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**Special Session on Regional Boundaries,
Regional Markets and Regional Institutions**

**Harvard Electricity Policy Group
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Rapporteur's Summary*

Retrospective analyses of the electricity market turmoil during the summer of 1998 have reinforced the pressure to create regional institutions for electricity markets. The Federal Energy Regulatory Commission has received new authority to define regional combinations. The Department of Energy Task Force on Electric Reliability has emphasized the urgency of getting "authorities and institutions in place." The FERC is launching a generic process to address the issues. Many themes in electricity restructuring must come together in this process. Drawing regional boundaries would advance restructuring policy, but leave many continuing and contentious questions unanswered. Market institutions and procedures inside the boundaries still need to be defined, and the regional market design interacts with the specification of the boundaries. The sometimes conflicting and sometimes complementary roles of independent system operators (ISOs), companies that own the transmission wires (GRIDCOs), and for-profit entities that own and operate the wires (TRANSCOs), need to be established within a consistent framework. Whatever the choice, coordination across the regional boundaries must address the fundamental difficulties of transmission loading relief (TLR) to meet reliability standards given the realities of the commercial market institutions. Everything affects everything else. The challenge is to define the options and ensure that the pieces of the puzzle can fit together without too much breakage.

Morning Session: Supporting Markets Through Regional Institutions

Speaker One

The goal of restructuring is to reduce energy costs for the American public by

achieving greater efficiency. One way to accomplish this is command-and-control of central dispatch through tight power pools via cost-based or market-

* HEPG sessions are "off the record." The Rapporteur's Summary captures the idea of the session without identifying the speakers.

based bids. I'd like to explore whether this method fully exploits the efficiency gains that could be achieved from the transmission system.

On the generation side, competitive markets have been used to encourage electricity producers to reduce costs, for example by investing in efficiency-enhancing technologies. I think we need to explore the possibilities for introducing similar economic incentives on the transmission side. Our current model — in which the transmission owners turn the running of their assets over to separate organizations — decreases the incentives for the operators to reduce costs, and for the owners to invest in new technologies, because the market value of any efficiency gains cannot be captured. On the other hand, we want to maintain the separation of transmission and generation achieved by the creation of ISOs, which stops people using their transmission assets to favor their own generation.

What regulatory leverage exists to encourage further separation of transmission and generation assets? The easy transitions to regional transmission organizations have already been done — that is, the tight power pools (PJM, New England, and New York) and the state mandates (California and Texas) — so we're now in a situation where we can use either carrots or sticks to do more.

For example, one statutory stick that has been considered by Congress is to mandate the formation of ISOs. There are also regulatory sticks — e.g. some people are advocating that FERC should be highly restrictive in granting authority for mergers, requiring transmission

owners to turn their assets over to independent organizations.

There are also regulatory carrots that have not really been explored yet. For example, rather than continuing with multiple control areas and the problems they present for achieving greater efficiency, profit incentives could be used to create new, regional transmission organizations constituting single control areas. I think we could also obtain effective separation of the transmission entities and a logical management structure, in which transmission owners are active managers, with incentives to aggressively explore options for achieving greater efficiency.

What are the economic incentives that regulators can offer for-profit transmission companies? First, they can offer better returns — I think the situation we see developing, where transmission assets are owned by passive investors, will lead to ratepayers arguing that the return should be very low, because the investment is essentially risk-free. Owners may then be able to realize higher returns elsewhere, and so be reluctant to make efficiency-enhancing investments in transmission.

If, instead, we go to a structure with active management of the transmission assets by entities regulated like monopolies, it will be possible to provide profit incentives to encourage investments that enhance efficiency. Also, because there will be some risk under such a scheme, firms will be able to demand a return commensurate with that risk, and so have the ability to attract capital looking for a higher return.

Furthermore, if FERC policy is used to eliminate the benefit that transmission owners currently get by exempting their native load requirements from the scheduling requirements of Order 888, there will be little strategic value in continued ownership of transmission assets by an integrated company, because the return on investment would be increased by going to a TRANSCO. Further, the owners of transmission assets who've elected not to be TRANSCOs will have an incentive to turn those assets over to a TRANSCO — e.g. via a long-term lease or a separate spin-off company — in order to present their shareholders with a higher return. TRANSCOs themselves will have the incentive to grow by acquisition and merger.

There are, however, certain prerequisites that such independent transmission companies (ITCs) must get right before regulators will trust them. For example, no regulator should allow an ITC to go forward unless it has a plan for congestion management and pricing — I think there's been a tendency by the advocates of ITCs to give short shrift to this. Also, because they are critical cost-saving devices for consumers, ITCs must produce efficient markets in ancillary services.

Power markets need to be developed at the same time as TRANSCOs, because they provide the price signals that make congestion management and ancillary-services markets work. I'm not saying that a power market must be a function of an ITC, but it must be developed in tandem with an ITC to get the full efficiency benefits from this operational structure.

Finally, reliability is a concern that can't be left solely to the discretion of the for-profit TRANSCOs. Because there'll be a tendency for such TRANSCOs to reduce reliability in order to decrease costs, there needs to be an outside body that sets the reliability standards that the ITC will be charged with implementing.

There are certain other issues that I think need to be explored. For example, one of the criticisms of for-profit TRANSCOs is that they would have an incentive to overinvest in transmission, although I personally think there are rules in place to prevent that happening. A second consideration is planning: a TRANSCO will need to have a good working relationship with outside groups so that planning is handled on a regional basis, with good information coming in from potential users of transmission capacity.

Another critical issue is size, which is an area where the maxim about not letting the perfect stand in the way of the good is particularly applicable. Although it's nice to say that we should have large ISOs with regional scope, I think it's unrealistic to assume that they are going to arise immediately.

The final question we need to look at is eminent domain. In Wisconsin at the moment, I know that we're having an extended debate about the construction of new transmission facilities, and the perception is that those facilities will benefit other regions, not Wisconsin itself. As we look to legislation, I think the industry needs to inform Congress that a federal voice needs to be brought into the siting of new transmission facilities.

Speaker Two

Many of the advantages of a TRANSCO can be captured with what I call a "GRIDCO," namely an entity that owns, builds, and maintains transmission assets, but leaves the operation and control of the system to an ISO (a TRANSCO performs the ISO's function of operating the system, as well as owning and building the assets).

In the future, I see GRIDCOs providing a vehicle for growing the transmission business and generating value for shareholders, while satisfying several key FERC objectives. GRIDCOs offer a better return to investors than existing vertically integrated utilities, and create definite incentives to make transmission enhancements to reduce bottlenecks. But by providing focused transmission management that is independent of other interests, and to the extent that planning continues to be carried out by the ISO, they defuse the concern that investments are going to be made just for the sake of investing.

GRIDCOs and ISOs are not mutually exclusive, and the relation between other transmission owners in the region and the ISO will remain essentially unchanged — a GRIDCO would have the same relationship with the ISO as any other transmission owner. In fact, it would complement existing ISOs, which are finding that the vertically integrated utilities don't have a strong appetite for investment in transmission expansion, e.g. because many of them are effectively rate-capped, so can't recover investments.

Creating an ISO is a difficult process — there are lots of issues concerning

governance, funding, control, congestion management, planning, and so on, that need to be worked through. I think the time for letting a thousand flowers bloom has passed, and we should now look at the existing ISOs, see what their best features are, and become a little more prescriptive about what future ISOs need to look like.

Recently, Professor Pierce of George Washington University, has advocated six design criteria for ISOs, namely:

- their legal boundaries should be consistent with natural, physical, and economic boundaries of the regional grid;
- they should be big enough to support trade over a large area;
- there shouldn't be any "Swiss-cheese" ISOs — every owner of a segment of the grid should be included;
- they must implement an efficient transmission pricing system;
- they must have sufficient authority to manage transmission constraints;
- they must have an unbiased governance structure.

Similarly, in forming a GRIDCO, there are a number of daunting problems — just moving assets out of one body into another is akin to a mega-merger, with issues of mortgage indenture, tax, corporate structure, etc. I know this from experience because, in 1993, the PJM utilities embarked on the formation of a TRANSCO. We spent two-and-a-half years going down that path, until we realized we probably weren't going to meet the deadline for implementing open access. So the TRANSCO approach was dropped, and we created an ISO instead.

Now, however, since the ISO is up and running, some of us are revisiting the GRIDCO aspects of the TRANSCO we pursued earlier, forming a limited liability corporation (LLC) to explore the possibilities. (An LLC is tax-efficient and provides corporate liability protection, as well as independence and a shield from double taxation.)

How do you form a GRIDCO without getting caught up in all the complications? Initially, the GRIDCO would enter into service contracts with existing participants to carry out the maintenance services and other activities that the utilities now perform, which would avoid long drawn-out difficulties with union contracts, human resource adjustments, and so on, that need to be done to bring the workforces into the GRIDCO. By using asset management practices to see who best services those contracts, and giving bigger orders to those who do things the best, there would be a tendency to realize efficiencies.

Similarly, land would be left with the current owners for the time being because, when you start looking at real-estate transactions, trying to bring the land over on day one would be too daunting. Perhaps, over time, some of the land rights, or the land itself, might be transferred, but initially the GRIDCO would just obtain rights for land use from the investor-owned utility.

Finally, release from indenture on assets is an issue for a great number of investor-owned utilities. But, since transmission assets represent only about 10 percent of total utility assets, I think it should be possible to substitute a

combination of other property and cash for any assets removed.

The entire GRIDCO proposition, and I think the TRANSCO proposition also, is based on getting favorable, performance-based, incentive-type regulation. We're not looking to raise transmission rates — if anything, they would be lowered over time — but perhaps to have rate-capped periods, during which new investments could receive some sort of premium, either through accelerated depreciation or a better rate of return. Further, quality-of-service measures — perhaps based on facility availability or transmission-related outages — and a method for sharing efficiency gains both need to be developed. Also, I would try to implement incentives for installing new technologies that increase available transmission capacity and reduce bottlenecks.

A GRIDCO would be a going concern, with a strategic direction, a capital-expenditure plan, and a dividend policy, just like any other corporation, but its sole focus would be maintaining and building transmission assets to the highest standard, financed in accordance with the transmission risk profile. It would be viewed like a gas pipeline by the investment community, which means it will be leveraged more than traditional utilities, possibly up into the 70-80 percent range.

Furthermore, because you can't transfer the debt into an LLC, assets have to be brought over as pure equity. So, if the GRIDCO is initially 100 percent equity, but eventually gets leveraged up into the 70 percent range, there's a huge potential for investment — it will not only want to improve the system, but

will want to grow through the acquisition of transmission facilities. Therefore, I see GRIDCOs as being natural growth engines to promote expansion to larger and larger regional entities.

One of the other things that the GRIDCO does is to make the NERC/NAERO role much simpler because the compliance aspect of reliability can be collapsed through tariffs into the ISOs, which already have certain compliance capabilities. It takes away the need to pass legislation to get compliance-enforcement authority, and lightens the NAERO role essentially to one of producing uniform standards across the nation.

GRIDCOs will also add value through incentive-based rate treatment, which I mentioned before, through growth in volume, and by capturing scale economies and O&M synergy.

ISOs and GRIDCOs don't need to have coincident footprints. They can develop in that direction over time, with the GRIDCO's desire to grow in territory and assets serving as a driver. Numerous GRIDCO-ISO combinations are possible, while a TRANSCO structure is more restrictive in that the geography of the assets and the operation have to be coincident.

What is the optimum size for an ISO? Certainly ones of 60,000 MW are practical, and extrapolation to two to three times that size could be accomplished relatively easily. The legal and jurisdictional distinctions are not necessarily an appropriate basis for forming the boundaries, and I would suggest that trying, where practical, to

align ISO boundaries with regional boundaries would make sense, since it allows the compliance function to fall rather easily into the ISO.

Another thing is that, although ISOs develop, the infrastructure to create them doesn't jump into place overnight. The tight power pools in the Northeast probably had an easier time because they had more pre-existing infrastructure, but I see ISOs initially forming with multiple control areas, and later combining to produce larger control areas.

Speaker Three

The objectives of the New York ISO are to maintain the safety and short-term reliability of the New York system using market-based incentives. Key features of the New York ISO include an installed-capacity obligation on load-serving entities (to meet NERC reliability objectives), an energy market based on day-ahead and hour-ahead bidding, and transmission access based on congestion payments.

We also have two groups of ancillary services. One are cost-based — scheduling, system control, dispatch, reactive supply, voltage support, and black-start capability — and the other are market-based — regulation and frequency control, energy balance, and operating reserve — subject to day-ahead, or hourly bidding. Reactive supply, voltage support, and black-start capability are cost-based services only because we didn't have enough time to do anything else, although I would argue that they really ought to be market-based.

We've also had experience with command-and-control, or artificial incentives, to achieve our reliability objectives. The New York power pool has never done a good job of meeting NERC standards for control performance — we used to hit 70 percent on a good year, although NERC standards are over 90 percent. We had several initiatives to try to improve — in 1981, for example, we put in a pricing system. That is, the members used to put \$20 per megawatt of regulation into a pot; if you did well, you took money out, but if you did poorly, you lost your money.

Although this worked for about three months, during which we actually hit all our NERC objectives, somebody eventually figured out that it was often cheaper to lean on the system, i.e. not regulate at all, and just sell the power. So, what ended up happening is that when the cost of regulating was cheap we did a very good job, because the penalties were greater than the cost, but when the costs got very high, nobody regulated, because it was better to lean on everybody else.

We also have a two-settlement system. The first settlement is the "Security Constrained Unit Commitment" program running a day ahead — you nominate how much load you'll have tomorrow, and the market clears at day-ahead prices. The second settlement then clears any imbalances at next-day prices.

The reasoning for our first- and second-settlement system was simply that we ran some scenarios and found that there were a lot of opportunities for gaming if we had only one settlement. A two-settlement system provides market

incentives to ensure next-day reliability, while avoiding gaming.

Our key design drivers are using market principles to achieve reliability objectives, minimizing total costs (not just the cost of individual services), and ensuring that reliability objectives are met. I like to think about our goal as trying to drive costs as low as possible by simultaneously optimizing all system requirements, for which we believe a central operator is necessary.

Speaker Four

I'm going to give you an overview of the Midwest ISO (MISO), talking a little bit about what it is, about some of the issues that it's now facing, and about the next steps in the Midwest.

Following two-and-a-half years of discussions, nine utilities filed for FERC approval as the Midwest ISO in January 1998. On September 16 — that is after a relatively short time, considering the complexity of the issues — the Commission conditionally authorized the establishment of MISO; and the election for the Board of Directors is scheduled for December 11.

MISO spans three regional councils — most of MAIN, a good part of Western ECAR and parts of Eastern ECAR, and part of MAPP. MAIN and ECAR are linked on the East, and with Wisconsin there is some link to MAPP.

MISO isn't a single control area, didn't start off as a tight pool, and isn't one state: It is a transmission-control area that will evaluate requests and grant transmission service. It will be the only NERC security coordinator for the

member companies, and will have the ability to order load shedding and, if necessary, to impose penalties. Its remaining function, in accordance with the NERC definition of a control area, is simply to balance load and generation. As far as transmission, there will be a single, "postage-stamp rate" depending on where the load is, plus an average through charge.

I would like to talk about a few of the remaining issues that we feel are fairly important to getting the ISO running, some of which are part of the ISO/TRANSCO/GRIDCO debate. The first has to do with financial independence — the issue of pensions for officers, directors, and employees. For example, two of our directors are required to have experience in planning and operations, but we've had difficulty in finding such people who don't also have pension rights with a potential market participant in the area. This kind of problem will be resolved by the Commission, but it is something that concerns us.

We're also facing a couple of very difficult financial-incentive issues. The Commission ordered us to un-pancake the grandfathered transmission agreements entered into before the ISO order. This isn't a question of non-pancaking new rates, but means existing revenues are being taken away. Another problem is the rate of return on equity (ROE). In the NEPOOL litigation, our understanding is that the trial staff has recommended a ROE of 8.6 percent, which is awfully low if you're looking to get voluntary formation of regional organizations, especially if they have to make new investments.

Last June in the Midwest we had a "little energy crisis." It only lasted for a short time, but we didn't have a regional congestion-management system, we didn't have regional coordination, and we didn't have a regional organization to look at the TLRs, e.g. between MAPP and MAIN or between PJM and ECAR. Some of us have asked NERC to do an analysis to see if those TLRs were fully legitimate and to see if any other measures could have been taken. No one has seen the data, so it may just be that, on that particular day, everyone was out of capacity. But even if that is so, it shows that there has to be some congestion management in the Midwest. MISO will be doing that as part of its job, not through a central market, but using re-dispatch to prevent curtailment, re-dispatch to provide new transmission services, and, if nothing else works, TLR.

To give you an example of re-dispatch to prevent curtailment, on August 24, 1998, a set of severe thunderstorms came through the Midwest. They knocked out a major transmission line between Illinois and Wisconsin, and ComEd, in addition to halting transactions, lowered output to prevent overloads. In this case, the ISO would have had the absolute authority to maintain firm transmission service, to order re-dispatch or generation, and to provide compensation.

For new transmission services, the ISO is looking to use market mechanisms rather than command-and-control. The ISO will have the infrastructure to get real-time data, so they'll be able to determine which units should be raised and which should be lowered with a lot more certainty than individual

companies can do today. Essentially the ISO's job will be to identify the generators that can re-dispatch. Obviously the jurisdictional generators will have to participate, but other generators can submit bids by posting their availability so that market participants can arrange re-dispatch. In a way, this is very much like the structure that NERC's congestion-management task force is starting to look at.

Now as a last resort, you may end up with a situation where you actually have to curtail service, for example because there is no time to do anything else, e.g. when a storm comes through. As the security coordinator, the ISO, not the owners of the facilities or the market participants, will be the one calling for the line-loading relief. But the ISO will have real-time information and know what's really happening.

One of the issues I wanted to talk about is coordination. Obviously MISO can't operate in a vacuum — what happens in the Midwest affects PJM, and PJM affects the Midwest, and Ontario affects the Midwest, and we affect Ontario, and so on. In fact, if you look at the hundreds of TLRs that have been called in the Midwest in the last two years, the biggest problem has been dealing with loop flows.

Now, with MISO, things are going to be much simpler, because the loop flows within the ISO companies will be internalized, and there'll just be one security coordinator to deal with, who ultimately has the authority to order load shedding.

We've also had a lot of interest from potential generation entrants, but they would really like to have a power exchange as the ultimate place to sell. So, although MISO doesn't have a power exchange associated with it, I imagine that within the next year we will see one or more power exchanges starting up, and then hopefully integrated into MISO.

Discussion

Question: Doesn't the TRANSCO spin-off or divestiture run against the general corporate mentality of increasing earnings, because they're what corporate compensation is linked with? In other words, the pie has to get bigger for the CEO to get paid more.

Response: No, I don't think a spin-off (which is the most desirable procedure because it creates complete separation) is inconsistent with corporate mentality, because it's just a re-deployment of assets. If you eliminate the native-load priority, the assets no longer have strategic value, so you're faced with a low potential return and may want to reinvest elsewhere. Obviously a spin-off does reduce your pie, but it's only 10 percent of your total assets.

Question: Although people are saying that TRANSCOs are economically better than ISOs plus either vertically integrated utilities or GRIDCOs, it's not clear to me what kind of efficiency gains TRANSCOs actually provide. Are you somehow going to figure out a way to get more transmission capacity out of the system, or are you going to change your ratings, or are you going to change your operating guidelines? If the notion of more efficiency in the system is just that

we're going to have incentives to take more risks, does that include things like violating reliability or operating rules? What is it that you think the TRANSCO is going to do that the ISO and the existing owners can't do?

Response: First, I don't necessarily think that an ITC is better in every situation — it's obviously a matter of regional choice. Some regions have decided to go with ISOs, and others have decided to go with ITCs — I don't advocate one as always being superior.

As far as incentives, reliability is not something that can be given away in order for a TRANSCO to realize a greater profit, and that's why I want the reliability standards to be set externally, with an obligation on the TRANSCO to ensure that those standards are implemented. Where I do see an opportunity is that a TRANSCO can profit under an incentive plan where it has a guaranteed rate for a period of time, allowing it to invest in control devices for transmission that would permit the system to be operated closer to its limits — for example, because of better information — and hence reduce congestion costs.

Question: Looking at the natural gas model, do you believe that siting may need to be addressed by federal action, or do you think that we need to wait and see if states can deal with it?

First Response: From the standpoint of efficiency, it makes sense to transfer siting jurisdiction to the federal government, but that's probably not possible politically. As a matter of fact, if you look at what's happening with the natural gas acts, you're seeing a re-

assertion of local interests, and complaints that the federal government has too much power. Perhaps FERC could try to lead with some sort of regional coordination, but I would assume that if we got any federal legislation, what might be politically viable is some sort of regional siting authority that would have a veto when there's multi-state interest in a particular project. If there was a complaint about restraints on interstate commerce, the decision could be appealed to FERC, or some other body.

Second Response: One issue is to ensure that the native-load customers are not burdened by costs that would more appropriately be passed through to others. If "customers" is interpreted in a very parochial way, then there're going to be problems — one fear is that the native-load customers are going to lose some of the benefits and priorities they get for having paid for the system. But state regulators could deal with that simply, and without federal legislation, by taking away the residual revenue responsibility they put on the retail native load customers by virtue of putting it in rate base and making transmission revenues a zero-sum game. Unfortunately, very few, if any, states have done much about these matters.

Comment: This goes back to the question of a regional regulatory agency. One scenario is that bids would come in to the ISO, which would determine whether they satisfy a need in the transmission system. But, although the ISO would make the technical decision, the actual choice about which proposal gets implemented would go to a regional regulatory agency, which could take non-technical factors into account.

Response: I like the idea of having a GRIDCO come into service territories with the notion of building transmission upgrades, but I think there are a couple of issues that need to be thought through. One is to ensure that an outside entity would have the authority to build under the state's certificate jurisdiction — you'd need to look at the statutory relationship with the regulatory bodies and at what sort of entities would be qualified to file an application to build.

The second issue is rate relief. If an ISO goes out with an RFP for alternatives — e.g. construction of a new transmission line, or a transmission subsidy for a generator that would otherwise not be economic — and selects the least cost alternative, guaranteeing a stream of revenue to a particular enterprise, then FERC would need to accept that as being a competitively established rate, not subject to normal cost-of-service regulation.

Comment: None of the speakers dealt specifically with the reason we created ISOs, namely to get retail competition and mitigate market power for access. Efficiency's fine, but the bottom line is that even if you improve efficiency by 25 percent, in California that'd save less than 1 percent of the total bill.

Response: In fact, access wasn't the reason PJM went to an ISO. It went because it had a tight power pool that had to change, but it wanted to preserve some of the benefits it had enjoyed over the years through the pooling arrangement.

But competition at the retail level and access are important. I think that one reason that the ISO/GRIDCO approach

is better than the TRANSCO one is that some of the most daunting work in achieving retail access is getting the settlements correct — that is, reaching the right allocations of obligations, losses, load profile, mismatches, and so on. Half of it is settlement at the wholesale level, but the other half is retail. At least in our case, the ISO has been very helpful in working with utilities and state agencies to develop methods and systems that support competition at the retail level. I'm not sure that a TRANSCO would necessarily have quite the same interest in achieving and supporting state retail access.

Comment: In the TRANSCO conversation there are a lot of issues about the tradeoff between different models. But most of the critical issues that you'd have to address in terms of an ISO — access rules, pricing rules, and that kind of thing — you'd also have to address under a TRANSCO. That's quite different from the argument made by many people supporting TRANSCOs, which is to imply that you wouldn't have to deal with all those issues because they would be taken care of automatically by the TRANSCO's profit incentives.

Response: There are a lot of people who would like to pursue the TRANSCO model without dealing with those tough issues. I think that the real value of ITCs is that they promote competitive markets. Real savings come because you allow the electricity markets to work and get cheaper power to the consumers, not so much through cost reductions per se.

I wouldn't say that ISOs are necessarily simpler, because the investment cost to put one together is very high. For

example, it is difficult to establish the computational capacity required to realize efficiencies over a large area. The existing tight pools had a large amount of the necessary equipment because they were already centrally dispatched, and California was fortunate in that its state legislature mandated that the funds would be put forward by the IOUs in conjunction with the PUCs, making investment possible.

So, without some sort of mandate, the incentive to create ISOs is very limited. Unfortunately, most states are not like California — where there is a large enough market within the state to mandate an ISO that can achieve efficiencies. When you have multi-state trading regions, unless you have a federal mandate, you need some sort of regulatory incentive to get ISOs created.

Question: In the congestion management scheme for the Midwest ISO, I heard you describe a multi-step process in which you announce which generators can relieve congestion, and then let people go out and negotiate with those generators. Now, that may work when you have a lot of time, but if you need some short-term congestion management a day ahead, or maybe even an hour ahead, that scheme seems rather cumbersome. Do you have any concept of how long it would take, and why don't you just let a real ISO do it?

Response: First of all, no multi-step analysis is needed to keep firm transactions flowing — the ISO simply goes to the generators and says, "You move here, you move there, and the payments will be sorted out after the fact. Just do it and keep the system reliable." The second step, the one that

you were asking about, is for getting new transmission service, which is done in a long-term environment. The thing that is missing from the MISO proposal is short-term congestion management on economic transactions, which the Commission has encouraged the ISO to develop.

Question: What I hear in the TRANSCO versus ISO debate is that ISOs are too expensive. Are we really going to save that much money with one form of structure over another when you get out of the tight power pools where a lot of the infrastructure existed?

Response: I don't think the question is whether ISOs are cheaper than TRANSCOs — that's open to future investigation — but rather, how do you get the investment to create regional transmission providers? You can pass federal legislation giving FERC the authority to order ISOs, but that really isn't going to do any good if the entities involved aren't willing to invest, for example in the equipment that's going to allow good congestion management on a national basis. That's why, as we try to expand, we need to think about whether economic incentives can bring about investments.

Comment: If you look at what we've proposed for real-time congestion, the ISO has the ability to re-dispatch economically because the generators have to bid into the ISO ahead of time, and the ISO can select the least-cost option for alleviating constraints. In the longer term, the issue arises of whether there could be a way to get other kinds of bids — demand-side management, or generation, or other things. The Midwest ISO, I think uniquely, has said

that it's going to set up a bulletin board where alternative congestion solutions and the corresponding costs can be posted, so that people can pick and choose from them. This method tries to accommodate market mechanisms to overcome congestion, both in the short and long terms.

Afternoon Session: Coordinating Reliability and Trading Across Regional Boundaries

Speaker One

The objectives of my presentation are to discuss various alternatives for congestion relief, to describe a problem with the current NERC procedures, and to propose some market-efficient alternatives that are compatible with current institutional structures.

Congestion can lead to high spatial volatility, which, although not necessarily a bad thing, either in markets or in power systems, can reduce economic efficiency, for example if prices cannot respond accordingly.

The NERC TLR procedure is "market blind" in that it completely separates security and economics. Their method for determining who to curtail and by how much is based on pre-computed flow sensitivities, and, although NERC doesn't use an explicit formula, their procedure in effect amounts to the following: They determine how much they need to curtail and the flow sensitivities, then figure out the size of every transaction that could have an impact, and finally decide the curtailment amounts.

This method eliminates congestion every time, but has a number of problems. The first is with what I call "phantom schedules," which means that in anticipation of congestion, people overstate the amount they want to trade, so that when they get curtailed, they end up where they really wanted to be in the first place. This sets up a perfect

situation for gaming, and also leads to sub-optimal, and possibly unstable, market conditions.

A bigger problem is the inability to create packaged multilateral schedules: When you have one congested line, you need two units on the margin. When you have two congested lines, you need three units on the margin. That's already a packaged trade — unless you're dealing with the three units simultaneously, if you decompose them into single transactions and curtail them individually, you're not going to get to the optimum solution.

There is, however, another approach, namely to change the spot prices instead of using curtailments. You can get to the same solution by such use of transmission pricing as a means of congestion relief, but it's a very different methodology. Although there are some difficulties, e.g. about response time, in theory it is possible to attain a secure operation using price signals.

Now some recommendations. The first is to improve NERC rules. The simplest change I can propose is to allow packaged trades. If they're going to curtail, they should curtail the package, not individual trades. This would improve operations, although it wouldn't eliminate the problem of phantom trades.

An alternative is to use economic signals in some way — e.g. via a full spot-pricing market, or bid/auction dispatch, in which people bid prices for what

they're willing to charge during an emergency, and then voluntary trading of transmission congestion contracts is allowed.

What I'm suggesting is that either packaged trades or economic signals should be allowed, but that it would be a mistake to try to mix the two in the same time frame, because prices and quantities shouldn't be changed simultaneously.

Other recommendations would be to enable a futures market that permits hedging against spatial volatility, and to integrate demand management into the entire picture. As an analogy, when airlines were deregulated I couldn't predict the prices, but suddenly I was being offered \$500 to get off a full flight. That's congestion management by voluntary load relief, which I think we need to consider.

Speaker Two

What needs to be agreed between regions in order for physically realizable trades to take place between them? (I want to construe "region" very broadly — it could be a traditional control area or a larger area, perhaps under a security coordinator.)

I want to concentrate on what is normally referred to as "power," but what electrical engineers call "real power." As an aside, there are analogous issues for "reactive power," and there's some coupling between the decisions made for real power and for reactive power, but because real power issues are more pressing, they're the ones I'm going to talk about. Reactive power has much more local character to

it, so it's not as relevant for inter-regional trading.

Let's think about how we might specify interchange between regions in a traditional contract-power type of approach. Suppose region A wants to sell 100 MW to region C, and region B wants to sell 300 MW to region C. The way they do it is that A generates 100 MW more than its local demand, B generates 300 MW more than its local demand, and C generates 400 MW less. Although this story looks great, it doesn't really match the facts very well because there are loops in the system, and so the flows on the lines between the regions don't match the nominal trades between them.

Because the contractual and the actual flows are not the same, the transportation analogy used to develop the contracts doesn't work very well, which leads to a number of problems. In particular, if you want to set up contracts that respond to true transmission limits, you need to figure out what the actual flows are on the lines. In order to do that you need some representation of the transmission system, and you need to implicitly solve the equations specified by Kirchoff's laws together with the net injections — that is, it's not just the net injections that count, it's also their interaction with the network.

What's the upshot of that in our three-region world? Well, the net imports and exports into a region don't tell me what's flowing on the lines, because I also need to specify the impedances. Knowing the impedances and the injections enables you to calculate the "voltage angles of the complex voltage phasors" — I'm going to call them the

“angles” — which you need to know in order to predict the flows. They’re actually roughly equivalent to the power-transfer distribution factors, and in some sense, the two representations are equivalent.

There are several proposals on the table for coordinating the use of transmission lines, which will hopefully provide incentives for the efficient use of scarce transmission capacity. Imagine that somewhere there are some rules to be applied at utilities, at control areas, or perhaps at ISOs, to coordinate what’s going on within the jurisdiction of the particular entity. So, California’s doing its thing, PJM is doing its thing, and so on. What I want to turn to now is how to coordinate between the regions, i.e. what happens when, say, PJM wants to trade with someone else?

The problematic issue is that different regions have different internal-dispatch models. For example, there might be some utilities that stay with rate-of-return regulated central dispatch, some dispatched by a central, bid-based pool, and some trading bilaterally. How do we provide an interface between them? When I say interface, I don’t mean a transmission-line interface, I mean a market interface that respects transmission issues. How can we set up a standard for trades between different, and possibly inconsistent, internal-dispatch models?

One way is to break up regions by splitting them at the middle of the transmission lines that tie them together. This division specifies what I’ll call a “border bus.” If it corresponds to an actual switching station, or an actual bus

in the system, that’s great. If not, we can think of it as a notional border point.

It turns out that you can specify a consistent set of power flows and a consistent set of angles at these borders, and, as usual, if you want to know how much you’re exporting, you just add up the net amount of power that’s going over your border.

How would one achieve trading under these circumstances? Suppose that:

- each region specifies a tentative set of flows on its lines and a tentative set of angles at its borders;
- for every border, say between region A and region B, region A’s specification of the power flow and angle agrees with what region B wants;
- what each region stated about their borders is consistent with its own internal-dispatch model.

If these things are true, and the internal dispatch is within internal transmission constraints for each region, then it turns out that you get a feasible set of flows for the whole multi-region system that’s consistent and satisfies all the transmission constraints.

Now, suppose we set up some sort of trading arrangement that involves each party agreeing to its flows and angles. What would happen under circumstances where we might traditionally have had significant loop flows? For example, let’s suppose B has agreed to send 300 MW to C in a trade that involves flow through A, but the resulting flow violates A’s transmission constraints, so he blocks the deal. In this case, what we need is some adjustment process to

provide a feasible dispatch for the whole system.

One such process is to imagine that you have prices on the angles, as well as on the tentative power flows, across each tie line at the border bus. Each region could take those prices, consider what it would like to do, and come up with a tentative dispatch. But this still wouldn't necessarily give the right answer, because the resulting flows and angles may disagree.

This could be overcome by adjusting the prices. Each region would exchange tentative flow and angle information with adjacent regions — a relatively small quantity of data — and then adjust prices based on the discrepancies at each border, iterating between updates of prices and flows.

From a theoretical perspective, if each region performs at optimal power flow, then, under slightly unrealistic conditions, you can prove that the iterative process converges to a solution of optimal flow for the whole multi-region system. I should mention that there are some unresolved issues, relating to what's called the "reference bus" and to contingency constraints, but from a theoretical perspective, the method works pretty well.

What about from a practical perspective? There is some computational evidence for convergence. We took the Electric Reliability Council of Texas (ERCOT) system, which has about 2,700 buses in our representation, and broke it up into the eight regions represented by the major utilities in Texas, and some other smaller players.

At each iteration, each region performed an optimal power flow, and we ignored the rest of the system by using dummy generators of the dummy buses. In three to five iterations, we were able to solve for an optimal, ERCOT-wide economic dispatch, without having to care very much about what was going on in other regions, and only having to exchange a limited amount of data at the borders.

What happens if the regions don't perform optimum power flows? We aimed to coordinate regions in a rational way, but, in practice, the main goal for regional coordination is not necessarily to get optimal dispatch, but rather to get a consistent set of trades between the regions that doesn't overload any transmission limits. From the theoretical analysis, we can say that if the flows and angles at the borders match, and are feasible from an internal-dispatch perspective, then the corresponding multi-region dispatch is feasible. In other words, just by passing information back and forth between adjacent local regions, without explicitly coordinating across the whole system, we're able to internalize loop flows.

What use are the prices? If each region performs optimal power flow, the power price that comes out of the iteration is the right price for cross-border energy trades, i.e. the marginal cost. What's less clear is how to interpret the angle prices — it's not like I'm selling you a commodity called "angles" in the way that I'm selling you something called "power."

One possibility is to think of angle matching as a standards issue, because to have a physically realizable set of power trades, you've got to have a consistent

set of angles at the borders. Although there may still be some issues with strategic behavior, if someone lied about the relationship between angles and flows, it would be obvious, because the flows and angles just wouldn't match. Anybody trading with a dishonest player would therefore be able to discern it pretty quickly.

There are some implementation issues associated with this sort of regionalization. For example, how often are we going to do this iterative process? In principle, as often as the demand changes, and certainly after any major outage.

How big should a region be? I wouldn't chop up an existing region that already has a well-run internal-dispatch model. I'm thinking more of trades between regions that currently exist and that have internally self-consistent dispatch models. In other words, a region should be as large as it can possibly be with a single dispatch model.

What if we don't get an agreement, or the agreement can't be met in time? In non-emergency situations, one has to come up with some default prices (although I'm not quite sure how to do it), and one certainly also needs a backup mechanism like TLR to deal with emergencies.

In summary, I think it's pretty evident that the U.S. is evolving into a patchwork of different models, and that there's a pressing need to coordinate trade between them. I've presented one possibility for coordinating regions by decomposing them, either at explicit borders or at some notional tie lines, such that loop flows are internalized.

This allows one to coordinate regions that have differing internal-dispatch models using interfaces that both speak to physical reality and allow economic trading.

Speaker Three

The current TLR process has multiple security coordinators who exchange information about schedules and power-transfer distribution factors and produce schedule curtailments, which give the adjustments that people are supposed to make.

How would we go from such a market-blind system to something that integrates market forces? The work I've been doing has been motivated in part by the fact that, although it's easy to say that there should, in principle, be some market-oriented TLR system out there, until you see some concrete examples of how it could actually work, it's very hard to think through what should actually be done.

Clearly, prices are an important part of the story — the notion that NERC is going to run security coordination and TLR within a market system without participants having price information is very hard for me to conceptualize.

Schedules, bids, and economic re-dispatch are also going to be important, as is iteration — if multiple security coordinators are going to oversee a single grid and make decisions based on partial information, there has to be some kind of iterative process. In places like PJM the iteration is hidden, because they're doing it internally, but it will become explicit when security

coordinators exchange information to achieve mutually consistent re-dispatch.

Also, a settlement system will be needed, because real payments will have to be made — you can't just have phantom prices. For example, if one region is producing for another region's consumption, it's pretty obvious that money is going to have to flow from one to the other.

Finally, we want to integrate markets and reliability to make the system more efficient and more reliable by expanding the tools available to deal with avoidable problems, like those we had in the Midwest last summer. The supposed dichotomy between markets and reliability is false, with consequences that are at best inefficient, and at worst dangerous.

Where would we like to go? The general idea is to have a system where schedules and bids come in to the security coordinators from the market schedulers, so that the security coordinators are exchanging information about prices as well as quantities.

In the first step, the market schedulers would send information about their schedules, as well as bids to adjust those schedules, to the security coordinators. The security coordinators would then communicate that information among themselves, but not necessarily to the market schedulers, through some kind of iterative process to find an efficient market solution that balances the system and relieves transmission constraints. The final stage would be to send information about re-dispatch and the prices back to the various market participants.

Essentially, this method produces a "virtual ISO" for the whole region. That is, you'd end up with an internally consistent solution identical to what an ISO would do for the entire system, given the same information.

Note that you'd like to have the system set up such that it converges pretty quickly. Some methods only get to the solution after thousands of iterations, but there's no time for that — we need to get a solution in a few steps. Although I can't prove it, I'm convinced the key to achieving this has to do with drawing the regions so that there's as little interaction as possible across them, effectively internalizing regional effects.

There are two approaches to regional decomposition and coordination. In one, discussed by the previous speaker, the local security coordinators have to know about their local transmission grid, the constraints on their local system, and the flows and the angles at their boundaries. To get convergence to a consistent solution for the whole system, they look at the information coming in at their connecting points, but don't have to worry about what's happening elsewhere.

An alternative model is one in which each region sees the whole grid, but the local security coordinator is only responsible for worrying about the constraints in her region. That is, the coordinator has a description of the whole network — so she can get flow descriptions, loop-flow effects, and so on — but runs her system to find the best solution given her own constraints.

Those are two different ways of approaching the problem. Using the first

method, you might be doing economic dispatch for, say, PJM, but modeling the rest of the system and everything that's flowing around it as well. You'd take the bids of everybody in PJM, and use them to get economic dispatch for the system.

Under the second method, you would do something slightly different. You'd take bids from everybody inside PJM, and take the information the security coordinators had published about the prices and congestion costs at other locations. Effectively, the PJM system operator schedules re-dispatch around the whole grid in order to solve the problems in PJM, but has to buy and sell power at other locations at the published prices, and has to pay for the congestion that she induces in other systems. But she doesn't have to have a detailed description of the constraints everywhere, just the prices.

Using this scheme, the optimization problem looks just like the problem that's currently being solved, so existing software and methods could be used. That is, you've got all the usual system-balance limitations, and you have to worry about local constraints, but not the constraints elsewhere. You have to publish information about the prices and congestion in your area, but every other security coordinator is doing the same thing.

Both methods ought to end up at the same solution. So you could choose either one — you could describe these networks and separate them and then describe the connecting variables, or you can have a description equivalent to the whole network, and publish and iterate the prices.

There are lots of implementation issues, and I won't go through all of them, but I'll mention a couple. First, we'd like to know the implications of this methodology for drawing the boundaries, which has to do with internalizing the loop-flow effects. Second, there are issues about how accurate the model of the outside system needs to be. My suspicion is that, although you can always get a feasible solution, the degree of efficiency will depend on the accuracy of the rest of the model.

A final issue is gaming and honest revelation. In the procedure I described, the security coordinators get their information from the market, have an extended conversation among themselves, and then send the information back to the market. If instead you allowed market participants an opportunity to respond to interim coordination and price information, then I think you'd get tremendous gaming problems, with regional coordinators able to provide misleading estimates, or make strategic schedule changes, to gain local advantage.

Speaker Four

How should the boundaries of reliability regions be set? What are the underlying principles guiding their formation? What might the final map look like?

We've heard quite a bit about the fact that FERC has newly delegated authority with 202(a) that it might use to encourage the industry to aggregate into larger reliability regions. But, if you read 202(a), it doesn't actually say too much. There's nothing about being able to force people to do anything and it

doesn't even mention reliability, so it's not at all clear that the transfer of 202(a) from the Department of Energy to FERC really did a whole lot to move things forward.

It seems to me that FERC should establish some principles and criteria for the boundaries, but let the industry participants create the actual regions for themselves. The new regional boundaries should, to the extent that it is possible, internalize the loop flows, the transmission constraints, and the natural market trading, bearing in mind political, historical, and regulatory differences between states.

I don't think it's really possible to get all this done without any legislative action — there at least has to be some kind of clarifying legislation indicating that FERC has both specific authority over reliability and jurisdiction over transmission facilities. I am, however, reluctant to see FERC have the power to order any transmission owner into a regional organization. My preference would be to give FERC the authority to require regional solutions (for example, they could set up a time line for reaching certain criteria), but let the industry decide how to achieve them. This would give FERC backstop power, but provide the industry with incentives to solve its own problems.

Under this scheme, I would suggest the following "responsibility pyramid" for reliability. At the top would be FERC, which should set policy, determine underlying principles, and be the final judge of whether the lower levels are actually doing what they're supposed to be doing. Hopefully FERC would be a

light-handed regulator, providing a forum for resolving disputes.

At the next level down would be NERC, transformed into NAERO, with some kind of independent governance based on FERC principles. This level would set the international rules and standards to which the independent organizations would agree.

Level three would be the regional reliability organizations (RROs). I believe that there are specific regional issues that need to be taken into account as reliability rules and operating guidelines are developed under the aegis of NAERO.

Level four would be the independent transmission operators (ITOs). At some point in the future, there may be an independent transmission company (ITC) that is also an operator, which would have the ability to meet all the criteria. Unfortunately, I think a lot of people have been distracted by the ISO versus ITC argument, which gets in the way of making progress on some of these issues.

The fifth level would be the pools and power exchanges. In the Midwest we don't yet have those, but I think there's an opportunity to get one or more power exchanges up and running. They would have specific responsibilities and would have to follow standard rules.

Finally, you get down to the control areas and the load-serving entities. I think there's a good reason why they need to be kept separate, namely we don't want the ISO or the ITC to become a debating society where people try to figure out what changes should be made

in the rules. We want these people to focus on the operation of the system, and take the rules as given, whether they're service rules from FERC or reliability rules from the RROs.

All transmission facilities would be a part of an RRO, but they could choose which one as part of the initial set-up — just as today a transmission owner can choose which reliability council to be in, and may sometimes move around among them.

The RRO would design reliability rules to fit regional characteristics, and those rules would be enforced by the independent operator. The word "enforced" brings with it a lot of problems — I know in MAIN, we've been trying to give more teeth to a lot of our rules, but we haven't succeeded yet.

Debates about rules should be held at the level of the RRO, not the ISO, which would give you a nice way to move disputes up through the system if necessary, namely if you have a problem with the application of the rules at the ISO, you resolve it within the RRO. FERC, because of its new legislative authority, would always provide a backstop, but they wouldn't be the first agency for people to go to if they have a problem.

There would still be the problem of congestion between the regional boundaries, although I think that minimizing TLR will be a lot easier if we have larger regions with economic re-dispatch. I don't think we should necessarily abandon TLR as a concept, but there's a feeling that it could be done better. The point is that we're trying to

use a market-based approach to look at re-dispatch and congestion.

Discussion

Question: Assuming legislation isn't going to give FERC the siting authority that it has for gas, does regionalization give us a tool to bring states together for rational siting of transmission and generation, allowing some tradeoffs within regions? Does 202(a) provide the organizational infrastructure for FERC to take the lead on something that would rationalize expansion?

First Response: I don't think so. Nor would it necessarily be a good idea for FERC to have that kind of siting authority. We just went through a whole week of siting a small transmission line to hook up a new power plant, and it makes sense to have the local people involved, because they're the ones that are going to be held accountable to the customers. Having a regional ISO that has a planning function, with the regulators and all of the various constituents involved, should make it easier to site power lines.

One reason why I'm not particularly thrilled with the idea of for-profit TRANSCOs is that the notion of such entities coming into a pristine environmental area and saying, "We're going to build this line because it's going to add to our bottom line" may not be viewed as favorably as an ISO coming in and saying, "We've looked at the region and we really need this kind of a facility."

Furthermore, in the Midwest at least, we are starting to see regulators talking to each other. They're not necessarily

considering a regional compact, but merely a regional way in which to determine local needs and then figure out the best way to do the siting.

Second Response: The word "voluntary" is pretty prominent in 202(a), but what does it actually mean? I don't know how it's going to play out, but you can imagine one interpretation as being that FERC gets to draw the lines, and then you get to decide whether or not to join the resulting organization within them. Now, that's not the same thing as FERC being able to tell you that you have to join, but it could eliminate some of the Swiss cheese problems and also the difficulty of multiple non-cooperating organizations existing within the same region.

Question: Does economic re-dispatch totally eliminate TLR or just reduce the number of occurrences?

Response: In principle, it eliminates TLR completely. You have the re-dispatch information and a description of the rest of the grid, and you only model your own system and the constraints on it. For example, in principle, PJM isn't worrying about the constraints in Ohio. As long as the constraints in Ohio are not binding, i.e. they don't have a TLR problem as well, then it works just fine and that's all you need. But if you have constraints in both places, then you require some mechanism that reflects both of them, i.e. PJM has to have some information about what's happening in Ohio. In principle, however, you'd have a market solution, with voluntary adjustment that would solve the TLR problem.

Question: Is the virtual ISO you described over the entire grid, or over smaller sections? To have a virtual ISO, doesn't it mean that everybody would have to operate within the same set of rules to correct the individual problems within each of the smaller parts?

First Response: I don't think the virtual ISO needs to cover the whole country, but it has to cover entire interconnections. The DC lines are like valves — you can turn them up or down to wherever you want without externalities — but there's not enough synchronizing power that can move across the AC lines.

Second Response: You could go back to the suggestion of having five or so regions in the Eastern interconnect, because politically it may be too hard to have just one. If all five follow the same rules and have appropriate information, then you'd get the same results as you would if there was just one region. So, in that sense, it's like there's a single, virtual ISO even though you don't have one overarching entity, only a set of rules and information flows.

Now suppose that, in an interconnected grid where everybody affects everybody else, some people aren't following the same rules. It's very hard to give a general answer for what would happen in that case — it depends on what the rules are, and in what ways people are deviating from them. I can imagine situations in which people aren't following the rules, but it doesn't affect anybody else, or situations in which it costs people to not follow the rules, so they have an incentive to comply. But I can also imagine situations where people are not following the rules and the lines

are burning down, although I think most of those would be prevented if we had the NERC TLR procedure as a backstop.

The end goal is to create more efficient, better functioning markets, and to improve the system's reliability in a way that's compatible with people's voluntary choices. One of the real difficulties, which I think is under-appreciated, is having a system where rules and price incentives are incompatible, i.e. if people follow the rules they end up losing money.

Comment: The reason you're seeing so many TLRs is that you don't have coordination on the front end. For example, on the Eastern interconnection, someone can make a transaction more or less following the rules, but only looking at the impact on their own sub-system not the system as a whole. The transaction happens, and now another sub-system, which didn't know anything about it, has a problem. In fact, the vast majority of the TLRs on the Eastern interconnection haven't occurred following the outage of a major facility, but simply because transactions were allowed to build up. However, when there's coordination on the front-end — whether it's between ISOs, control areas, mini-ISOs, or TRANSCOs — it needs to be on an interconnection-wide basis, or you will still need TLRs.

Comment: Curtailment always strikes me as being something of a meat-cleaver approach — it solves the problem, but is never very good, and distributes the pain inappropriately (that is, people who don't have much impact on the problem often wind up paying a lot for it). We should move towards a pricing approach in which, as long as there is some sort of

economic dispatch and an agreement on what information to report and coordinate, the internal process in each region could be somewhat different.