MEMORANDUM

2 December 1993

TO: Bill Hogan

FROM: Scott Harvey

SUBJ: Why is electricity different than gas?

As I suggested yesterday I think there are at least two fundamental differences between gas pipelines and electric generation and transmission:

1. Short-run variable cost varies greatly across electric generation units but not across gas wells.

2. All electric systems have the complex tradeoffs between capacity and production that are found on only parts of only three or four gas pipelines.

I do not think that either difference provides any reason that open access transmission policies cannot be applied to the electric transmission industry. I do, however, believe that there are reasons that access to centralized dispatch is likely to provide generators with a decisive competitive advantage over firms relying on individual bilateral contracts to serve their customers.

One implication of the first difference is that it can make a lot of difference to costs which units are used to meet electric demand but it does not make much difference which gas wells are used to meet gas demand.¹ There are therefore likely few gains to efficiently “dispatching” gas wells, but there may be large gains to efficiently dispatching electric generation.

¹ It is essential in considering this issue not to confuse gas prices with costs. In this discussion the cost of production means the resource cost, not the price paid by the buyer.
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The issue can be illustrated with a simple example. Suppose that generator A has a contract to sell power at 3.5 cents per kwh on a firm basis and has a variable cost of 2.5 cents, the value to generator A of running is 1 cent per kilowatt hour. In a bilateral contract market (or a market in which each utility meets its own load) there may be hours in which other units (generator B) having a variable cost of 2 cents per kilowatt hour are not running because their customer is off line. There is a potential gain from trade between A and B of .5 cent per kilowatt hour that would enable generator B to pay generator A its 1 cent margin not to run and still make a profit at a price of 3.5 cents per kwh. Alternatively, a pool can create a market that automates these trades by back-off all generators whose variable cost (or offer price) exceeds the market price.

This possibility for gains from trade among the parties to bilateral contracts does not appear to exist to anything like the same degree in the gas pipeline industry because the difference between the market price and the short-run variable cost of production is about the same for all gas wells at a given market price. Thus, it is likely not possible to materially reduce the total short-run variable cost of meeting a given level of gas demand by changing which wells are produced to meet that demand. The main exception of which I am aware is that gas produced from oil wells has the lowest (negative) incremental production cost because not producing the gas requires shutting in the oil production. It is my impression that this situation has historically been handled through must take contracts. It might be interesting to examine whether there have been changes in oil well gas contracting in the post 636 gas market. This is one case in which there might in the abstract be significant gains from trade between bilateral contracts, because gas producing oil well owners would want to keep selling into the pipeline regardless of what happened to the demand of an individual customer under a bilateral contract. Such producers should therefore in principle be willing to trade with other producers rather than shut-in production when demand falls. In fact, however, I do not believe that this situation is typically (if ever) handled through trades between sellers.

Other situations in which one might expect that there might be cost differences permitting gains from trade would involve the higher costs associated with gas that needs to be desulphurized or requires additional compression. Once again, however, I do not believe that trades among producers are often used to minimize production costs. One interpretation of the absence of central dispatch in gas industry operations is therefore that the gains from central dispatch would be small compared to the gains

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8 Instead, oil well gas is probably simply aggregated with gas well gas in a package so that the oil well gas is always the inframarginal supply. This need for aggregation is created by the bilateral contract market structure and would not exist if gas pipelines were operated like electric pools.
in electric generation. Another possible interpretation is that the gains from central dispatch in gas transmission would actually be large, but that the gas network control system is much too primitive to allow an electric style market oriented dispatch system to function. Thus, an alternative to both the traditional pipeline merchant operation and the current Order 636 pipeline market structure would be a centrally dispatched pipeline transporter that equilibrated gas demand and supply by moving up an offer curve of gas supplies and down a bid curve of gas demand in each period.

Conversely, I imagine that one could run an electric transmission system like an order 636 gas transmission system, with bilateral contracts linking specific generation to specific demands based on Hogan style feasible transmission rights and the pool simply maintaining the electrical stability of the network. Unlike in the gas industry, however, there would be enormous gains from trade, even between utilities (who are likely to have many more units than an individual IPP) in such a system, from running the units with the lowest operating cost to meet demand even if these low cost units were not contractually committed to meet that demand. The gains from inter-company trade would likely be even larger for IPP's having a narrower mix of generation units on the grid in a particular region.

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3 This could be the case because the differences in variable cost are small or it could be because of the depletable resource characteristic of gas production. That is, unlike electric generation, when one shifts production between gas wells one does not really avoid production costs, one merely shifts them in time. If one produces a lower cost met today, this does not avoid the cost of producing the higher cost met but only shifts the cost through time. This time shifting is still a real resource saving, but it may sufficiently diminish the magnitude of the gains from trade to make central dispatch unattractive.

4 Thus, rather than suggesting that the electric system is not likely to develop along the lines of the gas pipeline system because the electric transmission system requires faster reactions, this would imply that the gas system does not look like the electric system because gas pipeline operational controls are too slow and undeveloped.

5 This would include contracting for units to provide spinning reserve for contingencies and voltage support. An empirical/theoretical question that we might want to examine, however, is whether the Hogan style feasible transmission capacity of a network would be reduced if the pool cannot control the operations of all generators on the system to meet contingency constraints and VAR support.

6 In addition, the cost of bilaterally contracting to serve customers in the event of various contingencies would likely be prohibitive for any IPP. I assume that even under a Order 636 style electric system the pool would somehow take advantage of the economies of massed reserves in meeting contingencies, although I am not quite sure

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The magnitude of the potential for these gains from inter-company trade in a bilateral contract market system is, I believe, a fundamental difference between the gas and electric industries. The need to realize these gains in an efficient market system does not necessarily preclude reliance on a bilateral contract market system in the electric industry, but it is a problem that must be addressed by a bilateral contract system in the electric industry but not in the gas industry. In practice, I believe that it would be extremely difficult to obtain an economically efficient level of these gains from trade through bilateral trades for two reasons. First, the ramping up and down of electric generation units is happening constantly during the day and it would take far too long to call around and arrange bilateral transactions. This process would also be pointless and inefficient in a Bill Hogan style pool because all the generator needs to know is the system lambda (or nodal spot price) and whether that is higher or lower than his avoided costs. The second limitation of the bilateral solution is that because of the loop flow problem and transmission constraints, the relevant transactions might involve a number of parties (i.e. generator A can cease operations allowing generator B to run instead, if generator C also reduces its level of operations to avoid a thermal overload, and generator D runs out of merit to compensate. This is the transmission/congestion problem.

The second difference between the electric transmission and gas pipe line industries, the inability to precisely define capacity in an electric network, is also likely to give rise to efficiency gains from centralized dispatch. Although Hogan defined transmission rights are by definition a feasible solution for the grid, they will not always reflect the efficiency frontier in the sense that there may be times at which more capacity is available between particular points than is feasible in the Hogan sense, because of differences in load elsewhere in the system. This potential for “free” additional transmission capacity is available through pool operation but by definition cannot be utilized in a bilateral market because no one has the ownership rights to this transmission capacity. Whether these gains are large or small and occur frequently or rarely is of course not known. This is exactly the problem with which you and Larry have been wrestling in defining transmission rights that provide full hedging in all states of the grid. Although I have not worked this out, it is my intuition that the value of the transmission capacity gains from central dispatch correspond exactly to the residual rents generated by the grid under a nodal spot pricing system. With access to sufficient real network data, we should be able to quantify the magnitude of these gains in existing networks.

On another level, it should also be kept in mind that the kind of bilateral contracts necessary to obtain market efficiency, i.e. paying a competitor not to produce, would be highly vulnerable to antitrust attack if conducted outside the framework of the pool.
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You suggested once or twice in the heat of the discussion on Tuesday that absent transmission congestion bilateral trades would be fine or efficient in replacing central dispatch. I am not sure that is necessarily the case. First, consider the gains from cost minimizing dispatch. The trading required to minimize generation costs in a bilateral contract system would be reduced if there is no congestion because the trades required to minimize costs would be bilateral trades not multilateral trades. Nevertheless, I suspect that the volume of required bilateral trades would still probably overload the ability of traders to respond to changes in price and load in real time in a real electric grid. I visualize a Hogan style pool as in effect an electronic market that equilibrates automatically in real time, through the use of offer prices precisely because individual negotiations would cost too much and take too long.

Second, even if there is no transmission congestion, there may still be gains from central dispatch in creating additional transmission capacity. Indeed, these gains may actually be more likely at times when the system is not fully loaded.

It also strikes me that there is some evidence suggestive of the magnitude of the potential savings from substituting pool dispatch for bilateral trades. Within NEPOOL (and PJM) utilities can arrange bilateral trades instead of going through the pool. There is even an artificial incentive for utilities to do this because of the silly split savings rules. Companies therefore have an incentive to do as many bilateral deals in advance of dispatch as they can, in order to capture a larger share of the gains from trade. Nevertheless, NU found in evaluating its margin with PSNH that by merging with PSNH and obtaining in effect instantaneous trades between itself and PSNH through the pool, NU was able to obtain an additional share of those gains from trade that was in the hundreds of millions of dollars (present value). This gain was not even equal to the entire gain from trade, but was just the value of the increase in NU and PSNH's share

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* In fact, some of the discussion on Tuesday of current gas pipeline operations suggested to me the impossibility of arranging real-time bilateral trades even within the gas pipeline industry. It was my understanding from the discussion that gas pipelines arrange in advance with producers to provide "swing service" in response to upsets or emergency conditions. This is exactly what an electric pool in effect does, i.e. it obtains price offers in advance so that the pool can make the market and respond in real time to changes in the market. The bilateral contract solution would be for a gas pipeline to get on the phone and call around with gas producers and agree on a price for changes in supply every time an emergency occurred. The fact that gas pipelines do not find it efficient to rely on such a procedure for even these occasional upsets, suggests it is hardly likely to be an efficient system for the hour by hour dispatch of the electric grid.
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of the gains from the trades that could not be obtained through bilateral trades. This suggests that the total gains from spot trades that can not be forecast are enormous.

I do not agree with the fear expressed on Tuesday that utilities might require pool dispatch of IPP's as an exclusionary device. Just the opposite, I think the best exclusionary device for the utilities would be the reverse, to limit IPP's participation in the electric generation market to bilateral contracts, while permitting utilities to optimize their operations through central dispatch. I anticipate that IPP's that cannot offer the gains from trade realized through central dispatch to their customers will be at a decisive competitive disadvantage. The reality is likely that the pools could allow (indeed if they were clever they would force) IPP's to enter into firm bilateral contracts (using their Hogan defined feasible transmission rights) without damaging the operations of the pool. Some gains from trade would be foregone, however, whenever the IPP generation unit was running when its variable cost exceeded the market price (at that node). This would disadvantage the IPP. Furthermore, if the IPP for some reason wanted to run regardless of whether its variable cost was above or below the pool price, it could accomplish this within a centrally dispatched system merely by bidding its unit at less than its true marginal cost.

This discussion of the value of central dispatch is not to say that there are no changes in pool operations that need to occur as we move to an open access market with Hogan style transmission rights and energy pricing. Some of the changes we have previously discussed are:

- Hogan style lambda pricing (either locational or pool wide);

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There are some pool imposed limits on the minimum length of bilateral deals and how far in advance they must be negotiated. I have not gone back and looked at what these were at the time of the merger. These rules regarding bilateral trades only matter because of the split savings rule used to calculate energy prices in the pool, as the payments depend on who owns which unit. In a Hogan style pool with system lambda pricing (or better yet nodal spot pricing), the pool would have no influence on bilateral transactions because pool pricing would have nothing to do with unit ownership.

We need to further explore what rules might be required to ensure system stability. Since the grid is operated to remain stable despite various contingency events, I would think that the grid could in fact be operated under a 635 style system, it would simply operate far far inside the efficiency frontier. This might actually be profitable for traders if everyone had to abandon central dispatch (because the system's inefficiency would create lots of trading opportunities) but it would be bad public policy. In reality, however, the utilities are unlikely to give up the gains of central dispatch and traders relying on bilateral contracts would simply be uncompetitive.
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- Disclosure of system lambdas;
- Pool membership open to all generators (and dispatchable consumers);
- All pool members having the right to sell all services to the pool (real power, reactive power, spinning reserve, black start capability etc);
- No restrictions on bilateral trades. 11

Other more contentious policies might be:
- the permitted degree of complexity (i.e. time variation etc) in unit offer prices over time;
- the permitted frequency of changes in offer prices;
- the pricing of contingency services or backup power.

11 These restrictions would probably disappear on their own once lambda pricing is adopted.