DP&L Company, Atlantic City Electric Company, Conectiv Delmarva Generation, Inc. and NRG Energy, Inc., with the FERC in Docket No. EC00-91-000 contains a 3-page Term Sheet for the Power Purchase Agreement ("PPA") between NRG Energy, Inc, a Delaware Corporation, and DP&L. (Exh. ODC-26 to this testimony). This term sheet states that NRG will deliver 500 MWh of firm electric energy each hour during the term of the contract which runs from the closing date of the agreement and the related agreements and continues through December 31, 2005 at the following prices: for calendar year 2000, $20.90/MWh; for calendar year 2001, $28.56/MWh; and for all following calendar years, $29.13/MWh. According to this term sheet, the delivery point for the electricity is the Western Hub of PJM.

Because I do not have access to the entire contract, I am unable to verify if other conditions in the contract make the effective delivery point a location or combination of locations in the DPL Zone. However, if the delivery point of the contract is the Western Hub, then NRG clearly has a strong incentive to bid and schedule its units in DPL South to reduce the price at the Western Hub relative to the LMPs in DPL South, where its units are located.

To understand this incentive, consider the following simple example. Assume, for simplicity, that all of the NRG's units receive the DPL South price. Suppose that NRG manages to reduce the price at the Western Hub relative to the price at DPL South. According to the PJM rules, NRG is paid the day-ahead DPL South price for all energy it schedules in the day-ahead market and the real-time price for all incremental or decrement energy it sells or buys in the real-time market. However, according to this term sheet, it will also earn the difference between contract price and the Western Hub price times 500 MWh as profits from this bilateral contract. Consequently, the higher the

DPL South price and the lower the Western Hub price, the more profits NRG would make from supplying energy from its units in DPL South. These two prices differ when there is congestion in the DPL Zone.

Q. Are there other factors that suggest exercise of local market power by DP&L and NRG described above?

A. A comparison of the fraction of operating hours that units located the DPL Zone are cost-capped under the PJM local market power mitigation mechanism in 2000, 2001 and 2002 appears broadly consistent with this logic of differing incentives of unit operators in the DPL Zone to bid and schedule their units to cause congestion across the three regimes because of changes in system operating procedures, contractual terms among suppliers and LSEs and changes in ownership of these units. There is a substantial increase in both the number of units that are cost-capped from 2000 to 2002 and a general increase in the fraction of operating hours that units are cost-capped from 2000 to 2002. Cost-capping occurs when the PJM operators determine that suppliers possess significant local market power which they could use to raise prices on the DPL Zone through their bidding behavior. As noted in Wolak (2002), capping reduces, but does not eliminate, the ability of these suppliers to exercise their local market power. Consequently, the evidence on increased number of units and the fraction of operating hours that each unit is cost-capped from 2000 to 2002 suggests increased opportunities for suppliers in the DPL Zone to cause congestion through the exercise of local market power.

<u>Congestion on the DPL Zone in Day-Ahead and Real-Time Markets Across Three Regimes</u>

Q. Please describe how you plan to assess changes in the magnitude and duration of congestion in the DPL Zone across the three regimes?

A. As stated earlier, a comprehensive analysis of congestion in the DPL Zone would require far more data than has been made available to me and more time to perform the analysis. Nevertheless, with several simplifying assumptions, reasonable estimates of changes in the average costs of congestion throughout the day in the DPL Zone, can be obtained for each regime.

Under the PJM market rules, the average wholesale price paid by an LSE within an electric distribution company ("EDC") network is based on the actual buses where the

LSE serves load and the actual loads at those buses. The EDC typically does the calculations necessary to determine the actual load of the LSE at each bus, but these calculations are subject to verification by PJM. Consequently, to determine the congestion costs each LSE in the DPL Zone pays, one needs to know where the LSE purchased energy supplied from outside of the DPL Zone each hour, the LMP at that location and the average hourly wholesale price the LSE paid for all of its energy. This is an extremely data intensive task for one LSE, assuming that the data is available. However, this information was not available from any other LSEs in the DPL Zone besides ODEC.

To obtain a reasonable estimate of the $/MWh magnitude of congestion borne by LSEs in the DPL Zone, a straightforward approach would be to assume all of the power purchased from outside of the DPL Zone came from one of the trading hubs in the PJM system and that all power inside of the DPL Zone purchased by the LSE paid one of the zonal prices in the DPL Zone, either the DPL South or DPL North prices. The Western Hub is the only liquid trading hub in PJM, and as such is a common reference location for LSEs within PJM to purchase wholesale energy. An alternative reference price for quantifying the magnitude of congestion in the DPL Zone is the PJM average price. Using this price implies assuming that the LSE is purchasing energy outside of the DPL Zone at the system-average hourly price Using either the PJM average or Western Hub price to measure congestion for any LSE in the DPL Zone necessarily involves some approximation error for the reasons given above, unless that LSE purchases all of its energy from either of these two locations.

Q. Please describe the methodology you use to estimate the extent of congestion in the DPL Zone?

A. I quantify the extent of congestion in the DPL Zone and the magnitude and distribution congestion and congestion costs over hours of the day since April 1, 1998 using the following magnitudes:

PR(i,d,h,y) = price in hour h of day d in year y at location i for real-time market

PD(i,d,h,y) = price in hour h of day d in year y at location i for day-ahead market

For each hour h of day d for year y, compute the mean hourly price over all days in each of the three regimes [(1) June 1, 1998 to July 23, 1999; (2) July 24, 1999 to June 24, 2001, and (3) June 25, 2001 to present] defined above for the day-ahead and real-time prices. The real-time price series starts June 1, 1998 and ends June 20, 2003. The day-ahead price data starts June 1, 2000 and ends June 20, 2003, so that day-ahead price data only exists for Regimes 2 and 3. Call these variables PR(i,h,R) and PD(i,h,R), for the mean price in hour h for regime R (R=1,2,3) at location i for the real-time and day-ahead markets, respectively.

Q. What findings are presented in your analysis?

A. Figures 1 to 3 plot these daily means for the real-time price for each hour with the 24 hours of the day on the horizontal axis and $/MWh (price) on the vertical axis for regimes 1 to 3. Figures 4 and 5 repeat this same plot for a portion of regime 2 and all of regime 3 for the day-ahead price series.

Q. Are these finding consistent with your previous analysis of the incentives to cause congestion in the DPL Zone?

A. The real-time graphs are consistent with the logic outlined above concerning the incentive to create congestion in the DPL Zone under the three regimes. Specifically, Figure 1 shows little, if any, difference in the pattern of daily average real-time hourly prices between the PJM system-wide price, the Western Hub price and the DPL North and DPL South prices. Consistent with the logic outlined above for an LSE with local generation and significant amount of FTRs into that region, Figure 2 shows that the daily average real-time hourly prices between DPL South and other three prices is noticeably higher across all hours of the day. This difference is particularly large for the peak hours of the day. Figure 3 is also consistent with the logic outlined above concerning the impact on congestion of the introduction of another owner of a substantial amount of generation in the DPL Zone, in this case NRG. Both the prices in DPL South and DPL North are persistently above the average hourly Western Hub and PJM system-wide average prices during the peak hours of the day, although average hourly prices now agree during the off-peak hours of the day. Because DP&L owns less than 50 MW of generation in DPL South during Regime 3, its ability and incentive to create congestion in that region differs from Regime 2. Moreover, depending on the delivery points of its FTR holdings, DP&L may find it profitable to cause congestion in DPL North (using the strategies described above), where it still has substantial generation holdings. This logic could explain the increased difference in average prices and increased amount of congestion between the Western Hub and the PJM system-wide price under Regime 3 relative to Regimes 1 and 2.

Q. Have you performed a similar analysis of the day-ahead prices?

A. Yes. The patterns of the day-ahead prices in Figure 4 replicate the qualitative patterns shown in Figure 2 for the real-time prices. The DPL South price is persistently above the other three prices during all hours of the day. Figure 5 replicates the qualitative features of Figure 3. Both the DPL North and DPL South prices are above the PJM system-wide and Western Hub prices during the peak hours of the day, but all four average prices agree during the off-peak hours of the day.

To investigate whether these patterns differed across seasons of the year, I performed this same daily average price pattern calculation only for the summer months (June 1 to September 30) contained in each regime. Figures 6 to 8 contain the results for Regimes 1, 2, and 3 for days during the summer months only. Although the pattern of the real-time average prices has a significantly higher peak for the summer months, similar differences in average prices across the three regimes occur to those in Figures 1 to 3. The four price patterns agree in the first regime, DPL South is higher in Regime 2, and both DPL North and DPL South are higher in regime 3. Figures 9 and 10 compute these averages for the summer month only for the day-ahead prices. These results are also qualitatively consistent with the results in Figures 4 and 5, respectively.

Q. What conclusions do you draw from these analyses?

A. These results show that congestion in the DPL Zone only becomes significant following the transfer of operation of the low voltage system in the DPL Zone to PJM. The pattern of average congestion over hours of the day and across regions in the DPL Zone also changed after the sale of DP&L generation assets to NRG. During Regime 2, significant congestion occurred during all hours of the day and primarily impacted the DPL South price in the DPL Zone. Specifically, average hourly DPL South prices were noticeably above other three average hourly prices during all hours of the day. In contrast, during Regime 3, congestion became much more of a peak-hours-of-the-day phenomenon and it occurred in both the DPL North and DPL South prices, but slightly more intensively with respect to DPL South prices. Average hourly DPL North and DPL

South prices were very close to average hourly prices at the Western Hub and the PJM system-wide price at night and during the early hours of the morning. Moreover, the differences between the hourly average values of the DPL South and DPL North prices and the Western Hub and PJM system-wide average hourly prices is larger during the peak hours of the day during Regime 2 relative to Regime 1.

<u>Distribution of Congestion Charges Across LSEs in the DPL Zone</u>

Q. What is the purpose of this portion of your testimony?

A. This section estimates the distribution of congestion charges across LSEs in the DPL Zone by first breaking wholesale energy purchases made in the DPL Zone into: (1) energy imported into the DPL Zone and (2) energy supplied from units located in the DPL Zone.

Q. How does ODEC supply it energy needs in the DPL Zone?

A. Until very recently, ODEC owned no generation in the DPL Zone, so it paid the DPL South price for all of its wholesale energy purchases, whether this energy was supplied from units off of the DPL Zone or from units located in the DPL Zone. In contrast, the remaining LSEs in the DPL Zone own local generation or have full requirements contracts for supply from DP&L, so these LSEs are subject to congestion charges only for purchases made from units located outside of the DPL Zone.

Q. How should the location of generation used to serve an LSE's load affect congestion?

A. By the logic of the example of two LSEs discussed above, allocating less FTRs to the LSEs that own local generation should reduce the frequency of congestion, because these firms will find it less attractive to use their generation units to cause congestion because they will not receive substantial FTR credits to offset the increased costs of operating high cost local units in favor of lower cost local units in order to set high local LMPs. DP&L's average FTR allocation for the DPL Zone during Regime 2 strongly suggests that the magnitude of FTRs revenues DP&L received seems more than sufficient to pay for operating higher cost units more frequently in order to cause the observed magnitude and duration of congestion even if these cost-high units are capped under the PJM local market power mitigation mechanism.

The data presented in PJM Response to PHI-1, attached as Exhibit ____, is consistent with this view. Using PJM's definition of Net Congestion Costs (which differs from the net congestion costs in the ODEC Analysis) for all years from 1999 to 2002, DP&L received large net congestion payments from PJM. In contrast, according to PJM's analysis, ODEC made large net congestion payments to PJM for all years from 1999 to 2002.

Q. Are the other LSEs in the DPL Zone subject to the same amount of gross congestion costs as ODEC?

A. To compute the extent to which LSEs in the DPL Zone, besides ODEC, are subject to congestion charges, I compute the share of energy consumed in the DPL Zone that is supplied by imports over the Keeney intertie into the DPL Zone, the share of total demand in the DPL Zone that is supplied by local generation, and the share of total demand in the DPL Zone from other LSEs, besides ODEC, that is served by imports.

To make these calculations more concrete, define the following notation:

QS(d,h,y) = total generation in hour h of day d in year y on the DPL Zone computed from the unit-level hourly output data

T(d,h,y) = flow of energy in hour h of day d in year y on Keeney intertie into the DPL Zone

QD(d,h,y) = total load in hour h of day d in year y in the DPL Zone

QO(d,h,y) = total load in hour h of day d in year y in the DPL Zone for ODEC

I then compute following variables on an hourly basis

RD(d,h,y) = OD(d,h,y) – QO(d,h,y) – QS(d,h,y) = residual demand for imports by loads in the DPL Zone, besides ODEC

SIMP(d,h,y) = T(d,h,y)/QD(d,h,y) = share of total demand in the DPL Zone served by imports over Keeney intertie

SGEN(d,h,y) = QS(d,h,y)/QD(d,h,y) = share of total demand in the DPL Zone served by generation in the DPL Zone

SRD(d,h,y) = RD(d,h,y)/(QD(d,h,y) – QO(d,h,y)) = share of total demand for other LSEs besides ODEC in the DPL Zone served by imports.

Q. What results do you report from this analysis?

A. Figure 11 plots the 24 hourly means of SIMP(d,h,y), SGEN(d,h,y) and SRD(d,h,y) over all days in the first regime given above from June 1, 1998 to July 22, 1999. Figure 12 plots the daily means of these three variables for the 24 hours of the day for the second regime from July 23, 1999 to June 24, 2001. Figure 13 plots these same three sets of hourly means for the third regime from June 25, 2001 to December 31, 2002.

Q. What conclusions do you draw from these figures?

A. A number of conclusions emerge from comparing these three figures. The first is that a uniformly larger fraction of total demand in the DPL Zone was met from imports during the first regime versus the following two regimes. In particular, during the first regime, the average hourly percentage of load in the DPL Zone served by imports was more than 65 percent during a number of the early hours of the day. During the peak hours of the day, this average percentage of load in the DPL Zone met by imports was 50 percent or higher. In contrast, during the second and third regimes, this average hourly import share was only slightly above 55 percent during early hours of the morning and only slightly above 45 percent during the peak hours of the day. The means of SIMP across hours of the day during the second two regimes are very similar. This result and the fact that the average values of SIMP for the first regime are uniformly higher than the means of SIMP in both the second and third regimes is consistent with the view that turning over operation of the low voltage facilities in the DPL Zone to PJM significantly reduced the percentage demand in DPL Zone that could be served by imports during all hours of the day. Further research is needed to determine the precise timing in the decline. My analysis only shows significant decline across all hours in the day in the average hourly share of demand in the DPL Zone met by imports between Regime 1 and Regimes 2 and 3.

The second conclusion is that the percentage of total demand from other LSEs in the DPL Zone, besides ODEC, served by imports, SRD, increased substantially between the first regime and the second and third regimes. For example, during the peak hours of the day of the first regime, the average hourly fraction of the demand of DPL Zone from LSEs besides ODEC served by imports was 30 percent. In both the second and third regimes, this average hourly fraction of demand served by imports during peak hours of the day rose to approximately 45 percent. The average hourly fraction of total demand in DPL Zone served by local generation was also substantially higher during the first regime relative to the second and third regimes. For example, during peak hours of the day, the average value of SGEN is slightly more than 60 percent during the first regime, whereas it is slightly less than 45 percent during the peak hours of the day during the second and third regimes.

Q. What are your findings based on these conclusions?

A. Taken together, these two results are consistent with the logic that LSEs with local generation use FTRs as revenue sources, rather than as a passive hedge against congestion costs. Very generous FTR allocations to LSEs with generation in the DPL Zone during Regimes 2 and 3 appear to have made creating congestion in the DPL Zone more profitable than limiting congestion. By the logic of the example of the two LSEs presented earlier, the increased congestion revenues that the LSEs in the DPL Zone with local generation earned from their substantial FTR holdings made withholding local generation profitable in order to increase the frequency and magnitude of congestion and the overall amount FTR revenues paid to these LSEs.

I would like to emphasize that these conclusions are not definitive. However, they are certainly highly suggestive of the logic that DP&L may be using its substantial FTR holdings as a source of substantial revenues and therefore causing congestion rather than limiting it. By the examples presented earlier, re-allocating FTRs from DP&L to other LSEs in DPL Zone that do not own local generation should reduce the extent of congestion in DPL Zone. Further study of these issues is needed to determine the precise FTR allocation scheme, although Wolak (2002) provides a general framework for designing an efficient FTR allocation scheme.

Net Costs of Congestion in the DPL Zone Among LSEs

Q. Please summarize the goal of the next step of your testimony.

A. This step assesses the magnitude of congestion costs accounting for the impact of FTRs allocated to different LSEs in the DPL Zone, to estimate their "net" congestion costs. I only have data on ODEC's hourly load and total load in DPL South, DPL North and DPL Zone. My analysis focuses on ODEC versus all other LSEs in the DPL Zone, because I am unable to breakout these hourly zonal load numbers into the various LSEs in the DPL Zone. With data on the FTR holdings, the hourly load, and average wholesale price paid for each LSE on the DPL Zone, a more comprehensive analysis of the net costs of congestion on the DPL Zone could be performed.

Q. What is the purpose of your analysis?

A. The purpose of my analysis is to compare the hedge against high prices on the DPL Zone due to congestion provided by FTRs allocated to ODEC relative to all other LSEs located on the DPL Zone over the three regimes. All instances when prices on the DPL Zone are higher than those at the Western Hub or the PJM system-wide price are the result of transmission congestion or other ISO operating constraints which require higher cost units on the DPL Zone to supply energy rather than less expensive units located outside of the DPL Zone. However, as noted earlier, whether this energy is supplied from outside of the DPL Zone or from units located on the DPL Zone, LSEs with no local generation must pay the price on the DPL Zone for all of the energy they consume.

Q. How meaningful is it to distinguish between congestion costs and high-priced local energy for an LSE that owns little or no local generation?

A. Returning to the example of the two LSEs, when there is congestion the LSE with no local generation pays $50/MWh, the price in the constrained area, for all 100 MWh of its load. The LSE that owns local generation only pays the production cost for power supplied from the units it owns, although it receives $50/MWh for any energy it produces beyond its own energy requirements. In our example, the LSE that owned local generation sells 10/MWh at a price of $50/MWh, but was able to produce the vast majority of this energy for $20/MWh, with only 15/MWh produced at a variable cost of $50/MWh.

Q. How might this high cost of local energy borne by LSEs with limited local generation be hedged?

A. Some commentators on the DPL Zone congestion issue have suggested that LSEs with no local generation should sign forward contracts with local suppliers to hedge their risk of paying high spot prices for local energy. This is only rational for the LSE in the congested area if it is able to secure a hedge with a generator for delivery in the congested area at an average price below the average price it expects to pay for purchasing this energy in the day-ahead or real-time markets. However, if the suppliers that own local generation behave rationally, they will only be willing to sign forward contracts to supply energy to LSEs in the congested area at an average price at or above the average price it expects to be able to sell this energy in the day-ahead and real-time markets. Consequently, the assumption of expected profit-maximizing behavior by both LSEs and generation owners in the congested area is inconsistent with the success of this forward contracting strategy reducing the wholesale energy procurement costs of the LSE with no local generation. A necessary condition for the success of this strategy is that the generation owners in the congested area are risk averse. This fact would imply that these suppliers are willing to accept a lower average price for the forward contract than the average price at which they expected to be able sell this power in the day-ahead and real-time markets, because this forward price is certain at the time the contract is signed and the day-ahead and real-time prices are not. In our example, suppose the LSE with no local generation approached the LSE that owned local generation and asked to sign a forward contract for energy from its local generation units. If the generation-owning LSE sold energy in a forward contract at a price below \$50/MWh it would be giving away profits, because it knows that it can sell all of its energy within the congested area at \$50/MWh if it withholds enough low cost power to cause congestion. Consequently, the LSE that owns local generation cannot expect to buy forward contracts from local generation owners at a price below what these suppliers will expect to be the prevailing spot price. Otherwise these suppliers would not be serving their fiduciary responsibility to their shareholders.

This example shows that local generation ownership and FTR holdings both provide protection against high local prices due to congestion. Forward contracts with local generation owners at prices equal to those outside of the congested area also provide an effective hedge. However, as shown above, expected profit-maximizing suppliers with local generation would not find it optimal to offer such contracts. Although there are circumstances where such a contract might exist, for example, suppose that an LSE that owns local generation sold some of these units to another entity but the new owner was required to sell back power to the former owner in a forward contract each hour at a fixed price. To the extent that this forward contract price is below prices in the DPL Zone, the LSE would have a very effective hedge against high local energy prices even though it no longer owned the units. By the same logic, the more the variable cost of the local generation owned by the LSE is below the price in the congested region, the better is the hedge against high local energy prices provided by this local generation affiliate. Finally, the lower the LMPs at the source point of an FTR that has a sink bus in the LSE's service area, the better is the hedge against high prices in the DPL Zone provided by the FTR. However, as noted above, attempting to negotiate a forward contract with a supplier in the DPL Zone as a way to hedge high local energy prices is very likely to provide little, if any, hedge against high local spot energy prices, because the seller of the contract should have at least as much information as the buyer of the contract about the likelihood of congestion during that hour which then leads to high local energy prices. As noted above, an expected profit-maximizing local supplier would be willing to sell power in a long-term contract only if the profits from this sale exceed the profits the supplier expected to make from selling that energy in the day-ahead and real-time markets.

Q. Please describe the analysis that you performed of the distribution of net congestion costs among LSEs in the DPL Zone?

A. To measure the relative amount of protection from high local prices provided by FTRs held by ODEC relative to FTRs held by all other LSEs in the DPL Zone, I define the following notation:

FTR(h,d,y) = ODEC's FTR holdings during hour h of day d of year y

FTRTOT(h,d,y) = Total available FTRs to LSEs in the DPL Zone during hour h of day d of year y.

Compute the following the magnitudes:

SFTR(h,d,y) = FTR(h,d,y)/QO(h,d,y) = Share of ODEC's load covered by FTRs

SFTROTH(h,d,y) = ((FTRTOT(h,d,y)–FTR(h,d,y))/(QD(h,d,y)–QO(h,d,y)– QS(h,d,y))) = Share of other load net of own generation covered by FTRs.

Q. What results do you present from this analysis?

A. Figure 14 in Exh. ODC-23 plots the means of SFTR and SFROTH for each hour h for the first regime. For the entire Regime 1 period, ODEC had no FTRs so the value of SFTR is identically equal to zero for all hours and days. Because all of the available FTRs were allocated to other LSEs in DPL Zone, the average value SFROTH is many times greater than 1 in many hours. Moreover, there are a number of hours when the amount of local generation exceeded the demand of all other LSEs besides ODEC. That is why the mean value of SFTROTH is negative for a number of hours, as is shown on the top right of Figure 14.

Figure 15 in Exh. ODC-23 plots the means of SFTR and SFTOTH for Regime 2. Once again, the average value of SFTROTH is orders of magnitude larger than the average value of SFTR for all hours except hour 17, when the mean value of SFTROTH is negative for the same reasons as those discussed above. Figure 16 plots the means of SFTR and SFTROTH for Regime 3. This plot shows that for the off-peak hours, the means of SFTR and SFTROTH are remarkably similar. However, for the on-peak hours, the mean SFTROTH is often more than double the mean of SFTR. These results show that the extent to which ODEC's FTR allocation hedges it against high prices in the DPL Zone relative to all other LSEs in DPL Zone has steadily improved across Regimes 1, 2, and 3. However, particularly during the peak hours of the day, ODEC has a significantly smaller hedge—roughly half as large--against high prices in the DPL Zone relative to the hedge against high prices in the DPL Zone provided to all other LSEs by their FTR and generation holdings. Therefore, while ODEC's hedge against congestion has increased across the three regimes, ODEC still lacks sufficient FTRs and faces high congestion costs.

Q. Please describe your findings regarding summer peak periods.

A. Because the summer months are periods of substantial congestion in the DPL Zone, I have re-computed Figures 14 to 16 restricting the sample to only the summer days (June 1 to September 30) during each regime. These results provide an even clearer picture of the change in the relative hedge against high prices in the DPL Zone provided by FTRs held by ODEC relative to the FTRs held by other LSEs in the DPL Zone. Figures 17 and 18 show other LSEs in the DPL Zone received an extremely generous average FTR coverage relative to the average FTR coverage received by ODEC for the summer days of Regimes 1 and 2. Figure 19 shows the average value of SFTR is slightly less than 1, whereas the average value of SFTROTH is higher than 2 during all peak hours and as high as 3 during hour 19. This figure implies that during the peak hours of the summer months of Regime 3, the quantity of FTRs allocated to ODEC provides it with substantially less protection against high prices in the DPL Zone relative to protection provided to other LSEs in the DPL Zone by the quantity of FTRs allocated to them and their own generation.

Q. What conclusions do you draw from this analysis?

A. The results in Figures 16 and 19 are consistent with the logic that the current FTR allocation among LSEs in the DPL Zone awards too few FTRs to ODEC and too many FTRs to other LSEs in the DPL Zone. Particularly, during peak demand periods of the summer months, it would appear that these suppliers have an incentive to restrict output from their own units in order to increase the revenues they receive from their FTR holdings. Similar to the example presented earlier, by allocating more FTRs to LSEs that do not own local generation and less to suppliers with local generation, the generation-owning LSEs will have a stronger incentive to bid and operate their units to alleviate congestion.

Q. Please summarize the results of your analysis thus far

A. The analysis presented thus far suggests that the frequency, duration, and magnitude of congestion in the DPL Zone have been adversely impacted by the bidding and scheduling behavior of suppliers in the DPL Zone and the operating protocols employed by PJM for managing the low voltage system in the DPL Zone. A final potential source of congestion is the frequency and magnitude of transmission outages in the DPL Zone. Because DP&L is the transmission provider in the DPL Zone, the largest LSE in the DPL Zone, and the largest owner of generation in the DPL Zone, another way for DP&L to exploit the very generous FTR allocation given to DP&L is through scheduling forced and planned transmission outages. When DP&L operated the low voltage system in the DPL Zone we would not expect it to use planned or unplanned transmission outages in this manner. However, during Regimes 2 and 3, another way to increase the frequency, duration and magnitude of high prices in the DPL Zone is to declare unplanned outages and schedule planned outages at the appropriate time.

<u>Causes of Congestion on the DPL Zone</u>

Q. Please describe you analysis of the impact of transmission outages in the DPL Zone on congestion costs?

A. To assess the extent to which transmission outages contribute to high prices in the DPL Zone for each of the three regimes described above, this analysis requires the following notation. Define the following indicator variable:

TRANOUT(h,d,y) = 1 if hour h of day d in year y has a planned or scheduled transmission outage on the DPL Zone (including the Keeney intertie) and zero otherwise

For each hour compute

OUTCONG(h,d,y) = TRANOUT(h,d,y)*(PD(DPL Zone,h,d,y) – PD(WH,h,d,y))

CCONG(h,d,y) = (PD(DPL Zone,h,d,y) – PD(WH,h,d,y))

where PD(DPL Zone,h,d,y) is the DPL Zone real-time price and PD(WH,h,y) is the Western Hub real-time price. For each of the three regimes compute the hourly mean value of OUTCONG(h,d,y) and CCONG(h,d,y).

Q. What results are presented from this analysis?

A. The 24 hourly means of both variables are plotted in Figure 20 for Regime 1. Figures 21 and 22 contain these two pairs of hourly means for Regimes 2 and 3. Comparing the hourly means of CCONG and OUTCONG shows that although congestion tends to occur in hours 13 to 17 before the lower voltage facilities were turned over to PJM's control, transmission outages provide no predictive power for explaining the magnitude of congestion. The results in Figures 21 and 22 show the exact opposite result. The hourly means of OUTCONG closely track the hourly means of CCONG in both Regimes 2 and 3. Moreover, there is very little difference between these two hourly means for all hours of the day in both Regime 2 and 3, suggesting that virtually all of the congestion costs, as measured by CCONG, can be explained by transmission outages. The results for Regime 3 are particularly notable because the average value of CCONG is almost $12/MWh in hour 15 and the average value of OUTCONG is close to $10/MWh. These results suggest that the strategy for causing congestion in the DPL Zone using transmission outages described above could be particularly profitable during the peak hours of Regime 3.

Figures 23 to 25 plot the hourly means of CCONG and OUTCONG for the summer days (June 1 to September 30) of the three regimes. These results strongly reinforce the above conclusions. During the summer months of Regime 1, transmission outages explain none of the congestion in the DPL Zone during the peak hours.

However, during Regime 2 and 3, transmission outages explain virtually all congestion charges during all hours of the day. Finally, during the summer hours of Regime 3 the average value of CCONG reached as high as $31/MWh during hour 15 and the average value of OUTCONG is almost $26/MWh suggesting that a strategy of declaring transmission outages during these peak summer hours could be extremely profitable to DP&L as an LSE that owned a significant amount of FTRs and local generation.

Q. Did you perform this analysis for the day-ahead market?

A. Yes. To investigate whether this same pattern holds for the day-ahead market, I compute CCONG(h,d,y) and OUTCONG(h,d,y) using the day-ahead price. Unfortunately, the day-ahead market only started June 1, 2000, which is in the middle of Regime 2, so it is not possible so compare the day-ahead values of CCONG and OUTCONG before PJM took over control of the low voltage system in the DPL Zone. Figures 26 and 27 show that the relationship between CCONG and OUTCONG computed using the day-ahead prices is even stronger than for the real-time prices. This conclusion is even stronger for Regime 2, before DP&L transferred control of a number of units in DPL South to NRG. CCONG and OUTCONG are virtually identically across all hours of the day. Figures 28 and 39 compute Figures 26 and 27 restricting the sample to days during the summer months. For Regime 2, despite average values of CCONG in some hours of over $7/MWh, OUTCONG is virtually identical to CCONG across all hours of the data. Figure 30 shows that even though the peak hours of the day have large mean values of CCONG, the means values of OUTCONG are only slightly smaller than the mean of CCONG. Consequently, the day-ahead price results reinforce the conclusions of real-time price results.

Q. What conclusions do you draw from this analysis?

A. This analysis implies that the vast majority of congestion in the DPL Zone during Regimes 1 and 2 can be explained by transmission outages. This result suggests that the price signals contained in the significantly higher hourly average DPL Zone prices during Regimes 1 and 2 should not cause suppliers to build new generation capacity in the DPL Zone. If these suppliers recognize that virtually all of the difference between prices in the DPL Zone and those at the Western Hub can be attributed to transmission outages, they will be extremely reluctant to invest in capacity based on such an unreliable price signal.

For example, if PJM adopted procedures for planning transmission outages that accounted for the potential congestion cost due to this outage, provided strong incentives to the transmission owners to reduce the probability of unplanned outages, and adopted the other recommended remedies given at the end of my testimony, the difference in prices between the DPL Zone and the Western Hub should be substantially reduced, along with the financial viability of a potential new generation project. For this reason, I believe it is very unlikely that any supplier would invest in new generation capacity based on this price signal.

One possible mechanism for strengthening the incentives for transmission owners to limit the frequency and magnitude of transmission outages would be for PJM to set target annual average transmission capacity levels between all nodes in the transmission network at the start of each year. To the extent that the actual annual average amount of available transmission capacity ("ATC") between two locations during that year was less than this magnitude, the transmission owner would be penalized. To extent that the actual annual average ATC exceeded this target, the transmission owner would be rewarded. This scheme could be further refined by making the distinction between peak and off-peak hours of the year and setting set the penalty and reward higher during peak hours, to increase incentives for transmission owners to guard against unplanned outages during peak periods.

Additional Studies of Cost, Burden and Causes of Congestion on DPL Zone

Q. Are there other studies that could be performed to assess the extent to which local market power has contributed to the costs of congestion in DPL Zone?

A. Yes, there are a number of other studies of the causes of congestion in the DPL Zone that could be performed to investigate in more depth many of the issues raised by the analyses presented in this testimony.

As noted above, with information on the hourly energy flows at each location in the DPL Zone a more detail analysis of the impacts of local market power in DPL South price versus the DPL North price could be performed. This information would include, at a minimum, flows south on the 230 kV lines at Keeney, the 230 kV line at Red Lion and the 138 kV line at Glascow.

Information on the hourly load of each LSE in the DPL Zone at each Bus in the DPL Zone could be combined with information on the FTR holding of each LSE in the DPL Zone to compute a better estimate of the relative costs of congestion borne by LSEs in the DPL Zone. This calculation could be further refined with hourly information from PJM's e-schedule system and information on the day-ahead energy schedule of each LSE in the DPL Zone and the real-time energy purchases of each LSE in the DPL Zone.

Q. Are there studies that could be performed to quantify the cost to ODEC of the exercise of local market power in the DPL Zone?

A. Yes, the methodology outlined in Borenstein, Bushnell and Wolak (2002), henceforth, "BBW," for measuring market inefficiencies in wholesale electricity markets can be applied to the DPL Zone to assess the extent to which the exercise of local market power has raised prices in the DPL Zone.[2] This methodology was first applied to the California electricity market which depends on imports for approximately 20% of its annual electricity needs. Treating the DPL Zone as a separate market similar to the California ISO control area and the imports into the DPL Zone as analogous to imports in the California ISO control area, the BBW analysis can be directly applied using the confidential information on hourly production from units in the DPL Zone and hourly imports into the DPL Zone. The counter-factual competitive supply curve in the DPL Zone can be constructed using the heat rates, fuel costs and variable operating and maintenance costs described earlier in my testimony.

I have performed a preliminary analysis of the BBW methodology for the DPL Zone from June 1, 1998 to December 31, 2002. The difference between the average real-time hourly DPL Zone price weighted by ODEC's hourly load and the average hourly competitive benchmark price in the DPL Zone (computed using the BBW methodology) weighted by ODEC's hourly load this entire time period is approximately \$6/MWh. This means that the combination of local market power and inefficiencies in the PJM market design cost ODEC on average \$6 per MWh for energy that it consumed. This estimate is very conservative for a number of reasons. First, I used the DPL Zone price as the price ODEC pays for load even though it actually pays the DPL South price, which is consistently higher than the DPL Zone price. I also assumed substantially higher forced outage rates for units in the DPL Zone than is contained in the National Electricity Reliability Council (NERC) historical forced outage rates for similar types of generating units. I also used conservative estimates for natural gas and oil local distribution costs in the DPL Zone.

Translating this $6/MWh into an estimate of the cost of local market power and other market inefficiencies over the period of June 1, 1998 to December 31, 2002 by computing the difference between the hourly real-time DPL Zone price less the hourly competitive benchmark price times ODEC's hourly load summed over all hours, yields approximately $40 million. This means that ODEC paid approximately $40 million dollars more than it would have paid had the market inefficiencies described above and local market power, that it in part enabled, not existing during this sample period.

These results are very preliminary and therefore subject to change. However, the order of magnitude of this estimate of the costs resulting from: (1) PJM's local market power mitigation mechanism, (2) its operating protocols for the low voltage transmission system in the DPL Zone, and (3) the method it uses to allocate FTRs, implies that further studies of these issues is warranted in order to solve the problem on the congestion in the DPL Zone.

Q. What else did you learn from this preliminary analysis?

A. I also attempted to assess the extent to which higher heat rate units (more inefficient units) in the DPL Zone were run more intensively and lower heat rate units run less intensively than would be predicted by the competitive benchmark pricing dispatch in the BBW analysis. Specifically, I found that the higher values of the hourly deviation between actual output and the output predicted by the BBW analysis were associated with higher unit-level heat rates. This result means that the higher heat rate units were run more intensively than would be predicted by the BBW benchmark pricing dispatch and lower heat rate units less intensively, consistent with the exercise of local market power as described earlier in the example of the two LSEs serving local demand. The same caveats apply to this analysis, but the results suggest further study is warranted.

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[2] Borenstein, Severin, Bushnell James, and Wolak, Frank A. (2002) "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," *American Economic Review*, December, pp.

Q. What do you conclude from all of the analyses described above?

A. Although the analysis of the magnitude of the costs congestion in the DPL Zone, distribution of these costs across LSEs, and the causes of congestion in the DPL Zone, could be extended in a number of directions, one conclusion clearly emerges: There are a number of market inefficiencies that enhance the ability of suppliers and transmission owners to profit from congestion in the DPL Zone. Further analysis may provide better estimates the costs of each of these market inefficiencies, but the results presented in Figures 1 to 29 provide strong evidence that a number of improvements in system operation, the local market power mitigation mechanism, the FTR allocation process and transmission outage coordination can substantially reduce the costs of congestion in the DPL Zone and improve the efficiency of the wholesale energy market in the DPL Zone.

Several of these proposed changes are discussed in the testimony of other ODEC witnesses as well as in the next section. (*See* List of ODEC recommendations, Exh. ODC-2) However, the major conclusion that I draw from these analyses is that there are a number of flaws in the current market design used to manage congestion in the DPL Zone. Whether or not these proposed changes are adopted, the market inefficiencies described above are worthy of further study and must be addressed in order to craft a permanent to solution to the problem of congestion in the DPL Zone, and other areas like it in the PJM control area.

<u>Suggested Remedies for Market Inefficiencies</u>

Q. Please summarize your suggested remedies for these market inefficiencies.

A. There are four categories of deficiencies in the current market design in PJM that enhance the ability of suppliers and transmission operators to profit from causing congestion in the DPL Zone. The first concerns the protocols used by PJM to operate the lower-voltage facilities versus the protocols used by DP&L during Regime 1. The second concerns the local market power mitigation mechanism used to determine which generation units possess local market power and what to pay units deemed to possess substantial local market power. The third relates to the mechanism used by PJM to allocate FTRs to LSEs. The fourth category deals with how planned transmission outages

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1376-1405, attached as Exh. ODC-28.

are determined and how the costs of unplanned outages are allocated among market participants.

Q. Please address PJM's operational control over lower-voltage facilities.

A. The comparison of the average hourly mean of SIMP across the 24 hours of the day in Regime 1 relative to Regimes 2 and 3, suggests that protocols used by PJM to operate the low voltage system in the DPL Zone leaves a smaller average hourly share of demand of the DPL Zone to be served by imports during all hours of the day. Consequently, unless there were clear reliability problems associated with how DP&L operated the low voltage system in the DPL Zone, the PJM operators should adopt features of these protocols which allow greater import participation in meeting the total demand in the DPL Zone.

Q. What is your recommendation regarding PJM's local market power mitigation mechanism?

A. Wolak (2002) discusses the incentives for leveraging local market power created by the current PJM local market power mitigation mechanism. The results in Figure 1 to 19 suggest that these leveraging strategies could be extremely profitable to suppliers owning generation in the DPL Zone, because the bids for the mitigated units are allowed to enter the LMP pricing mechanism. The incentive to withhold lower cost units to cause congestion increases because allowing a mitigated bid that contains an ad hoc adder above an already high estimated variable cost of producing energy will set an extremely high price within the constrained area. Wolak (2002) proposes a mechanism based on the concept of a pivotal supplier to determine whether a firm possesses local market power worthy of mitigation. This mechanism does not allow the bid from the portion of the generation unit that is mitigated to enter the LMP mechanism. This constraint on the LMP mechanism limits the incentive and ability of suppliers with local market power to leverage this market power to other units in their generation portfolio. Wolak (2002) discusses this proposal in detail and compares its properties to the current PJM local market power mitigation mechanism.

Even this recommended local market power mitigation mechanism is not adopted by PJM, a formal process should designed for setting the cost-based bids for generation unit in PJM, so that suppliers are unable to set variable costs the deviate significantly from the unit's heat rate times the price of the input fuel plus the unit's verifiable operating and maintenance costs that can be causally related to producing an additional MWh of energy. As noted earlier, allowing too much discretion in how these regulated costs are set can unnecessarily allow suppliers to exercise local market power.

Q. Do you have a recommendation regarding PJM's FTR allocation mechanism?

A. Yes. Wolak (2002) also discusses how failing to account for local generation ownership of an LSE in the FTR allocation mechanism can lead to the LSE using its FTRs as a source of revenues, rather than as a hedge against congestion charges, much to the detriment of market efficiency. A mechanism for allocating FTRs is proposed and its market efficiency-enhancing properties are discussed in Wolak (2002). The example presented above explains the basic logic of this FTR allocation mechanism: Account for local generation owned by the LSE to the extent that it provides an effective a hedge against high local energy prices as owning FTRs. For example, if on an annual basis, 100 MW of local generation provides the same level of protection against high local energy prices as 50 MWs of FTRs, then an LSE owning this 100 MW unit should receive 50 MW less FTRs than an LSE that does not own local generation.

Q. What is the final source of market inefficiencies that should be addressed?

A. The final market inefficiency is illustrated and quantified by Figures 20 through 29 which show that during Regimes 2 and 3, transmission outages explained virtually all congestion costs between the Western Hub and the DPL Zone average price. These results imply that the PJM ISO should take a more active role in planning transmission outages and recognize the incentives faced by transmission owners with generation-owning affiliates or LSE affiliates that also have a substantial quantity of FTRs. These results also suggest that transmission owners with generation and LSE affiliates should also face strong incentives to remedy unplanned transmission outages as soon as possible. Different from the case of purely independent transmission owners, these firms may in fact wish to prolong transmission outages because it increases the profitability of their generation portfolio or it increases the revenues their LSE-affiliate receives from its FTR holdings.

As noted earlier, in areas such as the DPL Zone, few market participants want economically viable transmission upgrades to occur. As noted earlier, the local portfolio generation unit owner and the generation-owning LSE with significant FTR holdings would prefer to have congestion, which raises the prices they receive for their energy. The LSE with significant FTR holdings that is affiliated with the transmission owner faces the same incentives to cause congestion. Only the LSE with no local generation holdings would like transmission upgrades that satisfy a benefit cost test to occur. However, as noted earlier, it has limited ability to implement these upgrades. Consequently, PJM must ensure that all of the incentives against these economic upgrades taking place do not prevent them from going forward in a timely manner. For this reason, a final remedy is to formulate a pro-active mechanism for PJM to monitor the transmission network to identify economic upgrades and ensure that the relevant transmission owner implements them as soon as possible.

Q. Do you have any concluding comments?

A. The analyses presented in my testimony demonstrate that congestion in the DPL Zone is a problem that has continued over time and the extent and pattern of this problem has changed in response to changes in the PJM market design. Unless the market inefficiencies identified here are addressed, this problem is unlikely to be solved. Continuing with the current market design with no significant transmission upgrades and the same FTR allocation mechanism will continue to create significant incentives for suppliers in the DPL Zone to create rather than eliminate congestion. The transmission network experiences congestion because this is the most profitable market outcome for each supplier and demander given the actions of all other market participants. Consequently, whether congestion occurs under a given set of demand conditions depends on the market rules and other incentives faced by suppliers, load and transmission network providers. Unless these incentives are changed it is difficult to see how problems with congestion in the DPL Zone experienced by ODEC will be eliminated.

Q. Does this conclude your testimony?

A. Yes.

Figure 1

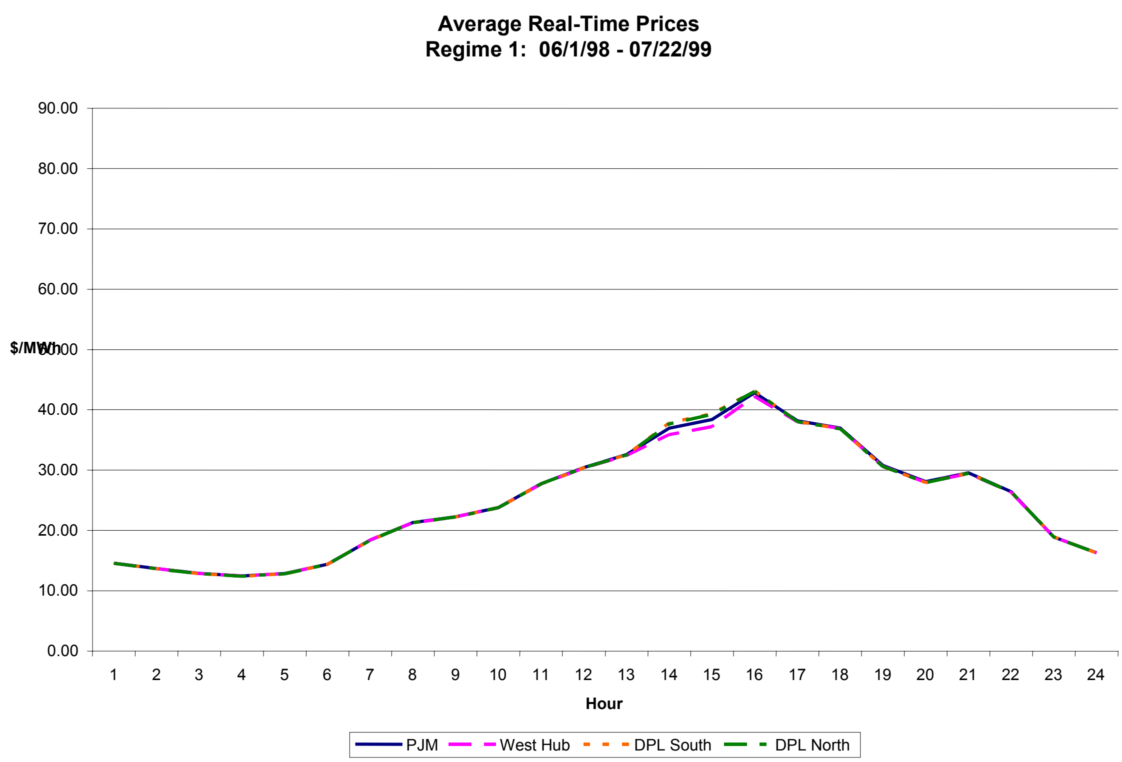


Figure 2

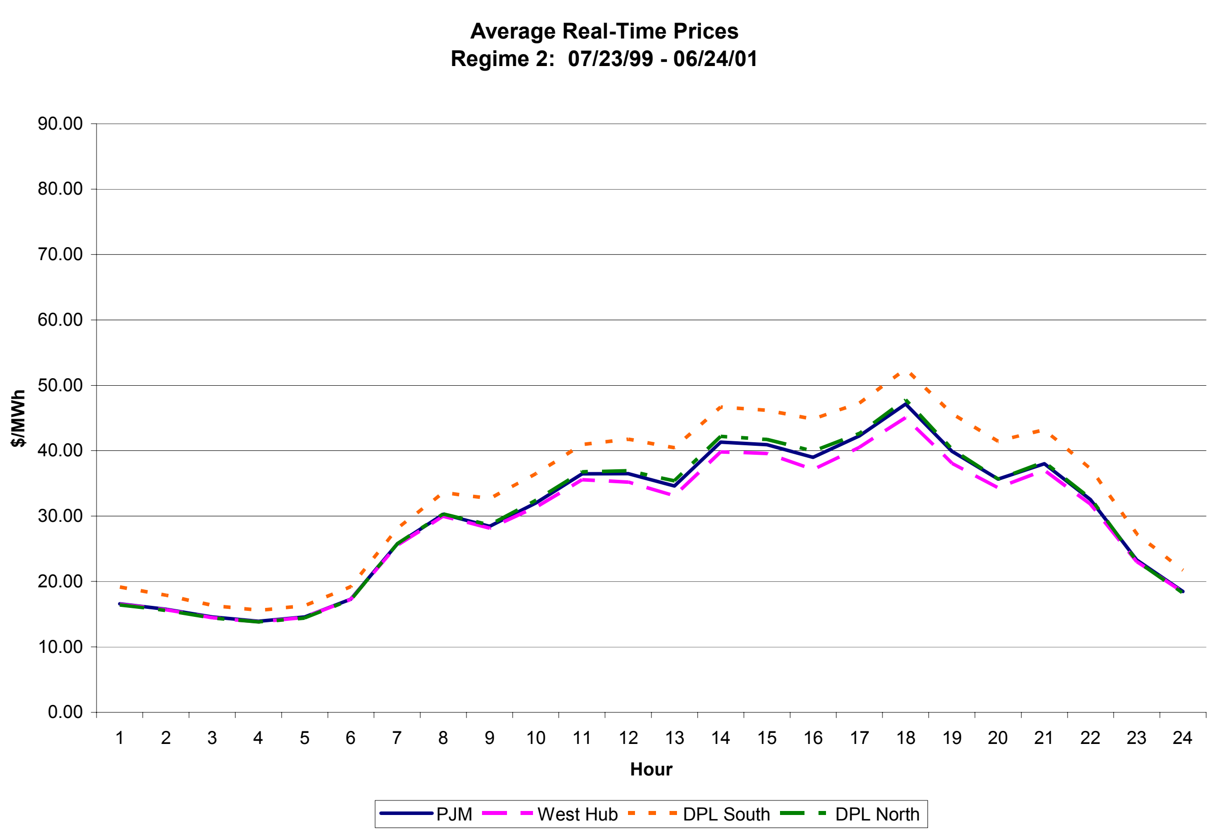
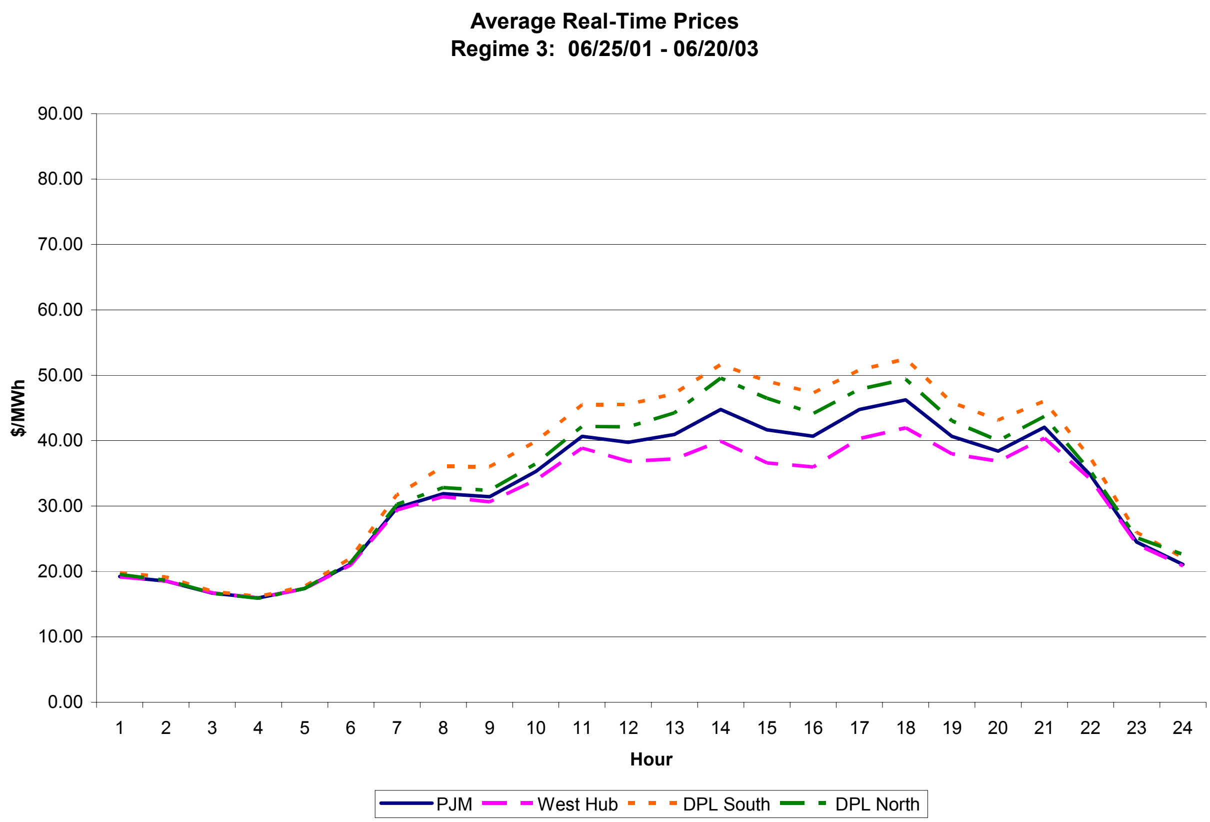


Figure 3



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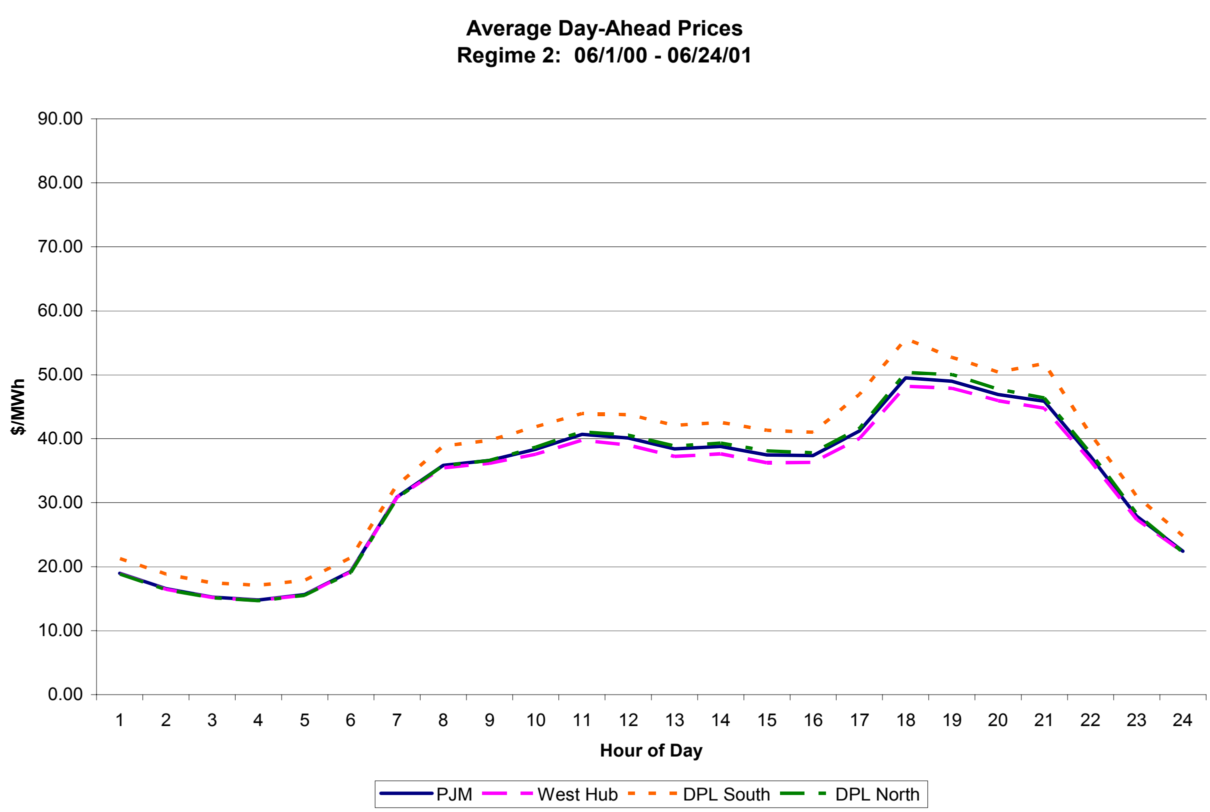

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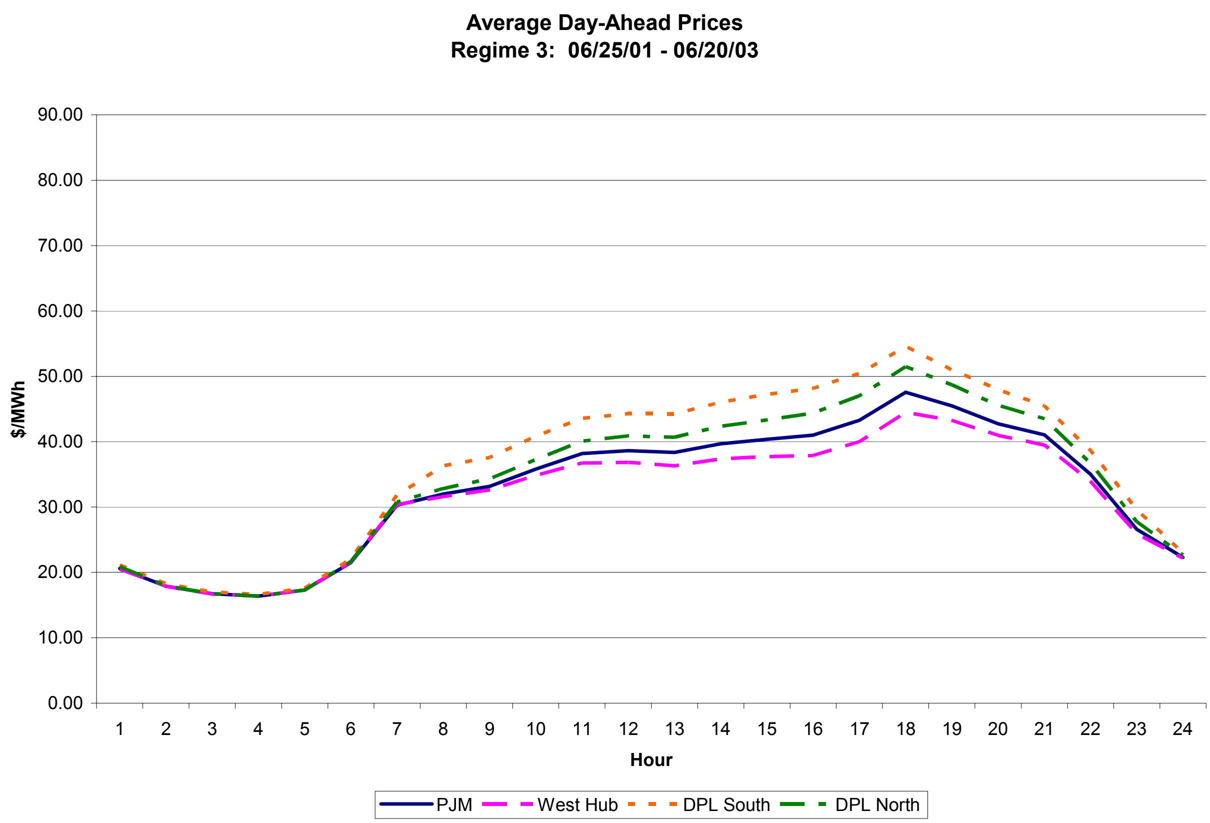

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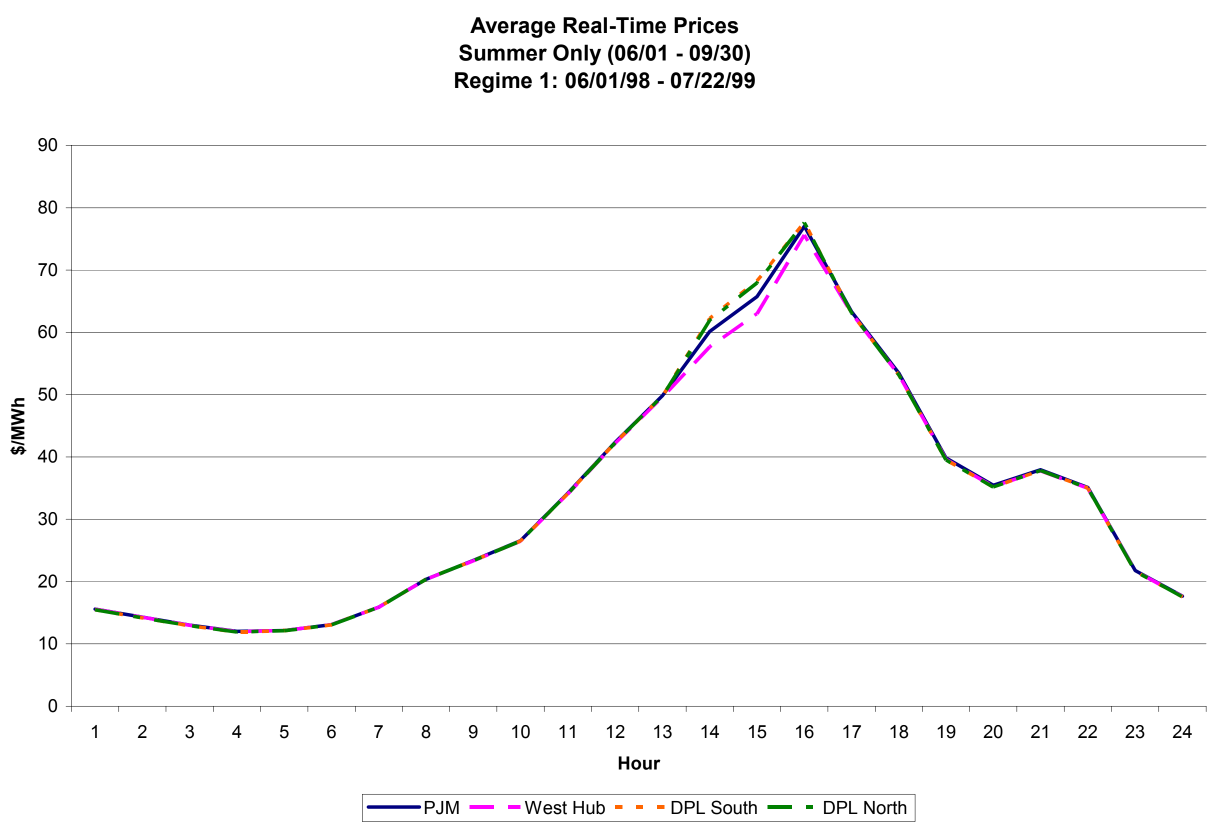

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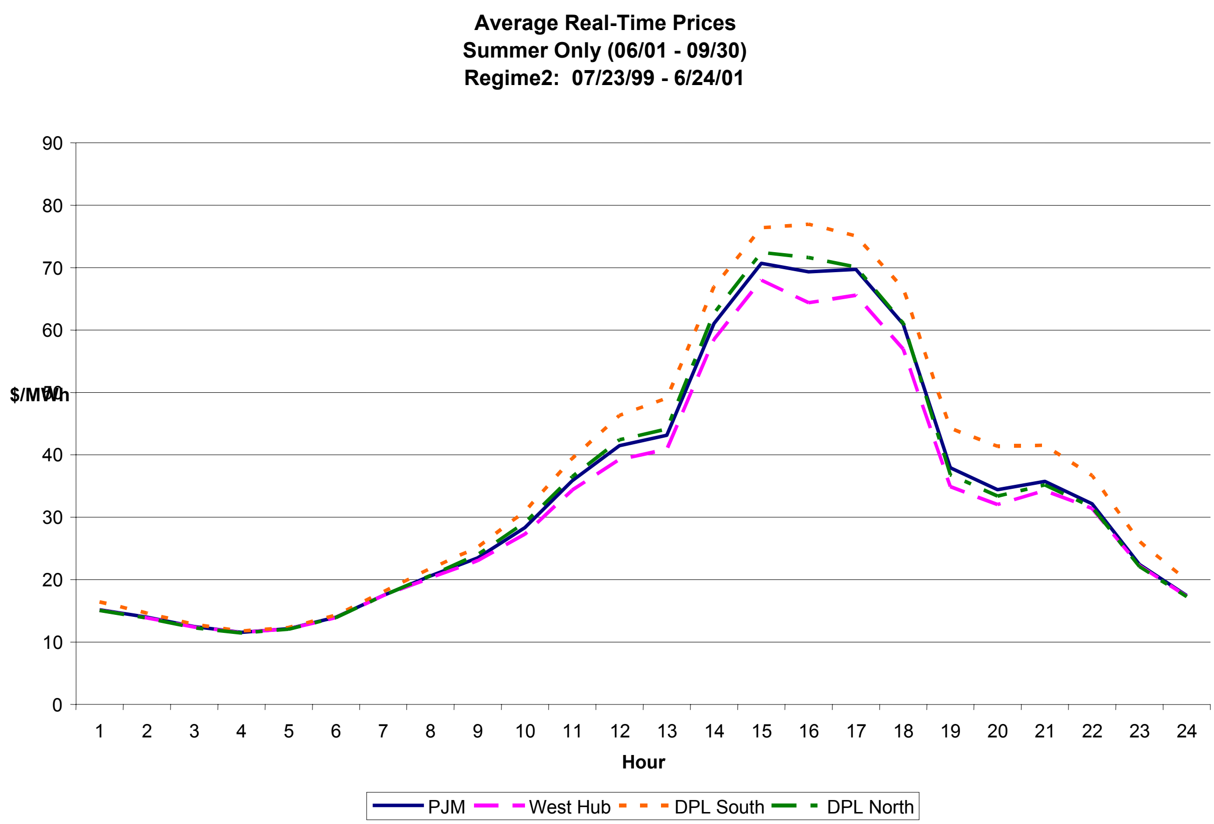

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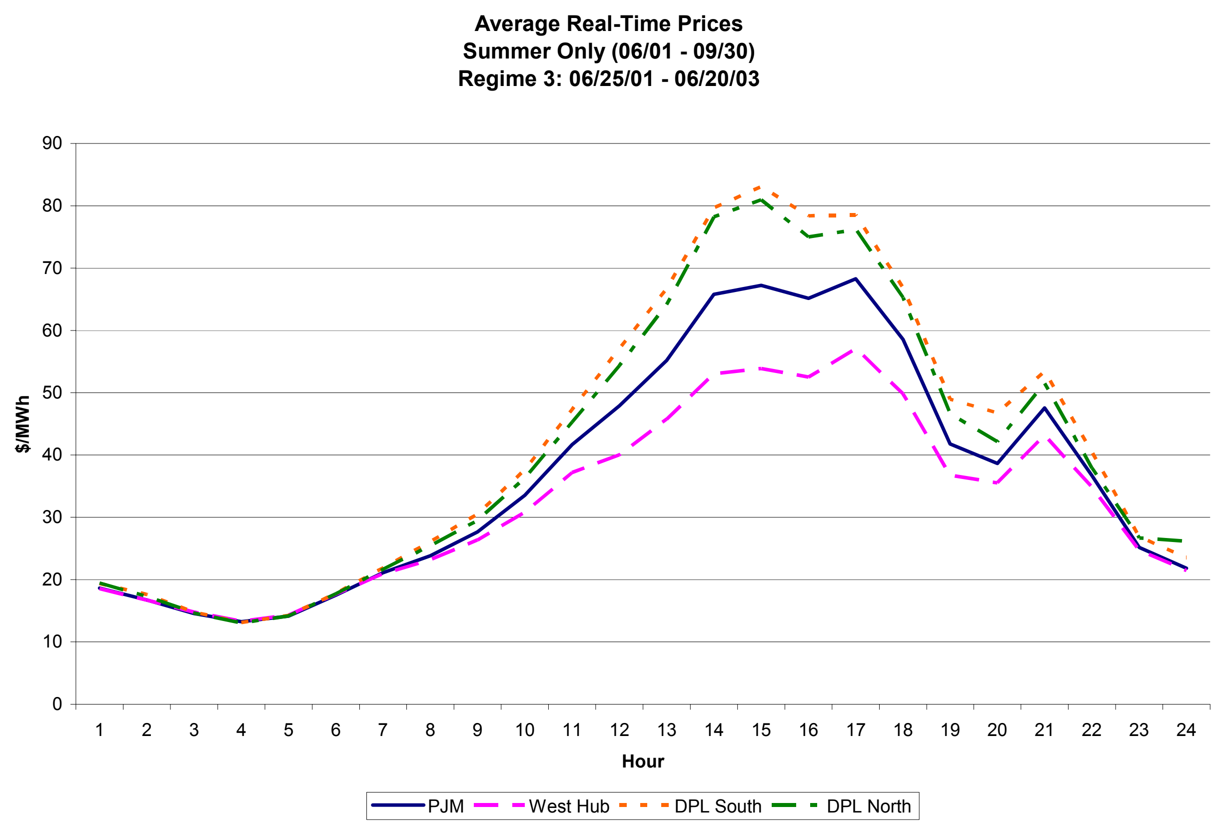

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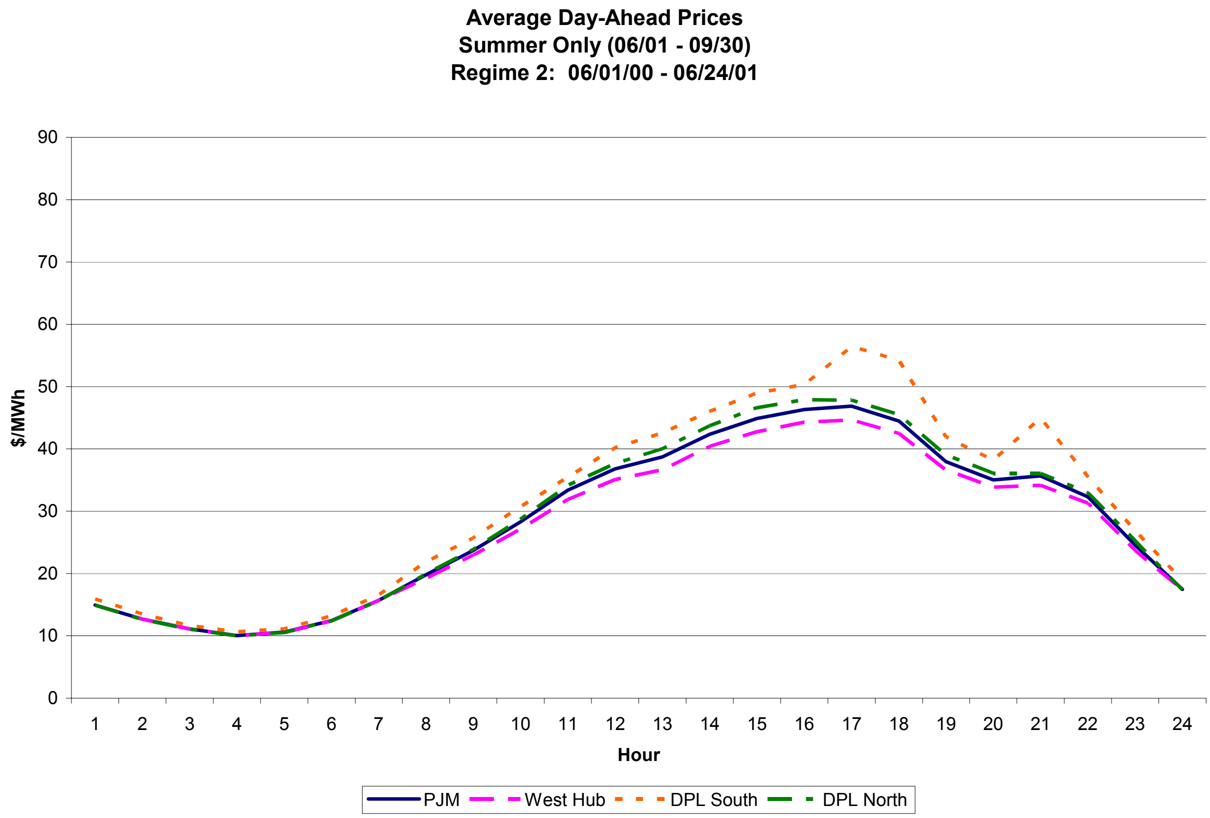

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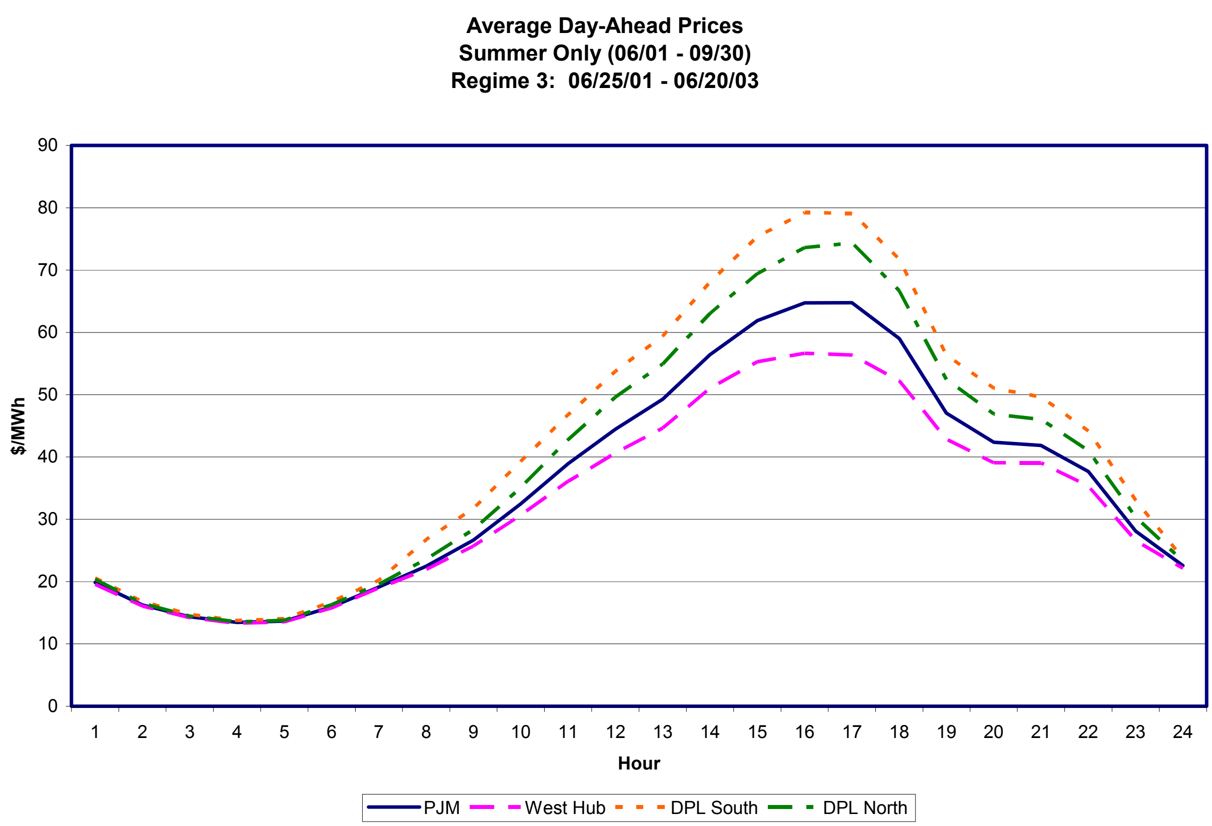

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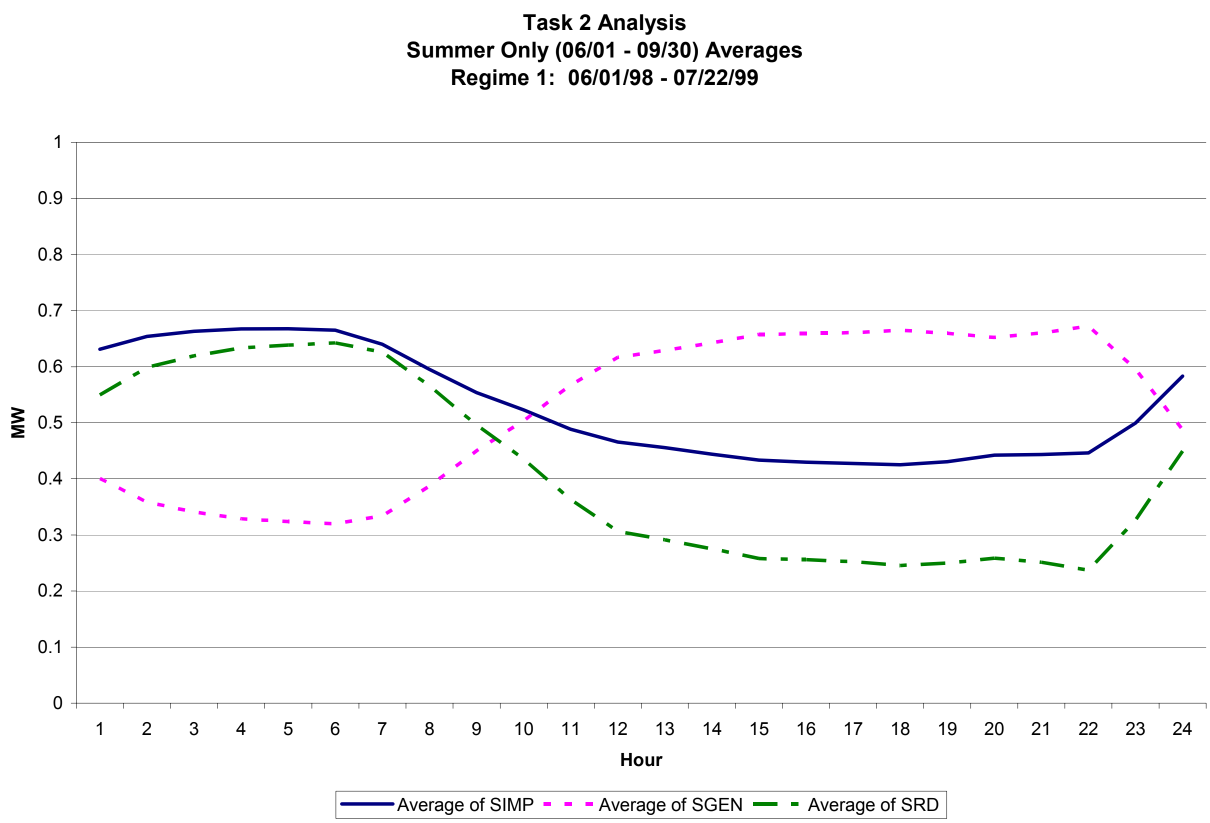

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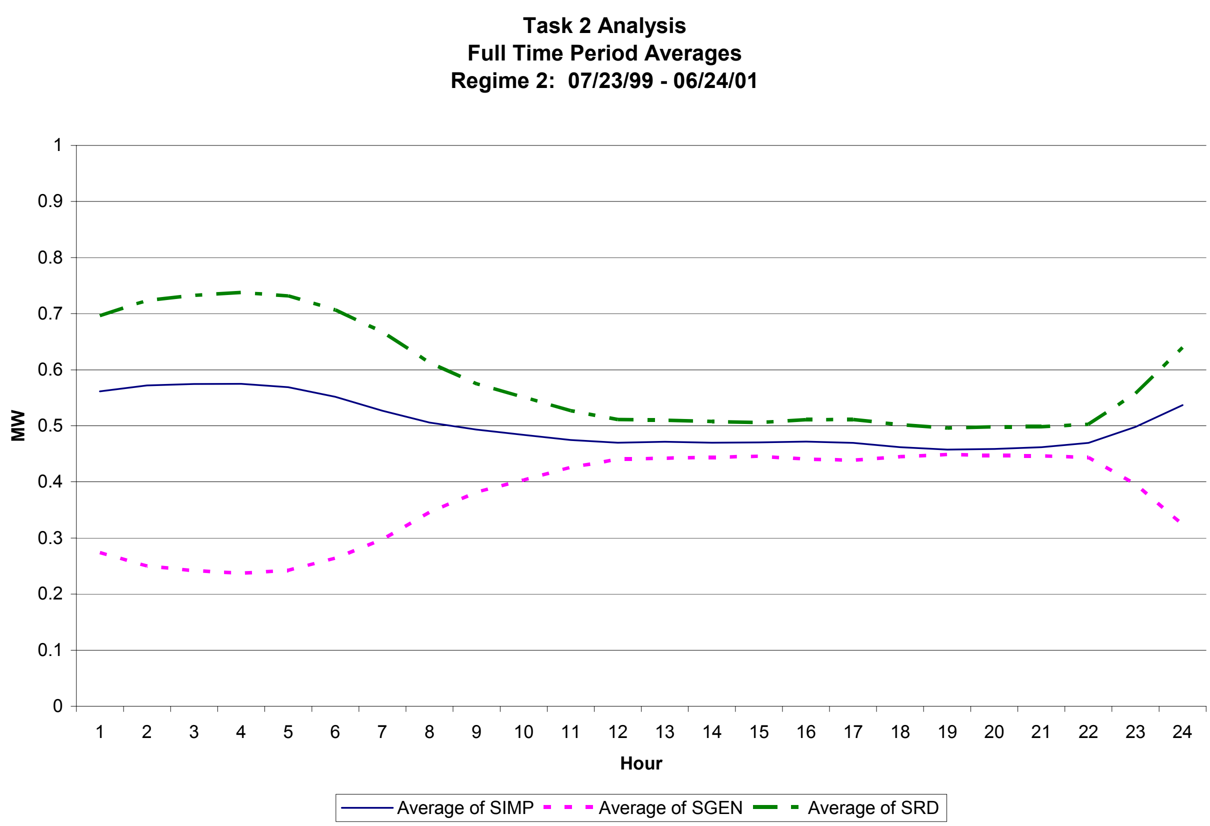

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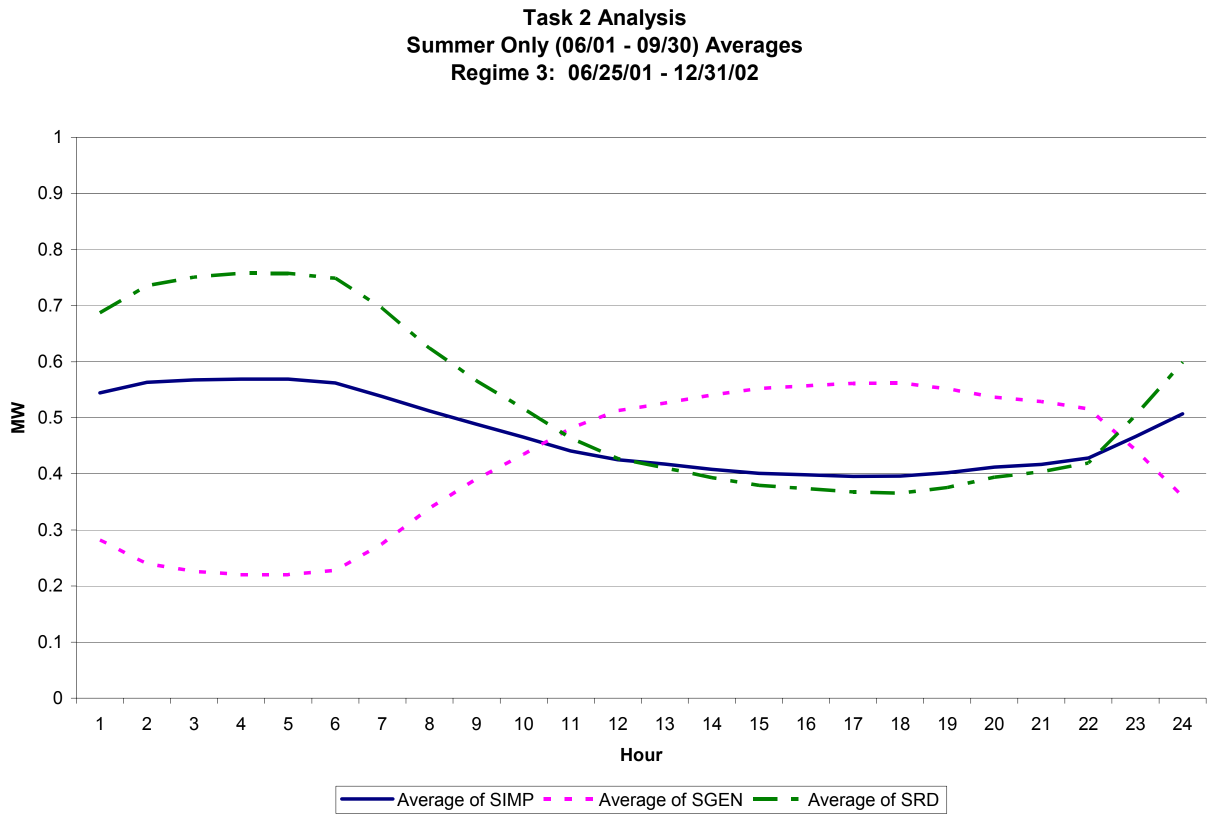

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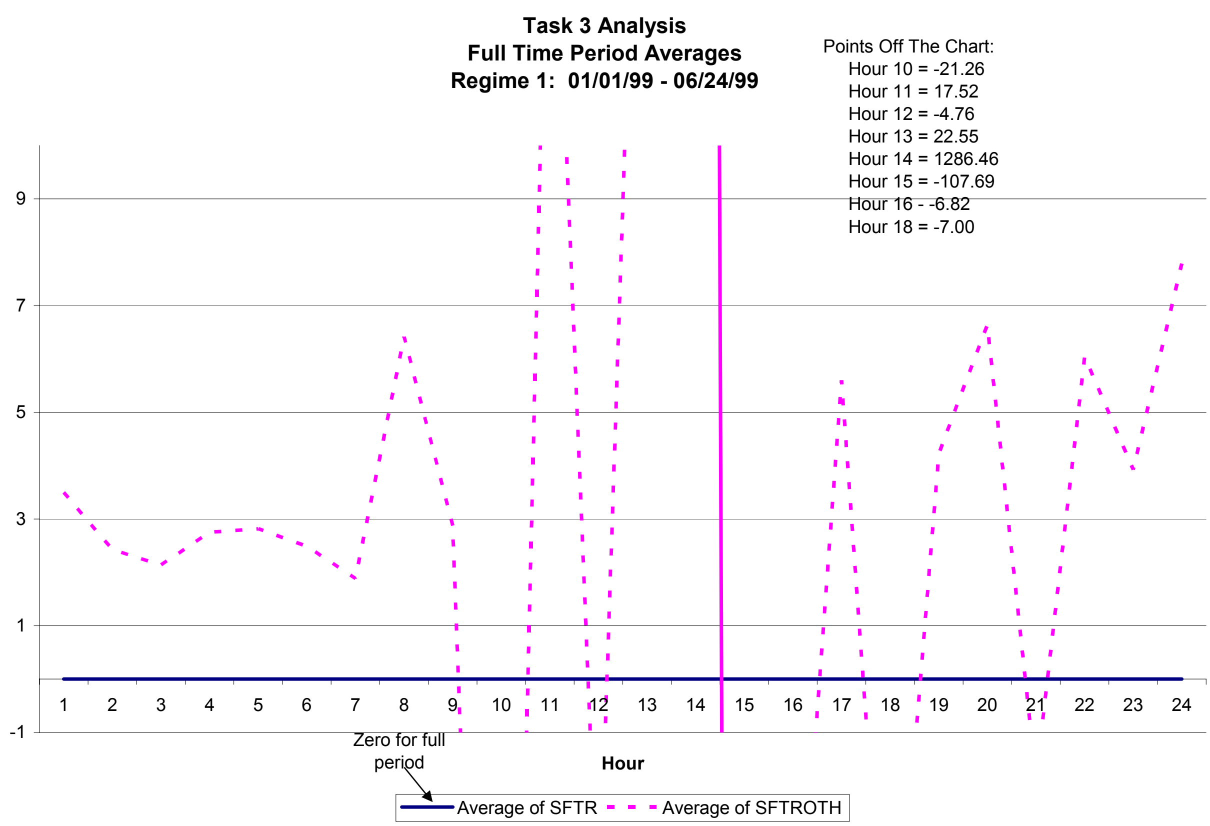

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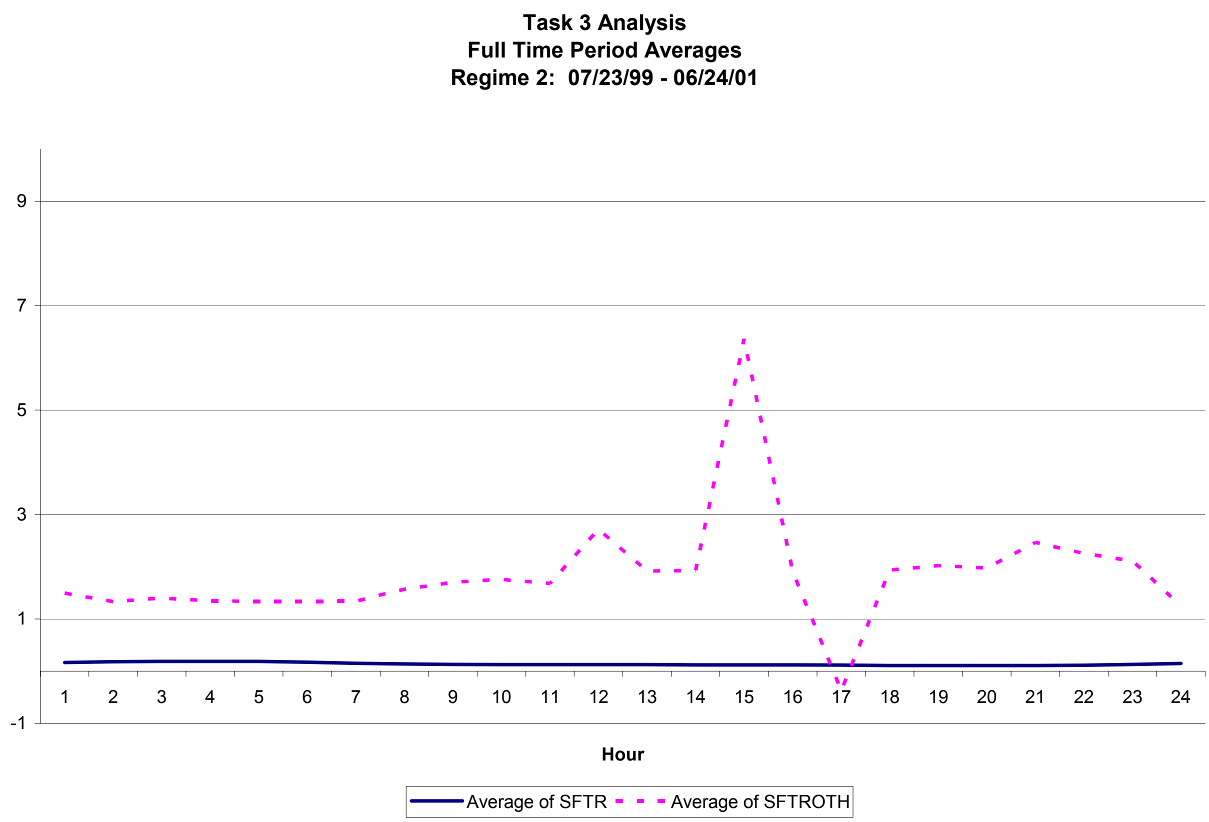

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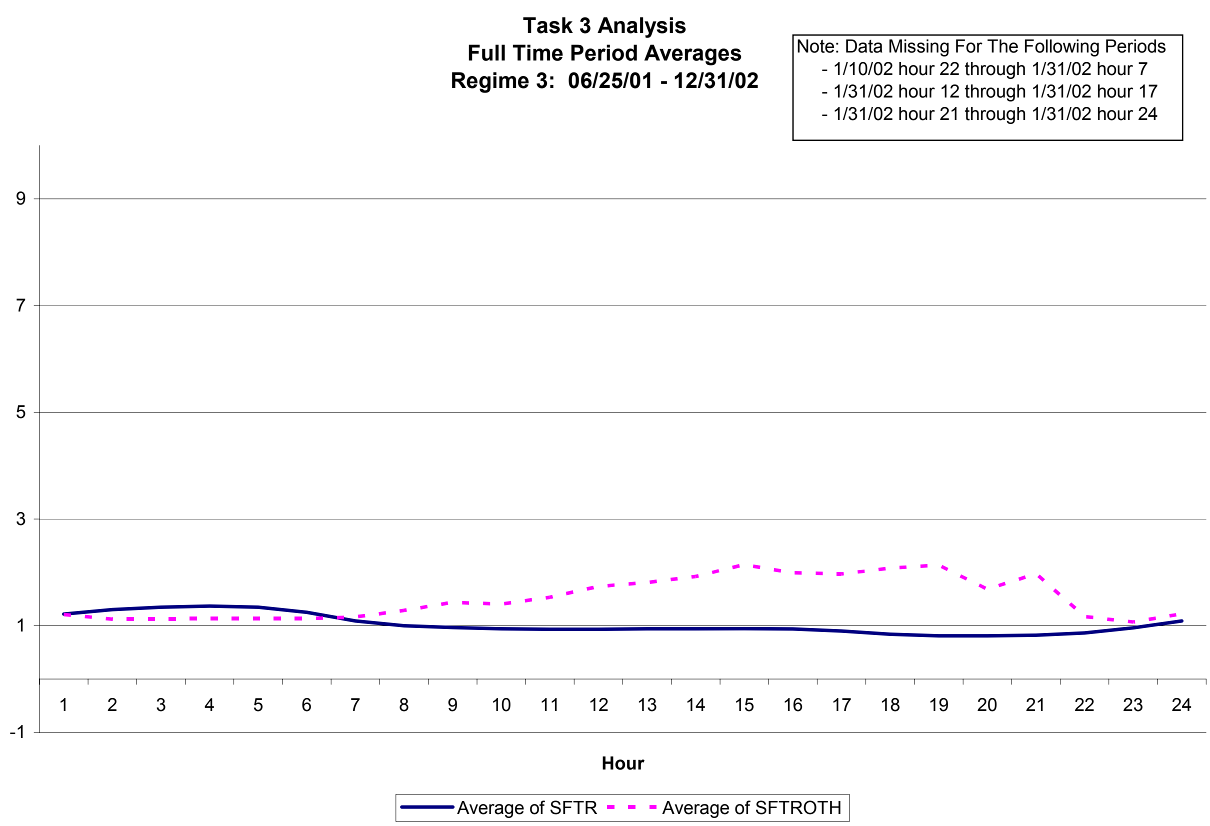

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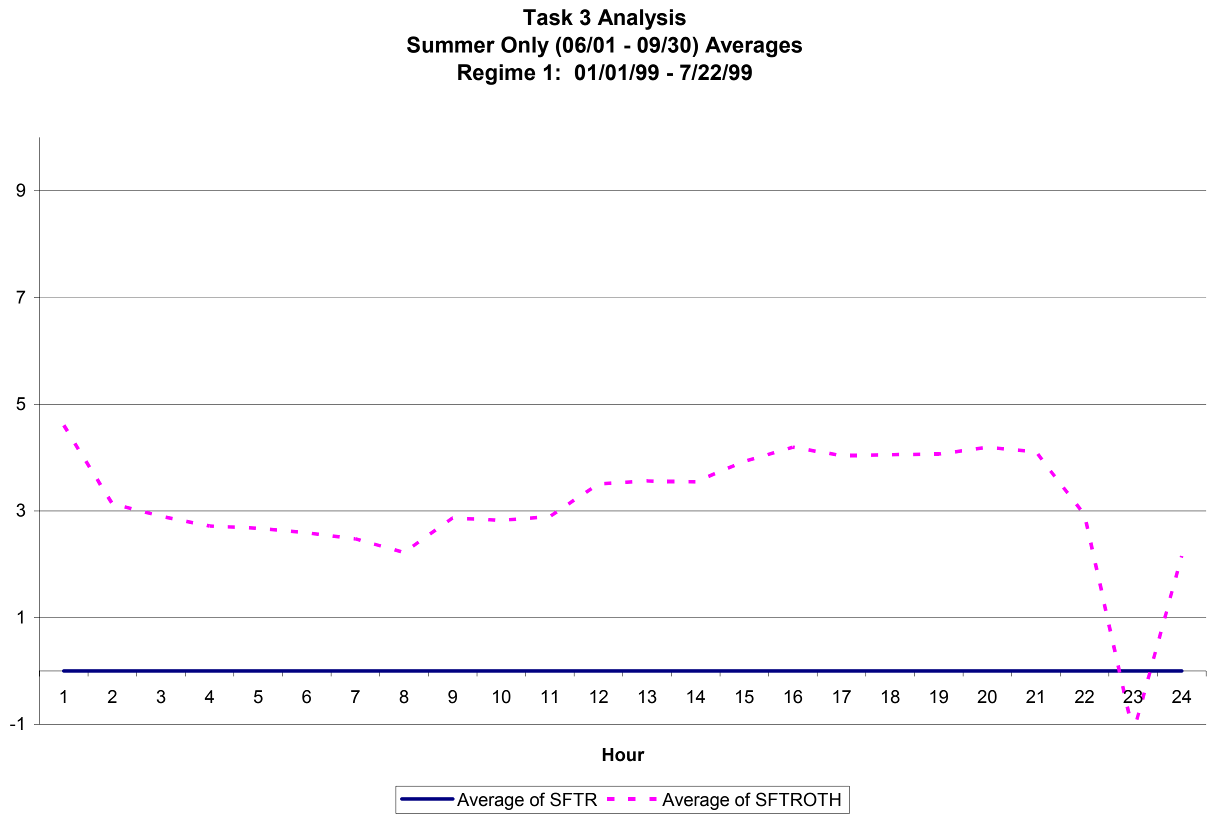

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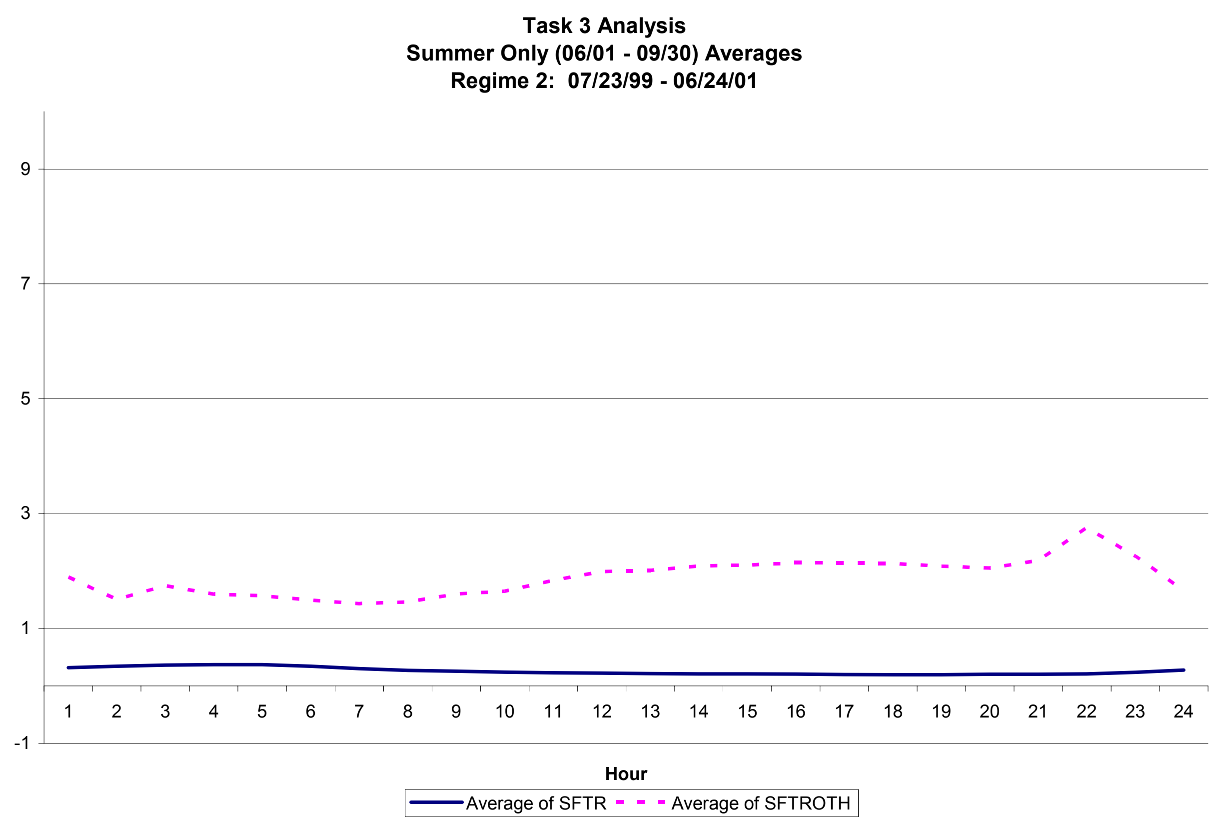

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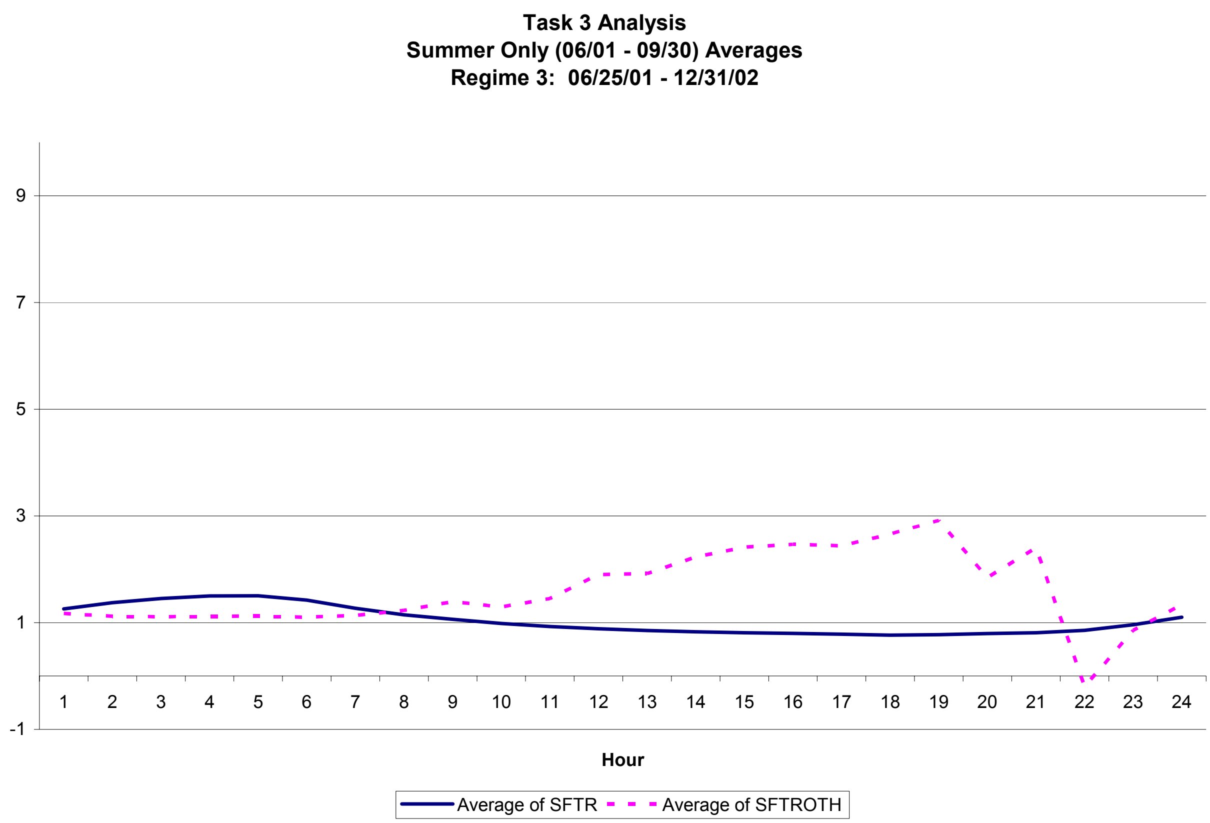

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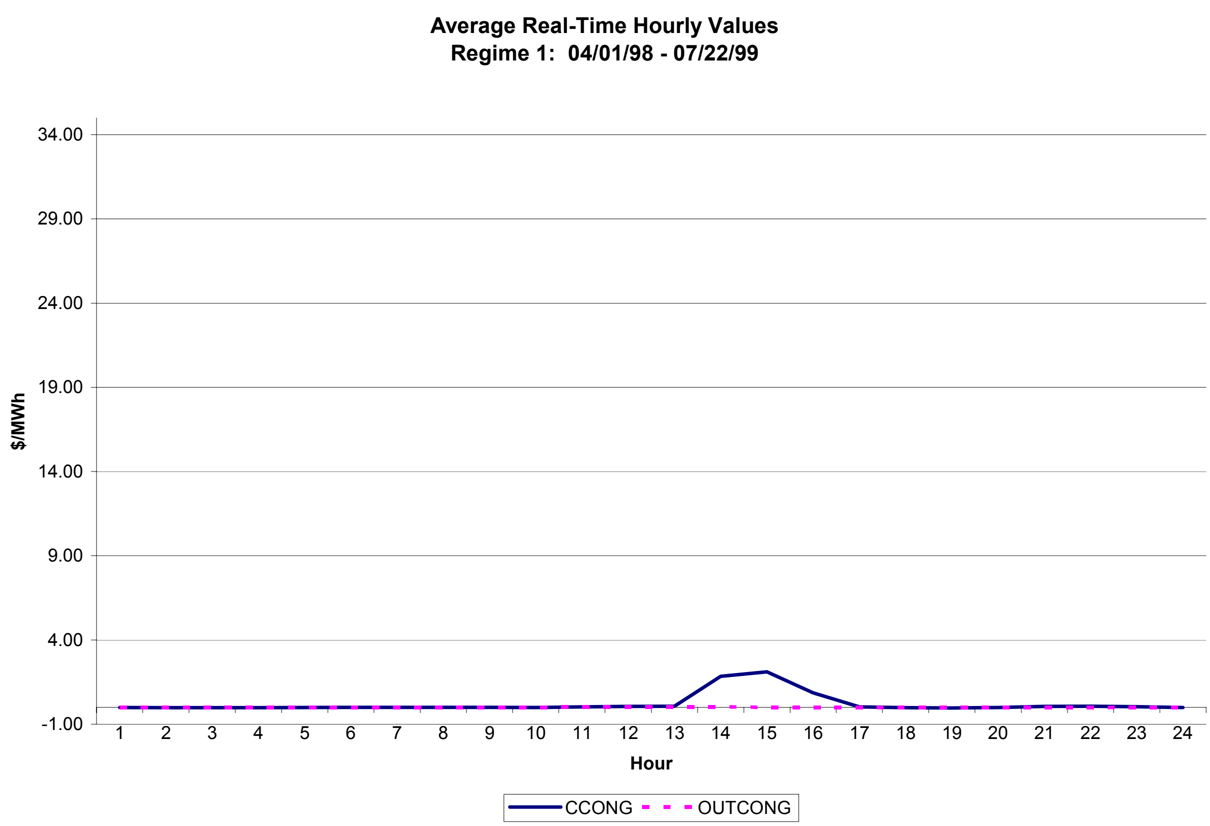

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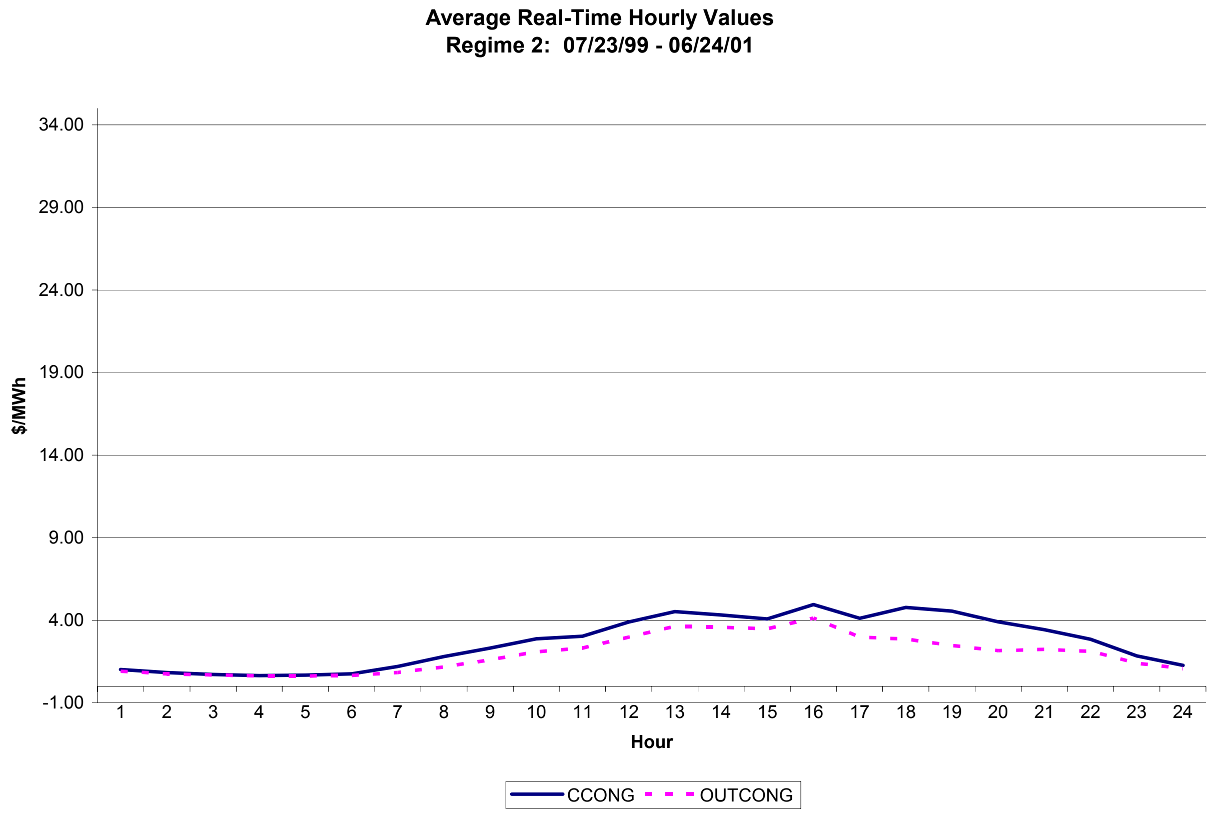

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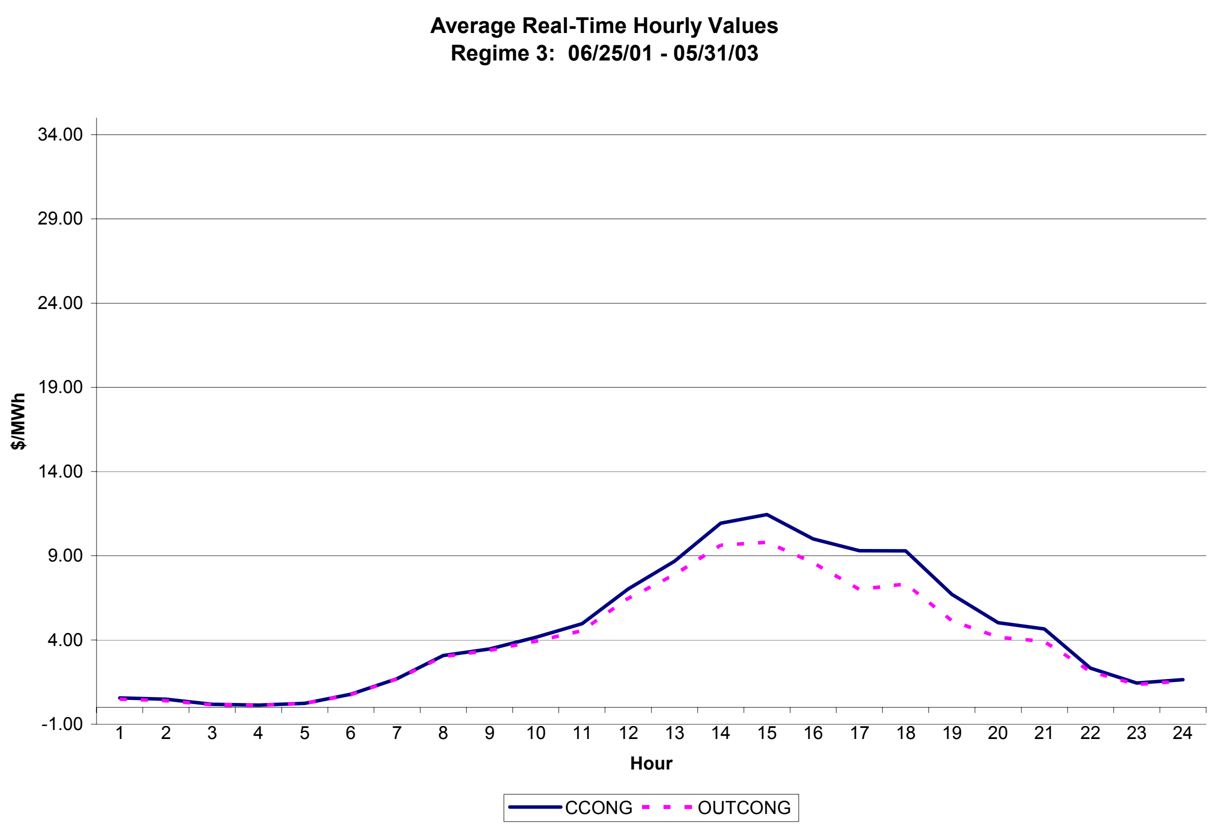

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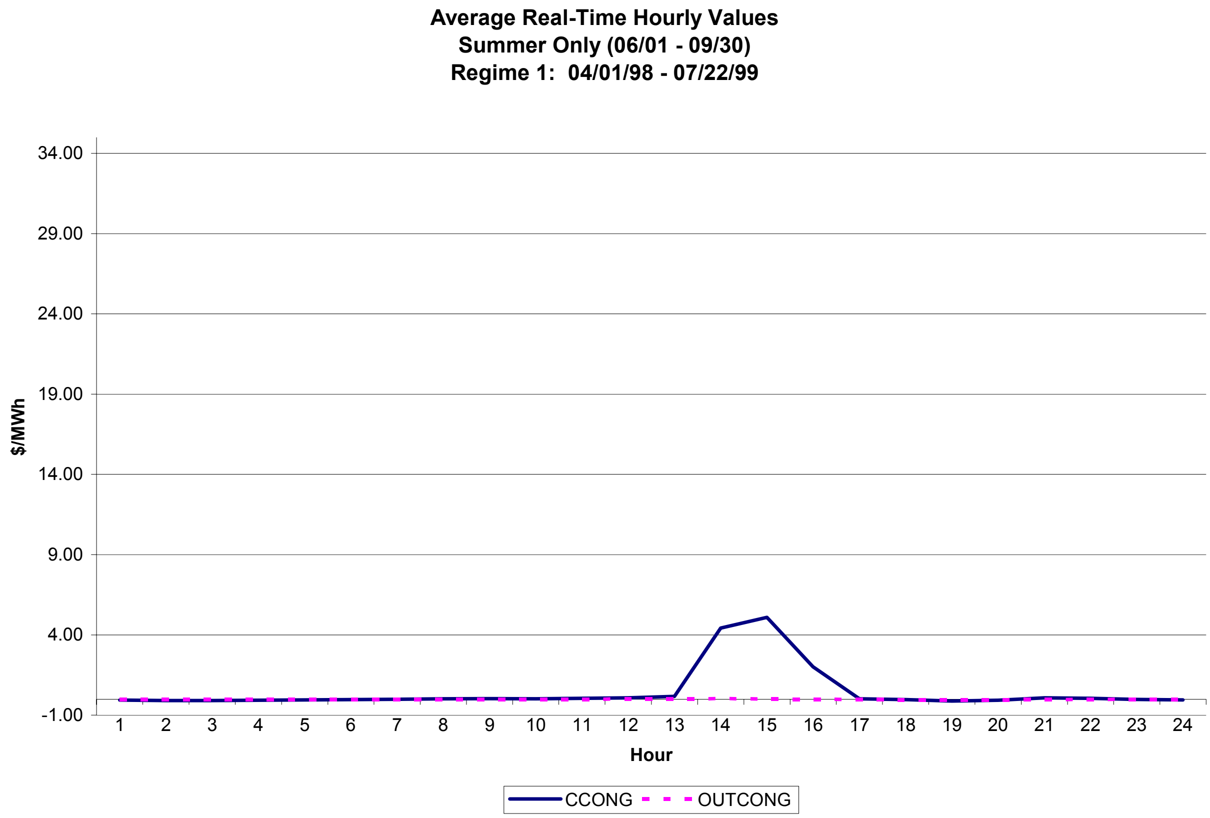

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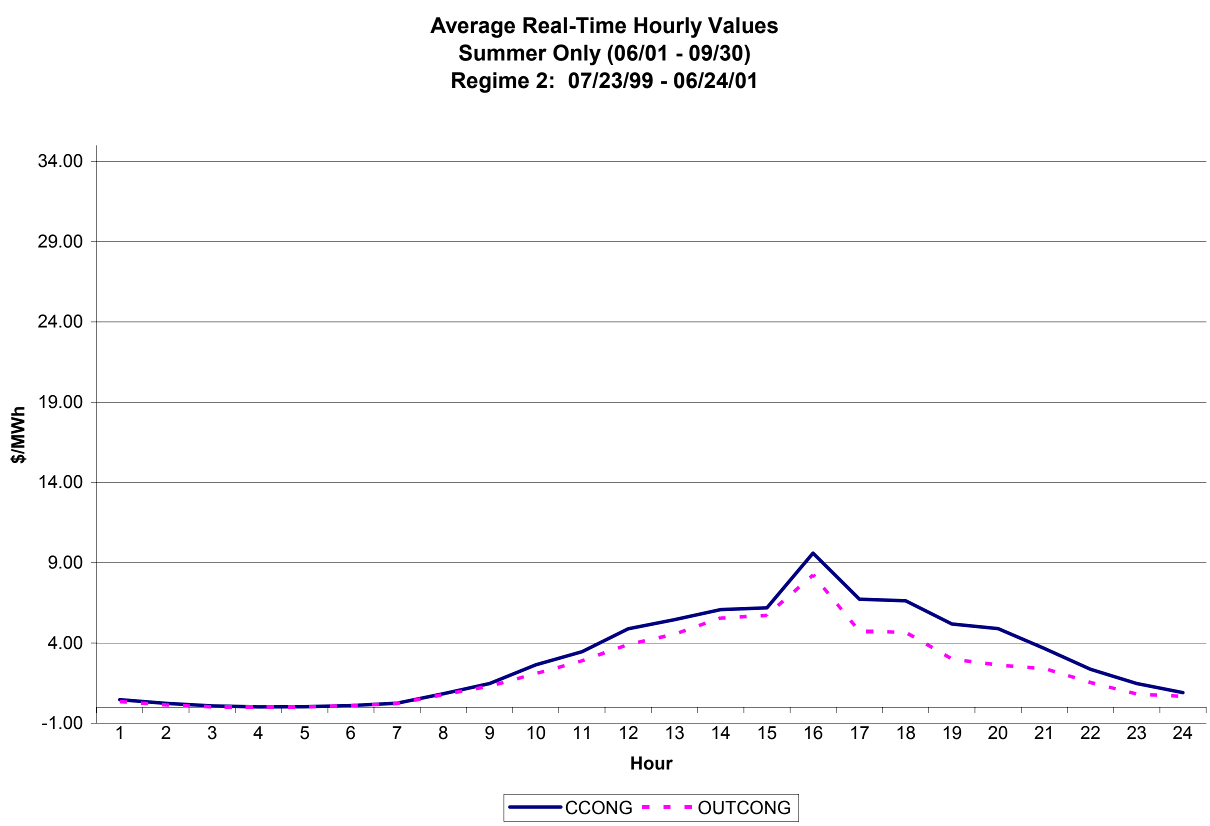

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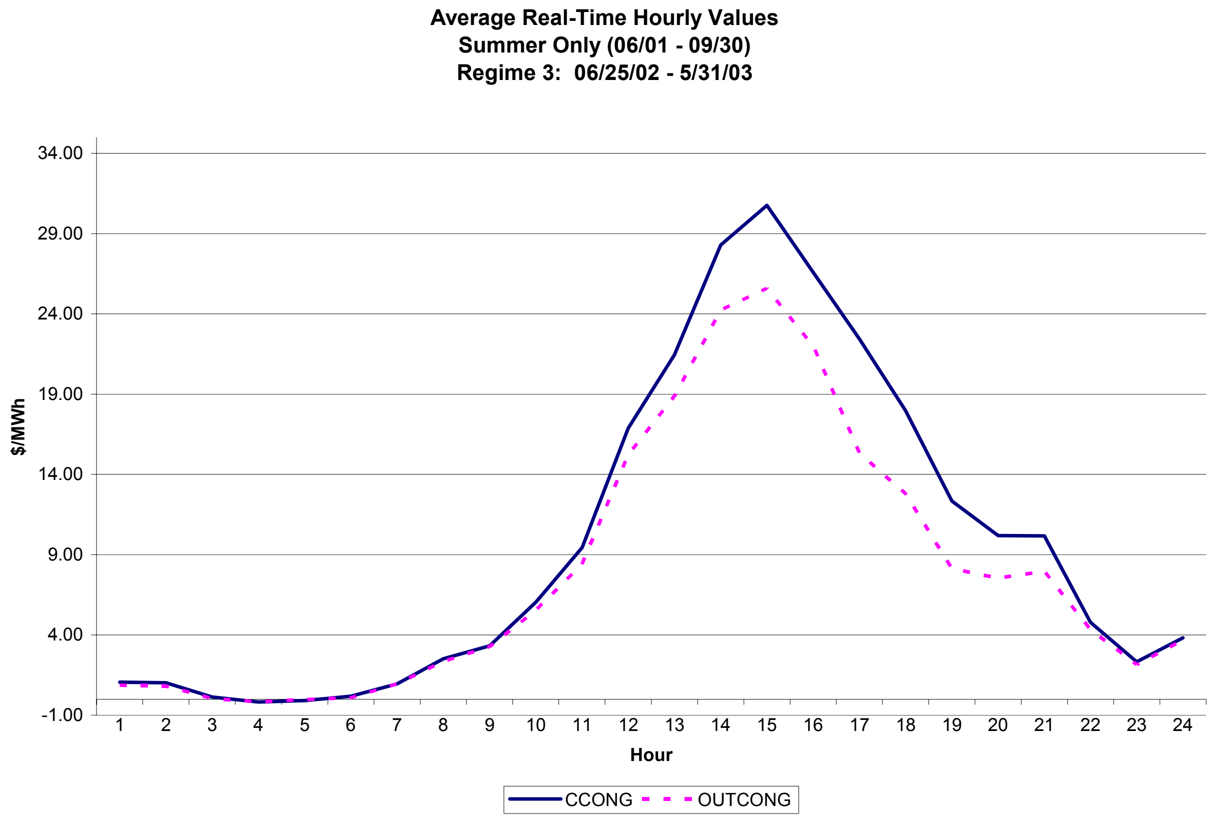

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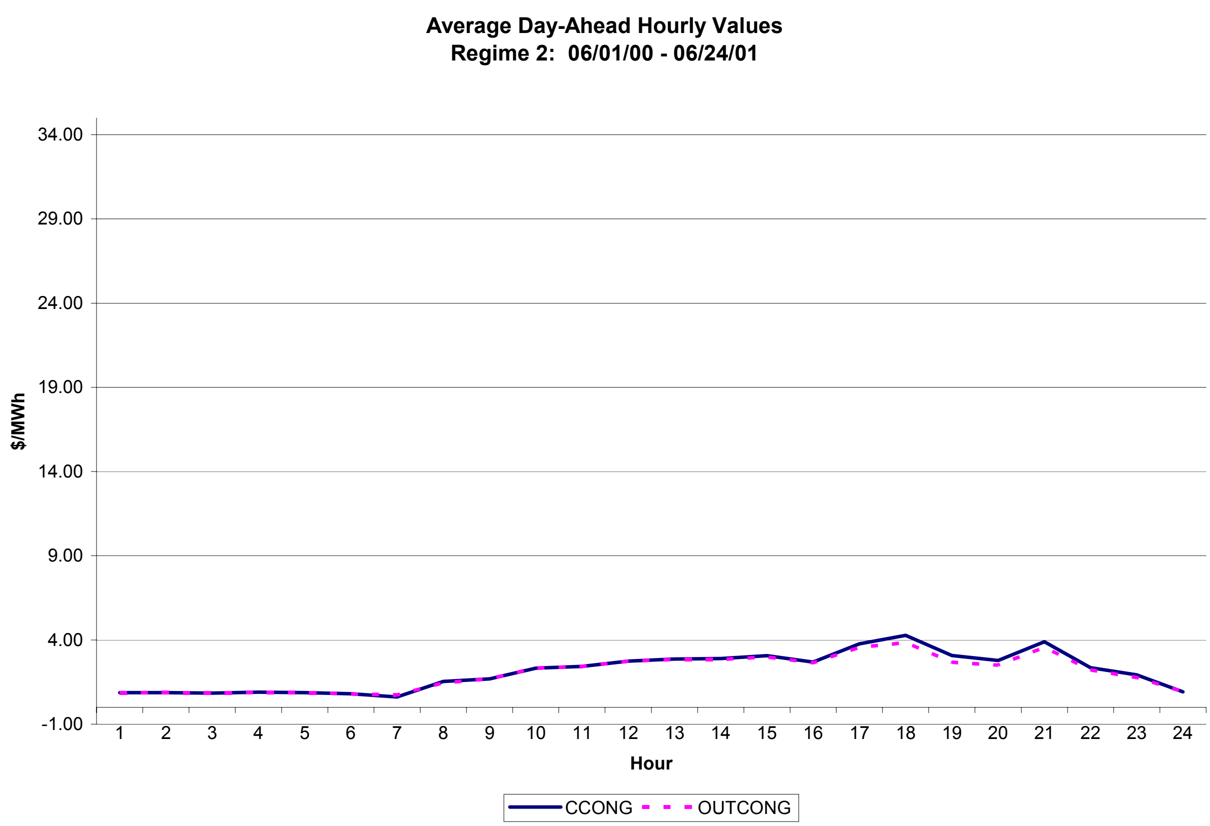

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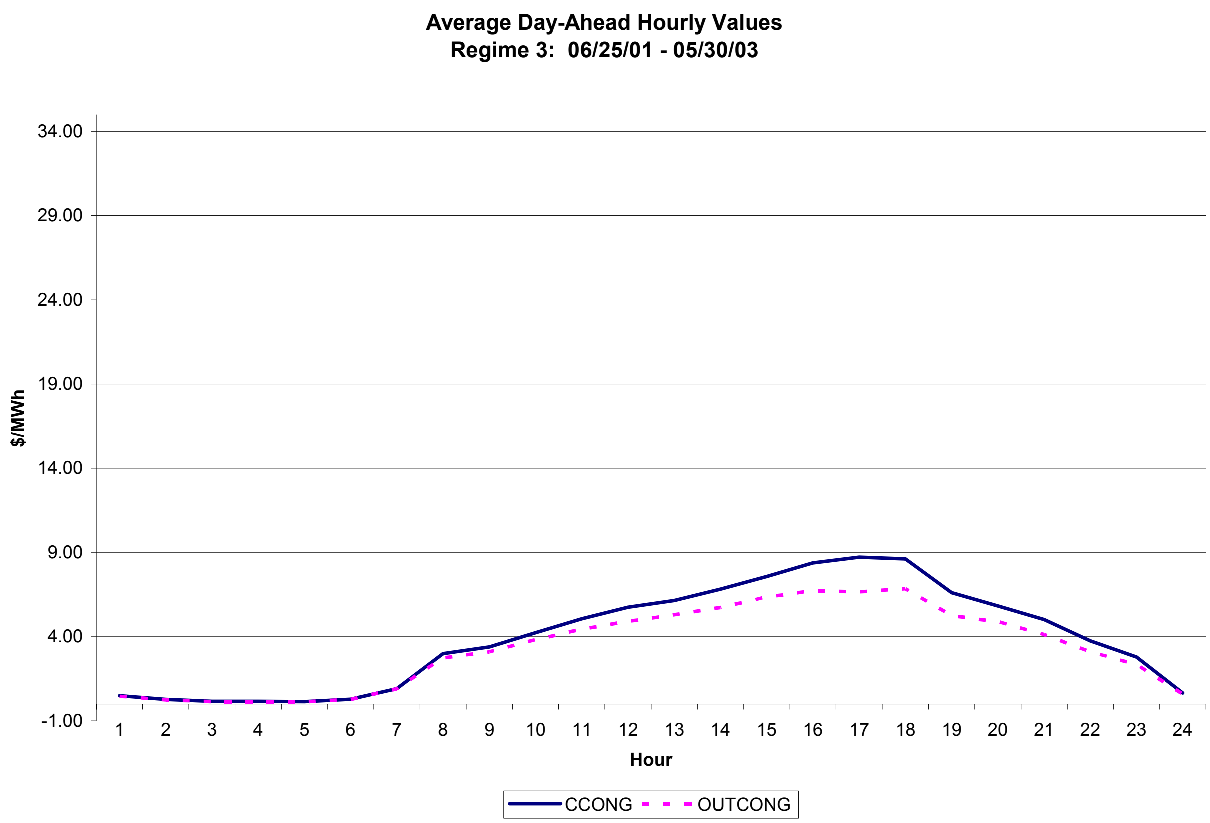

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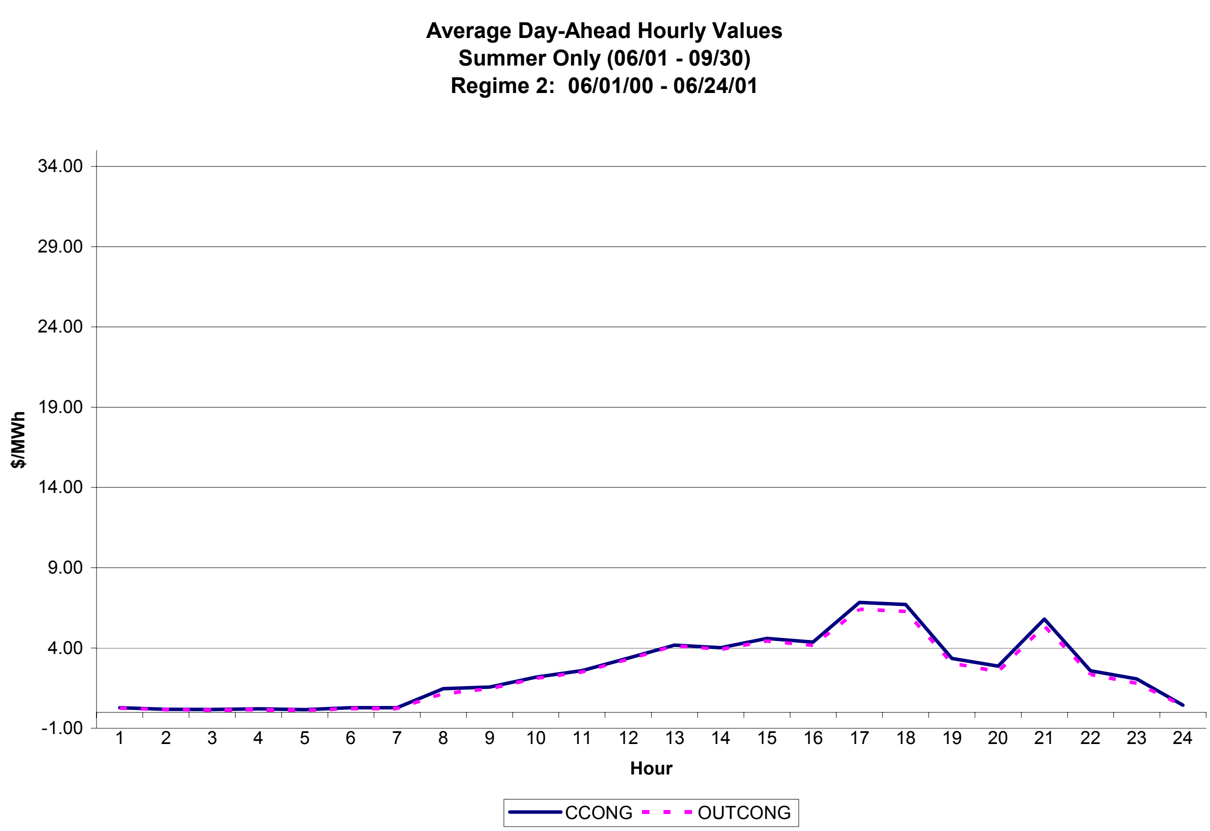

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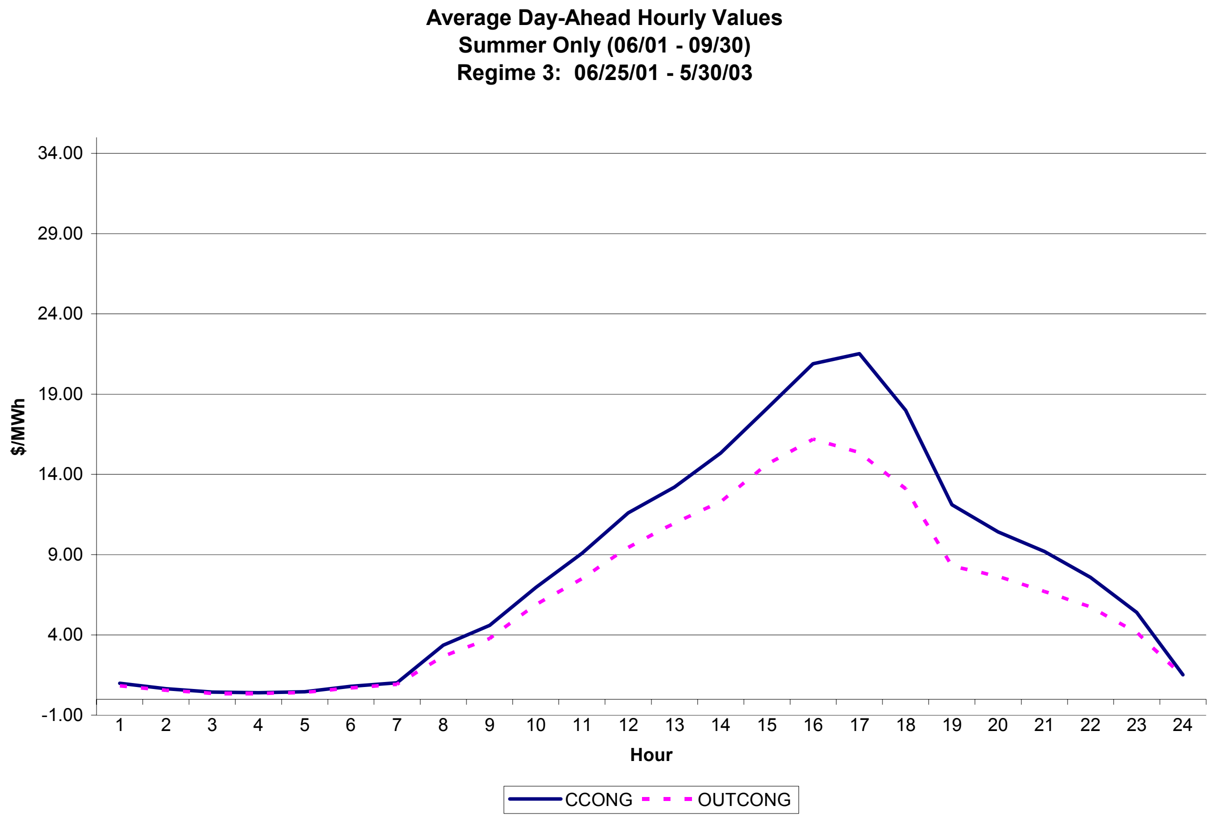
Average Day-Ahead Hourly Values
Summer Only (06/01 - 09/30)
Regime 3: 06/25/01 - 5/30/03
34.00
29.00
24.00
19.00
14.00
9.00
4.00
-1.00
$/MWh
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
CCONG
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