UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	))	Docket No. ER04-691-000
Public Utilities With Grandfathered Agreements in the Midwest ISO Region	))	Docket No. EL04-104-000

AFFIDAVIT OF
DR. RONALD R. MCNAMARA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald R. McNamara. I work at 701 City Center Drive, Carmel, Indiana 46032.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed as Vice President of Regulatory Affairs and Chief Economist for the Midwest Independent Transmission System Operator, Inc ("Midwest ISO").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of California, Irvine with a B.A. degree in Economics and a B.A. degree in Social Ecology in 1979. I received an M.A. degree and a Ph.D. in Economics from the University of California, Davis in 1991 and 1993, respectively. I have been involved in the energy industry for approximately 20 years in the public and private sectors, as well as performing academic research on energy markets. From 1995 to 1998, as the Manager of Research and Development for the Electricity Market

Company Ltd, and as a Senior Advisor for Putnam, Hayes and Bartlett Asia-Pacific, I was involved in designing and implementing the electricity market in New Zealand. I have also worked for the Queensland, Australia state regulatory commission, Duke Energy, Enron and, most recently prior to joining the Midwest ISO, I was employed at American Electric Power.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES WITH THE MIDWEST ISO AS THEY RELATE TO THIS FILING.

A. I am the Midwest ISO Officer responsible for the Transmission and Energy Markets Tariff ("TEMT") and Market Design. In this capacity, it is my responsibility to ensure that the Midwest ISO's market design facilitates enhanced reliability, as well as, economic and operational efficiency.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to the Commission's Order of May 26, 2004,[1] which directed the Midwest ISO to provide evidence and comments on several issues related to the potential treatment of "grandfather agreements" ("GFAs"), as they are defined in the TEMT. In my testimony, I respond to the Commission's request for an explanation of how different ways of handling GFA transactions would affect regional reliability, market efficiency and fairness (*e.g.*, possible cost shifting) between GFA parties and non-GFA parties. My testimony first explains how GFA and non-GFA transactions are handled today by the Midwest ISO and its Control Areas under its current Open Access Transmission Tariff ("OATT"). I explain how this will change when the Midwest ISO begins to operate a regional, security-constrained economic dispatch and associated real-time and day-ahead

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[1] *Midwest Independent Transmission System Operator, Inc.*, 107 FERC ¶ 61,191 (2004) ("GFA Order" or "Order").

energy markets with locational marginal pricing ("LMP"). My testimony then examines the Commission's issues in the context of a proposed "carve out" approach preferred by some GFA parties but opposed by others, and contrasts this "carve out" approach with the three scheduling and pricing options (Options A, B and C) proposed by the Midwest ISO in the TEMT.

Q. DOES YOUR TESTIMONY ALSO PROVIDE A QUANTITIVE ASSESSMENT OF THE EFFECTS OF TREATING GFA TRANSACTIONS UNDER DIFFERENT APPROACHES?

A. Yes. The Commission indicated an interest in specific evidence on, "the cost saving in moving from its [the Midwest ISO's] current congestion management process that relies predominantly on transmission loading relief ("TLR") to its proposed LMP-based congestion management system as applied to GFAs." Specifically, the Commission directed the Midwest ISO to, "file information on the economic impacts of TLRs in its region and quantify the benefits of the proposed congestion management system, focusing on how a carve-out of the GFAs would impede these cost savings." My testimony explains the analyses that Midwest ISO prepared under my direction and summarizes the results thereof.

Q. PLEASE SUMMARIZE THE FINDINGS EXPLAINED IN YOUR TESTIMONY.

A. Our approach to GFAs and the analysis that was performed under my supervision are based on certain unalterable facts with respect to "carving out" subsets of electrical flows. In particular:

- All power flows on an interconnected electrical network affect transmission constraints, including congestion,

- All power flows on an interconnected electrical network affect dispatch and hence reliability,
- All power flows on an interconnected electrical network need to be coordinated through the dispatch process, and
- "Dispatch prices" – whether implicit or explicit – are simply a manifestation of the real time coordination process.

With these four facts as background, the conclusions and results of the analysis can be summarized as follows:

1. A physical carve out from actual dispatch is not possible.

It is physically impossible to ignore or treat separately the electrical energy associated with grandfathered agreements (or any other bilateral contract) when arranging the dispatch and coordinating real time power flows.

2. Allowing a carve out from the scheduling timelines in the TEMT for Grandfathered Agreements jeopardizes reliability.

To the extent that the GFAs allow for more flexibility in scheduling than is allowed in the TEMT, the Midwest ISO will have to estimate the generation and load from the GFAs in order to commit sufficient units to ensure reliability. Without direct GFA scheduling data, these estimates will invariably be less accurate than the information the GFA parties themselves would be capable of providing under the provisions in the TEMT.

3. The introduction of regional security-constrained economic dispatch will improve reliability in the Midwest ISO footprint.

Changing from local control area dispatch based on transmission line loading relief to regionalized 5 minute redispatch will lead to more precise management of transmission constraints and will improve the reliability of the network. Carve out for GFAs would undermine both reliability and economic benefits by removing incentives for GFA parties to schedule efficiently and participate in a regional security-constrained economic dispatch.

4. The introduction of centralized security-constrained economic dispatch will reduce production costs in the footprint.

Operation of regional security-constrained economic dispatch using locational marginal prices will result in direct annual net benefits of $128.4 million in the form of reductions in the cost to serve native load.

5. The improved efficiency resulting from security-constrained economic dispatch will put downward pressure on prices.

The introduction of regional security-constrained economic dispatch will improve the efficient use of existing generation assets – thereby increasing the use of low cost generation and reducing the need to dispatch high cost generation. This will result not only in lower imbalance (or spot) energy prices but will put downward pressure on prices in bilateral contracts. The potential annual net benefit from this is $586.1 million.

6. Leaving parties to GFAs financially indifferent results in cost shifts to 3rd parties.

The intent of the TEMT, given that physical carve is not possible, is to leave the GFA parties no worse than financially indifferent to the price effects of regional security-constrained economic dispatch. The proposal could allow the parties to financially benefit relative to their historical position and will likely result in uplift and cost shifts to third parties.

II. HOW THE SYSTEM OPERATES TODAY IN THE MIDWEST ISO FOOTPRINT.

Q. PLEASE SUMMARIZE HOW THE SYSTEM OPERATES TODAY IN THE MIDWEST ISO FOOTPRINT.

A. Today's system is in transition, from a system dominated by many small Control Areas (over 35 Control Areas within the Midwest ISO footprint), each with its own local dispatch, to one in which much of system operations and the all important function of generation dispatch and related reliability functions will be performed or coordinated at the regional level by the Midwest ISO. As I indicated in my Affidavit of March 31, 2004, submitted in support of the proposed TEMT,[2] some of the regional coordination

[2] *See*, prepared Direct Testimony of Dr. Ronald R. McNamara, Exhibit No. ___ (MISO-4), Docket No. ER04-691-000 ("McNamara Testimony").

functions connected with reliability have already been assumed by the Midwest ISO, including the responsibility for operating the OASIS and handling requests for transmission reservations, inter-control area scheduling of transactions, and managing the use of TLR curtailment mechanisms for congestion that is not managed by the local control area dispatches. Midwest ISO functions as the regional Reliability Coordinator for its footprint. However, some of these current responsibilities will change somewhat under the TEMT, once the Midwest ISO assumes the responsibility for operating a regional, security-constrained economic dispatch.

Q. HOW IS RELIABILITY MAINTAINED TODAY UNDER THE CURRENT ARRANGEMENTS?

A. The current system relies on extensive coordination between the existing Control Areas and the functions managed by the Midwest ISO. The Control Areas dispatch generation to maintain system balance to achieve frequency and stable voltage levels for their portions of the interconnected grid. The local dispatches operate at best on a five-minute or longer interval, with the local system operators sending dispatch signals to the generators under their control. Each Control Area also provides area regulation for its local footprint, through automatic generation control ("AGC"), which is the fine tuning of the dispatch between the dispatch intervals, so as to maintain supply and demand balance and keep frequency at 60 Hz. Because the dispatching of the system is done on a local basis by many Control Areas, and the grid is one interconnected system with energy flowing freely across the interconnection, the Control Areas must arrange interchange between control areas. Once the interchange schedules are set, each Control Area must then dispatch its local portion of the grid in order to maintain the desired level of interchange with each of its neighboring control areas. Given this localized dispatch paradigm, the interchange cannot be adjusted more rapidly, so the interchange time interval can become a weak link in the overall system of maintaining reliable operations across the interconnection.

Within this framework of separate local dispatching for the many Control Areas in the Midwest, the Midwest ISO functions as Regional Reliability Coordinator for its footprint. In this role, the Midwest ISO can help avoid congestion and violations of grid operating security limits by limiting the transmission reservations it grants and the inter-control area transmission schedules it accepts. However, the Midwest ISO does not yet dispatch generation, so it cannot dispatch on a regional basis, nor can it directly redispatch generation to relieve congestion.

When transmission schedules and loop flows between the local Control Areas cause congestion or other violations of the grid's security limits, the current procedures limit the Midwest ISO to using the TLR rules fashioned by NERC to solve the problem. When scheduled flows from transmission reservations threaten to exceed the security limits on grid elements (or "flowgates") within the Midwest ISO footprint, the ISO can initiate TLRs to "unschedule" the grid in accordance with NERC TLR rules in order to bring flows back within security limits. Because the TLR tool is time consuming and imprecise and its actual effects on flows uncertain, it is a very blunt tool to manage flows; however, in the absence of a more precise and reliable tool (*e.g.*, – a regional security-constrained economic dispatch) – TLR is the principal mechanism available to ensure reliability in the Midwest ISO footprint. Improving the reliability of grid operations and enhancing grid utilization are therefore major reasons why the principal focus of the proposed TEMT is to enable the Midwest ISO to implement a regional, bid-based security-constrained economic dispatch for the entire ISO footprint.

The key point, therefore, is that under the current system, the all important reliability function of security-constrained dispatch is performed locally and controlled by many individual Control Areas, which have no obligation to redispatch generation to relieve congestion caused by loopflows from other parts of the footprint or from transactions that source and/or sink in other Control Areas or outside the Midwest ISO. Instead, each Control Area's dispatch is limited to congestion associated with its own efforts to serve loads within its own control area and to maintain interchange flows at agreed upon levels.

Q. WHAT IS THE CONSEQUENCE OF CONTINUING TO RELY ON LOCAL CONTROL AREA DISPATCH AND TLRs TO MANAGE LOOPFLOWS AND CONGESTION WITHIN THE MIDWEST ISO REGION?

A. As the Commission has noted on several occasions,[3] TLRs have numerous drawbacks that make it difficult to maintain reliable operations and virtually impossible to ensure full and efficient use of the grid.

Q. HOW DOES RELIANCE ON TLRs MAKE IT DIFFICULT TO MAINTAIN RELIABLE OPERATIONS?

A. There are several aspects of the TLR mechanism that make significant reliance on TLRs problematic for reliable operations. First, TLR procedures are cumbersome and time consuming. TLRs rely on numerous phone calls between Control Areas and parties using

[3] *See*, GFA Order at 22-23 and footnote 48, citing the U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada; *also, see*, McNamara Testimony at 12-15.

the grid to achieve physical curtailments of transactions after they have been scheduled by the parties. These conversations often take place after the schedules have been initiated and are flowing. While grid conditions and the speed of electrical flows demand rapid responses by system operators to maintain flows within operating security limits, TLRs typically take from 30 to 60 minutes to implement. The parties' reaction and response times to TLR calls are uncertain, making it difficult to know how quickly flows will start to be affected by the curtailments and what that effect will be. System operators neither predict with any precision when actual flows can be brought back within security limits, nor how close to the security limits the flows will be. Moreover, any TLR event may result in the curtailment of many schedules and ongoing transactions, so the total effect on flows is even more uncertain. This uncertainty then forces the Reliability Coordinator, whether it is Midwest ISO or another entity, to be conservative in how many curtailments to request, so as to make sure that the final outcome brings flows well within the operating security limits that would otherwise be violated.

Q. COULD RELIABLE OPERATIONS BE IMPROVED BY COORDINATED REGIONAL DISPATCH IN LIEU OF TLRs?

A. Yes. It is invariably the case that congestion can be relieved more quickly, more precisely, and with greater certainty by coordinated regional dispatch of generation. By using a centralized security-constrained economic dispatch, the grid operator can adjust generation dispatch every five minutes. Generators then respond to the dispatch instructions in short order to maintain reliable flows across that portion of the grid subject to the dispatch. The continuous use of five-minute security-constrained dispatch can usually avoid violations of security limits *before* they occur, and when contingencies occur, the next five-minute interval's dispatch can relieve violations rapidly and with greater certainty after they occur.

The effect of replacing TLRs with security-constrained economic dispatch to relieve congestion is a substantial improvement in the overall reliability of the grid. However, for this improvement to occur, the security-constrained dispatch must be coordinated at the regional level, not the local control area level, so as to capture the fact that loop flows are a broad regional phenomenon, not just a local issue.

Q. IS THE USE OF CENTRALIZED SECURITY-CONSTRAINED ECONOMIC DISPATCH TO RELIEVE CONGESTION MORE ECONOMIC THAN RELIANCE ON TLRs?

A. Yes. It is invariably the case that if generation were centrally dispatched using security-constrained economic dispatch to relieve or avoid operating security violations, the costs would be less than the total costs incurred by the parties and Control Areas that must curtail transactions when TLRs are called.[4] At the Commission's request, the Midwest ISO has examined numerous TLR events and quantified the economic benefits of the system of congestion management proposed in the TEMT in Part VI of my testimony.

Q. IF A SECURITY-CONSTRAINED DISPATCH TOOL IS MORE EFFECTIVE AND MORE ECONOMIC THAN TLRs TO MAINTAIN RELIABLE OPERATIONS, WHY DON'T THE LOCAL CONTROL AREAS UTILIZE THEIR RESPECTIVE LOCAL DISPATCHES FOR THIS PURPOSE?

A. There are several reasons why this redispatch will not be offered unless it is centralized and implemented at the regional level by the Midwest ISO. First, asking the local

[4] *See*, GFA Order at 25 and footnote 56.

Control Areas to redispatch for congestion caused by loop flows requires that the Control Areas incur redispatch costs to accommodate flows from transactions that typically do not sink in their service areas, yet the Control Areas have no workable mechanism to recover those costs from the parties whose transactions and loop flows contributed to the congestion or other security limit violations. This cost arises from the fact that to relieve congestion, the dispatcher must direct one or more low-cost generators to reduce their output at some location so as to reduce flows across the congested grid facility (or "flowgate") and then require one or more higher-cost generators at other locations to increase output to rebalance the system. The net change from low-cost to higher-cost generation is an increase in total dispatch costs.

Second, because the Control Areas do not operate a bid-based dispatch priced at LMP, they have no efficient way to price the marginal cost of any redispatch needed to accommodate a transmission schedule that may otherwise contribute to security limit violations. Hence, local Control Areas cannot easily offer an efficiently priced redispatch service.

Third, given the location of dispatchable generators relative to the binding constraints, the most economically efficient redispatch options are not necessarily available to the local Control Area that experiences the congestion. Instead, the most cost-effective combination of generation redispatch for relieving a given grid constraint may be in another Control Area or shared by two or more Control Areas. Absent coordination mechanisms to achieve an efficient, least-cost dispatch solution across the control areas and a mechanism to compensate those who provide redispatch and charge those who caused the costs to be incurred, this cost-effective solution is lost. Hence, if a local Control Area were forced to redispatch only the generation within its control, it would not only incur uncompensated redispatch costs, but those costs could be higher than a more regionalized economic dispatch would have incurred if a regional dispatch were available to solve the congestion.

For these and other reasons, NERC TLR rules do not require (and in the absence of emergency conditions, it would not make sense for the Midwest ISO to require) that the local Control Area(s) offer redispatch to accommodate loop flows that cause security limit violations on the grid elements in their local areas.[5] Only a centralized bid-based, security-constrained economic dispatch, regionally coordinated by the Midwest ISO can solve these problems.

Q. WHY DOES PRINCIPAL RELIANCE ON TLRs MAKE IT DIFFICULT TO ENSURE FULL UTILITZATION OF THE GRID?

A. Reliance on TLRs for congestion management inherently leaves transmission capacity under utilized because the TLR approach relies on imprecise flow estimates and cannot accurately reflect system interactions. Regional reliability coordinators cannot distinguish transactions, including GFAs, that source and sink within an individual control area and are not subject to tagging requirements. The amount of congestion relief achievable from the TLR approach is therefore imprecise and somewhat unpredictable. The Regional Reliability Coordinator that calls the TLR cannot accurately predict how much relief the constrained grid will realize through each TLR curtailment, and therefore may curtail many transactions in each TLR event. Further, the Reliability Coordinator

5 It is typical for Regional Reliability Coordinators, including the Midwest ISO, to have the authority under emergency conditions to order local Control Areas to perform redispatch. These emergency provisions are rarely used.

calling the TLRs cannot know how long each of the scheduling parties will take in implementing the requested curtailments.

Under NERC procedures, the impact of control area-to-control area transactions and control area generators on constrained facilities is estimated using power flow distribution factors. The estimated distribution factors reflect reported control area-to-control area interchange schedules and reported transmission facility outages. However, power flows estimated using NERC procedures and data do not directly correspond to actual power flows, introducing another level of imprecision.

Moreover, TLRs are issued to curtail specific transmission transactions. When a transaction is curtailed, the affected control areas must then redispatch generation, curtail load or reconfigure their systems to comply and maintain balance. Each of these actions takes time and occurs within constantly changing levels and patterns of load, generation and power flows. Because each change in dispatch, load levels, or system configuration will have power flow impacts, and each of the parties to the curtailed transaction is responding individually against a backdrop of changing power flows, the simultaneous impact on the constrained transmission facilities (or flowgate) of the responses to a TLR is difficult to predict accurately.

As a result, it is not possible for the Midwest ISO or any Regional Reliability Coordinator to use TLRs to maintain power flows right at or close to post-contingency security limits on a sustained basis. Instead, more TLR curtailments than may eventually prove necessary must be called to avoid frequent and prolonged security limit violations. Consistent with the responsibility of Reliability Coordinators to avoid operating system limit violations, this necessarily means that some amount of transfer capability goes unused during TLR events.

Q. HAVE YOU QUANTIFIED HOW MUCH GRID CAPACITY GOES UNUSED AS A RESULT OF RELIANCE ON TLRs?

A. Yes. We have examined the records of monitored flows on congested flowgates for which TLRs were implemented during 2003 and determined that after the curtailments occurred, the actual flows on the constrained flowgates were often well below the post-contingency security limits. On average, those parts of the Midwest ISO grid were under utilized by as much as 12.9%, compared to the higher level of flows that could have been accommodated had the grid been efficiently dispatched using a regional security-constrained economic dispatch. In response to the Commission Order of May 26, 2004, we performed this analysis for flowgates in three areas: (1) the MAPP footprint; (2) the WUMS sub-region; and, (3) the rest of the Midwest ISO. We found the under utilization of transmission capacity during Level 3 and higher TLR events averaged 16.4% in the MAPP footprint, 10.9% in the WUMS sub-region, and 7.7% in the remainder of Midwest ISO for 2003. The average unused capacity during all TLR events studied was 12.9%. In short, the grid is being persistently under used because of the imprecision and uncertainty of the TLR approach. This study is explained further in Part VI of my testimony.

Q. DOES RELIANCE ON TLRs ALSO RESULT IN ECONOMIC INEFFICIENCY?

A. Yes. Under NERC TLR procedures, when a curtailment is needed, all transactions in the selected service priority (gradations of firm and non-firm service) that impact the constrained flowgate by more than the minimum (5 percent) threshold are cut on a pro-rata basis. However, the economic value of the curtailed transactions never enters into the pro rata allocation of TLR curtailments. Moreover, as redispatch is neither offered nor priced, there is no mechanism by which the parties that are subject to TLR curtailments can determine whether it would be more economic to pay for redispatch in lieu of curtailment or to accept curtailment. The only result of TLR is that it helps curtail transactions until the Regional Reliability Coordinator is assured that flows are back within security limits.

In the absence of a real time price signal, it is not possible to determine the economic impact of curtailing any particular transaction, nor is it possible to compare the marginal cost of redispatching generation to the economic value of the transactions that are curtailed by TLRs. However, it will often be the case that the costs of implementing a TLR greatly exceed the cost of a comparatively small redispatch that could provide the same reduction in flows over the constrained flowgate. For these reasons, it is highly unlikely that the grid can be efficiently used under a TLR approach.

Q. HOW DOES THE MIDWEST ISO CURRENTLY HANDLE REQUESTS FOR TRANSMISSION RESERVATIONS WITHIN ITS FOOTPRINT?

A. The Midwest ISO is currently the independent transmission provider for transactions within its footprint. Parties make reservations for transmission service using the ISO's OASIS and schedule their transactions through the ISO. When considering requests for transmission reservations and actual transmission schedules, the Midwest ISO considers the effects of flows throughout the footprint. This is a significant improvement over the prior practice used by pre-ISO Control Areas of considering reservations and schedules on the fictitious "contract path" basis. Using this regional perspective, the Midwest ISO can at least attempt to avoid exacerbating the conditions that over reserve and over schedule the grid, as occurred often under the contract path approach.

Q. GIVEN THE CURRENT APPROACHES, WHY ARE THERE STILL MANY TLRs BEING IMPLEMENTED IN THE MIDWEST?

A. Many of the TLRs still being called are a result of prior reservations made under the contract path approach and parties using those reservations to schedule transactions. Many of these schedules are submitted under long-standing contracts between parties in the region.

Q. HOW ARE TRANSMISSION SCHEDULES PURSUANT TO GFAs CURRENTLY HANDLED?

A. Today, the affected local control area handles GFA transmission schedules that are strictly intra-control area. The Midwest ISO does not see these schedules. If the transmission schedule is between control areas, the inter-control area schedule is submitted to the Midwest ISO, either by the Transmission Owner (TO) that is the original service provider under the GFA or by the Transmission Customer (TC).

Q. HOW ARE GFA TRANSMISSION SCHEDULES TREATED TODAY WHEN THERE IS CONGESTION?

A. If the GFA transmission schedule is strictly intra-control area, and the congestion is in that same control area, the control area would presumably uses its own dispatch to maintain the firmness of the transmission service required by the GFA. Any redispatch costs incurred would likely be absorbed by the TO GFA party unless such costs were otherwise allocated under the terms of the GFA.

If the GFA transmission schedule is inter-control area, then the schedule is submitted to and accepted by the Midwest ISO, based on the transmission reservations implicit in the GFA.

In either case, the flows from the GFA transmission schedule can contribute to violations of security limits outside the GFA TO's control area, in which case the Midwest ISO would need to use TLR curtailments to bring flows back within security limits. Whether the GFA transmission schedules would be curtailed or not would depend on the priority (category of firm or non-firm transmission) of the transmission service required by the GFA. If the GFA transmission service is long-term firm, it would only be curtailed by TLRs if all lower priority services were curtailed first, and then on a pro-rata basis with similar firm reservations. If the GFA transmission service has a lower priority, it can be curtailed more often, also pro rata. The financial effects between the GFA parties if such a curtailment occurred may or may not be specified by the GFA itself.

III. HOW THE SYSTEM WILL OPERATE UNDER THE MIDWEST ISO'S PROPOSED TRANSMISSION AND ENERGY MARKET TARIFF (TEMT).

Q. DESCRIBE THE PRINCIPAL MECHANISMS THE MIDWEST ISO WILL USE TO OPERATE THE GRID UNDER THE TEMT.

A. The principal feature of the TEMT is that the Midwest ISO will operate a bid-based, regional security-constrained economic dispatch. This dispatch will be:

- *Bid based* – the Midwest ISO will accept supply offers from generators and demand bids from loads (or load-serving entities) and use them to arrange the dispatch.
- *Regional* – the dispatch will cover the entire Midwest ISO footprint and provide regional-wide balancing and congestion management on a five-minute basis. The

regional scope of this dispatch will allow loop flows to be internalized and handled by a single dispatch across the region.

- *Security-constrained* – the Midwest ISO will arrange the dispatch and issue dispatch instructions to generators (and dispatchable loads) so that flows across the grid can go up to, but not over, the security limits of the grid, thus avoiding congestion before the fact and/or relieving congestion quickly and reliably after the fact should it occur unexpectedly. The security-constrained dispatch will be arranged and implemented on a post-contingency basis, so that in the event that a significant outage of transmission and/or generation occurs anywhere on the system, the Midwest ISO will be able to bring the resulting redistribution of flows quickly back within the grid's operating security limits.
- *Economic* – Given the price and quantity offers and bids from parties participating in the dispatch, the dispatch arranged by the Midwest ISO will, to the extent practicable, reflect the most efficient utilization of generation, flexible demand and transmission. This is sometimes referred to as "least-cost" dispatch. If there is congestion on the grid, the security-constrained dispatch to avoid or relieve this congestion will be arranged so that the most cost-effective combination of generation dispatch will be used to relieve the constraints, given the offers and bids.

In addition, the Midwest ISO's security-constrained economic dispatch will be:

- *Open and non-discriminatory* – All generators and eligible loads will be allowed to participate in the dispatch, without regard to ownership.
- *Voluntary* – While Parties must supply information to the Midwest ISO regarding their desire to generate, they may participate or not in the dispatch by submitting

offers or bids. Parties are also free to submit schedules for bilateral transactions without being dispatchable or to submit self schedules, such as scheduling their own generation to serve their own loads. In addition, generators with these schedules may also indicate their willingness to be subject to dispatch and submit price and quantity offers.

- *Efficiently priced using LMP* – Consistent with Commission guidance[6] and in response to the successful use of locational marginal pricing in other ISOs, the Midwest ISO will price energy bought and sold through the dispatch (imbalances and spot sales and purchases) at LMP. LMP allows parties to pay or be paid for imbalances at marginal cost, thus avoiding any cost shifts or "leaning" on the system. Further, in an LMP market, point-to-point schedules pay a usage charge equal to the difference between the LMP at the point of delivery (sink) and the LMP at the point of receipt (source). This feature makes any party (and the ISO) financially indifferent to whether it schedules and pays for transmission service between location A and location B or simultaneously sells energy at A at its LMP and buys energy at B at its LMP. This pricing thus allows parties to move freely between reliance on bilateral (or self-scheduled) transactions and spot transactions.

Q. WILL THE USE OF LMP-BASED PRICES FOR ENERGY AND TRANSMISSION USAGE SUPPORT RELIABLE GRID OPERATIONS?

A. Yes. As other LMP-based ISOs have demonstrated, pricing the dispatch and transmission usage at LMP provides economic incentives that support what the system operator needs to do to ensure reliable operations. First, the LMP prices are consistent

6 *See,* GFA Order at 18 and footnote 38.

with the grid operator's security-constrained economic dispatch. Paying generators for their dispatch output at their respective LMPs thus provides an incentive for the generators (or dispatchable loads) to follow the system operator's dispatch instructions. Second, using LMP differences between source and sink to price transmission usage sends the correct economic signal to grid users. This usage charge reflects the marginal cost of using the grid - that is, the marginal cost of redispatching the grid when it is congested to accommodate the flows of each transaction without violating security limits. When the LMPs and resulting usage charges are made transparent (they will be posted on the Midwest ISO website), parties can then make rational economic decisions and will tend to make decisions consistent with reliable operations. For example, when the grid is congested and generation must be redispatched, if the resulting LMP-based usage charge is greater than the economic value of their transactions, scheduling parties will have a clear incentive to voluntarily curtail their schedules and thus help relieve the constraints, without forcing the Midwest ISO to impose involuntary TLR curtailments. When the economic value of their transactions exceeds the LMP-based usage charge, the scheduling parties have an incentive to pay the usage charge (which covers the ISO's marginal cost of redispatching to relieve the congestion) and continue their transactions. Thus two principal reliability benefits of the LMP system are that (1) it allows more rapid and reliable economic dispatch to replace less reliable and uneconomic TLRs and (2) it provides market-based price incentives to encourage grid users to take voluntary actions to support grid reliability without resort to less reliable administrative mechanisms.

Q. DESCRIBE THE MARKETS THAT MIDWEST ISO WILL OPERATE UNDER THE TEMT.

A. As explained above, the Midwest ISO will operate both a real time (balancing) market and a day-ahead energy market. The real-time (balancing) market arises naturally from the real-time security-constrained economic dispatch, which the Midwest ISO will use to maintain reliable grid operations. The market and its LMP price incentives are thus directly linked to and supportive of the dispatch that is used to ensure reliable operations. Having parties subject to the market mechanisms, and in particular, subject to the LMP incentives that support a reliable dispatch, is thus critical to ensuring reliable operations on the Midwest ISO grid.

Q. WHY WAS IT NECESSARY FOR THE MIDWEST ISO TO OPERATE A REAL-TIME BALANCING MARKET?

A. Order 2000 requires ISOs to provide real-time balancing markets. Order 2000 recognized that parties using the grid must have a mechanism to cover the imbalances and deviations from schedules that invariably occur on the system, because it is extremely difficult for each party to perfectly match its injections and withdrawals. Once imbalances are provided, the parties need pricing rules to settle for the amounts provided by that balancing mechanism. A balancing market is the logical outcome.

But there is a more fundamental reason for the ISO to operate a real-time balancing market and it is related directly to reliable operations. A real-time balancing market is a natural and necessary consequence of operating an open, bid-based security-constrained economic dispatch. All of the features of a spot market arise from the requirements of that dispatch. If the dispatch is operated regionally by an entity independent of generation owners, there must be an objective way for generators owned by different companies to indicate, through price and quantity offers, their willingness to be dispatched at different levels and prices. Once these generators provide energy through the dispatch, there must be an efficient, non-discriminatory way of compensating the generators for the energy they produce, which then leads to the use of market-clearing prices for energy provided through the dispatch. Similarly, loads whose demands are satisfied through the dispatch must pay for the energy they use, and these payments must be consistent with the prices paid to the generators and reflect the fact that some generators must be dispatched out of merit order to relieve congestion. In short, an RTO must operate and efficiently price a real-time balancing (or "spot") market if it operates a regional security-constrained economic dispatch to ensure reliable operations. *Non-discriminatory dispatch and operating the balancing market are identical. The dispatch for maintaining reliability and the real-time market cannot logically be separated.*

Q. DOES THE PROPOSED DAY-AHEAD ENERGY MARKET ALSO SUPPORT RELIABLE OPERATIONS?

A. Yes. From the market participant's perspective, the day-ahead energy market is another way to arrange transactions. It provides a means for parties to lock in energy and transmission usage charges day ahead, leaving them sufficient time to commit units and/or make decisions about whether to continue those transactions or to deviate from them in real time, such as selling back energy in real time in response to expected real-time prices. From the Midwest ISO's perspective, however, the day-ahead energy market provides a means for the system operators to gather important information on how grid users intend to use the grid the next day. Using transmission schedules, offers and bids submitted by the parties in the day-ahead market, the Midwest ISO can plan for a security-constrained economic dispatch day ahead that can, if parties follow their schedules in real time, avoid or solve much of the congestion that would occur in real time. To the extent that system operators can anticipate and solve grid problems day ahead, the job of maintaining reliable grid operations in real time can be simpler and more predictable.

Of course, the system operators must still respond to actual grid conditions in real time and arrange a security-constrained, economic dispatch in each real-time five-minute dispatch interval. However, the day-ahead market and its LMP energy and transmission prices will encourage parties to make decisions day ahead that are consistent with a reliable dispatch in real time. While parties are then free to deviate from the day-ahead schedules in real-time, these deviations are themselves subject to the real-time market LMPs, which are consistent with the real-time dispatch used to maintain reliable operations. In this way, the day-ahead energy market and its LMP incentives, and the real-time balancing market and its LMP incentives, provide a coherent, internally consistent set of measures and incentives aimed at ensuring that in real time, the Midwest ISO grid will operate in a reliable manner.

In addition to these basic reliability features of the Midwest ISO markets, the Midwest ISO will also operate a bid-based unit commitment service in the day-ahead time frame. The ISO will use this service to ensure that sufficient generating units are committed in advance so that enough capacity will be available in each hour of the next day to meet the ISO's forecasts of real-time loads.

Q. WHAT WOULD HAPPEN IF A SIGNIFICANT FRACTION OF GRID USERS WERE ALLOWED TO USE THE REGIONAL GRID BUT WERE NOT SUBJECT TO THE RELIABILITY-BASED LMP INCENTIVES YOU DESCRIBED ABOVE?

A. The more that grid users and grid usage are subject to incentives that support reliable grid operations, the more likely it is that grid users will voluntarily submit and follow schedules that tend to support reliable operations. Conversely, the more that grid users and grid usage are exempt from these incentives (*i.e.,* "carved out"), the more likely it is that voluntary actions will be inconsistent with what the grid operator requires to maintain grid reliability. The more that voluntary actions in response to poor price signals undermine reliable operations, the more the grid operator – the Midwest ISO – must resort to involuntary measures, including mandatory curtailments using TLRs.

Q. WILL THERE ALSO BE A CONCERN FOR EFFICIENT GRID USAGE AND/OR COST SHIFTING IF SOME TRANSACTIONS ARE EXEMPT FROM THESE INCENTIVES?

A. Yes. As I explain in more detail below, if grid users are subject to efficient price signals that reflect the marginal costs or benefits of their proposed transmission usage, they will tend to use the grid more efficiently than they would if they were not subject to efficient price signals. Further, to the extent that some grid users were exempt from the efficient price signals, and used the grid inefficiently, other parties would have to pay for the measures the Midwest ISO would have to take to ensure reliable operations. For example, parties that scheduled transmission without having to pay the marginal cost of redispatching generation to accommodate that grid usage would force third parties to pay the marginal cost of redispatch that the Midwest ISO incurred to accommodate the exempt parties' grid usage. Hence, reliability, efficient grid use and basic fairness all argue for having all grid usage, and all grid users, subject to the same set of efficient incentives that reflect the marginal cost that each usage imposes on the system.

IV. WHAT A "CARVE OUT" APPROACH MEANS

Q. WHAT DO YOU UNDERSTAND THE CONCEPT OF "CARVE OUT" TO MEAN WHEN IT IS SUGGESTED AS AN APPROACH FOR HANDLING GFAs?

A. It is important to be very clear about what a carve out approach means. The Commission GFA Order sometimes speaks of a "carve-out from the market" and other times indicates that the carve out has something to do with physical scheduling requirements. However, because dispatch and use of the real-time market are the same thing, it is not meaningful to consider concepts that assume that somehow, GFA schedules could be handled "outside the market." Because all schedules, all injections and all withdrawals are using exactly the same grid, *all* schedules and grid uses affect flows on the grid and all schedules must be accounted for in the system operator's security-constrained economic dispatch. The flows from all schedules and grid uses determine the degree and location of congestion and thus affect the need for and the costs of congestion redispatch. Hence, there is no meaningful way in which GFA schedules can be "carved out" without affecting the market and the market prices faced by third parties. In this sense, the very concept of a "carve out" is problematic.

The notion of a "physical" carve out is also incompatible with the requirements for a reliable dispatch. In his March 31, 2004 testimony discussing GFA treatment, Dr. Hogan made clear that a total physical carve out of all possible grid usages that could occur under the many GFAs is simply not workable. Dr. Hogan emphasized, and the Commission noted in its March 26 Order, that the grid operator must know the net injections and net withdrawals, by location, of each grid usage, in order to arrange a security-constrained economic dispatch. Dr. Hogan noted that this information is, of necessity, provided today to the local entities responsible for grid operations and so must be provided to the Midwest ISO when it takes over the same grid operation functions, such as a regional security-constrained economic dispatch. Dr. Hogan concluded that all grid users, including parties to GFA transactions, must provide to the Midwest ISO the same information on each schedule's net injections and net withdrawals and must do so within the same time deadlines that apply to all proposed grid usage.[7]

I assume that when the Commission refers to a carve out, it is not suggesting that GFA schedules could somehow be exempt from these most basic requirements for maintaining reliable operations. However, if such an extreme interpretation were imposed, the Midwest ISO would have to accommodate GFA schedules no matter when they were submitted, no matter what the net injections or net withdrawals were and no matter what locations were affected, up to the limits defined in the GFAs.

Q. WHAT ELSE IS MEANT BY A CARVE OUT APPROACH?

A. I understand the concept to mean that GFA parties would not participate in any way in the enhancements the Midwest ISO is bringing to the region in the TEMT: These enhancements include:

- A regional security-constrained economic dispatch, and the availability of this dispatch to replace the use of TLRs. A carve out could mean that somehow, GFA

[7] Prepared Direct Testimony of Dr. William Hogan, Docket No. ER04-691-000 at 23-24 ("Hogan Testimony"); GFA Order at 21.

schedules would need to be subject to the same degree of TLRs as they are now, and the Midwest ISO would not offer or provide redispatch to support GFA schedules if they would otherwise have been subject to TLR. Conversely, GFA parties would not be allowed to purchase and pay for this redispatch service, even if redispatch were available and more economic than TLRs. The Midwest ISO would instead impose TLRs on the GFA schedules to the extent TLRs would have been used in the absence of the ISO's regional dispatch.[8]

- The ability to use the real-time balancing market to provide and price imbalances and to buy and sell spot energy. GFA parties would, instead, obtain balancing service from the local control areas under the restrictions and penalties that apply today.
- The ability to use the day-ahead energy market to lock-in energy and transmission prices in advance.
- The use of LMP prices for imbalances and spot sales and purchases, and the use of LMP-based usage charges to price transmission usage and congestion redispatch.
- The ability to be compensated for counterflows that help relieve congestion.

Q. IF THE MIDWEST ISO WERE REQUIRED TO "CARVE OUT" GFA TRANSMISSION SCHEDULES, WHAT WOULD IT HAVE TO DO?

A. The carve out approach would confront the Midwest ISO with a set of undesirable choices. The dilemma would be that no matter which choice it made, one or more undesirable outcomes would occur. The Commission is correct in concluding in its May 26 GFA Order that it is not possible to reconcile the conflicting goals of allowing some parties to continue to operate under exactly the same terms and conditions as they

[8] It is not clear how this aspect of a carve out could be achieved, because it would be impossible for the Midwest ISO to determine when TLRs would have applied if there were no regional dispatch.

did before under the GFAs, and retain the same benefits and obligations of these GFAs, while achieving all the potential reliability and economic benefits of the efficient price incentives proposed in the LMP-based TEMT.[9] Nor is it possible for GFA parties to be made exactly financially indifferent to the LMP-based pricing mechanisms without imposing some cost shifts on third parties. The Midwest ISO and Dr. Hogan examined the alternative approaches for resolving these dilemmas and essentially concluded that they are unavoidable.[10]

Q. HOW WOULD THESE DILEMMAS MANIFEST THEMSELVES UNDER THE CARVE OUT APPROACH?

A. Depending on the choices and tradeoffs the Midwest ISO would be required to make, one can foresee different outcomes with different adverse effects. Suppose "carve out" means that the GFA schedules were not subject to the same scheduling deadlines and net injection and withdrawal data requirements as other grid users and not subject to LMP-based energy and usage charges in either the day-ahead or real-time markets. In that case, the Midwest ISO would still need to account for the capacity likely to be used by GFA schedules when they were finally submitted. In the day-ahead energy market, two approaches are possible, assuming GFA schedules would not be submitted by the day-ahead scheduling deadline:

(1) *Ignore the GFA schedules in the day-ahead market*. The ISO could ignore the likelihood of eventual GFA schedules and flows and arrange the day-ahead dispatch, defining day-ahead LMP-based energy and transmission usage charges.

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9 GFA Order at 26.

10 Hogan testimony at 42-46.

Without considering the many GFA schedules and their associated flows, congestion in the day-ahead market would be much less likely and day-ahead usage charges would be correspondingly lower or zero. If there were congestion, non-GFA parties could be hedged against usage charges by the Financial Transmission Rights (FTRs) they receive in the FTR allocation process or acquired through secondary trading. In any event, the FTRs would be cashed out in the day-ahead energy market settlements. However, when the GFA schedules were finally submitted closer to real time, real-time congestion would likely be greater and the Midwest ISO would incur greater congestion redispatch costs in the real-time dispatch. The non-GFA parties who had followed their day-ahead schedules in real time would, under the TEMT, not have to pay for increased congestion in the real-time market *for their own transmission schedules*, because they would already have purchased transmission for those schedules at day-ahead usage prices by paying the day-ahead usage charges. However, the non-GFA parties would still be exposed to the unhedgeable risks of real-time congestion costs, because it would be the non-GFA parties, not the carved out GFA parties, who would have to pay the uplift for the unrecovered costs of congestion redispatch required in real time. Thus, this carve out choice would result in cost shifts to third parties.[11] Furthermore, because the carved out GFA schedules would not have to pay the marginal costs of redispatch for congestion imposed by their own schedules, the GFA parties would not have any incentives to schedule

[11] As Dr. Hogan noted, it is also possible that at least some of the GFA schedules could provide counter flows that could reduce congestion and the costs of redispatch. It seems unlikely that this would apply to a large fraction of the GFA schedules.

efficiently or to choose wisely between alternative generation that might limit redispatch costs. This would tend to increase real-time congestion and redispatch costs, thus raising the uplift charged to third parties while fostering inefficient use of the grid. In addition, because little of the actual congestion experienced in real time would have been managed in the day-ahead market, there would be a greater burden on the Midwest ISO to manage the actual congestion in real time, but the resulting LMP price signals would not have the desired effect of supporting reliable operations, because the GFA parties would not be subject to those price signals.

(2) *Assume GFA schedules in the day-ahead market*. If instead of ignoring the likelihood of GFA schedules in the day-ahead market, the Midwest ISO assumed a set of GFA schedules and reserved transmission for them in the day-ahead market, then the level of transmission usage accounted for in the day-ahead security-constrained economic dispatch would increase, thereby increasing the likely level of congestion in the day-ahead market. Congestion redispatch costs would likely increase for other parties. Non-GFA parties participating in the day-ahead energy market could be hedged for their own schedules through the FTRs they held, but again they would find it difficult to hedge against the redispatch costs the Midwest ISO incurred as a result of redispatching for the congestion

attributable to the GFA schedules that the ISO had assumed in each hour.[12] Those unrecovered costs would have to be recovered through uplift on non-GFA parties. Thus, this carve out choice also leads to unhedgeable uplift costs to third parties. While non-GFA parties could attempt to hedge themselves in the day-ahead market through virtual offers, bids and schedules, the non-GFA parties would be working with much less information about the amounts and locations of likely GFA schedules than the GFA parties themselves would have. Hence, risk-averse non-GFA parties would be unlikely to attempt these strategies, and risk-taking non-GFA parties would be at a disadvantage compared to GFA parties in terms of anticipating likely GFA schedules. Also, as in first choice above, GFA schedules would not be subject to the LMP price signals that encourage behavior consistent with reliability, so there would be no incentives for GFA parties to take actions consistent with reliable dispatch. Nor would there be any incentive for the GFA parties to participate in the day-ahead market, so that the Midwest ISO could not get any improved advance indication on how the grid would be used in real time other than its own guesses of expected GFA transmission usage. Carving out GFA schedules would thus do nothing to improve reliable operations and could make it worse. Carving out would not use the incentive tools the TEMT provides to support reliability or allocate grid use efficiently, and it

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12 It would be impossible for the Midwest ISO to guess correctly the amounts, times and locations of the GFA schedules, particularly given the very large number of such contracts and the large uncertainty associated with each contract's scheduling flexibility. The Midwest ISO would almost always be wrong one way or another, with either an underestimate or overestimate of GFA grid usage. If the Midwest ISO overestimated the amount of grid use to carve out in the day-ahead market, the effect could produce what has been called "phantom congestion," which would tend to increase the redispatch costs in the day-ahead market. Virtual schedules could be used to reduce this effect. This problem can only be solved if the GFA parties themselves take responsibility for telling the ISO what they intend to do, when and where, as the TEMT proposes.

would force the ISO to deal with more reliability issues in real time, rather than day-ahead.

Q. WOULD THE CARVE OUT APPROACH ALSO ADVERSELY AFFECT THE MIDWEST ISO'S RELIABILITY UNIT COMMITMENT PROCESS?

A. Yes. Without direct information from the GFA parties about their likely schedules, the day-ahead unit commitment process would be based more on the Midwest ISO's best estimates of real-time loads and generation requirements than on information from the parties most likely to know those loads and how they would be met. There would be a tendency to overcommit resources day ahead, to be certain that all loads could be covered by on-line generation or units with quick start capability. This would tend to increase commitment costs, which must be recovered through uplift on all parties.

Q. WHAT EFFECT WOULD A CARVE OUT APPROACH HAVE ON THE ECONOMIC BENEFITS OF THE REGIONAL ECONOMIC DISPATCH?

A. A carve out approach would either prevent or discourage generators responsible for serving GFA loads from participating in the bid-based security-constrained economic dispatch. With fewer flexible generators subject to regional dispatch, the "least-cost" dispatch would likely be higher cost than if the dispatch had access to all of the generators in the region. The reduced participation by generators would tend to increase LMPs generally, with the effect of increasing imbalance costs. Reduced participation could also tend to raise the costs of congestion redispatch and hence the transmission usage charges, which if not hedged by FTRs would be borne by non-GFA parties.

Q. HAS THE MIDWEST ISO ATTEMPTED TO QUANTIFY THE ECONOMIC EFFECTS YOU DESCRIBE?

A. Yes. Under my direction we compared a scenario in which generation throughout the region is available for economic dispatch and a scenario in which a substantial amount of generation is withheld from regional economic dispatch to serve the loads of carved out GFAs. This study is described more fully in part VI of my testimony. In summary, we found that for the peak hour examined, the carve out approach could significantly raise peak hour prices.

V. TREATMENT OF GFA SCHEDULES UNDER THE PROPOSED TEMT SCHEDULING OPTIONS A, B, AND C.

Q. DESCRIBE THE PROPOSED TEMT TREATMENT OF GFA SCHEDULES.

A. The TEMT provides three scheduling and pricing options for GFA parties to choose from in the event they do not voluntarily elect to convert to full LMP-based compliance with the TEMT. These are designated Options A, B and C. Regardless of the Option chosen, the GFA parties must first designate an entity that will be responsible for assuming the obligations for paying Midwest ISO charges for its various Tariff Schedules. In addition, the GFA parties must designate the entity that will be responsible for scheduling transmission usage pursuant to the GFA. The responsible scheduling entity will submit to Midwest ISO the daily and hourly scheduling information required for all transmission schedules submitted to the ISO. As Dr. Hogan explained in his March 31, 2004 testimony, and as FERC recognized in its May 26 GFA Order,[13] this is the minimum

[13] *See*, Hogan Testimony at 9; GFA Order at 22.

level of conformance with the TEMT that is needed to allow the Midwest ISO to arrange a security-constrained economic dispatch and ensure reliable grid operations.

Q. WHAT DOES SCHEDULING OPTION A PROVIDE?

A. If the GFA parties elect Option A, one of the parties agrees to take transmission service under the TEMT. Transmission schedules submitted to the Midwest ISO will be subject to the LMP-based energy and transmission prices and the party may participate in the day-ahead and real-time balancing markets just like any other party. The party will also be eligible to participate in the allocation of FTRs, just like other parties. As Dr. Hogan testified, the choice of Option A, which resembles either voluntary conversion or a "next-best" solution, is a desirable outcome for reliability, for market efficiency and for avoiding cost shifts to third parties because it preserves all of the incentives of LMP-based energy and transmission pricing for GFA schedules. While the GFA parties may keep the economic/price terms of their GFA intact and continue to settle at the GFA rates between themselves, the responsible entity will settle with the Midwest ISO like any other party.

Q. WHAT DOES SCHEDULING OPTION B PROVIDE?

A. If the GFA parties elect Option B, then GFA transmission schedules can be made at least financially indifferent to the LMP-based energy and transmission prices in the day-ahead market, provided that the GFA schedule is submitted in the day-ahead market. To accomplish the goal of financial indifference, the Midwest ISO will first apply the LMP-based transmission usage charges to the GFA day-ahead schedules, but it will then effectively rebate any usage charges to that GFA schedule. Under LMP, the usage charge will include both a congestion component and a component reflecting the cost of marginal losses. The GFA party will be credited with a rebate of the congestion component during the day-ahead settlement, just as though it had a set of FTRs that perfectly matched its day-ahead schedules. The GFA party will also receive a rebate of the difference between the marginal losses for the transaction and a value representing the average losses. The net effect of this latter rebate is that the GFA party would pay only for average losses, as defined by that value. The combined effect of Option B is to leave the GFA parties no worse than financially indifferent to the imposition of LMP-based transmission usage charges.

Q. TO THE EXTENT GFA PARTIES SELECT OPTION B, HOW WILL THE MIDWEST ISO ACCOUNT FOR THE TRANSMISSION USAGE RESERVED FOR GFAs WHEN IT ALLOCATES FTRS?

A. To have a meaningful allocation of FTRs and one that does not result in revenue inadequacy in the day-ahead energy market settlements, the Midwest ISO must account for the transmission that is likely to be used by GFA transactions. In that way, FTRs will not be over allocated beyond the capacity of the grid, and the ISO settlements will normally be able to fund all FTRs at the settlement value. One approach would be for the GFA parties to designate the FTRs they think best represent their expected transactions and then have those parties bear the risks (and rewards) of any difference between the allocated FTRs and the schedules they actually use. However, GFA parties generally expressed no interest in being engaged in this process. The alternative is to have the Midwest ISO designate and set aside an appropriate set of FTRs in the FTR allocation process, thus preserving the associated grid capacity as the ISO allocates FTRs to other parties. This is the approach proposed in the TEMT.

Q. IS THERE ANY ADVANTAGE TO GFA PARTIES OR DISADVANTAGE TO NON-GFA PARTIES IN THIS APPROACH?

A. There can be. If the Midwest ISO assigns to the GFA schedules fewer (or less valuable) FTRs than are needed to hedge the actual GFA transmission schedules, but still credits the GFA parties as though they had a perfectly matching set of FTR hedges for their schedules (financial indifference), the result would likely be settlement periods in which congestion revenues would be insufficient to fund all FTRs at full value, while still making the GFA party financially indifferent. When that happened, the revenue inadequacy would have to be made up either by decreasing the FTR payments to non-GFA parties or making up the difference through some form of uplift paid in some part by non-GFA parties. Either way, non-GFA parties would pay for making GFA parties financially indifferent.

Alternatively, if the Midwest ISO assigned too many FTRs to the GFA schedules, then the over assignment could reduce the number of FTRs that could be allocated to other parties. In that event, other parties might receive fewer FTRs than they would otherwise be entitled to receive and could thus be less fully hedged against the congestion component of usage charges. Thus, non-GFA parties would again pay for making GFA parties financially indifferent.

The Midwest ISO will endeavor to designate FTRs for expected GFA schedules so as to minimize the chances of either type of adverse impacts on non-GFA parties, by matching FTR assignments to the best estimates of expected schedules. To do this, Midwest ISO must have reasonably accurate information from the GFA parties about the transmission schedules they actually expect to submit. Submission of this information is essential to minimize cost-shifts to third parties, but even with this information, estimates are likely to be wrong to some degree. Some degree of effect on non-GFA parties appears unavoidable.

Q. IF GFA PARTIES SELECT SCHEDULING OPTION B AND SUBMIT DAY-AHEAD SCHEDULES, HOW DOES THE TEMT TREAT DEVIATIONS FROM THOSE SCHEDULES IN REAL TIME?

A. Any deviations from day-ahead schedules would be subject to real-time LMPs. This means that Option B provides "financial indifference" to GFA parties only for schedules submitted in the day-ahead energy market and followed in real time.

Q. WHY DID THE MIDWEST ISO PROPOSE THIS TREATMENT FOR REAL-TIME DEVIATIONS?

A. After considering the effects on non-GFA parties and the importance of preserving the reliability and efficiency benefits of real-time LMP price signals, the Midwest ISO concluded that making GFA schedules subject to real-time LMP for deviations was the minimum conformance necessary to encourage reliable operations and efficient scheduling. Because only day-ahead schedules will be shielded from LMP-based usage charges, this rule will tend to discourage GFA parties from underscheduling in the day-ahead market. At the same time, parties may be encouraged to schedule their full GFA entitlement day-ahead (for which the usage charges are rebated), even when they expect to use less transmission in real time. In effect, the parties would sell back any unused transmission in the real-time market. In his March 31 testimony, Dr. Hogan considered this incentive and concluded that GFA parties and other parties would also have incentives to submit virtual schedules in the day-ahead market to the extent day-ahead schedules did not represent expected grid usage in real time. The arbitrage effect of these virtual schedules would tend to encourage efficient scheduling overall with no significant adverse effect on reliable operations. However, Dr. Hogan noted that GFA parties would be better informed about their actual real-time intentions and would therefore be in a better position than non-GFA parties to arbitrage between day-ahead and real-time markets.[14]

Q. OVERALL, WOULD GFAs BENEFIT OR BE HARMED BY THE FEATURES OF OPTION B?

A. Option B provides a balance of benefits and disadvantages to the GFA parties. The parties achieve at least financial indifference to LMP-based charges for schedules in the day-ahead market, but they also see exposure to LMP-based imbalances if they deviate from their day-ahead schedules. They benefit from the fact that the ISO's regional security-constrained dispatch will greatly reduce the use of TLRs, reducing the risk that GFA schedules will be subject to TLR. Compared to a carve out approach that excludes access to the market, they benefit from the ability to arbitrage and gain financially by scheduling their full entitlements in the day-ahead market and selling back any unused transmission in the real-time market. On the other hand, in exchange for financial indifference for day-ahead schedules, the Option requires that the parties give up some flexibility in the way they currently schedule transactions, including the ability to schedule close to real time without financial consequences.

[14] Hogan Testimony at 43-46; GFA Order at 31.

Q. WHY DID THE MIDWEST ISO OFFER OPTION B?

A. With Option B, the Midwest ISO recognized that the several goals set forth by the Commission for GFA treatment could not be perfectly harmonized.[15] Reliability could not be maintained if the Midwest ISO were required to leave the GFA terms for scheduling transmission unchanged. To ensure a reliable dispatch and gain the reliability benefits of both the day-ahead and real time markets, all grid users needed to meet the TEMT's physical scheduling requirements. Similarly the goal of financial indifference (or retaining the economic benefits and obligations of the GFAs) could not be met without some risk of exposing non-GFA parties to potential cost shifts. Conversely, cost shifts to third parties could not be minimized without requiring GFA parties to be subject to at least some of the LMP-based incentives, such as for real-time deviations from day-ahead schedules, to promote reliable operations and efficient grid use. After carefully considering a number of alternative approaches, and extensive discussions with all parties, the Midwest ISO concluded that Option B was a reasonable compromise and balance of competing goals of preserving reliability, ensuring financial indifference to GFA parties, and limiting cost shifts to third parties.

Q. WHAT DOES SCHEDULING OPTION C PROVIDE?

A. Under Option C, the GFA parties would be subject to LMP in the day-ahead and real-time markets but would not participate in the allocation of FTRs. This Option is expected to be used only in those cases in which the parties anticipate that the FTR allocation

[15] The Commission also recognized "the potential conflict between our desire to preserve the GFAs and our instructions that the Midwest ISO develop a market–based system of congestion management." GFA Order at 26.

process might result in assignment of FTRs with negative values, posing a financial risk to the GFA parties.

VI. SUMMARY OF THE QUANTITATIVE STUDIES.

Q. WHAT QUANTITATIVE ANALYSIS HAS THE MIDWEST ISO UNDERTAKEN IN RESPONSE TO THE COMMISSION'S ORDER?

A. The Commission directed the Midwest ISO to provide additional information on the reliability and economic benefits of its proposed congestion management system with GFAs included in the market. More specifically it requested evidence on:

1. The historical impacts of TLRs in the Midwest ISO region;
2. The economic impact of TLRs and a quantification of the benefits of the Midwest ISO's proposed congestion management system; and
3. How a carve-out of GFAs could impede the reliability of the proposed Day 2 markets and the achievement of cost savings.

In response to the Commission's Order, under my direction the Midwest ISO undertook three studies. First, an analysis was completed on the historical reliability and economic impacts of TLRs. We examined the TLR events on Midwest ISO monitored flowgates occurring in calendar year 2003.

Second, utilizing the data from our analysis of TLR events, we quantified the near term economic benefits to the region associated with moving from the current system of rationing physical rights to managing congestion based on security-constrained, regional unit commitment and economic dispatch as proposed in the TEMT. This analysis was performed using the PROMOD IV production costing and power flow model.

Third, we examined the impacts of a "physical carve out" and compared such a carve out to the options provided in the proposed TEMT. The TEMT, is designed to provide GFA holders the economic benefit of their transmission agreements without impacting the reliable and efficient operation of the power system. The idea is to make the GFA parties financially indifferent to LMP or LMP-based usage charges. Indeed, one of the options available to GFA holders under the TEMT (Option B) in some respects may place them in a superior financial position relative to the benefits they have historically enjoyed under their existing transmission agreements. Under a financial carve out, generators would comply with Midwest ISO scheduling rules, but would not be subject to the LMP-based prices and usage charges. Given a physical carve out, GFA holders would not have to follow Midwest ISO scheduling rules and would not be responsible for the economic impacts on others of their greater scheduling flexibility.

We reviewed the extent to which GFAs include requirements that service be scheduled in advance. To explore the impacts of carve out, we also examined scenarios that will illustrate how – in the absence of following scheduling requirements and being financial responsible for the consequences of greater scheduling flexibility – a physical carve out of GFAs could impede the achievement of reliability and economic benefits.

A. SUMMARY OF HISTORICAL IMPACT OF TLRs

Q. WHY IS IT IMPORTANT FROM A RELIABILITY PERSPECTIVE TO CONSIDER THE IMPACTS OF TLR EVENTS?

A. TLRs are the principal means by which the Midwest ISO seeks to keep power flows within security limits and maintain system reliability at times when not all scheduled transactions can be physically accommodated.

Each element of the electric system has ratings which determine how much current can flow through it. Excessive current can damage equipment, knocking that element out of service, which is not only costly to replace, but can unbalance the system as flows rearrange themselves at near the speed of light. The failure of elements can, if sufficiently severe or not reacted to promptly, cause a cascading blackout, in which the failure of parts of the network lead to failures in other parts of the network. To avoid this, system operators must ensure that transmission facilities on the network do not exceed their ratings by following operating security limits. These limits may be based directly on the flows that can be accommodated over a specific facility or may reflect the need to protect that facility from the impact of the flow that would occur in the event of a contingency resulting from the loss of another element in the system.

Since the Midwest ISO assumed responsibility for regional reliability coordination, our regional perspective enabled us to identify additional contingencies and flowgates, which in some cases were not previously monitored. Protecting such security limits can require calling TLRs and curtailing transmission service that has been oversold.

Unfortunately, as I described in my March 31, 2004, direct testimony in Docket No. ER04-691-000, TLRs are a cumbersome, imprecise, and inefficient mechanism for maintaining transmission reliability. TLRs require reliability coordinators to anticipate power flows and the impact of curtailing given transactions on flows over specific facilities, based on imprecise estimates of how such transactions may be impacting the constrained facilities, and without coordinating the choices that different control areas and market participants may make regarding how to respond to the curtailment of given transactions. As a result, it is simply not possible to match power flows to security limits on a sustainable basis using TLRs. To protect reliability, TLRs in some instances leave a portion of transmission capacity under utilized at a time when transmission service is being curtailed. And, in other cases, attempting to rely on TLRs can result in actual power flows exceeding operating security limits.

Q. WHY IS IT IMPORTANT TO CONSIDER THE IMPACT OF TLR EVENTS FROM AN ECONOMIC PERSPECTIVE?

A. First, reliance on TLRs results in under utilization of the transmission system at times when requests for transmission service are being curtailed. Second, TLRs are part of an approach for managing congestion in the transmission that is based on physical rationing of available capacity. Initiated without reference to price signals, TLRs curtail transactions with little regard for the economic value the transactions may be creating at the time of curtailment. Third, following NERC TLR procedures in some circumstances requires the curtailment of transactions that have only a small impact on the constraining flowgate. As a result, TLRs can create larger and more inefficient shifts in generation than would be necessary to relieve a given constraint.

Q. CAN YOU PLEASE DESCRIBE THE ANALYSIS OF HISTORICAL TLR EVENTS THAT WAS UNDERTAKEN FOR THIS PROCEEDING?

A. We analyzed the power flows that actually occurred during Level 3 and higher TLRs on Midwest ISO flowgates during calendar year 2003. The Midwest ISO Flowgate Monitoring Tool (FGMT) generally records at approximately 30-second time-stamped intervals: actual power flows on each flowgate, post-contingency power flows calculated based on actual flows over the flowgate and the contingent network element the failure of which would increase flows over the constrained flowgate, and the flowgate's operating security limit given current network topology. It also records when actual or post-contingency flows have violated the security limit. Using data from the FGMT, we were able to analyze the results of 926 TLR events that occurred during 2003. This analysis covered more than 10,800 hours of TLR events. It extends the more limited samples of TLR data discussed in my March 31, 2004, direct testimony in Docket No. ER04-691-000.

We calculated average unused capacity for the duration of each TLR as the MWH of unused transfer capability divided by the total transfer capability of the flowgate given operating security limits.

This analysis includes all 2003 Level 3 or higher Midwest ISO TLRs for which FGMT data was available. Time periods for which data was unavailable in the FGMT and TLR events for which data was either unavailable or available for less than 50% of the duration of the event were excluded from the analysis.

Q. WHAT WERE YOUR FINDINGS FROM THE REVIEW OF THESE TLR EVENTS?

A. First, the historical reliance on TLRs has resulted in under utilization of transmission capacity. For purposes of quantifying under utilization, we divided the region into three areas:

1. The MAPP footprint: This area contains a higher concentration of GFAs in comparison to the remainder of the Midwest ISO footprint. It is also an area in which there are multiple seams and overlapping companies, making it more difficult to anticipate the effects of curtailing specific transactions. Although not a MAPP

member, the Alliant West control area was included because it is surrounded by MAPP companies.

2. The WUMS sub-region (Eastern Wisconsin and the Upper Peninsula of Michigan): This area is the most heavily constrained portion of the Midwest ISO footprint.
3. Remainder of Midwest ISO: This area includes the Southern portion of the MAIN Region and portions of ECAR.

We found that the under utilization of transmission capacity during Level 3 and higher TLR events averaged 16.4% in the MAPP footprint, 10.9% in the WUMS sub-region, and 7.7% in the remainder of Midwest ISO for 2003. The average unused capacity during all TLR events studied was 12.9%.

Q. WHAT FACTORS MAY CONTRIBUTE TO THE HIGHER LEVEL OF UNUSED CAPACITY IN THE MAPP REGION?

A. The higher concentration of GFAs in the MAPP region makes it more difficult to forecast power flows, anticipate participant responses to TLRs, and manage congestion using TLR procedures. As addressed in subsequent section of my testimony, most GFAs do not include any contractual time limits on scheduling transmission service. And, many GFAs source and sink within an individual control area and are therefore not subject to tagging and scheduling requirements. The holders of such unscheduled GFA rights may change their use of transmission service without notifying the Midwest ISO. Thus, reliability coordinators must anticipate and work around the possibility the market participants may offset the curtailment of a particular transaction with use of GFAs that also might impact on the constrained flowgate. The greater number of seams and overlapping service territories in MAPP also may make it more difficult to correctly anticipate power flows and the effects of a TLR and may contribute to the higher observed unused capacity in the MAPP region.

Q. WHAT ELSE DID YOU FIND IN YOUR ANALYSIS OF TLR EVENTS?

A. Reliance on TLRs for congestion management makes it more difficult to maintain power flows within operating security limits. Actual or post-contingency power flows violated security limits at some point in 556 of the 926 TLR events studied. The total time spent in violation of the security limits equaled 2,163 out of the total of 10,820 hours or 20% of the duration of the 926 TLRs studied. While most of the excursions above the security limits were for limited periods and within the emergency limits of the affected transmission facilities, the fact that they occurred at all reflects the inherent difficulty in relying on TLRs to protect system reliability.

B. BENEFITS OF TEMT PROPOSED SYSTEM OF CONGESTION MANAGEMENT

Q. WHY IS EFFICIENT CONGESTION MANAGEMENT IMPORTANT?

A. The transmission system in the Midwest cannot simultaneously accommodate all reservations and requests for transmission service. System operators have to perform a complex task of managing congestion to keep power flows within operating security limits. When that task is performed efficiently, resources are committed and dispatched and the transmission system may be reconfigured to optimize economic outcomes subject to meeting reliability based limits on power flows.

Q. WHY IS CONGESTION MANAGEMENT A COMPLEX TASK?

A. The electric power system has unique characteristics that increase the complexity of congestion management. First, power flows can change instantaneously. Following the laws of physics, when load, generation, or transmission facilities change, power flows immediately redistribute themselves along the paths of least impedance. Second, within the short time frames that are critical for managing such flows, the transmission system in large part lacks the capability to operate as a switched network. Thus, unlike a telephone call that can be rerouted when a line goes out of service, power system operators have limited direct control about where power will flow when a line or transformer fails. Third, given that power flows will change at near the speed of light in the event of an equipment failure, operators would be unable to respond with sufficient speed if each element in the system were loaded up to its individual thermal limit. Therefore, the transmission system is operated on a contingency basis. That means the security limits on the use of specific transmission lines must be based not only on the physical capabilities of each line, but on how the flows over that line would change in the event of the failure of other transmission facilities. Fourth, a single transaction from point A to point B produces a distribution of power flows that can affect transmission paths across a broad region of the grid. The changing overall pattern of generation, load, and transmission facilities in service determines which paths will be impacted. And in some circumstances, a power transfer in one part of the grid can produce a disproportionate impact on the ability to move power in a geographically distant portion of the system. Finally, changing the location at which power is generated is the primary mechanism used to manage power flows within security limits. Thus, efficiency of congestion management is a direct function of the scope and efficiency with which generation can be re-dispatched to accommodate transmission constraints. By facilitating the economic re-dispatch of generation in response to transmission constraints on a region-wide — not just a local — basis, the Midwest ISO energy markets are expected to significantly reduce the costs of congestion management.

Q. HOW WOULD THE MIDWEST ISO'S TEMT IMPROVE CONGESTION MANAGEMENT?

A. A primary objective of the TEMT is to achieve reliable, economic, and non-discriminatory unit commitment and dispatch to efficiently manage transmission congestion. Once the dispatch is arranged, the proven way to encourage generators to follow dispatch instructions this is through the use of locational marginal pricing. The proposed real-time and day-ahead energy markets are the means to secure price bids to facilitate coordinated unit commitment and security-constrained economic dispatch.

Under current operations, the Midwest ISO, in its role as reliability coordinator, does not dispatch generation. The existing method for managing congestion, relies on reserving and scheduling estimated Available Flowgate Capacity ("AFC") and, when not all scheduled service requests can be physically accommodated, curtailing transmission service under TLR procedures — in essence, physically rationing transmission capacity based on priorities related to firmness and length of service. Like other physical rationing mechanisms, the current approach contains inherent inefficiencies due to underutilization of assets and the inability to optimize asset utilization based on prices and economic value.

Q. HOW WILL THE MIDWEST ISO COORDINATE ECONOMIC UNIT COMMITMENT AND DISPATCH GIVEN THAT NOT ALL RESOUCES MAY SUBMIT PRICE BIDS IN THE DAY AHEAD AND REAL TIME MARKET?

A. It is not necessary that all resources provide price schedules to achieve the economic benefits of coordinated economic unit commitment and dispatch. Under the Midwest ISO's proposal, resources for which there is any foreseeable possibility that they could end up economically on the margin will want to submit price bids because they run the risk of operating at a loss — operating generation that costs more to run than the price at which the supplier could purchase equivalent power in the market to cover its supply obligations.

Q. WHAT APPROACH DID YOU TAKE TO EVALUATE THE ECONOMIC IMPACTS OF TLRs AND THE BENEFITS OF THE MIDWEST ISO'S PROPOSED SYSTEM OF CONGESTION MANAGEMENT?

A. Our analysis is based on comparing the near term benefits and costs to market participants in the Midwest ISO footprint of continuing current operating procedures to the benefits and costs of our proposal to manage congestion through regional security-constrained unit commitment and economic dispatch.

We examined the benefits of our proposed system of congestion management from two perspectives. First, we examined benefits from the perspective of the cost of power at market prices, quantifying the reduction in load zone average market clearing prices as a result of improved congestion management. Second, we also quantified the benefits to Midwest ISO members from a cost of service perspective, taking into consideration reduced generation costs, changes in net Midwest ISO purchased power costs, and increased revenues from off-system power sales outside to purchasers outside of the Midwest ISO. We estimated the net economic savings from the proposed system of congestion management by deducting the annual charges to market participants for the implementation and operation of the proposed markets.

Q. WHAT DID YOU DETERMINE TO BE THE NET ECONOMIC BENEFITS FROM THE PERSPECTIVE OF THE COST OF POWER AT MARKET PRICES MOVING FROM THE CURRENT SYSTEM OF RATIONING TRANSMISSION CAPACITY AND TLRs TO THE PROPOSED SYSTEM OF CONGESTION MANAGEMENT?

A. From a cost of power at market prices perspective, Midwest ISO members are likely to realize net economic benefits from implementation of the proposed TEMT of approximately $586.1 million dollars per year. This reflects $713.1 million dollars per year in savings from lower market prices for power in the Midwest ISO region. To calculate the net savings, the amount of the benefit was offset by $127.0 million per year in fees to cover the implementation and operation of the proposed markets. The average load zone market clearing price of power in the Midwest ISO footprint is forecast to be lower under the Midwest ISO TEMT by $1.18 per MWH. On a monthly basis, average price per MWH savings range from $0.46 in April to $1.94 for July. The reduction in the load weighted average market price was multiplied by Midwest ISO load to calculate the reduction in the market cost of power given the improved efficiencies from the proposed system of congestion management.

Q. WHAT DID YOU DETERMINE TO BE THE NET ECONOMIC BENEFITS FROM A COST OF SERVICE PERSPECTIVE OF MOVING FROM THE

CURRENT SYSTEM OF RATIONING TRANSMISSION CAPACITY AND TLRs TO THE PROPOSED SYSTEM OF CONGESTION MANAGEMENT?

A. From a cost of service perspective, Midwest ISO members are likely to realize net economic benefits from implementation of the proposed TEMT of approximately $128.4 million dollars per year. This reflects $255.3 million dollars per year in net savings from reduced generation and purchased power costs and increased revenues from off-system sales to parties outside the Midwest ISO footprint. This amount is offset by an estimated $127.0 million per year in fees to cover the implementation and operation of the proposed markets.

Looking at the overall footprint from a cost of service perspective the savings are largely the result of lower prices for purchased power and an increase in both power imports and exports from Midwest ISO member companies. Total power purchases by Midwest ISO member companies from non-Midwest ISO generators are estimated to increase in the proposed market by 4.9 million MWH per year under the proposed TEMT. However, despite the increase purchase volumes, coordinated unit commitment and dispatch can be expected to reduce market-clearing prices such that the average price paid for power imports would fall by an average of $2.74 per MWH or 9.1%. The reduction in market clearing prices for such purchases is forecasted to result in a savings of $98.7 million per year, offsetting most of the impact of an increase in the volume of purchases. Additionally, power sales from Midwest ISO to non-Midwest ISO entities are expected to increase by 10.8 million MWH per year given the proposed Midwest ISO energy markets. The increase in revenues from sales to entities outside of the Midwest ISO of $282 million per year, less the cost of increased power purchases from others, which given lower prices in the Midwest ISO equal $36.4 million, results in a net benefit to Midwest ISO members from off-system sales and purchases of $245.6 million per year.

Additionally, total generation costs in the region are forecasted to decline by $9.7 million per year given the proposed system of congestion management. This is a calculation of net savings after taking into consideration the cost of generating an additional 5.8 million MWH for export.

Given the limited time available in this proceeding, we did not complete additional model runs to separately analyze the cost of serving Midwest ISO native load. However, if one were to make a pro rata allocation of generation and purchased power costs on an energy basis between the cost of serving native load and cost of supporting off-system sales, the savings in generation and purchased power costs for serving Midwest ISO load under the TEMT would be approximately $292.9 million per year.

Q. HOW DID YOU DETERMINE THE COST FOR IMPLEMENTATION OF THE PROPOSED MARKETS?

A. These costs reflect proposed Midwest ISO OATT Schedule 16 and 17 fees and are based on Midwest ISO budget projections for completing market implementation and on-going market operations. A significant portion of the fee is designed to recover capital expenditures associated with market development and implementation. We anticipate completing the recovery of these capital expenditures by 2009.

Q. IF THE COMMISSION DID NOT APPROVE THE MIDWEST ISO'S TEMT WOULD THE COSTS OF THE MARKET THAT YOU HAVE INCLUDED IN YOUR ANALYSIS BE AVOIDED?

A. No. A significant portion of the market implementation costs included in my analysis has already been expended in preparing for the start of the market. I have included the full annual cost impact of implementing and operating the market to provide the Commission a conservative assessment of the benefits and costs of implementing the proposed TEMT congestion management system.

Q. WHY DO THE BENEFITS OF THE PROPOSED SYSTEM APPEAR TO BE GREATER WHEN EVALUATED FROM THE PERSPECTIVE OF THE MARKET PRICE OF POWER?

A. The market price perspective reflects impacts on wholesale power prices and potential impacts on retail generation prices in retail access jurisdictions. Market prices reflect the marginal cost of generation. More efficiently resolving transmission constraints reduce the use of the most expensive resources and thus reduces marginal costs by a greater amount than it reduces average or total costs.

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THESE RESULTS?

A. The results of any benefit – cost analysis are best viewed as indicative rather than precise estimates. Nonetheless, our analysis suggests that Midwest ISO participants will be economically better off on an annual basis as a result of implementing a regional, security-constrained economic dispatch and the of real-time and day ahead energy markets associated with that dispatch. Furthermore, this conclusion is based entirely on near-term congestion management benefits and does not reflect a number of significant less quantifiable longer term benefits, such as the potential for improvement in investment decisions, improvements in forced outage rates, enhanced demand-side management, and other impacts of more efficient and transparent price signals.

Q. HOW DID YOU ESTIMATE THE PRICE AND COST OF SERVICE IMPACTS OF IMPLEMENTING THE MIDWEST ISO TEMT?

A. We completed a detailed production costing and power flow analysis of prices and costs for projected Midwest ISO market participants in two cases comparing implementation of the Midwest ISO TEMT to the continuation of reliability coordination and tariff administration under current operating procedures.

This analysis was conducted using the PROMOD IV® model which integrates hourly chronological production costing and detailed power flow analysis. Both the TEMT and current operations cases utilized identical input assumptions related to loads, generator costs and characteristics, and a base case power flow. The model included a representation of power system operations for most of the Eastern Interconnect, including 5,000 generating units, 40,000 transmission buses, and 50,000 transmission lines. It was used to project near term production costs and location-specific market clearing prices based on forecasts for 2005. The model calculates and can track location-specific, hourly prices for up to 8,000 specific locations.

Q. WHAT WERE THE PRIMARY FACTORS DISTINGUISHING THE TEMT AND CURRENT OPERATIONS MODEL RUNS?

A. The quantification of benefits is driven by two factors that distinguish the TEMT and current operations cases. First, in the current operations case, we represented the expected maximum utilization of monitored flowgates during periods of transmission congestion based on the historical average utilization of flowgates during TLR events. Second, we reflected appropriate tariff rates and the inherent inefficiencies of exclusive reliance on a bilateral market in hurdle rates that were applied to transactions between dispatch pools in the two cases.

Q. HOW DID YOU REFLECT EXPECTED MAXIMUM FLOWGATE UTILIZATION IN THE TWO CASES?

A. In the current operations case, the capacity of monitored flowgates in MAPP, WUMS, and the remainder of area modeled was derated based on our analysis showing under utilized capacity during TLR events for the MAPP footprint, the WUMS sub-region, and other Midwest ISO flowgates, respectively.[16]

Under the Midwest ISO's proposed TEMT, bids and offers will be accepted in real-time based on actual and post- contingency power flows. This will allow the Midwest ISO to match the resulting power flows over constrained flowgates to operating security limits. In the absence of a physical carve out, more precise management of power flows in the real-time market will permit the Midwest ISO to approach full utilization of available flowgate capacity. Thus, we did not derate the effectively available flowgate capacity in the TEMT case.

Q. HAVE YOU PERFORMED A SENSITIVITY ANALYSIS SHOWING THE EFFECTS OF A HIGHER LEVEL OF MAXIMUM AVAILABLE CAPACITY?

A. Yes. We ran a set of cases in which the 7.7% derate of flowgate capacity that was identified in the analysis of TLR events in portions of the Midwest ISO outside MAPP

[16] At the time we initiated PROMOD model runs, only the preliminary results from our analysis of flowgate utilization during TLRs were available. Our preliminary numbers of 17.4% unused capacity in the MAPP footprint and 11.05% for the WUMS sub-region varied from the final results for these areas of 16.4% in MAPP and 10.9% in WUMS. We would not expect this variation to have a substantial impact on the conclusions of our study.

and WUMS was applied to all flowgates outside of LMP markets. The results of those cases indicate that significantly reducing the derate of flowgate capacity in MAPP and WUMS resulted in a modest reduction in the benefits of LMP-based congestion management. From a market cost of power perspective, the congestion management benefit was lowered from $713.1 million per year with higher derate on maximum flowgate utilization to $559.2 million. And, from a cost of service perspective, the congestion management benefit was reduced from $255.3 million per year to $200.5 million.

Q. HOW DID YOU APPLY HURDLE RATES IN THE TWO CASES MODELED?

A. To take into account these market inefficiencies and prevent the model from relentlessly over optimizing transactions in comparison to actual bilateral market experience, hurdle rates were applied to transactions between dispatch pools. These hurdle rates may include two components:

- The incremental transmission charge associated with purchasing power from another area to serve load within the dispatch pool; and
- A transaction and opportunity cost component to reflect the inherent inefficiencies of relying on a bilateral market.

Q. HOW DID YOU SET THE TRANSMISSION CHARGE PORTION OF THE HURDLE RATE IN THE TWO CASES?

A. In both cases, the incremental tariff charge for transactions within the Midwest ISO was set to zero to reflect the ability of Load Serving Entities to use network integration service. Similarly, the tariff component was set to zero for transactions between the Midwest ISO and PJM, reflecting an elimination of through and out rates between the two RTOs. Applicable hourly non-firm point-to-point transmission charges for exports from the system on which the generation is located were applied to transfers between other entities.

Q. WHY IS IT APPROPRIATE TO ALSO INCLUDE A COMPONENT IN THE HURDLE RATE TO REFLECT TRANSACTION AND OPPORTUNITY COSTS?

A. In the absence of coordinated regional unit commitment and economic dispatch and transparent day ahead and real-time energy markets, individual market participants must engage in a sequence of bilateral transactions in an attempt to improve the economic utilization of their facilities.

Reliance on bilateral trading involves inherent inefficiencies:

- Current practices reflect a conservative bias, which may be appropriate given the lack of a liquid spot market, towards commitment of each utility's own generation to serve its native load.
- Existing scheduling procedures limit market participants to whole hour or longer transactions. By contrast, the Midwest ISO energy markets will be able to optimize the operation of generation across member utilities on at least a five-minute basis.
- Finding a cost-effective mix of purchases and sales requires bilateral negotiations with multiple other market participants. Such negotiations and the resulting transactions impose transaction costs related to the search for cost-effective transactions, contracting, scheduling, settlement, managing counter-party risk, and dispute resolution. These transaction costs are a direct cost to market participants.
- In such negotiations, each participant has an incentive to limit its disclosure to counter parties to capture as large a portion of the benefits from the transactions as

possible. Given imperfect information and a non-transparent market, identifying a cost-effective mix of transactions takes time and not all economic transactions will be discovered.

- Given a lack of transparency, price spreads will occur that do not reflect genuine differences in marginal costs. These spreads create misleading operating incentives that may fail to mitigate and in some cases exacerbate transmission congestion.
- Power markets are highly dynamic. Given the transaction costs and the time involved in completing bilateral transactions, the utilities' generation, purchases and sales are rarely optimized. This failure to optimize the operation of generation across entities imposes an opportunity cost on each utility and can significantly increase total generation costs.

Regional security-constrained economic dispatch under the proposed Midwest ISO TEMT will optimize resource utilization without market participants having to engage in serial short-term bilateral transactions. A liquid LMP market assures a load serving entity (or supplier) located inside that market that it can consistently purchase (or sell) real-time or day-ahead energy at the best competitive price bid (or offered) with respect to the location of its load (or generation). This is not true for the load serving entity (or generator) outside the boundary of the LMP market. For such a buyer (or seller), purchasing (or selling) at the boundary of the LMP market is only one of numerous alternatives for which it must forecast results and that it must evaluate in comparison to other potential bilateral deals. Thus, the load serving entity (or supplier) outside the boundaries of the LMP market still faces transaction costs and substantial opportunity costs associated with maintaining a sub-optimal mix of generation, purchases, and sales.

Q. HOW DID YOU SET THE TRANSACTION AND OPPORTUNITY COST COMPONENT OF THE HURDLE RATES IN THE TWO CASES?

A. The transaction and opportunity cost portion of the hurdle rate was generally set at $3/MWH for transactions between pools that were not part of the same day ahead and real-time regional energy market.[17] It was applied in the dispatch of generation. A separate hurdle rate was not applied to unit commitment, although the model does commit generation, in part, based on anticipated sales given the dispatch hurdle rate.

Q. ON WHAT BASIS DID YOU DETERMINE THAT THIS WAS AN APPROPRIATE HURDLE RATE?

A. Setting the hurdle rate at the applicable tariff charge plus $3 for transaction and opportunity cost for bilateral transactions provides a conservative estimate of the inherent barriers to transactions. Comparable studies have used higher hurdle rates to reflect such inefficiencies, see: Table 1. And, a review of transaction volumes in the model for current operations in comparison to historical transaction levels also suggests that this is a reasonable constraint for representing the bilateral market.

Table 1: Comparison of Hurdle Rates Applied to Transactions Not Within an RTO Market

Study	**Unit Commitment Hurdle Rate**	**Dispatch Hurdle Rate**
U. S. Dept. of Energy, *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market*	Between Control Areas: $10/MWH	Between Control Areas: $5/MWH + Tariff Charge

[17] To recognize the impact of American Transmission Company LLC ("ATC") redispatch procedures that affect some but not all TLR events, the hurdle rate within ATC was reduced to $2.50 / MWH in Case 2.

Design (April 30, 2003)		
CRA, *The Benefits and Costs of Dominion Virginia Power Joining PJM,* (June 25, 2003)	Between Control Areas: $10/MWH	$7/MWH for single control area to control area sale + $4/MWH for each additional control area to control area transfer
CRA, *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast* (November 6, 2002)	Between Control Areas: $10/MWH	$5/MWH + Tariff Charge
Midwest ISO – Current Study	**None**	**$3/MWH + Tariff Charge**

C. GFA Carve Out

Q. WHAT APPROACH DID YOU TAKE TO ANALYZE THE RELIABILITY AND ECONOMIC IMPACTS OF A CARVE OUT OF GFAs?

A. We approached the analysis in three steps. First, based on a review of the contracts, we identified key characteristics of outstanding GFAs. Second, we identified considerations which the Commission should take into account in deciding whether and how to carve out GFA transactions. And, finally, we developed a simplified illustrative case to show how these considerations might come into play in the Day 2 market.

Q. CAN YOU GENERALLY DESCRIBE THE OUTSTANDING GFAs THAT WILL AFFECT THE MIDWEST ISO'S ABILITY TO PERFORM SECURITY-CONSTRAINED UNIT COMMITMENT AND ECONOMIC DISPATCH?

A. GFAs, as defined in the TEMT, are agreements for transmission service that were entered into before September 16, 1998, and are listed in Attachment P to the Midwest ISO OATT. Given the historical nature of many of these contracts, it is not surprising that there is little consistency among GFA contract provisions. Specific details regarding usage, scheduling requirements and megawatt quantity or capacity often are not readily apparent on the face of some of the contracts. Through the Midwest ISO's review of these agreements it found that approximately 55 percent were geographically located in the western half of the Region, while 45 percent were geographically located in the eastern half of the Region. Furthermore, of the contracts reviewed, approximately half had a specific megawatt value associated with the contract, which, in the aggregate accounted for approximately 20,000 megawatts of capacity, with 55 percent of this capacity being located in the eastern half of the Region, while the remaining 45 percent of capacity was located within the western half of the Region.

Q. HAVE YOU ANALYZED THE TRANSMISSION REQUIREMENTS ASSOCIATED WITH THESE GFA CONTRACTS?

A. Yes. We identified and analyzed the terms of 323 current GFA agreements. And, based on the contract terms or being able to associate contracts with OASIS reservations, we were able to identify specific MW profiles associated with 146 of those contracts. It should be noted that where these profiles were derived from current OASIS reservations, the profile does not necessarily represent the maximum service entitlement under the contract. These specific MW profiles represent over 20,600 MW of transmission service requirements. The transmission service requirements associated with all GFAs using Midwest ISO operated transmission facilities could be as much as double the identified volume of transactions. We were unable to identify the MW profiles associated with the remaining 177 contracts. We believe many, if not all, of these remaining contracts may be associated with service that sources and sinks within a single control area and thus is not subject to Midwest ISO scheduling requirements.

Q. HAVE YOU ANALYZED THE SCHEDULING REQUIREMENTS CONTAINED IN THESE GFA CONTRACTS?

A. Yes. First, we examined the contracts for requirements related to scheduling and when service must be scheduled. Of the 323 contracts analyzed there were 26 which required the customer to schedule service on a day ahead or earlier basis. These contracts represent identified service profiles totaling an estimated 3,103 MW. An additional 4 contracts authorize the transmission service provider to schedule service. One of these four contracts is associated with an identified service profile of 22 MW. The remaining contracts representing nearly 85% of the MW service entitlements that we have been able to identify either do not address scheduling of service or provide customers the right to schedule transmission service without specifying an obligation to schedule service in advance.

Second, we also considered the extent to which contracts may not involve inter-control area transfers and in the absence of tariff requirements would not be required to schedule service with the Midwest ISO. It is reasonable to assume that many of the 177 contracts with which we have been unable to associate a transmission reservation may involve primarily intra-control area power transfers and for which reservations and scheduling with the Midwest ISO are not required. However, the Midwest ISO's information about the use of these contracts is necessarily limited. We identified an additional 17 GFA related reservations for 379 MW where the source and sink of the transaction appear to be within the same control area.

Q. WHAT CONSIDERATIONS SHOULD BE TAKEN INTO ACCOUNT IN EVALUATING THE CARVE OUT OF GFAs?

A. The Order of May 26th states that in this proceeding the Commission's "goal is to ensure that the GFAs are accommodated in the Midwest ISO's energy markets in a way that will not harm reliability or third parties, yet preserves the commercial bargain between the parties." Considerations that are relevant to achieving this goal include:

- What were the material commercial benefits of the bargain secured by these agreements?
- The transfer of responsibility for providing the transmission service from the transmission provider that was the original party to the GFA to the Midwest ISO could enhance the reliability and increase the value of the service provided given that the Midwest ISO will to redispatch regionally to avoid curtailments.
- Given transparent markets and limited definition of the entitlements under many of the GFAs, GFA holders may be able secure benefits that exceed those originally anticipated at the expense of third parties by engaging in transactions beyond what is required to serve the loads historically served under these contracts.
- When accounting for expected flows from GFAs, a financial or physical carve out of GFAs could limit the FTRs that may be available to third parties or necessitate an uplift that would have to be paid by third parties.
- A carve out applied to the day-ahead market could increase redispatch costs for third parties.
- A carve out that exempted GFAs from LMP-based charges – particularly given that they may continue to trade with third parties otherwise subject to market prices –

would create incentives for GFA holders to schedule in a manner that did not alleviate and in some cases increased transmission congestion in the day-ahead market, possibly increasing costs to others.

- A physical carve out of a large volume of GFA entitlements affecting constrained areas of the grid could force the Midwest ISO to rely more on TLRs to maintain power flows within operating security limits than if GFAs were requirement to meet TEMT physical scheduling requirements.
- Given the difficulty that the Midwest ISO will face in anticipating GFA generation if GFA holders are not subject to TEMT scheduling requirements or market based imbalance charges, a physical carve out could lead to an over commitment of generation increasing costs to third parties.
- Given that it will be extremely difficult for the Midwest ISO to accurately anticipate post-day ahead GFA schedules, prices in the day ahead market could diverge significantly from the real-time market, potentially threatening the liquidity in the day ahead market unless non-GFA parties were successful in arbitraging these divergences through virtual schedules. If they were not successful, significant disparities between the day-ahead and real-time markets could undermine reliability planning, economic unit commitment, the use of operating guides to improve system topology, demand-response programs, and the hedging value FTRs which settle in the day ahead market.

Given these and other considerations described in Dr. Hogan's testimony, a physical carve out in which GFA holders would not be required to schedule service on a day ahead basis or pay imbalance charges for schedules that differed from assumed levels is neither consistent with the Commission's stated goal nor a workable approach.

Q. IS IT FEASIBLE TO IMPLEMENT A PHYSICAL CARVE OUT APPROACH?

A. More simplistic notions of a physical carve out are not feasible. All schedules, whether GFA or non-GFA cause flows on the same grid, and all schedules and flows must be accounted for in arranging a security-constrained economic dispatch. In that sense, carving out only GFA flows and applying the dispatch only to non-GFA related flows is a non-starter and has no technically coherent meaning. Even if a physical carve out were defined in terms that made electrical sense, it is unlikely that the Midwest ISO would be able to implement such a physical carve out in time to meet the Commission's March 1, 2005, schedule for the start of the Day 2 market. While it is not well understood what all a "physical carve out" might require, we do not have time built into our existing schedule to make business process and system changes to accommodate this option. Moreover, even with unlimited time and expenditures, it is not clear whether the resulting market could function in a reasonable manner given the magnitude of the carve out that might be required.

Q. WERE YOU ABLE TO QUANTIFY THE IMPACTS OF A CARVE OUT GIVEN AVAILABLE DATA?

A. Given the limited information available at this point in the proceeding about GFA sources, sinks, and entitlements, it was not feasible to complete a detailed quantitative analysis of GFA impacts. However, we were able to prepare a simplified illustration of how such impacts could affect peak prices in the energy markets.

Q. PLEASE DESCRIBE HOW YOU PREPARED THAT ILLUSTRATION.

A. We prepared a simplified one-hour case focusing on the potential impact of GFAs that source in Wisconsin and surrounding MAPP control areas, sink in a control area different from their source, and have an identified MW profile. This illustrative case was developed in Power World's Simulator Optimal Power Flow model. The model is a power flow analysis tool that automatically identifies economically optimal redispatch in response to transmission constraints. It also calculates locational marginal prices associated with that dispatch. In this case, we simulated economically optimal power flows and calculated the resulting prices with and without a physical carve out for known GFA reservations.

The simulation was developed starting with a power system representation that incorporates transmission and generation improvements anticipated to be in place in 2005, forecasted loads for a July 2005 peak hour, a converged base case AC power flow, and generator cost functions taken from the production costing analysis described earlier in my testimony.

Given the function of this illustration and time constraints of this proceeding, the case incorporates conservative simplifying assumptions. First, we applied power flow limits and monitored 122 out of more than the 1,100 flowgates – potential transmission constraints – actually monitored by the Midwest ISO. Second, we increased the MW limit by 35 percent on the most constraining flowgate in the region (Cranberry Loop) to ensure that the model would solve with and without enforcing a set of GFA transactions. Third, we did not include in the model any hurdle rates or limits on transactions, effectively permitting generation throughout most of the eastern interconnect to be redispatched to the extent it might alleviate constraints. Fourth, as additional information becomes available, GFAs may be associated with specific points of receipt and delivery defined at a bus level. For most GFAs we did not have that level of detail available for this analysis and permitted all generators in the source control area to be economically dispatched to meet the GFA load.

Q. HOW WOULD YOU CHARACTERIZE THE TWO CASES YOU COMPARED FOR THIS ILLUSTRATION?

A. A central theme of those who argue for some type of carve out for GFA transactions is that the GFA parties wish to be left to meet the GFA loads essentially in the same manner as they always have, without reference to the Midwest ISO's regional economic dispatch, the day-ahead and real-time markets associated with that dispatch, the use of LMP for pricing imbalances and usage charges or the availability of FTRs. The first case is therefore constructed to simulate for the July peak hour what would happen to peak hour prices if the GFAs scheduled as they always have, without taking advantage of the Midwest ISO markets or being exposed to the LMP-based pricing incentives. The second case assumes that GFA parties were subject to the Midwest ISO regional economic dispatch, associated markets and associated price incentives. The idea is that faced with these incentives GFA suppliers and load would respond in an economically rational manner and, to the extent they could benefit from using those markets to meet the GFA loads, they would do so. A simple way to describe the difference is that in the one case, the GFA suppliers would self-schedule whatever local generation was available to serve the GFA loads without regard to the potential for more economic regional dispatch, whereas in the second case, the parties would take advantage of whatever economic benefits could be achieved from a regional economic dispatch.

Q. WHAT WERE THE RESULTS OF YOUR ILLUSTRATIVE ANALYSIS?

A. Despite the conservative simplifying assumptions we observed significant differences in average load zone prices for the July peak hour when we simulated physically accommodating known GFA reservations. The inclusion of a physical representation of known GFA reservations in the model increased transmission congestion and average prices in the Wisconsin Public Service load zone by 52.1% from $143.60 to $218.35 per MWH, for Wisconsin Power and Light by 20.9% from $133.15 to $161.02 per MWH, for Upper Peninsula Power by 11.2% from $138.65 to $154.18 per MWH, and for WE Energies by 5.1% from $133.86 to $140.73 per MWH. In the absence of our conservative simplifying assumptions the impacts of physically carving out these transactions might have been greater.

Q. WHAT DO THESE FINDINGS INDICATE ABOUT THE ECONOMIC RATIONALE FOR CARVING OUT THE GFAs AND LEAVING THEM OUTSIDE THE MARKETS?

A. The illustrative findings strongly suggest that carving out GFAs in a manner that avoids exposure of the GFA parties to the economic benefits of regional economic dispatch and LMP's efficient price incentives could significantly raise peak hour prices (and probably non-peak prices as well) for all parties in the region. The impact of these higher prices would be felt by both non-GFA and GFA parties alike. Non-GFA parties could face higher LMPs and possibly higher LMP-based transmission usage charges because with less generation available for dispatch, the marginal cost of redispatch would be high than it would be with greater participation by generators. The findings also suggest that a carve out would force GFA suppliers to incur higher costs in meeting their load obligations than they would incur if they participated in the regional dispatch. These represent lost opportunity costs to the suppliers and potentially lost opportunity costs to the GFA loads to the extent their contracts allowed them to capture some of the potential savings.

The effect on GFA loads is more complex. While the illustration suggests that the cost of serving load in the carve out case would be higher, the GFA loads would presumably continue to pay whatever their contracts provided. But it should not be assumed that GFAs would ignore the commercial opportunities available to them in the bilateral market, even though they chose not to participate in the Midwest ISO's spot markets. It would be rational to expect GFA loads to look for opportunities to sell unneeded power they purchased through the GFA at GFA prices and then resell that power to others at market-based prices, prices that would be somewhat inflated because of the absence of GFA suppliers from the regional economic dispatch.

Q. WHAT CONCLUSIONS ABOUT A PHYSICAL CARVE OUT CAN YOU DRAW FROM THIS ILLUSTRATIVE ANALYSIS?

A. First, a physical carve out may increase congestion, reduce economic efficiency, and increase costs. These increased costs are likely to be borne by third parties. Second, physical carve out can increase locational price differentials. This may provide GFA holders an incentive to schedule transactions for the purpose of increasing congestion so as to enhance their ability earn margins by selling lower cost power into congested areas without paying associated congestion costs. This could both impose costs on others and potentially make the power system less reliable. Third, given the difficulty that MISO may have in anticipating post-day ahead scheduling by GFA holders, a physical carve out, in which GFA holders are not required to schedule their transactions in advance or pay imbalance charges, has the potential to create a significant artificial divergence between day ahead and real-time prices. Consistent and significant price divergence has potential to undermine the value of the day-ahead market.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Q. DO YOU ATTEST THAT THE FOREGOING TESTIMONY IS TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE?

A. Yes.

AFFIDAVIT

County of ______________)
)
State of Indiana)

RONALD R. MCNAMARA, being duly sworn, deposes and states: that he prepared the Affidavit of Ronald R. McNamara and the statements contained therein are true and correct to the best of his knowledge and belief.

/s/ Ronald R. McNamara
Ronald R. McNamara

SUBSCRIBED AND SWORN BEFORE ME, this the 25th day of June, 2004.

/s/ Dorothy M. Shute
Notary Public

My Commission Expires: 05-08-09