Submitted in Response to Formal, Non-Public Investigation
Under 18 C.F.R. § 1b.5
Subject to 18 C.F.R. §§ 1b.9 and 1b.20

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Up-To Congestion Transactions) Docket No. IN10-5-000

Affidavit and Appendices of Richard D. Tabors, Ph.D

My name is Richard Tabors. I am a Vice President of Charles River Associates (CRA) in Boston, Massachusetts. I have spent my professional career at the interface between economics and engineering, primarily in the design and implementation of markets in the electric power sector. Along with three colleagues while at the Massachusetts Institute of Technology (MIT), I co-authored ***Spot Pricing of Electricity***, which is generally considered the basic theoretical text for the design of electric energy and transmission markets worldwide. I have been a director of research and research laboratories and a faculty member at both Harvard University (1970 to 1976) and MIT (1976 to 2005). In 1989, along with two of my colleagues, I formed Tabors Caramanis & Associates that became a part of CRA in 2004.

My full resume is included as Appendix B to this affidavit.

I have been asked to provide expert opinion on the functioning of Up-To Congestion (UTC) trading within the energy market of PJM Interconnection, L.L.C. (PJM). In addition, I have been asked to review the trading strategy of Dr. Alan Chen, trading on behalf of Powhatan Energy Fund LLC (Powhatan), and the impact that the Federal Energy Regulatory Commission's

(FERC or Commission) decision to allocate Transmission Loss Credits (TLC) to cleared UTC transactions had upon that strategy. I also review the impact of any enforcement action applicable to these transactions on the broader market. Finally, I consider whether the strategy pursued by Dr. Chen constituted rational and legitimate economic behavior.

This affidavit is divided into three sections. The first section begins with a discussion of the nature of UTC transactions within the PJM market design and financial (virtual) participants' involvement in UTC transactions. It also discusses the genesis and allocation of TLCs as well as the relationship between the transmission reservation requirements of UTC transactions and the allocation of the TLCs that result from the marginal loss calculations of PJM.

The second section of the affidavit discusses the theoretical and practical incentives created, and consequences incurred, by allocating TLCs to virtual traders who engaged in UTC transactions. It also discusses the consequences of penalizing behavior that FERC explicitly recognized that it would incentivize by allocating TLCs to UTC traders but failed to prohibit.

Finally, the affidavit will review, from the perspective of an economist who has participated widely in the design of electric energy markets throughout the world, the virtual bidding strategies executed by Dr. Chen. I explain how Dr. Chen engaged in five types of trading strategies of UTCs, none of which were either designed to *ensure* receipt of TLC revenues or guaranteed only to operate at a loss but for TLC revenues. All five strategies were instead designed to seek profit from price spreads while mitigating transaction costs with TLC revenues. I conclude that all the strategies reflect rational and legitimate economic behavior given the price signals and incentives created by PJM's market design in place at the time the transactions were executed.

In Appendix A to this affidavit, I have included a detailed explanation of how UTC congestion caps work. The fundamental characteristics of UTC transactions described in Appendix A are essential to understanding Dr. Chen's trading strategies and the incentives created by the allocation of TLCs to virtual UTC transactions that cleared the market.

In preparing this affidavit, I relied upon publicly available information from the PJM web site, information available from Energy Velocity (data provider to CRA), information from the Written Submission To Commission Investigation Staff On Behalf Of Dr. Houlian Chen submitted in Docket No. IN10-5-000 on December 13, 2010, and interviews with, and summary spreadsheets provided by, Dr. Houlian (Alan) Chen.

Section I. Market Design

"Up-To Congestion" Transactions

According to PJM, UTC transactions were first incorporated into the market design of the PJM Open Access Transmission Tariff (OATT) in order to give parties with physical delivery obligations, or physical wheels of power through PJM, the opportunity to hedge against congestion costs: "[UTC] transactions were originally created as a mechanism to hedge in the Day-ahead Energy Market the exposure to price differentials from the source to the sink of their physical energy deliveries into, out of or through PJM in the Real-time Energy Market, and to allow market participants who want to wheel power through PJM to set the maximum dollar value of congestion they would be willing to pay to wheel that power."[1] In order to engage in a UTC transaction, therefore, the PJM OATT required that the (physical) trader reserve, and in

[1] PJM Initial Filing in Docket No. ER10-2280 at 2 (Aug. 18, 2010).

most instances[2] pay, for firm or non-firm transmission service on the path between the two points used in the UTC transaction.[3]

Transmission service must be reserved *first*, before the trader enters the UTC bid into PJM's Enhanced Energy Scheduling (EES) system and before day-ahead prices are known. After transmission service is reserved and an Open Access Same-time Information System (OASIS) reservation number obtained, the trader may go to the EES system before noon eastern time the day-ahead and enter the OASIS reservation number as well as the desired congestion cap. After PJM publishes the day-ahead locational marginal prices (LMP) at 4 p.m. eastern time, the trader will know whether the UTC bid(s) cleared the market or not.

The following are costs associated with a UTC transaction:

- Cost of transmission service, which PJM's OASIS states is $0.67 per MWh for non-firm service. However, by agreement with the Midwest Independent Transmission System Operator, Inc. (MISO), PJM did not charge for transmission service when power was exported from PJM to MISO. The transmission reservation charge was incurred by the trader whether or not the associated bid cleared the market.

- PJM overhead costs (*e.g.* market monitor funding, PJM scheduling and dispatch services), which averaged $0.04 per MWh.

- Black start service, reactive supply and voltage control from generation services, which averaged $0.21 per MWh.

In addition to the costs above, PJM also provided a small "PJM Scheduling, System Control and Dispatch Service Refund – Market Support" (less than $0.01 per MW).

[2] PJM did not require parties to pay for transmission service associated with transactions exporting power from PJM to MISO.

[3] Attachment K – Appendix to the PJM Open Access Transmission Tariff, Section 1.10.1(b); *see also* parallel provision in Section 1.10.1(b) of Schedule 1 of the Amended and Restated Operating Agreement of PJM.

Prior to September 17, 2010, the FERC-approved PJM OATT required that virtual traders fulfill the same transaction requirements as do physical UTC traders, that is, that they reserve, and commit to pay for, transmission access service from MISO to PJM in advance of setting a position and paying the required costs for a UTC bid.[4] This was a questionable market design decision on the part of PJM and FERC given that virtual transactions are non-physical and are always closed out between the day-ahead and the real-time markets – no transmission is used in these transactions and neither reactive power nor voltage control were needed. Thus, the vast majority of the costs incurred by UTC traders, including the use of the transmission system and the reactive power/voltage control charges, are not relevant or necessary to accomplish a virtual UTC transaction. In effect, these payments subsidized the entities that actually required physical transmission and or reactive power / voltage control.

Allocation Of Transmission Loss Credits

Starting in October 2009, PJM began to *allocate* TLCs to UTC traders in direct relation to each MWh of cleared UTC transactions for which the trader paid for transmission service.[5] TLCs result from the decision of PJM, approved by FERC, to (correctly) calculate the cost of losses on the transmission system based on the marginal rather than the average cost.[6] This principle provides to all participants in the market the theoretically correct locational price for

4 *PJM Interconnection, L.L.C.*, 132 FERC ¶ 61,244 (2010) (Order Accepting Tariff Revisions).

5 *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,042 at P 12 (2008) ("*Black Oak II*"); *order on clarif.* 126 FERC ¶ 61,164 (2009) ("*Black Oak III*").

6 *Atl. City Elec. Co. v. PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,132 at P 22 (2006) ("Billing on the basis of marginal costs ensures that each customer pays the proper marginal cost price for the power it is purchasing. It therefore complements and reinforces PJM's use of LMP to price electricity. Moreover, by changing to the marginal losses method, PJM would change the way that it dispatches generators by considering the effects of losses. As a result . . . the total cost of meeting load would be reduced.").

energy against which they then can make their energy purchase, sales and investment decisions. Charging for losses at the marginal value means that, on average, more revenues are collected than are needed to pay for the actual cost of losses. There is no perfect way to allocate these excess revenues. The principle, however, is that these excess revenues should be allocated to market participants in a manner intended to not adversely affect operating decisions, most specifically of generators bidding into the market. As FERC stated, "the ***only fundamental principle*** to be applied is that the distribution should in no circumstance be based on the amount paid for transmission line losses, because that would distort the appropriate price signals which the use of marginal line loss pricing is designed to facilitate."[7] In the case of PJM, these excess revenues were allocated in the form of TLCs to those entities – primarily load – that paid for transmission service. FERC ultimately determined that because UTC traders paid for a transmission reservation, they would also be eligible to receive a portion of the TLCs based on UTC transactions that cleared the market.[8]

TLC allocations vary significantly on a daily basis. Figure 1 below provides a graphic of daily TLC allocations per MW from May 29, 2010 through August 19, 2010.[9] During this period, average daily per-MW TLC allocations ranged from approximately $0.70 up to $2.10. For the period of May 29 through August 19, 2010, the average TLC allocation was $1.25 with a standard deviation of $0.32.[10] Moreover, because TLCs originate from over-collection of

[7] *Black Oak II*, 125 FERC ¶ 61,042 at P 37 (emphasis added; footnote omitted).

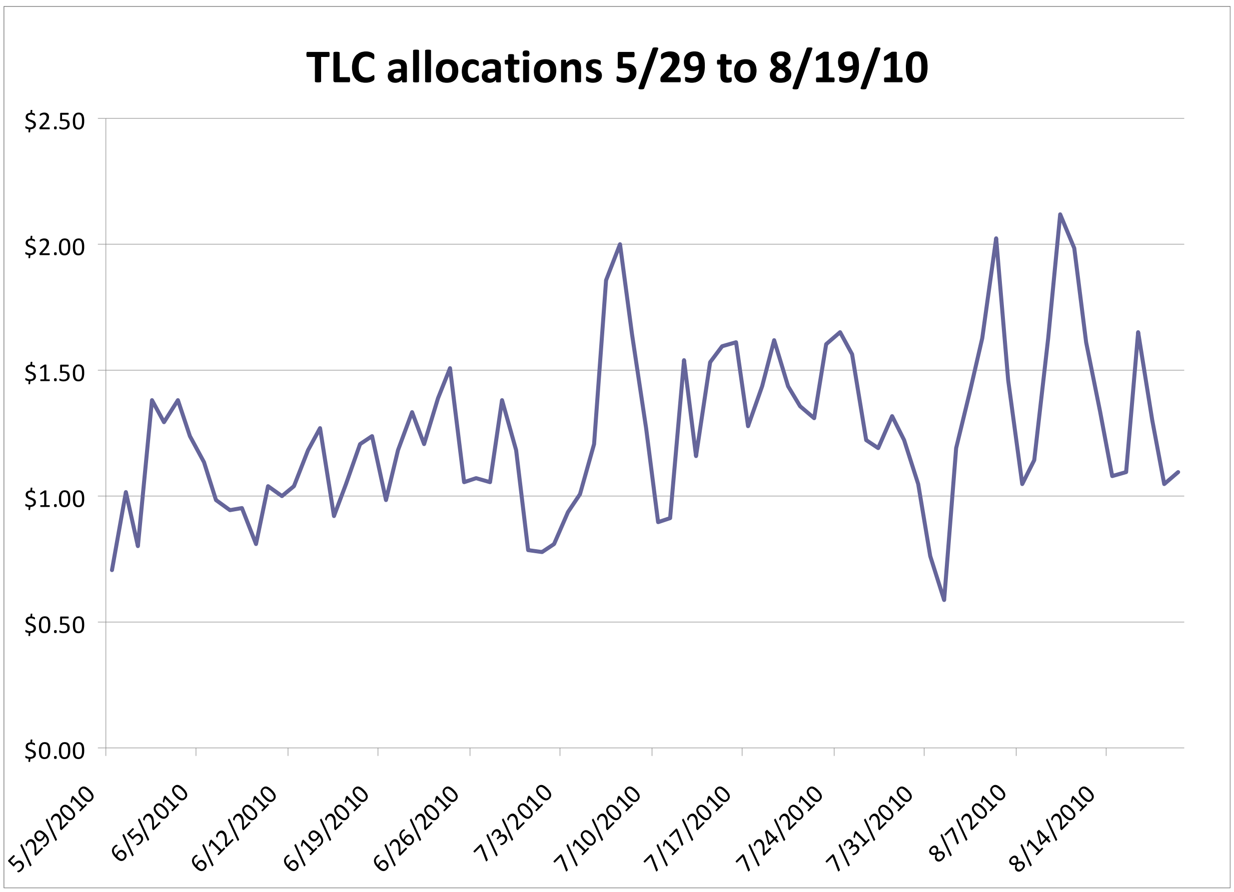
[8] *Black Oak III*, 126 FERC ¶ 61,164 at P 15.

[9] While TLC allocations also vary significantly on an hour-by-hour basis, hourly TLC allocation data is not publicly available.

[10] The standard deviation is a measure of the variation of the data about the mean. One standard deviation on either side of the mean is an indication that 34.1% of the values lie above and 34.1% lie below this value. As can be

transmission line losses that are based on marginal line loss rather than average line loss, the amount of the hourly over-collection – and thus the amount of the TLC allocation – was unknown to traders until after the deadline for placing UTC bids had passed. Thus, a trader, including Dr. Chen, cannot know in advance whether the TLC allocation would be less than, equal to, or greater than the costs associated with placing an individual UTC bid.

Figure 1



seen from the standard deviation in the allocation of TLCs, there was significant variation during the period reported.

Section II: Theoretical And Practical Incentives Created By TLC Allocation To Virtual UTC Transactions

The Decision To Allocate TLCs To Virtual UTC Transactions That Cleared The Market Necessarily Created An Incentive To Engage In High-Volume UTC Transactions

The decision to allocate TLCs to virtual UTC traders created a market signal. To the trader, payments for transmission and other costs are fixed, per MWh per trade. Receiving a credit from transmission losses – independent of the size of that credit – reduces the fixed cost per MWh per trade, thus making it possible for a trader to place more trades at the same cost to the trader – increasing the volume of trades undertaken. In short, transactional costs are reduced. At the same time, reducing this transactional friction allows UTC traders to identify additional trading strategies where volumetric increase could provide a higher payoff from low probability events. Because transactional friction is reduced, it is economically rational to pursue such low probability, but high payoff, events more aggressively.

Prior to the advent of TLC allocations to UTC virtual traders, the financial benefits of trading UTCs stemmed from being able to predict the relationship between the day-ahead market prices and the real-time market prices on the two sides of the PJM interface with an adjoining ISO, such as MISO. With the original transaction price structure ($0.67 per MW per hour for transmission plus an additional $0.25 per MWh for voltage control, scheduling and black start) there were only a finite number of UTC positions that a trader could afford to take on a regular basis. Allocation of TLCs fundamentally changed the cost of putting on UTC bids. Where previously the cost of a transaction was $0.92 per MWh, the cost (netting out the benefit of the TLC) now ranges from $0.22 per transaction to a point at which the trader is ***being paid*** $1.18

per MWh for each trade. When the cost of transactions were dramatically reduced, as occurred with the advent of receipt of TLC allocations, virtual traders gained the ability to change their strategies to increase their trading positions in terms of the number of positions taken, the volume of individual positions or the types of trades, or any combination thereof.

There are undoubtedly multiple ways in which traders could modify their likelihood of profit in the market given this change in the cost of transactions and associated risk profile. With allocation of TLCs, it now became possible to focus attention on strategies whereby volume (in both number of trading positions and the size of the positions) became far less expensive.

Given that individual trading positions could be put on at a very small cost or even a credit (after all of the allocations and costs had been netted), it became possible to consider putting on large trading volumes that were conditional upon the magnitude of the day-ahead price spread. The UTC product allowed for precisely this strategy when the cost of the transaction was minimized (or turned into a credit) due to the TLC allocation. In other words, the TLC allocation allowed UTC traders to make large volume trades even when the trader believed that the TLC allocation would be less than the fixed cost of the trades, *i.e.*, lose a little bit of money because the potential return exceeded the costs of the trades. By placing UTC bids in both directions between two points with the same positive cap, the trader could guarantee that one bid will fail to clear the market while the other bid clears in the unlikely event that congestion exceeds the set cap. The goal of the strategy was to "hit the home run" on the spread: not to make a small amount of money on every position but rather to make a significant amount of money when the pre-specified condition occurred. The pre-specified condition would occur when transmission congestion in the day-ahead market exceeded the cap set by the trader. This might have been a cap at $50/MW, the maximum that was allowed by PJM rules, or a cap at half this amount ($25/MW). With transaction costs reduced or even eliminated, the trader could put on larger volumes more often in the hope of "hitting the home run."

Why could one "hit the home run?" The answer is that with the net reduction/elimination of the transaction costs, it was possible to put on UTC positions that would essentially cancel each other out ***unless the condition was met***. Placing a UTC bid into PJM with a cap of $25/MWh and simultaneously placing a UTC bid out of PJM at the same positive cap would cost little (or provide a small net return) if the cost of congestion in the day-ahead was less than $25/MWh.[11] As soon as the cost of congestion exceeded $25/MWh, the into PJM position would fail (and there would be no TLC allocation), but the into MISO position would clear because it also has a ***positive*** cap.[12] Under these circumstances, the trader would hold a counter flow spread position in the day-ahead market and would then profit, or not, in real-time as a function of whether the real-time price for congestion into MISO from PJM was higher or lower than the position the trader holds – the traditional spread transaction. The TLC allocation minimizes the cost to the trader of waiting for the high day-ahead congestion event (and thus the spread position) to occur.

This transaction differs from the original one-way spread transaction in that the trader now knows that the spread will ***only*** be operational (profit or loss) under the ***condition*** that the

[11] It is important to note that there is no specific reason in this strategy or this example that individual transactions need to be paired, even imperfectly. Busses close to the border with MISO will tend to co-vary and certainly do so within the range of the cap that any trader is likely to put on. Taking it one step further, if one were to consider putting an identical position in place randomly from every PJM bus to MISO, and the reverse position randomly from MISO to every PJM bus, the result would be numerically perfect pairing even though the individual busses and their values would be significantly different.

[12] See Appendix A for additional explanation of why one bid always clears where two bids are entered with positive caps, one in each direction between two nodes.

congestion is greater than the cap that the trader has chosen – in this instance $25. The trader requires two additional pieces of analytic information before initiating this strategy. The first is the probability that at any given cap, one of the UTC positions will fail (MISO to PJM or PJM to MISO). The second is the probability that if a position fails (say the cap is exceeded from MISO to PJM in the day-ahead market), that the congestion in the real-time market will be less than it was in the day-ahead market. Both probabilities are calculable.

The trading strategy is more easily described than it is implemented. The reason is that while the probabilities are calculable, the case in which the UTC bid will fail has an extremely low probability of occurring and results from an event that is not predictable as to when and where it will occur (*e.g.*, loss of a transmission line due to a lightening strike). The only way to improve the probability that the trader has UTC bids in place at the time the event occurs is to hold positions for every hour. Moreover, if you set the cap at $50, the probability of the bid failing is lower than if you set it at $25, and the probability is non-linear between the two. The critical consideration in deciding to lower caps is whether congestion will reduce in the desired direction between the day-ahead and real-time or instead will increase, in which case the trader will end up losing money. This point is captured in the analysis of what occurs when there is a congestion spread in the day-ahead greater than the cap value. The critical issue is whether experience (and analysis) has shown that where day-ahead spreads are large, the real-time spread tends to be less. The theory of market operations says that market transactions (without an external physical event) will work to reduce the cost of congestion between the two market periods.

The "home run" strategy described above is precisely that: a strategy to profit from rare but very profitable events, much as the slugger may swing for the wall on every pitch, seeking the home run, but strike out nine times out of ten (or worse). To consider implementation of such a strategy requires that the trader be capable of solid statistical analysis and be experienced in the market. The risk of never hitting the "home run" is extremely high. Only under the condition in which the cost of setting the UTC positions is very low can one consider such a strategy and thereby wait for the fast ball in the center of the plate (in this case, put on UTC trades in each hour awaiting the rare conditions in which congestion exceeds the cap specified by the trader in the UTC bid). Such a strategy is rational economic behavior where transactional costs are low to non-existent.

As is clear, the "home run" strategy does not require a TLC; it requires low transactional friction. Were there no costs associated with putting on a virtual UTC transaction, there would be more transactions of many types and along many strategies that would take advantage of the volume of positions as opposed to precision on each individual transaction. The strategy described above is one that structures risk around the condition that exists when and if a directional UTC bid fails. As such, the strategy accepts the risk that the event will never occur and simultaneously the risk that when and if it occurs, the real-time market will not converge relative to the day-ahead market. Those risks both become acceptable because the pay-out – the "home run" – is more than sufficient to cover the transactional costs, the opportunity cost associated with funds tied up in the transactions, and the administrative and time costs of the traders involved.

In summary, from the perspective of the UTC trader, the allocation of the TLC provides an incentive to the UTC trader to increase the volume of trades. The only certainty of the TLC is that it will be a positive number. Because it is a positive number related to transmission reservations, it is related to the number of MWs of UTC transactions cleared each hour rather than in any way to the profit or loss from each individual UTC transaction. As a result, the market impact of TLCs on the UTC trader manifests as a direct reduction in the cost of the UTC transaction. This reduction in ***transactional friction*** is precisely the effect that occurred with the advent of the allocation of TLC monies to traders bidding UTCs. Reduced transactional friction provides an incentive for traders to identify and implement trading strategies whereby they can benefit from greater numbers of trades – where there is a potentially large (or very large) benefit possible from a low probability event.

Traders in all markets are financially rewarded for identifying precisely such strategies. These strategies, as in this case, are within the rules of the market and are, as in this case, neutral or positive with respect to the operation of the market itself.

It Would Harm The Market If Traders Are At Risk for Disgorgement And Penalties By Engaging In Trading That FERC Acknowledged Would Occur, But Failed To Prohibit.

In 2008, FERC denied the complaint of several virtual traders, or arbitrageurs, who sought to either be relieved of the obligation to pay marginal line losses in locational energy prices or be allocated a portion of the TLCs.[13] In rejecting a TLC allocation for virtual traders, FERC stated:

> Paying excess loss charges to arbitrageurs also is inconsistent with the concept of arbitrage itself. The benefits of arbitrage are supposed to result from trading acumen in being able to spot divergences between markets. As stated above, arbitrageurs create their own load by the volume of their trades. ***If arbitrageurs can profit from the volume of their trades, they are not reacting only to perceived price differentials in LMP or congestion, and may make trades that would not be profitable based solely on price differentials alone.***[14]

Thus, FERC fully anticipated that allocating TLC revenues to virtual traders would create an incentive for traders to profit by "trades that would ***not be profitable*** based solely on price differentials alone" – that is, transactions that would not be economic but for the TLC allocation. Nevertheless, FERC granted rehearing and held that traders that paid for transmission and engaged in cleared UTC transactions must receive a TLC allocation, since they too contributed to the fixed costs of the transmission grid.[15] In that rehearing order, FERC again acknowledged that permitting virtual traders to receive TLC payments could create "an incentive for arbitrageurs to engage in purchase decisions, not because of price divergence, but simply to increase marginal line loss payments"[16] but did not prohibit such trading.

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13 *Black Oak Energy, LLC v. PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,208 (2008) ("*Black Oak I*").

14 *Id.* at P 51 (emphasis added).

15 *Black Oak II*, 125 FERC ¶ 61,042 at P 49.

16 *Id*. at P 43.

As explained above, trading strategies developed in response to reduced transactional friction due to the TLC allocation constitute rational economic behavior. In addition, having predicted that allocating TLCs to virtual traders would result in volume-based transactions that would be uneconomic but for the TLCs, and then authorizing the TLC allocation to virtual traders anyway, FERC treatment of such transactions as market manipulation now would harm the energy market. Electric energy markets are no different from markets of other commodities, though in the past they may have tended to be more heavily regulated. Traders enter markets knowing the regulatory rules and working their strategies within those rules. It is often stated that the ability to estimate and operate within a structure of financial risk (hedging) is the critical characteristic that differentiates successful from unsuccessful traders and trading entities. A second risk that may be equally critical is that of regulatory risk. The role that traders can play in all markets is improving liquidity and price transparency. They count on regulatory stability in making decisions. Living by the regulatory rules assures the trader that if there are legitimate profits to be made through wise transactions, those profits will be kept. In an environment of regulatory uncertainty – one in which the rules are in flux or the interpretation of those rules changes – the trader becomes wary of the market and perceives what can be called "increased transactional friction." This represents a price (monetized or not) that the trader perceives must be paid to stay in the market. In behavioral terms, it may be a rule change that prevents a structured transaction from being profitable. In more concrete financial terms, it may be a total change in direction on the part of the regulatory body by which, *ex post*, a set of transactions that were within the rules are now transactions subject to clawback of revenues and penalties. When market participants and traders perceive a regulatory environment with significant transactional friction, the number of trades is reduced with a consequent loss of both liquidity and price transparency. Markets without liquidity and price transparency are no longer functional and often cease to be traded. While there may never be complete regulatory certainty, there needs to be regulatory consistency if there is to be a well-functioning market.

The Market Was Not "Well-Functioning" When It Allocated TLCs To Virtual Traders That Did Not Need Transmission Service.

UTC trading grew, as was discussed earlier, as a hedging mechanism for physical traders who needed to cap their risk incurred to move energy between markets such as PJM and MISO. These trades were physical in nature in that the participants purchased (bilaterally) a quantity of energy in MISO for sale (often bilaterally) in PJM. Their uncertainty was in the cost of the congestion since they had to reserve the transmission ahead, but would not know the cost of congestion until after the transaction was in place. The UTC structure provided the answer: the ability to complete the transaction up-to a congestion price of $X. PJM put a ceiling on the price at $50, but this is largely irrelevant since the physical trader would know the maximum value of congestion that the transaction could carry.

The UTC product provided a logical trading product for a virtual trader. Virtual traders used the UTC product with the same rules as existed for the physical trader, namely that they reserve – and pay for – transmission. This represented a significant cost for the UTC virtual transactions and undoubtedly affected the number of such positions put on. That said, however, virtual transactions are precisely that: virtual. No energy was transmitted in virtual trades; there was no need for reserved transmission, voltage support or black start support. Logic would dictate that virtual trades should carry no physical requirements since they would be cleared in, or before, real-time.

The legacy remained, however, and virtual UTC trades continued to require transmission reservations. Given that these transactions paid for transmission, the argument made in the *Black Oak* cases was that traders such as Black Oak should receive a portion of the TLC allocation given that those traders through their payment of transmission charges paid their share of the transmission fixed charges. In *Black Oak I*, FERC rejected the argument. In *Black Oak II*, FERC reversed itself, finding that virtual UTC trades should receive part of the TLC allocation.

From the perspective of logic and good market design, where charges are intended to cover real costs, the case of the TLC allocation to virtual UTC traders is one of "can two wrongs make a right?" If it was illogical for TLC traders to be paying transmission reservation charges, did allocating part of the TLC to those same players correct for the earlier error? Given that the FERC has now reversed itself a second time by accepting in 2010 PJM's proposal to eliminate the requirement that UTC trades reserve transmission service (and thus eliminating TLC allocations to UTC transactions), the answer is certainly ***no***.

The market was not well-functioning in 2008 when virtual UTC traders were required to pay to reserve transmission. It was not well-functioning in 2009 when virtual traders were allocated a part of the TLC. The logic of the changes to PJM's tariff adopted in 2010 is that, from a market design perspective, UTC traders are paying for what they use and not paying for what they do not use. In the period between 2009 and 2010 when the rules changed, UTC traders may have been trading in a market that was not well-functioning, but they were playing by the rules of that market.

Powhatan Paid For Transmission Service And No Other Market Participant Is Entitled To The TLCs It Received In Return.

As discussed above and in Appendix A, in questions of allocation, there is never a singular right answer. The general objective, and that of the Commission, in allocating TLCs was that "the ***only fundamental principle*** to be applied is that the distribution should in no circumstance be based on the amount paid for transmission line losses, because that would distort the appropriate [economically correct] price signals which the use of marginal line loss pricing is designed to facilitate."[17] UTC traders received a TLC allocation based on the MWh of cleared UTC transactions associated with transmission reservations that they paid for.

The TLC allocation is not a market. It is an allocation of excess revenues. The decision as to how to allocate these revenues fulfilled the objective of FERC in that the TLCs were allocated to those entities that paid for transmission fixed costs and were not allocated to entities in a manner that could affect LMP prices. As FERC indicated, no other party has a claim to the TLCs allocated to Powhatan because Powhatan paid a portion of the fixed cost of the transmission grid, and the "fundamental principle" underlying the allocation dictates that "no party within PJM is entitled to receive any particular amounts" through the TLC allocation.

[17] *Black Oak II*, 125 FERC ¶ 61,042 at P 37 (emphasis added; footnote omitted).

Section III. Dr. Chen's UTC Bidding Strategies.

Dr. Chen's Trades Were Intended To Seek Profit On Price Spreads Between Two Nodes While Mitigating Transaction Costs With TLC Revenues.

I have reviewed records recently provided by Dr. Chen regarding his UTC transactions on behalf of Powhatan during the May through August 2010 period. There were five (5) categories of transactions:

(1) Directional UTC transactions between an interface node and one node within PJM (*e.g.* MISO to Greenland, Mt. Storm to MISO);

(2) Transactions in opposite directions between the same two nodes at the same MWh volume and bid at a +$50/MWh congestion cap in both directions (*e.g.* 10 MW from MISO to Mt. Storm bid at the +$50/MWh maximum cap and 10 MW from Mt. Storm to MISO bid at the +$50/MWh maximum cap);

(3) Transactions in opposite directions between the same two nodes at the same MWh volume, but bid at a congestion cap of *less* than the +$50/MWh maximum cap (*e.g.* 10 MW from MISO to Mt. Storm bid at a +$25/MWh cap and 10 MW from Mt. Storm to MISO bid at a +$25/MWh cap);

(4) Transactions in opposite directions between the same two nodes at *different* MWh volumes, but bid at the +$50/MWh maximum cap in both directions (*e.g.* 10 MW from MISO to Mt. Storm bid at the +$50/MWh maximum cap and 5 MW from Mt. Storm to MISO bid at the +$50/MWh maximum cap); and

(5) Transactions in opposite directions between the same two nodes at *different* MWh volumes and bid at a congestion cap of *less* than the maximum +$50/MWh cap in both directions (*e.g.* 10 MW from MISO to Mt. Storm bid at a +$25/MWh cap and 5 MW from Mt. Storm to MISO bid at a +$25/MWh cap).

Dr. Chen stated that two-thirds of Powhatan's UTC transactions were bid with a congestion cap of ***less than*** the +$50/MWh maximum cap. This fact is critical to understanding the trading strategy and the risk profile that Dr. Chen employed during this period.

It is obvious that had Dr. Chen's objective been solely to "harvest the TLC," he would have behaved significantly differently from the actual behavior the trading records show. To implement a "harvesting" strategy, the objective would have been to always set the bids at equal volumes and to have always set the cap at the PJM maximum of $50/MWh. This would have reduced the probability that a net spread position in either direction would occur, though as explained above, setting the cap at $50/MWh could never eliminate the possibility of a net directional spread occurring should congestion exceed $50/MWh and only one bid clear.

As indicated by the categorization of the five trading types listed above, Dr. Chen was not trading for the TLC revenues but was instead using the TLC revenues, netted against the transaction costs, to be able to more frequently (and in greater volume) undertake a strategy of "swinging for the wall with every pitch." In section 2 of this affidavit, I discussed in detail the "home run" strategy that was based on knowledge and analysis, logical, legitimate and, most clearly, profit seeking. While one might argue that there were positive revenues attributable to simply placing the trades based on the net of cost against TLCs, the real profits to be had were from the low probability event, the "home run," that Dr. Chen was seeking.

Type one above represents the standard spread transaction undertaken by UTC traders. Transactional risk was hedged primarily by trader knowledge of the market. The other four of the five transaction types listed above, and identifiable in Dr. Chen's trading records, sought a profit well beyond that achievable by "harvesting" the net of the uncertain TLC allocations and the transaction costs, and carried a very different risk profile. Underlying these four transaction types was the opportunity to capture the large pay-out event. Two of the four transaction types exhibited the pure "home run" strategy but with a very significant difference and risk profile. In type two above, the probability of losing a UTC position was as low as possible given that the cap was set at the PJM maximum of $50/MWh. Type three above is quite different. In this type of transaction in which the cap is less than $50/MWh (and it varied as low as $25/MWh), the trader is both "learning" the behavior of the risk associated with a different cap and looking for a broader spread to the opportunity to "hit the home run." While a bid with a cap of $25/MWh will have a greater probability of being rejected, the reciprocal bid with a $25/MWh cap that always clears in the opposite direction will also have a greater probability of losing money if and when there is divergence, rather than convergence, between the day-ahead and real-time markets. At the same time, however, it should be obvious that setting the cap at, say $25/MWh, will also allow for the "home run" at $49 or $200.

The final two types of transactions above are hybrids. In both cases, the trades are a mix of traditional spread trading (the asymmetric volume) and the "home run" bidding (the paired volume).

The five transaction types are focused on different characteristics within trading UTCs in the overall PJM energy market. Each has a very different risk reward profile. This difference in the profiles of the individual categories, when blended hourly, daily or monthly, allowed the trader to develop a portfolio risk profile that could vary as knowledge and experience were gained. What made this process work and allowed Dr. Chen to trade in larger absolute volumes with clearly different strategies was the fact that the transactional friction – the cost of the individual trades – was vastly reduced with the allocation of TLCs to virtual UTC traders.

Powhatan's UTC Transactions Had No Negative Impact On The Energy Market.

Underlying the questions and challenges to the bidding strategies that have been discussed in this affidavit is the question of harm to the PJM energy market. Harm could occur in one of several manners, but certainly the most significant is that the actions of the trader affected the structure of trading that took place in the market, or that the actual trades themselves were manipulative, causing others players in the market to behave in a manner that did not respect the basic economic structure of the market itself. In the case of Dr. Chen's transactions, responding to the fact that the transactional friction of engaging in UTC trades was lessened or removed by the allocation of TLCs to cleared UTC trades did not cause harm to the market. The actions of those who responded to the change in transaction costs did nothing to affect the structure of the market other than to increase the volume of virtual trades. These traders also had no impact on other traders trading UTCs or trading in other elements of the PJM energy market. At a minimum, this increase in volume had no impact of any kind; to the positive, it might have provided additional price transparency.

The second question concerning possible harm is whether, in the process of undertaking these transactions, the trader made unwarranted profits by flagrantly violating the rules of the market. Certainly this was not the case here, because all of Dr. Chen's trades were totally transparent through the PJM system.

Conclusion

The conclusion that must be reached from an analysis of the UTC transactions undertaken after introduction of the TLC allocation to cleared virtual UTC transactions is that Dr. Chen's response was predictable and logical under economic theory. If we believe in economic man (and woman), economic incentives affect economic behavior.

In the instance of the UTC trades, there was no market manipulation, only response to economic signals. Dr. Chen responded logically and economically correctly to an environment in which the transaction costs – the transactional friction – of putting on UTC transactions had been dramatically reduced, and in which there were known and demonstrable low probability, unpredictable but high pay off outcomes – the "home runs" – that could be targeted with high volumes of bids across many hours.

In addition, and critically, there was no harm to the market caused by Dr. Chen's transactions. At worst, the impact was neutral to the functioning of the energy market in PJM. At best, it was positive through increased liquidity at the PJM boundaries and through increased price discovery.

Appendix A: Fundamentals of UTC Transactions

Up-To Congestion (UTC) transactions are bids submitted into the PJM day-ahead energy market between two nodes. The UTC bids include a cap on the maximum amount of day-ahead congestion that the bidder is willing to pay in terms of the difference in the nodal energy price in the day-ahead market. Congestion occurs when there is insufficient transmission capacity available from Point A to Point B to accept all desired transactions from Point A to Point B. Congestion is calculated as the day-ahead sink node (Point B) LMP minus the day-ahead source node (Point A) LMP. Importantly, congestion is always one-directional; that is, if a path between two nodes is congested (*i.e.* day-ahead sink LMP minus day-ahead source LMP is a positive number) in one direction from Point A to Point B, then the path will be uncongested (day-ahead sink LMP minus day-ahead source LMP is a negative number) in the opposite direction from Point B to Point A.

UTC transactions must always make use of at least one external interface node, and PJM maintains a list of source/sink combinations that are available for UTC transactions.[18] PJM's market rules stipulate that the cap on day-ahead congestion in a UTC transaction may not be greater than +$50 per MWh nor less than -$50 per MWh.[19] The original design of the UTC bid structure allowed physical suppliers of energy into (or out of) PJM to place a ceiling on the directional amount of day-ahead congestion they were willing to pay. Similar to other elements of the PJM energy markets, the UTC bid process spawned an active "virtual" bid process.

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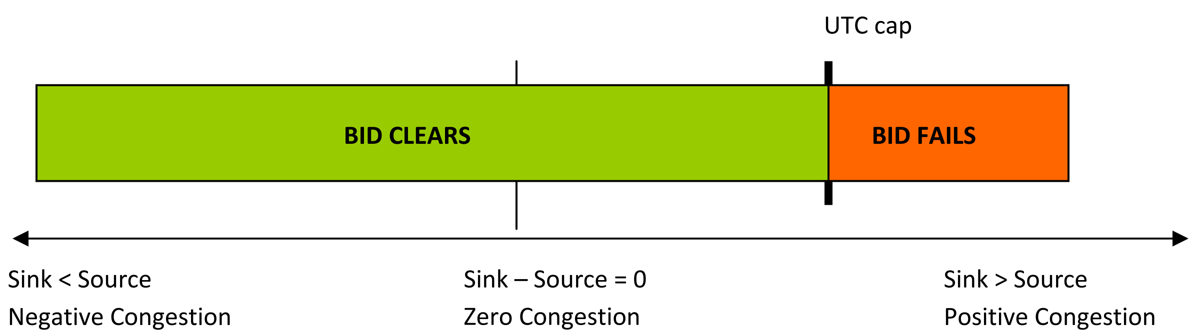
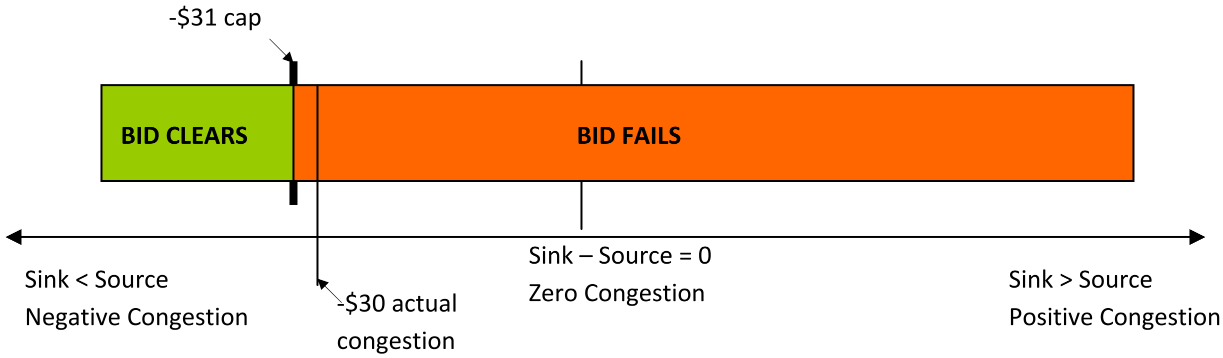
18 PJM Manual 11 at § 2.3.4.

19 PJM Manual 11 at § 2.3.4.

As an example of a UTC transaction, assume that the UTC transaction is to involve two nodes: the MISO interface node as the source and Mt. Storm node within PJM as the sink. Assume also that the trader bids a cap of +$50/MWh. At 4PM of the day ahead, PJM announces a day-ahead LMP for MISO of $20 and a day-ahead LMP for Mt. Storm of $50. For this UTC transaction, the day-ahead congestion is calculated as $50-$20 = $30 (day-ahead sink LMP less day-ahead source LMP). Because $30 is less than the trader's $50/MWh cap, the UTC transaction clears the day-ahead market. If instead the trader had bid a +$25/MWh cap, the transaction would fail to clear because the $30 congestion is greater than the +$25/MWh cap. This concept can be expressed graphically as follows:



Now assume that the trader instead bids in the other direction, with Mt. Storm as the source node and MISO as the sink node. The trader bids at the +$50 per MWh cap. As above, the day-ahead LMP at MISO is $20 and the day-ahead LMP at Mt. Storm is $50. The trader's day-ahead congestion cost (day-ahead sink LMP less day-ahead source LMP) is now ***negative*** $30. The bid clears the market because -$30 is less than +$50. Importantly, even if the trader lowers the bid cap to +$25/MWh, as in the prior example, the ***transaction still clears*** because -$30 is less than +$25. In fact, the trader would have had to bid a cap of at least ***negative*** $31/MWh before the transaction would fail to clear in this example.



Thus, a UTC transaction from Node A to Node B is ***never*** the equivalent of a UTC transaction from Node B to Node A. The likelihood of clearing the market is different for each transaction because congestion in one direction is a positive number, while the lack of congestion in the other direction is always represented by the reciprocal ***negative*** number. Thus, bidding the same cap for transactions in opposite directions guarantees that one of the bids will ***always*** clear.

Appendix B: Resume

CRA Charles River Associates

RICHARD D. TABORS

Vice President

Ph.D. Geography and Economics,
The Maxwell School,
Syracuse University

M.S. Social Sciences,
Syracuse University

B.S. Biology,
Dartmouth College

Richard D. Tabors, Vice President, is an economist and scientist with 35 years of domestic and international experience in energy markets, planning and pricing. He is a member of the group at MIT that developed the theory of spot pricing upon which locational marginal pricing (LMP) of electricity and transmission rights markets (such as FTRs) are based. Prior to joining Charles River Associates, Dr. Tabors was a president and founder of Tabors Caramanis & Associates. Dr. Tabors is working on the restructuring of the U.S. and international electric supply industry, where he provides expert testimony and works with clients on restructuring efforts at the state, provincial, regional, and federal levels in the United States and Canada, as well as in the United Kingdom. He has spent 30 years on the faculty and research staff of MIT where until 2006 he a senior lecturer in technology and policy and Assistant Director of the Laboratory for Electromagnetic and Electronic Systems (MIT's Power Systems group) He is also a visiting professor of electrical engineering at the University of Strathclyde, Glasgow, Scotland.

EXPERIENCE

2004–Present *Vice President*, Charles River Associates

2004-2007 Co-Head, Energy & Environment Practice, Charles River Associates

2004–Present *Visiting Professor of Electrical Engineering*, University of Strathclyde, Glasgow, Scotland

1986–2006 *Senior Lecturer*, Technology and Policy Program, Massachusetts Institute of Technology (MIT)

1988–2004 *Founder and Principal*, Tabors Caramanis & Associates, Inc.

1989–1998 *Lecturer*, Department of Electrical Engineering and Computer Science, MIT

- "Introduction to Power Systems Operations and Planning."

1992–1998 *Senior Research Engineer*, Laboratory for Electromagnetic and Electronic Systems, MIT

1985–1998 *Assistant Director*, Laboratory for Electromagnetic and Electronic Systems, MIT

- Responsible for laboratory administration and research in power systems economics and planning, research on power systems monitoring and control, principal investigator on research program in performance based monitoring and control.

1990–1993 *Principal Research Associate*, MIT

- Co-Faculty "Planning for Water and Sewerage" and "Dealing with the Complete System," MIT Summer Session.

1984–1989 Co-Faculty "Power Systems Planning & Operation: Methodologies for Dealing with an Uncertain Future", MIT Summer Session.

1978-1988 *Lecturer*, Department of Urban Studies and Planning, MIT

1973-1988 *Principal*, Meta Systems

- Head, utilities group in power systems planning, pricing and systems analysis

1985–1987 *Faculty*, Course 11.944, Department of Urban Studies and Planning (co-taught as KSG S115 with P. Rogers) "Energy Sector Planning in Developing Countries."

1971–1976 *Research Associate and Member*, Center for Population Studies, Harvard University

- Research on resource and environmental planning in developing nations of South Asia and Africa.

1978–1984 *Program Manager*, Utility Systems, MIT Energy Laboratory

- Economic and systems research and development in electric and gas utility systems; including the integration of new generation systems (photovoltaics) into the grid.

1979-1983 *Project Manager and Principal Investigator*, Electric Generation Expansion Analysis System (EGEAS) Project, under contract to EPRI, MIT Energy Laboratory.

1977-1982 *Project Manager and Principal Investigator*, Photovoltaics Project, under contract to U. S. Department of Energy, MIT Energy Lab.

1976-1977 *Economist*, Photovoltaics Project, MIT Energy Laboratory and Lincoln Laboratory.

1976-1977 *Energy Economist*, New England Energy Management Information Systems (NEEMIS), Energy Laboratory, MIT.

1974-1976 *Assistant Professor of City and Regional Planning*, Harvard University.

1973-1976 *Research Fellow*, Environmental Systems Program, Division of Engineering and Applied Physics, Harvard University.

1971–1977 *Co-Faculty*, with Professor R. Revelle, Natural Science 118, & 119, Human Population and Natural Resources, and Population & Environment and in Urban Setting, Harvard University.

1973-1974 *Lecturer on City and Regional Planning*, Graduate School of Design, Harvard University.

1971 *Resident Representative*, Harvard University, East Pakistan (Bangladesh) Land, Water and Power System Study, Dacca, East Pakistan.

1970 *Graduate Administrative and Teaching Assistant* to A. K. Campbell, Dean, Maxwell Graduate School of Citizenship and Public Affairs, Syracuse University.

1969–1970 *Syracuse University Intern*, Economic Division, USAID Pakistan.

- Informal advisor on Regional Economic Planning to the Urban Development Directorate, Planning Department, Government of East Pakistan (Bangladesh).

CONSULTING EXPERIENCE

- Provided expert testimony and case strategy support to international energy supplier in area of market operations and market manipulation before the US 9th Circuit in California (2008 – Present)
- Provided expert testimony to major international independent power producer in arbitration on cost responsibility for station power (2009 – Present)
- In cooperation with Merrill Energy, provide expert advice on implementation of legislation to recover capital cost of transmission investment in Peru.
- Direct and provide consulting advice to the Federal Electricity & Water Authority in the United Arab Emirates on corporate reorganization. (2007-Present)
- Provide expert testimony to major US independent power producer in arbitration with steam host. (2007 – 2009)
- Direct and provide expert services and consulting advice to Electricite du Liban on revenue recovery through development of AMI systems. (2006 – Present)
- Direct and provide consulting services to Electricite du Liban on restructuring of distribution services. (2006 – Present)

- Provide expert testimony in multiple contract disputes between bankrupt Independent Power Producer and power marketer. (2004 – 2006)
- Provide expert analytic assistance to Private Equity Fund on purchase of generation assets within the United States (2006- 2007).
- Member, Board of Directors, NeuCo Corporation.
- Direct and provide consulting services to Abu Dhabi Water and Electricity Authority on distribution system performance. (2003–2005)
- Direct and provide expert testimony on the development of the MidWest Independent System Operator. (2002–Present)
- Direct and provide expert testimony on long-term contract market in California. (2002–Present)
- Direct and provide expert testimony in purchase, contracting and regulatory approval of Midwestern transmission system. (2002–2003)
- Direct and provide expert testimony in 9-billion dollar California Electric refund case (2001–Present)
- Direct and provide expert testimony and consulting to major U.S. market and generator in the redesign of the California electricity market. (2002–Present)
- Member of the Blue Ribbon Task Force on design of electricity auctions of the California Power Exchange with Alfred Kahn, Peter Cramton and Robert Porter. (2000–2001)
- Member, Board of Directors of Dynamic Knowledge Corporation, Glasgow, Scotland. (2001–Present)
- Consultant to more than 20 power development companies for evaluation of locational value of new generation and transmission. (1999–Present)
- Consultant to and member of Technology Advisory Board, Excelergy Corporation, development of utility billing and system auction software. (1999–Present)
- Consultant to a Midwest utility for development of transmission congestion pricing structure. (1999–2001)
- Consultant to transmission asset development team of major U.S. corporation. (1999–2000)
- Consultant to and member of advisory board of Altra Energy Systems, electronic trading software and platform development company for electronic trading of electricity. (1998–2001)
- Consultant to major U.S. paper manufacturer for federal regulatory change required to interconnect a new co-generation facility. (1998–2000)

- Consultant to major Midwest utility in the development of an independent transmission company and the required tariffs. (1998–2002)

- Consultant with Enron Capital and Trade Resources on U.S. electricity restructuring with specific assignments in California, New York, Massachusetts and New England. Includes testimony in California "Blue Book" en banc hearings and participation in California Competitive Power Market Working Group. (1994–2001)

- Consultant to the Office of the Attorney General, Commonwealth of Massachusetts for Electric Utility Industry Restructuring. (1995–1998)

- Consultant with Sithe Energy on electricity pricing and electric industry restructuring. (1995–1998)

- Consultant with Independent Power Producers of New York (IPPNY) on restructuring of electric sector in New York. (1995–1998)

- Consultant to the Department of the Attorney General, State of Rhode Island and Providence Plantation for electric utility industry restructuring. (1996–1997)

- Consultant to the New England Competitive Power Coalition providing support for development of a blueprint for restructuring the New England Power Pool. (1995–1997)

- Consultant to ABB/Systems Control on transmission pricing and power systems operations. (1994–1997)

- Consultant to a major western utility for the development of transmission pricing strategies. (1994–1996)

- Development of real-time pricing strategies and rates for Oglethorpe Power Company, Atlanta, GA. (1995–1996)

- Consultant on the background to electric industry restructuring to Central Vermont Public Service. (1995)

- Development of real-time pricing rate response experiments for NYSERDA, EPRI and ESSERCo in ConEd and NYSEG service territories: Response to real-time pricing. (1989–1994)

- Development of marginal, cost-based, transmission system pricing system for the National Grid Company (NGC) of the United Kingdom. (1991–1993)

- Development of real-time rate structure and evaluation of customer impacts for Central Maine Power Company. (1990–1991)

- Development of purchase and transmission strategy for major U.S. independent power producer. (1990)
- Conservation and load management analysis and testimony for Boston Gas Company. (1987–1988)
- Development of Electric Power Systems Consulting Group, Meta Systems Inc. (1985–1988)
- Variable energy cost/spot pricing studies under contract to Integrated Communications Systems of Atlanta. Utilities included Mid-South and Pacific Gas and Electric, Southern California Edison, Central and South West. (1984-1987)
- Metcalf & Eddy Engineering, analysis of economic benefits of cogeneration/district heating for Columbia Point housing, Boston Redevelopment Authority. (1984–1985)
- Value of reliability study for Public Service of New Mexico. (1984)
- With East-West Center, Honolulu, Hawaii, study of electric futures of northeast Asia, Japan, Korea and Taiwan. (1983–1984)
- Independent variable energy cost spot pricing studies for Georgia Power, Florida Power and Light, Florida Power Corp., Tampa Electric and Gulf Power. (1983–1984)
- Petroleum pricing study, Philippines for IBRD. (1983–1984)
- Lignite pricing for electric power generation, Thailand. For IBRD (1982–1983)
- Independent, review of electric power futures for combustion engineering. (1982)
- Consultant, Microwave Associates, Inc., on electric load management and control. (1980-1981)
- Urban energy impact statement for HUD. (1979–1980)
- Consultant, Urban Systems Research and Engineering. Projects included: Analysis of Boston wastewater management plan for C.E.Q.; definition of 'modal' urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model; Interceptor project to evaluate the impact of EPA interceptor grants program or land use patterns in suburban and rural areas of EPA Regions 2, 4, 6; Rural growth project analyzing regional development in non-metropolitan multi-county areas in the United States. (1971–1977)
- Urban systems research and engineering analysis of Boston wastewater management plan for C.E.Q. (1977)
- Bangladesh energy study for Asian Development Bank and UNDP. (1975–1976)
- Urban systems research and engineering, definition of model urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model. (1975–1976)

- Land use and environmental quality modeling and case study analysis of land use impacts on water and air quality. Case studies focused on the Mill River basin in the New Haven SMSA. (1974–1975)

- Member, Technical Advisory Panel for Educational Evaluation in Massachusetts, Office of the Commissioner in Education, Commonwealth of Massachusetts. (1973–1974)

- Lake Chad polder development study of agricultural development with low-lift irrigation pumping in the area immediately surrounding Lake Chad. (1974)

- Urban systems research and engineering, interceptor sewer project to evaluate the impact of EPA interceptor grants program on land use patterns in suburban and rural areas of EPA Regions, 2,4,6. (1974)

- Decision-making and flood plain management in the Connecticut River valley, study for New England River Basin Commission. (1973)

FIELDS OF EXPERTISE

- Energy economics / energy pricing
- Power systems operations and planning
- Asset valuation: Generation, Transmission and Generation
- Water and wastewater management
- Corporate strategic planning and analysis
- Corporate reorganization and management

PROFESSIONAL AFFILIATIONS

- Institute of Electrical and Electronic Engineers
- American Waterworks Association
- International Association of Energy Economists
- Energy Bar Association

PUBLICATIONS

Books, Book Chapters, and Monographs

The Definition of Multifunctional Planning Regions: A Case Study of East Pakistan. A report to the East Pakistan Land, Power and Water Study, Harvard University Center for Population Studies, May 1971.

"Preferences for Municipal Services of Citizens and Political Leaders: Somerville, MA, 1971." With M.A. Vinovskis. *Population Policymaking in the American States: Issues and Processes*, D.C. Heath and Co., May 1974.

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"Framework for the Analysis of State and Local Population Policy." *Population Policymaking in the American States: Issues and Processes*, D.C. Heath and Co., May 1974.

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"Traditional/Renewable Energy Sources." With R. DeLucia. In Jacoby and deLucia, eds., *Energy Planning in Developing Countries: The Case of Bangladesh*, Johns Hopkins Press, 1982.

"Utility Spot Pricing to Coordinate Deregulated Utilities, Customers and Generators." With R. Bohn and F. Schweppe. In Plummer, Ferrar and Hughes, eds., *Electric Power Strategic Issues: Deregulation and Diversification*, Johns Hopkins Press, 1982.

Electric Generation Expansion Analysis System, Vols. 1 & 2. With M. Caramanis and F.C. Schweppe. With Stone & Webster Engineering, Vols. 3, 4 & 5, EPRI, Palo Alto, CA, Report No. EL-2561, 1983.

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"The New (Alternative) Electric Generation Technologies: An Evaluation of Their Potential." A.H. El-Abiad ed., *Power Systems Analysis and Planning*, McGraw-Hill, 1983.

"Using Spot Pricing to Coordinate Deregulated Utilities, Customers and Generators." With R. Bohn, and F. Schweppe. In Plummer, Ferrar and Hughes, eds., *Electric Power Strategic Issues*, Public Utilities Reports Inc., 1983.

"An Approach to Deregulating the Generation of Electricity." With R. Bohn, B. Golub, and F.C. Schweppe. In Plummer, Ferrar and Hughes, eds., *Electric Power Strategic Issues: Deregulation and Diversification*, Public Utility Reports, 1984.

"Utility Finance and Planning in Japan, Korea and Taiwan." With M. Castillo-Bonet. In Kim, Smith and Rose, eds., *Electric Futures of Asia and the Pacific*, East West Press Center, Honolulu, 1986.

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"Engineering Economic Analysis: Applications to Electric Utility Investment Planning." In M. Baughman ed., *Engineering Economic Analysis: Overview and Current Applications*, IEEE Tutorial, 1992.

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"A Louisiana Case Study: Towards a Single System of Substrate Regions." With C. S. Binkley. *Growth and Change*, January 1980.

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"Economic Integration of New Energy Technologies into the Grid Using Homeostatic Control." Invited paper, IEA Conference on New Energy Conversion Technologies, April 1981.

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"Wisconsin Study Shows Homeostatic Control has High Potential for Industrial Loads." With F. C. Schweppe. *Modern Power Systems*, Vol. 3, No. 1, pp. 43-46, January 1983.

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“Evaluation of Spot Price Based Electricity Rates.” With F.C. Schweppe and M. C. Caramanis. *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-104, no. 7 July 1985.

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“Coal to Natural Gas Seasonal Fuel Switching: An Option for Acid Rain Control.” *IEEE Transactions on Power Systems*, Vol. 4, No. 2, May 1989.

“Algorithms for a Spot Price Responding Residential Load Controller.” With B. Daryanian and F. C. Schweppe. *IEEE Transactions on Power Systems*, Vol. 4, No. 2, May 1989.

“Energy Systems for the Twenty-First Century.” With B. C. Ball and T. H. Lee. *International Journal of Global Energy Issues*, Vol. 1, Nos. 1/2, 1989.

“Planning for Future Uncertainties in Electric Power Generation: An Analysis of Transitional Strategies for Reduction of Carbon and Sulfur Emissions.” With B. L. Monroe, III. *IEEE Transactions on Power Systems*, 1991.

“Real Time Pricing as a Component of Least-Cost Power Strategies.” With M.C. Caramanis and B. Daryanian. *Proceedings of the American Power Conference*, 1991.

“An Experiment in Real Time Pricing for Control of Electric Thermal Storage Systems.” With B. Daryanian and R. E. Bohn, *IEEE Transactions on Power Systems*, 1991.

“A Computer Design Assistant for Induction Motors, Using Monte-Carlo Design Synthesis to Augment a Design Database.” With J. A. Moses, J. L. Kirtley, J. H. Lang and F. Cuadra. *Conference Record of the 1991 IEEE IAS Annual Meeting*, 1991.

“A Simulator of the Manufacturing of Induction Motors.” With C. L. Tucci, J. H. Lang, and J. L. Kirtley. *Conference Record of the 1991 IEEE IAS Annual Meeting*, 1991.

“A Framework for Integrated Resource Planning: The Role of Natural Gas Fired Generation in New England.” With S. R. Connors, C. G. Bespolka, D. C. White, and C. J. Andrews. *IEEE Transactions on Power Systems*, 1992.

“Optimal Demand-Side Response to Electricity Spot Prices for Storage-Type Customers.” With B. Daryanian and R. E. Bohn. *IEEE Transactions on Power Systems*, 1992.

"RTP-Based Energy Management Systems: Monitoring, Communication, and Control Requirements for Buildings under Real Time Pricing." With B. Daryanian and L. K. Norford. *ASHRAE Transactions*, 1992.

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Submitted in Response to Formal, Non-Public Investigation
Under 18 C.F.R. § 1b.5
Subject to 18 C.F.R. §§ 1b.9 and 1b.20

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Up-To Congestion Transactions) Docket No. IN10-5-000

AFFIDAVIT

RICHARD D. TABORS, being duly sworn, deposes ~~and states~~: that he prepared the Affidavit and Appendices of Richard D. Tabors and that the statements contained therein and the Appendices attached thereto are true and correct to the best of his knowledge and belief.

Richard D. Tabors

Subscribed and sworn to before me
This 21 day of October, 2011

Notary Public

My Commission Expires:

MELANIE DAWN JARVIS
Notary Public in and for the Prov. of Alberta
Appointment expires: December 31, 2011

MELANIE DAWN JARVIS NOTARY PUBLIC PROVINCE OF ALBERTA