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Rapporteur's Summary

Section I: Market Incentives and Regulatory Rules for Transmission Expansion

A restructured electricity industry with new institutions for competition in electric generation and services will change the fundamental incentives for transmission maintenance and expansion. In turn, these new incentives create the opportunity and the challenge to develop new approaches even for the "natural monopoly" of transmission. Separating operation of the network from ownership of transmission assets and use of tradeable transmission reservations would open the possibility of employing market-based incentives for transmission investment decisions. However, economies of scale and scope in the network loom large and may necessitate new regulatory rules to promote efficient investment. The proper balance between market incentives and regulatory rules is a policy issue that deserves early attention in the development of the new electricity market.

Speaker One

The handling of transmission should be influenced by the technological developments that are having profound implications on the market structure of the electricity industry. These influences are making the industry much more competitive and therefore more receptive to market-based pricing. The handling of transmission should also be influenced by the ability to regulate. A quote from <u>Economics of Regulation</u> by Paul Jaskow and Roger Knoll: "because social interventions generate direct and indirect costs for peculiar kinds of inefficiencies, attempting to deal with a monopoly may be as costly as leaving it alone." One of the more embarrassing aspects of economic regulation literature is that after a century the profession is still unable to reach a consensus on one of the most central issues it faces. Many economists believe that because of the imperfections of regulation, where there is any reasonable possibility that competition can exist, it should be actively pursued.

What should be done about transmission, including expansion and in the context of the overall objectives of electricity restructuring? The goals are to reduce prices, to rationalize and improve utilization of the capital stock, stimulate innovation, minimize political decision making, and create new rules which will not be outdated by the time they are implemented. In a regulated world, with vertically integrated utilities supplying a bundle commodity of generation transmission and distribution, it was not necessary to price components separately. In a competitive world, that will not be the case. Components will have to be priced separately and, since an objective of restructuring is to rationalize the capital stock, and since generation and transmission are increasingly interchangeable, it is important to establish both prices correctly.

It has been an article of faith that transmission is a natural monopoly, that it is inefficient and duplicative to have more than one set of wires. The traditional monopoly argument does not consider that one set of wires can have multiple owners, and, perhaps more importantly in the electricity area, the physical characteristics of the electricity system allow real coordination economies, with centralization of information and dispatch. However, the issue is not whether it is a natural monopoly but whether it should be regulated.

The principal argument against regulating transmission is that new technologies are making transmission markets contestable. Innovation is eroding transmission's monopoly status and making the network partially competitive. New technologies provide the ability to bypass wires and allow pipelines to compete with transmission. The second major argument against regulating transmission is that regulation is rarely implemented effectively. The trend is to establish independent system operators which are quite powerful regulatory agencies, responsible for all the operational aspects of the network, **representative of the** market's interests in the market, and beholden to no one. Obviously different ISOs have different designs; stronger ISOs are also responsible for economic dispatch, for administering systems of vocational spot prices, for administering systems of transmission congestion contracts, and perhaps even for making capacity decisions.

There area couple of questions that should be asked about ISOs. First, if they are responsible for all these things, how is their creation deregulation? It is not, but rather a highly regulated system for transmission. ISOs will have clear incentive structures that are unlikely to be economically efficient. Second, is the ISO expected to be the ideal economic planning organization that will operate the transmission system in the best public interest? This is wishful thinking. Their incentive structures will not steer them toward economic efficiency.

Vernon Smith and his colleagues at the University of Arizona have conducted experiments on ISO operators, in which they assumed the price of transmission to be a residual, created by passive pricing. They asked the question, "Who gets the congestion rents, under this type of framework, when there is a congested line?" They found, not surprisingly, that under this passive pricing framework a congested transmission line causes the generators at the end of the congested line to suffer.

Obviously, this scenario is problematic, and does not provide competitive signals. The correct signals would provide incentive to enter the market with new generation capacity where the line is already congested. The signal should lead either to expanding the transmission line or to locating new generation elsewhere, closer to the load. Thus, unless the transmission is an active participant in the market and there is some active pricing of the transmission service, the ISO may not yield efficient prices.

Any pricing system must consider the physical characteristics of the grid. One such model, which Bill Hogan discussed in a 1992 article, is the bi-cell model, in which essentially the whole transmission function is implicit. In this case, the transmission operator is the owner, and essentially buys its own loads and sells at other nodes with an implicit transmission price. There will be various hedge contracts against price uncertainties in both power and transmission because transmission charges are not necessarily going to cover the costs of constructing or retaining a network. There will be some sort of access fee. If there are competitive pressures and a fair degree of contestability to working transmission, there will be significant incentive on the part of transmission operators to internalize the knowledge to make the network work efficiently. Therefore, there will be voluntary cooperative pooling arrangements to get the benefits of centralized dispatch.

With respect to transmission expansion, the issue is really whether the pricing of transmission will provide signals for users to build their own small-scale generators. Pricing is increasingly **a very** critical issue for investment decisions. Will the regulatory ISO framework produce efficient transmission prices that are going to provide the right signals for investment? There is a need to have some sort of regulatory protection, at least during the transition, some sort of a price cap while the market adjusts. There is also a need for some more permanent procedures to address residual pockets of-market power, and to give victims of market power some recourse.

In summary, the market structure implications of the new generation technologies are enormous in terms of changing the competitive structure of the electricity industry, particularly transmission. Unless restructuring takes the new market realities into account, it will be out-of-date by the time it becomes effective, and previous regulation in this area has failed substantially as indicated by large stranded asset costs. The success of untried regulatory regimes is far from assured.

Speaker Two

I will discuss some additional features of transmission rights that are important in creating incentives for decision makers to make correct decisions. In particular, I will focus on transmission options versus obligations. Should transmission rights come yearly with transmission options or should customers be able to assume transmission obligations? Expanders ought to be able to choose between the two mechanisms. In addition, I would like to explore the question briefly of whether decisions on transmission rights are sufficient to promote efficient expansions. Private decision making may not be sufficient, a regulatory backstop to supplement private decision- making may prove necessary.

Transmission rights come in a variety of forms. The physical transmission options are the current norm and are familiar to most people. There is the option of physically transmitting **megawatts** from point A to the delivery point, although there is no obligation to make that physical transmission. Now if that option is made firm, it needs to be direction-specific since its feasibility depends on the direction of the transmission.

In principle, transmission rights could also come with the obligation that customers who have the right to transmit up to ten megawatts from point A to point B, must voluntarily assume the obligation to do so even when it isn't profitable. More rights with obligations can be issued than options because transmission between two particular points often involves counter-flows over parts of the grid that may be congested. The counter-flow relieves some constraints and allows additional transmission to take place.

Physical rights could also have a financial analog. A financial right, of ten megawatts from point A to B, would allow the rights-holder to collect the congestion revenues associated with transmitting that amount of power. In order for this financial right to be firm, it needs to be feasible. If the grid operator is dispatching efficiently and is setting efficient locational energy prices along the grid, the test for financial feasibility is the same as for physical feasibility, insuring that the dispatch underlying those rights is feasible. And since feasibility is direction-specific, financial rights also need to be direction-specific. The congestion rent associated with the right from A to B must be calculated as the difference between the energy price at the delivery point B minus the energy price at the receipt point A. The rights-holder hopes that **amount is positive,** and that the energy price of B is greater than A, but it's possible that the receipt point price is higher due to negative congestion.

Collecting a negative congestion rent means that the rights-holder must pay the grid operator. In such cases, the distinction between financial options and obligations becomes important. If financial options allow rights-holders to collect these congestion rentals when they're positive but not when they're negative, there would be no obligation on the part of the rights-holder to pay the grid operator. On the other hand, when congestion is negative, there is no obligation for option-holders to pay the grid operator. However, if someone voluntarily assumes the financial obligation, then the right must be performed even when unprofitable. If congestion is negative, the rights-holder must pay the grid operator.

Since the test for feasibility of physical and financial rights are the same, the two kinds of rights are interchangeable. Someone who holds a physical option could have the right to transmit physically between point A and point B without paying congestion charges. If he decided not to use the physical right, it would automatically be converted to a financial right and he would automatically collect the congestion revenue. With physical obligations, that interchangeability is essential. If someone with a physical obligation cannot honor that obligation, the obligation can immediately convert to a financial one. The right-holder would either collect or pay depending on the direction of congestion and the congestion revenues associated with that right. Obviously options are preferable to obligations, because obligations carry the risk of nonprofitable performance. As a result, people will pay more for options. However, more obligations can be issued, although they are not as valuable per unit.

Would potential expanders rather have a smaller amount of options that have relatively little risk or a larger amount of obligations? The answer is likely to depend on the uncertainty about the direction of congestion. For example, an area with a lot of hydro capacity has fluctuations in the amount of water which may determine whether to import or export energy at a particular point in time. In addition, fluctuations in a few places may alter the direction of congestion. If the direction of congestion is uncertain, accepting obligations can be very risky. The obligations must be direction-specific. If one chooses a direction that starts out having a positive amount of congestion but then switches, one is stuck with a large quantity of rights which must be paid or performed in a nonprofitable way. With options, there is no risk of loss, of having to pay the grid operator later on.

If there's relatively little uncertainty about the level of the direction of congestion, on the other hand, then obligations may be preferable. The direction can be chosen with some confidence, and, since the unit value of options and obligations is likely to be similar, the greater number of obligations available becomes attractive. Sometimes options are a more valuable reward for an expansion, sometimes obligations are. To maximize the private incentives to expand, both need to be available.

Without regulatory restrictions, however, these rights will not be sufficient to encourage Private expansion for at least three reasons. First of all, to the extent that rights-holders select options as their reward for private decision making for expanding, the options don't capture the full social benefits of the expansion. Since the option cannot be depended upon for counter-flows, it is likely that the options won't fully capture the quantity of additional created capacity. This additional capacity provides a social benefit to the system that would not be captured by the rights-holder in instances where the direction of congestion is uncertain. Since investors tend to choose options, generally under this scenario investors would not receive the full social benefits of the expansion. In addition, there may be a free rider problem. Expansion often changes energy prices which result in benefits to both energy suppliers and demanders. This fact creates incentives for them bide their time and wait for a free ride. The third reason is based on cheap expansibility, and associated with the incremental cost of expansion. Successive expansions may produce similar amounts of capacity, but at lower incremental costs. For example, a ***greenfield*** expansion will typically involve the costs of right-of-way as well as towers, and the cost of stringing the lines. A second expansion that creates similar amounts of capacity can avoid the costs of rights-of-way and towers. Therefore, if there is a rule that gives extra rights to those who put up the incremental costs of an expansion, the second expansion will provide more capacity for the investment. Therefore, there are incentives for investors to delay, and to wait for someone else to make the first move.

For these reasons, private decision making by itself may not be sufficient to stimulate the necessary amount of investment. Therefore, other remedies, such as a public or quasi public body, could supplement private decision making. However, this body should be granted the authority to spend others' money. The public body should help private decision-makers formulate efficient decisions, order expansions, and allocate costs. It must be independent and have incentive mechanisms to encourage efficiency. In conclusion, when it comes to transmission rights, let a thousand flowers bloom. There ought to be financial as well as physical rights. There ought to be available options as well as obligations. These rights by themselves, however, are not sufficient. A regulatory backstop should be considered.

Speaker Three

I will talk about transmission congestion contracts (TCCs) and transmission capacity reservations (TCRs). I'm more in favor of TCCs but I think TCRs are moving in the right direction and will eventually become the preference. There will eventually be some convergence between TCRs and TCCs.

TCCs and TCRs are rights given when an investor builds a transmission line. TCCs and TCRs are financial rights similar to rights, with slight differences: neither of them solve the free-rider problem, and both make it difficult to tell if a grid expansion is a good thing until it's too late. TCCs include a rule for what to give out when it's not clear whether the expansion is good or bad. With TCRs, the status of the expansion needs to be known in advance in order to decide how much to allocate.

TCRs provide price certainty for those who expand the grid. If a line is built, TCRs provide the builder the right to use it without getting charged for congestion. TCRs will **help** investment in the grid because they 1) result in new lines, and 2) the builder gets to use the line for free. TCRs and TCCs are not thereto pay for construction, but because lines are innately useful.

When proposing a grid expansion, the total system needs to be considered. The following is an example of how TCRs would be allocated - and - why- theyre-ambiguous. - A system has a municipal path from one region to another with two transmission lines. The path itself is rated, and the transmission lines have their own limits. What would happen if a line went down? How much could be transmitted? If the 200 megawatt line goes down, only 100 megawatts can be shipped. If a system decides they want the higher rating on their paths so they can transmit more power, what kind of TCR should be given? What rights should be allocated? Although the actual shipment across the path depends on where it originates, there are limits on how much transmission can be handled. Whatever the size of a newly constructed line, its path rating depends on how the path is being used. The system cannot tell you whether the path has been improved. Thus, TCRs are being allocated ambiguously.

This problem can only be resolved by looking at the TCC allocation rule, which considers the total system and gives the investor a choice of rules and location. The builder of the line makes that decision whether the choice is feasible. This is often difficult to determine, but is an inherent problem anyway with running a grid.

Another free rider problem is "lumpy investment." It's cheap to add to the line, but expensive to get it started. It is defined as the time when initial investments are made and lines will have to overcompensate, since investors will want to build a little too big so that they don't have to build a new line again soon. During "lumpy investment” there will be free riders. An example of how this might work:

Load A is a load that decides to build the lines so that it can get cheap power from a twenty dollar generator. When load A becomes large, it decides that instead of using its local generation for thirty dollars per kWh it would like to build a line for cheap generation. So it builds a line that is a little bigger than it currently needs, because it knows that there are other people to whom it can sell its rights once total demand for the line exceeded the line capacity. The investor is banking on future congestion and collecting some money through TCCs, which serves the social goal of lessening congestion through the incentive of profit. Investors will give people a free ride for a while, during the time when the total load doesn't congest the line, and there are no rents or congestion charges. TCCs can help to determine when a grid expansion is positive and how to treat it. Adding new lines can render the grid less capable of handling power, or, if power is purchased elsewhere, it can allow both the old and new power flow. It all depends how the TCCs and grid is used, and investors will need to know the effects in advance.

Reliability expansions are needed both in the Pacific Northwest's IndeGO system and in California. However, there are now two kinds of grid expansions, one for congestion which will be priced by the users, and one for reliability which will be priced by a regulator because congestion is not priced inside a zone. If congestion is not priced correctly, the market does not respond, the lines are overused, and there are reliability problems that have to be handled by regulators rather than the market. Pricing involves linear programs which take into account complicated transmission constraints, but the idea itself is actually very simple. Finding the right prices involves trying every possible dispatch of the system, until the least expensive way to produce the electricity to satisfy all your customers is discovered. Although there are many different systems that can determine the prices, they all are grounded in basic theories of economic pricing. TCCs can be assigned properly without knowing how the grid is going to be used, without any knowledge of what the generators are going to do. They depend only on the wires.

Speaker Four

I would like to begin by commenting on the experiments conducted by Vernon Smith at the University of Arizona. I have a slightly different interpretation of the results of those efforts than the earlier speaker. My observation has basically two components to it. The first is that one of the characteristics of the experiments was the presence of market power. In other words, there were relatively few players in the model. The generators were relatively large in its market place. Market power presents a problem in that people capture rents. Second, the assertion that passive transmission pricing is what creates market power issue is not quite correct. Active transmission pricing is defined as someone owning the transmission rights and being able to withhold it until his price demand is met. In effect, what this pricing does is to create a countervailing market power that oversees market power from the generation side.

IndeGO began with seven investor-owned utilities in the Pacific Northwest signing a memorandum of understanding. It has expanded to 21 signatories which include both the Rocky Mountain and the Northwest regions. IndeGO is now considerably larger in area and number of participants than when negotiations began. Our experience in transmission planning under a vertically integrated regime can help us with today's problems. In the past, planners tended to break problems down into bulk system transmission planning and local transmission; local generation was sometimes substituted for a remote generation with transmission; but since transmission does not generate energy yet, they are not perfect substitutes. Installations were made on short time frames of one to two years. The expansion plans were based on potential loading of individual pieces of equipment. The decisions tended to be based on local reliability concerns by local planners.

Unbundled service poses a problem for utilities because, in the past, decision making was done inside the utility. There was a review by the reliability council and siting review in the states, but those were the only external activities. The future expansion process allows more participants to make these choices themselves so that they can make their own combined supply decision. In order to do that, the decision making process needs to be externalized, either by the pricing of transmission services (supplemented with institutional procedures as necessary), or by dividing the system up into zones for pricing purposes. This proposal would concentrate the congestion management at the boundaries. All schedules are accepted by the ISO who allows the parties to manage themselves if they choose, or to let the ISO make the appropriate purchases. The transmission charge is an access fee to collect the fixed cost, the congestion charges, and the transmission capacity reservation.

The major constraints on the IndeGO network are geographical: where are the mountains, deserts, water, and fuel? It is proposed that inner-zone capacity additions should be placed where the congestion· price-would be evident to everyone. TCRs would be assigned to those who fund the construction of inner-zonal capacity. These expansion decisions become subject to regulatory or regional planning processes and expansion decisions will not be made in private. The immediate public interest concerns need to be addressed. If the proposed line is the last that can put down a corridor, it becomes a public interest issue as to whether or not a higher voltage facility should be built.

IndeGO has a fully independent board, similar to the Federal Accounting Standards Board (FASB) model. This board has a parallel technical advisory board to avoid conflicts of interests. IndeGO's planning function identifies options and feasible projects for the public. Planning would be done at the local level where there are common interests. The front range of the Rockies, for example, have planned together because the companies are so interlaced through their shared circumstances. There is a certain amount of tension, but there is evidence to indicate that the structure works reasonably well. The plan is to divide the responsibility for main grid planning between these two committees. The main grid planning would be done by the IndeGO staff with input from the parties for 230 KV and above projects. Local facilities would be locally planned with the IndeGO staff deferring to these parties if possible, and administering a dispute resolution process otherwise. The idea is to match planning responsibility with cost responsibility. There is a proposal for an area access fee that includes the local facilities upon their construction. The main grid facilities will eventually be built on the basis of TCRs and would be the reward in that case.

The contract structure is based on three sets of agreements, the first being the control agreement which specifies maintenance, the IndeGO tariff which provides for the region-wide transmission service and includes all transmission facilities, 46 KV and up, and interconnection agreements which apply to security concerns. Under these interconnection agreements, there are virtual must-run contracts which state that if the operator orders that the line is run, it must be run at a prearranged price. In other words, the price is set in advance. For expansion between zones, the general idea is that IndeGO research possibilities before giving their recommendation to parties who are willing to fund the projects. IndeGO may act as the project sponsor if there is no individual who could afford to build all 500 megawatts of capacity. An owner would sign a control agreement that he is liable for maintaining the wires. This work could be contracted out, since under the control agreement signatories do have some commitment to build. Finally, IndeGO files all these contracts with the FERC.

In recent years, the electricity network has been expanded on the backs of large generation projects. In the future, however, transmission development may occur for the sake of new generation. In this case, the generator identifies potential customers and considers the costs of all possible sites. There are three options under the IndeGO Proposal. One possibility is to assume the risk congestion cost (calculated on past history), and see what happens once operation begins. The second choice is to purchase existing capacity reservations from others. The third choice is for the generator to fund expansion on his own.

Within a zone, the purpose is to meet reliability expansion standards. In order to meet local delivery requirements, the area planning issues committees are open to all stake holders. The committees identify the problem and consider possible solutions, including non-transmission alternatives. They consult with IndeGO planners to see if a higher voltage facility can be tapped rather than building a facility. The cost of local projects is captured in the access fee. It may well be that a dispute resolution process is needed to finalize planning of a project. For example; a local utility decides that it needs to build a new distribution substation, studies indicate that the best solution is to propose a new 345 to 138 KV substation, but perhaps the existing substation should be reconducted, or the load should be shifted between distribution substations. After all these possibilities are discussed, a solution is recommended and the least costly option is usually embraced. However, since building transmission is not purely an economic matter, the public good is considered as well.

General Discussion

Would TCRs allocate solely temperamental transmission investment or would they also allocate for existing capacity based on ownership, contracts, or rights?

The current dilemma in setting up **IndeGO is** how to assign TCRs for the existing system, and how to convert today's system of contract rights into these TCRs. One of the problems for converting them is that they are not fully equivalent. The physical right model provides for exclusivity of use. TCR rights only avoid the congestion costs, so the conversion is causing some parties distress.

Typically, capital cost recovery for transmission was around 30-40 years in the deregulated environment. What is a reasonable time period for investors to consider recovery of the capital cost of building new lines?

I don't know the answer because there is gradual depreciation of transmission which must be balances against risk. The long-term horizon for planning is roughly the same as before, although larger projects today include generation. Even administrative siting issues can delay a project five years. It is important to understand that the distinction between active and passive pricing is not just that people are trading transmission rights explicitly, it is that they are allowed to withdraw these rights from the market place if they don't get the price that they want.

If there is a requirement that all of the transmission capacity must be used at the end of the day, and TRCs are made available by the system operator, then there won't be active trading. This may not be a function of market power, since subsequent experiments done within this framework found that there can be competitive results with a very small number of generators, whether they collect rents or not. If there is active pricing, supply can be withheld from people that don't pay your price.

It is not necessarily the withholding of but the withholding of TCCs (or other mechanisms used for financiaLor- physical- rights) in the secondary market that would create a market power relationship between the transmission grid and generators. To the contrary, the notion is to award TCRs and trade them--active trading. As the operating moment nears, the system operator announces that there is more capacity available than originally thought due to the patterns of use. With enough information about these patterns, more capacity could be transmitted using the same right. However, it is not active trading if the transmission rights are withheld from the market place because if they aren't exercised at first, the ISO will come along and sell them. Pricing results in this environment would be the same as passive pricing against the existing capacity. If the ISO did not use the existing capacity, and the only thing that is allowed were those initially allocated, then there would be active trading.

The Western System Coordinating Council (WSCC) used to have a system where capacity could be withheld. The commissioners determined that this could no longer occur because a lot of companies participated in rent sharing. The 'rent sharing' environment actually dispatched the same units that would be dispatched in an open network. The proposal for IndeGO is that all schedules are accepted, and participants are simply told what it costs to gain acceptance. In effect, participants can trade those costs with rights, but they can't block other transactions. The ability to hold out fora higher price would allow the transmitter to get congesture rents, but the **IndeGO** structure won't give the congesture rents to the owner of the line.

Is it really justified to withhold capacity from the market? A transmitter line is a public good. Withholding capacity can be thought of as a monopoly. A monopolist reduces supply in order to raise prices. The purpose of regulating a monopoly is to increase the supply towards the competition and away from the reduced monopoly level. The advantageous feature of the transmission monopoly is that an expert can determine how much capacity is available under certain conditions. This allows the system operator to quantify how much capacity a monopoly has, and thus can be expected to sell off. In a typical monopoly, the monopolist cannot be told to sell off because there is no definition of "off." However, the transmission system is easier to regulate because it is so quantifiable. A great rule for regulating the transmission monopoly is to establish a must-sell, no withholding rule. However, this approach only applies to existing problems, not expansion.

Given all the imperfections of the regulatory system, regulation which is targeted to solve monopolies exerting market power and withholding supply to raise the price, is better than broad antimonopoly regulation. A little bit of market power is a bad thing, but the regulatory system has a long history of misallocating resources. Moreover, in a market-based transmission system technological developments will be stimulated that in turn will make the system even more competitive.

The characterization of the experiments from Arizona as distinctions between active and passive trading of transmission rights is more a matter of withholding these rights. If **active trading exists** but the ISO is operating so that withholding can't occur, the problem isn't **solved.**

Transmission congesting contracts which have this passive pricing characteristic can be traded constantly. The system can be set up to ensure that ownership is changing all the time. **However,** if one of the options is to go to the ISO for capacity, the options can't be withheld. The premise underlying ISO proposals is FERC's dictum that parties will not be allowed to withhold. Considering the public policy issues, transmission isn't necessarily a contestable market. Eminent domain, condemnation rights, and the need to obtain certificates of convenience and necessity will affect the market, as will environmental problems and land-use regulation constraints. There are reliability issues such as what sorts of back ups are required and what levels of redundancy are required for certain classes of customers. How can it be argued that transmission is truly contestable?

If these issues present barriers to new construction, then transmission isn't contestable. However, aggregators can put together networks of micro-turbines which will have all sorts of reliability characteristics. Aggregation, micronetworks, and distributed generation are potential entrants which creates a contestable market. The ability to enter the system and compete with the transmission network acts as a constraint on pricing.

However, in order to build the micro-networks, the public must be used to negate the opportunity for competitors to use the regulatory process to prevent construction. Competitors can use regulation as a vehicle to hinder the access of new entrants. Given that regulation issues such as land use and siting are unlikely to go away, doesn't that make at a minimum the transition to a contestable or potentially contestable argument awfully costly?

Siting difficulties do hurt the contestability argument, however, I'm not sure that they are there to quite the extent that you **are** suggesting. New things are built in this country all the time. There are companies out there that are expanding their facilities, they obviously think they can be built.

If a line is built that is interconnected with the grid, it's impossible to keep power from flowing over capacity. Therefore, a grid operator is needed to decide who gets to go on and off to make sure that lines don't burn down. For that particular function, there is not a competitive alternative.

There are real economies to centralize due to the physical nature of the grid, but there are other systems that don't have that physical aspect. When those economies are centralized, however, competitive pressures exert a tremendous incentive for the grid operator or owner.

A transmission company (Transco) would be preferable to an ISO. A Transco would internalize some of the congestion costs because they have an automatic interest in incremental steps to maximize revenue. The regulatory lag is sufficient enough to allow incremental sales which, although the benefits they provide will ultimately be lost, are still acceptable. Unfortunately, few people are in a position now to spin off transmission assets and that's why the Transco concept has foundered. For whatever reason, people are averse to for-profit transmitters and for-profit operators of the system.

What would happen if a group of outside investors would come in and say, "we want to expand the transmission system in this particular. direction. -We're going to put up all the money and get the TCCs or TCRs. We have done our own market survey, and think there's a market for it."

The proposal would be evaluated by Indigo to make sure it did not reduce capacity, and then approved. If the new line caused disruption, the WSCC would determine that a line could not be closed or put into the network until the applicants had mitigated the damage to the other parties, which would require an institutional evaluation. In terms of revenue and the pricing of the service, the investors would then be centrally subject to pricing decisions by Committees of the ISO, over which they presumably would not have not a great deal of influence.

The ISO would dispatch any system that has added-against-value to the extent that a party believes that there's avoidable congestion. It does not solve the free rider problem. There is the possibility that people will just wait for someone else to build it, but that's no different than the system in place today.

IndeGO's zones arose primarily from geography. What provisions does the IndeGO Agreement have for moving those zone boundaries around as the system configuration changes? For instance, independent transmission development companies are eagerly looking to find places to build new transmission lines, but hesitate in fear that it would become a intra-zonal facility?

The whole basis of the zonal approximation is that there are certain constraints that are inherent to the network because of its topology such as the Sierra Nevada, the Cascades, the Great Salt Lake Desert, the Nevada Desert, and the Great **Basin.** The intention is to create more zones even if the zones don't have any particular value. In other words, the price differential across the zone boundary may be non-existent. Anywhere there's a reasonable likelihood that in the near future there might be a zone boundary, a zone should be created. It would be perfectly reasonable to have 40 zones rather than 10.

The models that have been discussed don't seem to calculate political realities into transmission system expansion. There is plenty of anecdotal evidence to lend credence to the theory that constructing new lines is difficult in practice. Is there any ability to enforce the siting decisions of the ISO or is it dependent upon the states authorization?

Even within one jurisdiction, taking into account political realities is a valid point. There isn't an enforcement mechanism short of the Federal Siting Authority, which is only practical as a last resort.

In the future, given the creation of TCCs or TCRs, will utilities who want to build in the future not seek to put the costs in at the retail rate base? Is there the option of creating this system from the beginning and removing all these assets from the rate base and then unbundling, in terms of the pricing arrangements and making transmission self-sufficient?

It is doubtfully feasible to keep the old transmission system out of the rate base, no matter how economically attractive.

The **IndeGO** Proposal places all transmission assets into IndeGO and relies on the state commissions to allocate its transmission expense. In effect, it comes out of rate base.

Section II: Institutions and Public Policy Issues in Transmission Expansion

Traditionally, the siting of transmission lines has been an exclusive domain of the states It has also been a contentious issue that often pitted utilities against community or other groups who oppose the siting of facilities near their homes or communities The combination of those factors led some observers to express concerns about parochial interests reigning over broader, economic interests often citing concerns ranging from health and environmental effects to aesthetics and property values. The coming of competition may well heighten the possibility of institutional and political stalemate over the siting of new transmission facilities ~ Not only will the-traditional battle lines continue, but now there may well be new actors with incentives to intervene in siting processes. Incumbents, particularly those with high costs, may well intervene to prevent increased transmission access to local markets for competitors. Groups who fear the potential environmental effects of increased use of coal burning facilities to serve distant markets to which they might not have access without new transmission facilities will also have incentives to intervene in cases they may have had little interest in historically. Moreover, the states themselves, the traditional arbiters of these matters, may well find that their narrow economic interests demand a particular result in a siting case. A number of public policy questions inevitably flow from the new dynamics of the marketplace. Among them are the following: Is there a federal or regional role in the siting of transmission lines? How should the traditional "need" criteria be redefined, if redefinition is required (i.e., whose need is paramount?)? What standards should be applied to determine standing for intervention (e.g., should competitors be allowed to intervene?)? How far beyond the immediate environmental consequences of the proposed facility should the environmental analysis go (e.g., should inquiry be made into changing dispatch patterns as a result of their new line?)? In short, what are the changing political mid institutional circumstances that will surround future siting proceedings?

Speaker Five

To begin, building transmission lines has never been easy, and will not get any easier in a restructured electric utility industry. Second, Texas's efforts to open the transmission system for access to all the market players can be examined as a case study. Third, transmissions issues are correctly characterized as "works in progress."

The ERCOT system consists of about seven thousand miles of 345 KV transmission system. Within this there are ten operating control areas. The owners of these control areas fall into the following categories: four investor-owned utilities, one co-op, two large municipal utilities that have control areas, one river authority in Texas with its own control area, and a combination entity. It's the only power pool in Texas, consisting of four cities plus one large cooperative. ERCOT is essentially isolated from the rest of the country, particularly from the Eastern Grid. There are two DC interconnects that connect ERCOT to the Southwest Power Pool.

Like most of the NERC regions around the country, ERCOT is examining its membership status. Over the past year, in conjunction with the Public Utility Commission, ERCOT has tried to comply with new transmission rules. **ERCOT** membership has been restructured and opened to all market participants, who have equal standing. The board of directors has 18 members, three from each of the **six** market groups: investor-owned, large municipals, co-ops and river authorities, transmission-dependent utilities, IPPs and power marketers. Each of these six market groups can select or choose three board members. Once on the board, each board members' vote carries equal weight.

Prior to the new FERC rules, ERCOT had a traditional kind of transmission pricing. Each individual utility had a cost-of-service hearing before the public utility commission and charged its own customers the cost of transmission service. Following the FERC order, ERCOT adopted a new transmission cost recovery methodology. This required that all ERCOT transmission owning-utilities file transmission cost of service cases. Afterwards, these were totaled up and it was determined there was about 697 million dollars of transmission cost being incurred by ERCOT. The pricing methodology, based on a state wide postage stamp system, was created to defray these costs. Seventy percent of these funds would be recovered through this mechanism, with the remaining 30 percent recovered through an impact rate.

This pricing arrangement has produced a couple of notable results. Although unintended, the cost shifting of about 95 million dollars incurred by the three largest utilities has taken place. This shifting was purely the result of the new system's cost-averaging affect and basis on planned transactions. All costs are recovered essentially through annual planned transactions. Any incremental transactions are charged only for the losses that they contribute to the system. There is not a wheeling fee for incremental wholesale actions. Two of the utilities have filed lawsuits, and there have been new transmission siting issues. For example, the Lower Colorado River Authority, which probably makes up less-than. I.0 percent of **ERCOT,** wanted to build a transmission line that is essentially in their service territory. As a result of this pricing methodology, LCRA's customers will only be paying 10 percent of the cost of that transmission line, 90 percent will be paid by someone else. In addition, there are many more incentives for people who want to intervene in transmission cases. Because all costs are being recovered from customers based on load size, that has a larger influence than before. The other aspect of this pricing methodology is that line siting and construction are no longer internal issues resolved only by utilities.

The new price structure presents many new questions. In an open access environment, utilities may be required to build a transmission line that doesn't benefit their native load. In the future, it will be a challenge explaining to communities why a line needs to be built to serve people outside the local area. Similarly, how should certificates of need and necessity be awarded? In a rate case, should the proceeding simply examine the benefits of the line and leave the costs to be allocated? Or since these costs are going to be paid for by all ERCOT utility participants, should the case include cost allocation proceedings? This scenario was not predicted, but the result of having to deal on a practical basis with new transmission rules. In addition, when a question arises over who should intervene, if it's simply a cost issue should anyone be excluded from being a participant in the CNN process? Once the new rules are in place, these issues will get resolved through practice.

In terms of building new transmission, there is not a lot of transmission in ERCOT that needs to be built, certainly over the next three or four years. This is fortunate because time is needed to figure out the right institutional structures to handle new sites, rules, and procedures. 95 percent of ERCOT's transmission network was constructed before 1990. There has not been much transmission constructed in recent years. The existing siting process is very complicated and lengthy. It requires a tremendous amount of documentation that firmly establishes need, and all sorts of routes and alternatives. Our planners would ideally prefer a 42 month planning horizon before filing a CNN. Unfortunately, if a new manufacturer come to town that needs wires, the planners have to move quickly. The Public Utility Commission has a minimum of one year to look at a CNN but typically the time is much longer because of intervention.

Speaker Six

The current proposals coming now from Commissioner Santa and others to federalize the traditional state siting process for transmission lines runs smack in the opposite direction of two fairly pervasive political and social trends in this country. The first is the movement towards greater respect in deference to states rights, particularly regarding property, and environmental and economic decisions. Secondly, there is a very strong and well-organized local property rights movement which is very skeptical of any regulatory body other than local land-use bodies. Local communities are not likely to have positive reactions to requests for construction posed by regional ISOs. There is also a much more rational public question of the public benefits to be gained versus localized disruption and environmental costs. People are concerned ...about their. community and are asking rational questions.

There are three points that the public and environmentalists will think about in transmission siting in the brave new world. First, what is the goal? The current system involves a certificate of public need and convenience. Historically, utilities building transmissions have done so to meet an obligation to serve. That's quite different than competitive generators and power providers seeking to maneuver the states police power to maximize their private profits. So what's the goal? Is it a public need and a public good? Or is it private gain? The second point is who makes the decisions? Is it state commissions or a regional body or a federal agency? Third, how do the proposed transmission siting roles for a particular proposal improve environmental quality? Most state laws that talk about utility regulation include a goal of environmental equality.

Historically, a state has exercised fairly extraordinary eminent domain power in order to facilitate new transmission line siting because it was a public good, not for private profit nor competition. However, many of the new transmission projects now being contemplated are initiated by investors trying to make a profit.

Should **a** private entrepreneur or private business be able to force people to give up their land through eminent domain? The reality of eminent domain is that most of the time people lose on price because the state wants to pay as little as possible to acquire land. In most cases, the people opposing the eminent domain don't have the resources to challenge the state Attorney General's office. Why should the public bear the environmental costs and the individual and community disruptions for new transmission lines that are being built for private profit rather than the public good?

For example, Lake Head Pipeline runs **a** series of pipelines in the Chicago metropolitan area. They want to expand their pipeline capacity because their current pipelines are full. They have some gas suppliers for western Canada who want to sell to oil refineries in Northwestern Indiana. Lake Head is asking the Illinois Commerce Commission fora certificate of public convenience to run a new pipeline through northeastern Illinois, rather than to satisfy the fuel needs of Illinois. They don't operate in Illinois, but for competitive reasons it is profitable to transport gas between Western Canada and Northwestern Indiana. The Illinois Commerce Commission is grappling right now with the issue of public good as opposed to private profit. What do local residents get for the disruption and the environmental cost of the pipeline?

There is a private solution. Motorola, a large industrial company, was proposing to build a major manufacturing facility. A Wisconsin utility asked Motorola to buy up the land in between for a power line to sell electricity less expensively than Commonwealth Edison, the local electric utility. Ultimately Edison beat the Wisconsin Utility price and wound up keeping its Customers, but the arrangement was quite different than the Lake Head pipeline or previous transmission contexts. A utility claimed that it could purchase eminent domain, and did not need state approval.

In order to begin exercising traditional eminent domain powers; those who are trying to build new transmission capacity will have to identify that public good beyond a "it's good for competition" argument. Second point, who makes the decision? The huge federal and regional land grab that would occur is contrary to all the political, social, and cultural trends in our country. There is a trend towards states' rights, dashing the hope that either FERC or a regional ISO will be allowed to exercise eminent domain authority. This can be compared with the federal framework for the interstate highway system, which serves a federal and public good of supporting trucking and transportation in a national market around the country. But there is no federal eminent domain to take land from any state in order to complete the federal interstate system. On the other hand, states cannot enact rules prohibiting double wide trailer trucks, banning shipments of radioactive waste, etcetera. It would unduly interfere with interstate commerce. With transportation, there area federal set of connections, but the states are responsible for assembling the rules within the state and making them work at a local level.

Courts are rolling back commerce clause authority. There was a major decision last year involving gun control laws in which the U.S. Supreme Court sharply restricted Congress' right to impede on states' rights.

States are probably in a better position to weigh the competing tradeoffs of public need verses public good. Reliability and need for power verses land and environmental control issues requires more than distant regional or federal body. Environmentalists would generally prefer the decisions to be made at the federal level. Environmental groups have more clout and more influence, more ability to access state PUCs than at FERC or some regional ISO body. In addition, environmentalists usually do better when the traditional power interests are fighting among themselves than against one big powerful interest against the under funded environmentalists.

In conclusion, I'd like to raise three additional points. First, restructuring ought to be an opportunity to improve environmental quality. The ISO could look at how to avoid transmission expansion through energy efficiency and distributed renewable. It depends again how the ISO's mission is defined as providing capacity or meeting needs or site transmission.

Second, new transmission lines can be a driver of sprawl, and local land use and regional growth considerations. Developers will build where there are roads, sewer lines, and transmission lines. The third concern relates to the effect a new line will have on air pollution. Obviously, environmentalists would be happy if a transmission line facilitated sales from a cleaner renewable than from a relatively dirty coal plant.

Speaker Seven

In my comments, I will address some of the changes I see from the perspective of an investor in new transmission facilities. In the past, the utility was the monopoly provider of the bundled product. What they sold and what people bought was electricity delivered to their facilities. Utilities had integrated planning for all aspects, GT&D, and as a monopoly their objective was to satisfy the regulators, not customers. The drives for new investment were basically just the forecasted need for the bundled product. How much electricity. did. people need and what was the least costly way of getting it there? Most of the least-cost- planning focused on generation, since they had very little transmission. Most new transmission projects were associated with need requirement for big generation. The reviews often had some minimal view of the question, "well, how did that affect the energy price?" or "was it justified based on energy prices?" Clearly that paradigm for transmission planning is outdated.

Market prices now drive all of the generation investment. The price of energy is what determines whether people build, operate, and maintain. This has produced some very significant changes in the criteria for planning and implementing new transmission projects. The obligation of the local utility in the old world was to provide energy-on- demand. In the new world, the obligation is more to connect the customer to a competitive energy market. If the energy supplier fails to deliver, it is not the local transmission company's problem. It is its problem to the extent that it may affect other customers but financially it is the consumer's problem.

What is the adequacy of the transmission system? In the past it was always a single criteria, is it reliable enough to meet energy on demand with the right level? In the future there will be more questions asked of the transmission system. Beyond "will be there energy at my facilities?," is the question "is the market competitive?" Does the market want more transmission, not necessarily because of reliability, or even competition, but simply because of opportunity for energy trading? The criteria for siting new transmission projects has also changed from "is it needed for reliability?", and "is the proposed project the cheapest option?", to "do you need it for competition?", and "are there certain generators that may otherwise enjoy unacceptable market power in the absence of transmission?" Will the market pay for more transmission to support the competition? There are also a number of issues for RTGs and ISOs, for example, voting for new transmission is going to be extremely difficult. We learned how ERCOT came to the 70/30 rule, and for every RTG there will probably be ten proposed transmission pricing models.

Integrated planning is falling by the wayside. Perhaps Western geography still presents certain barriers, but in general, market prices now drive the electrical topography. In many instances generation sites go where people want power and the opportunities for electrical trading is driven by the prices. Regionally, voting and expansion are the two critical issues. The golden rule might be that the need for new transmission facilities is based either on reliability or market criteria in order to make the competitive marketplace function efficiently. It would be a fundamental failure of the restructured electric utility industry to regulate generation prices only to fail to have the transportation network necessary to facilitate that market. In order to avoid this, the benefits that flow from new transmission projects have to be tied as closely as possible to its dollar support to it through pricing mechanisms. This also needs to be tied to voting rights.

Defining an electric market is an art, not a science, because potential for congestion on the existing system has to be examined. By and large, one can look at the market and say nodal prices aren't so different, and determine that there are major problems with transactions- The prices for transmission *within a* market may not be that of a postage stamp, and perhaps they should be point-to-point, but in general the capacity is available. On the other hand, if there is significant continued and sustained congestion *between* markets, one way of defining the market might be to equate an electric market to an RTG or a control area. The boundaries are established, transmission will have to support the two markets, and transmission will have to be priced. The network upgrades would become part of the RTG pricing. Whether it is based on postage stamp rates, by megawatt mile, or something in between, transmission investors don't really care because they work under the assumption that for those kinds of projects there will be an agreement to support the cost. For new projects though, for point-to-point projects, the concept of contract and capacity is more applicable.

There are different ways of gaining siting approval for transmission projects. Network upgrades will have demonstrate public need either for reliability or competition. In the future, competition must be brought to the market place and that criteria may dominate the siting approval. The RTG is probably the best place to plan to improve the network upgrades. Part of the public good for a state might be to say, "well, we've agreed to participate in the RTG, quid pro quo, we site new transmission that the RTGs approve and other states host transmission to support and facilitate ours." Once the project has been identified, competition can be introduced for the construction, financing and ownership of those projects. The local transmission utility does not have to own the transmission line. The transmission support agreement between owners and the ISO becomes the basis for financing it and now investors can pursue the financial tools of the IPP world to develop transmission. In summary, network upgrades can be a mixture of continued coordinated planning and market incentives and pressures to reduce the cost.

Other kinds of projects, in particular the point-to-point projects between markets, are most suitable to fully competitive development. These point-to-point projects between major markets will compete with local generation in each market. It really would be hard to make a case that, on a reliability basis, such a project is absolutely needed for reliability. The drivers are profit-suitable for fully commercial development, and there is the opportunity for unregulated market-base pricing. In this case, the siting criteria becomes much more like the approval criteria for merchant generation facilities. Are the sponsors financially credible? Are they going to have the money to finish the project? What are the environmental impacts? The traditional certificate of public necessity and convenience might be the right to use existing public lands, such as roads, or existing rights-of-way, or to attach to preexisting poles, but it would not bring with it any powers of eminent domain. In summary, transmission developers might see infra-market network upgrades that are required by reliability or competition criteria that would be identified, approved and supported financially by RTG-like entities with competition to construct, finance, or own them. That is probably the best way to site and develop new transmission.

Speaker Eight

The Massachusetts Siting Board is beginning to think about how the siting of transmission lines might change in a restructured electric industry. For the past two years, the focus has been entirely on rethinking the approach to siting generating facilities and, while a number of transmission lines over the past five years have been reviewed, they've all been relatively short lines that have been proposed by a single utility for essentially localized reliability problems. Even these very small projects can create considerable controversy however. Some preliminary thoughts that reflect the experience with siting generating facilities, with the interstate pipeline siting process, and with transmission lines. There are two parts to the siting process, getting permission to build things, and getting the police powers to build things. I think this reflects the dual function of the Massachusetts Siting Board both to insure that the facilities that are built are in the public interest, and that facilities that are in the public interest get built. FERC Commissioner Santa has recently suggested that the best way to approach transmission line siting might be to create a federal transmission line certification process, perhaps similar to FERC's Interstate Natural Gas Pipeline Process. This just isn't politically practical since it raises all sorts of jurisdictional questions. These facilities are properly viewed as distribution facilities and should be regulated by each state in a way which reflects that state's economic, environmental and energy policies. For example, some states, including Massachusetts, are very interested in looking into issues like "can you avoid a localized reliability-oriented transmission line by siting additional distributive generation by perhaps doing additional demand site management?" Other states may not care about this issue and individual states ought to invest those in ways that reflect their own policies.

Even for interstate transmission facilities, regional coordination, whether formal or informal, is preferable to a federal siting process. In addition to the issues of local benefits, different states correctly have different preferences with respect to issues such as environmental mitigation, and the extent of public participation in the siting process, and these differences are more easily accommodated in a set of coordinated state proceedings than they would be in a "one size fits all" federal process. This doesn't mean that the FERC process for siting interstate gas pipelines hasn't worked, but the one thing the FERC process doesn't do is encourage neighboring states to work together to resolve common issues. Therefore, states intervene individually. If a mechanism for siting can be developed that involves states' working together rather than states filing individual petitions with FERC, it would be more practical for everybody involved.

In order for regional coordination to work, of course, states would need to arrive at a common understanding on a number of issues. One of those issues is one of the questions raised in the program, "what do you mean when you say there's a transmission expansion needed or in the public interest?" I'd like to introduce a new term "legally practical" as opposed to "politically practical." The paradigm for siting transmission lines in a competitive market has changed, but the laws for siting transmission lines, generally speaking, have not. Massachusetts is beginning to regard competition as a public good. As a policy matter, it regards both reliability and probably the support of competition as good reasons-to support-the siting of a transmission line. However, it is not clear that the State Supreme Judicial Court would agree. Thus, the Commission is faced with two issues in developing some regional coordination on siting. One is, "can the states agree on what kind of transmission lines they are interested in siting and how to site them?", and two, "can the legislatures change the laws so that, in fact, Massachusetts can site a transmission line that is primarily there to allow power transfers between states with the understanding that next year New Hampshire will site a transmission line that primarily benefits Massachusetts?"

There is optimism that the Massachusetts Siting Board will eliminate the requirement for an administrative determination of need for power plants, and instead allow the market to dictate which of the plants will actually get built. While this approach probably isn't directly applicable to transmission lines, as a policy matter the state might be very interested in exploring the extent to market signals can be used to analyze the need for new transmission facilities.

The Massachusetts siting process is currently driven by proposals from facility developers. Need for a new facility is not considered until it has expressed an interest in building it. The question is "at what point do state regulators and the RTG start working together to develop a common way of deciding what needs to be built nextT"

As the states' determination of need, reviews of alternatives to a project is driven by statute, so, to a fairly large extent, is what is allowed in intervention. I've heard a couple of concerns today that business competitors may enter into siting proceedings with considerably greater force when they realize they have economic interests at stake. The state, at least by statute, limits intervention to those people who can raise issues which are actually jurisdictional to the Board. Issues which are limited to the need for the facility, the cost of the facility, and the environmental impacts of the facility. The Board has not generally allowed intervention by people who assert a purely economic interest in the project.

General Discussion

What is the definition of benefits when siting a line? In an extreme version, it is that the line is needed because the power that's going to flow is actually going to flow to these citizens in this state. That's the traditional way of analyzing it. At the other end of the spectrum is the attempt to quantify who will actually benefit from the line and what each party should pay.

Three quick answers. One, historically money hasn't been the entire answer. There has to be some tangible public good beyond somebody just simply paying a toll. From a utility case in 1977, "What constitutes the public convenience and necessity is within the discretionary power of the Interstate Commerce Commission to decide." A monopoly utility with **an** obligation to serve was accepted as providing a public good, reliability and electricity for everyone. The courts must define what constitutes public good in the new setting. Political bargaining between state and local governments will also define public good, such as transmission that increases reliability or reduces cost within the state, or provides environmental benefits by-reducing pollution.

What about the argument of supporting competition in other states who will likewise support competition in ours?

I wouldn't want to argue that to **a** court any more than I'd argue it to a state public utility commission. The reality is that we may have developing regional power markets that cross state lines but governors and state public utility commissioners are still appointed within the state lines.

Rights cannot necessarily be bought in the West. The federal government, which owns up to 70% of some states, is the landlord. Even if a state wants to build construction, the federal government has veto power. Environmental advocates, for example, will lobby the federal government to supersede a state's wishes if that construction is deemed to be environmentally harmful. Environmental groups would be remiss if they did not use all the legal tools at their disposal.

The federal government is currently engaged in a series of land transfers involving mineral rights with federal lands and wilderness lands in the west.

There's no such thing as regional authority. Short of a compact, and even those are a treaty between states that requires the federal government's approval, there's really only federal and state authority. There are no plans for the ISO to approve this, for though they realize they should, going to each state for its approval is an undesirable chore.

In some parts of the country, ISOs with considerable decision making authority are being proposed to the FERC. If approved, the role of the state would decrease sharply.

How could FERC approve citing authority when it isn't under their jurisdiction?

Some of the proposals suggest, as part of restructuring, that FERC would be given federal preemption with respect to citing. This would require federal legislation, which is what is being proposed. Short of federal legislation, the proposals suggest that the states and FERC approve the ISOs, and a condition of that approval would be to give the regional ISO considerable authority in terms of citing whether that's good or bad.