Response of Midwest Independent System Operator, Inc. to Questions Regarding Security-Constrained Economic Dispatch

In its Order Convening Joint Boards Pursuant to Section 223 of the Federal Power Act issued on September 30, 2005 ("Order"), the Federal Energy Regulatory Commission ("FERC" or "Commission") announced the formation of several regional Joint Boards, composed of one or more Commission members and members of various state regulatory commissions, for the purpose of examining issues related to the merits of security-constrained economic dispatch ("SCED"). By e-mail of October 20, 2005, Commissioner Brownell, who is the assigned commissioner for the Midwest region Joint Board, forwarded five specific sets of questions for the parties to address.

In this Response, the Midwest ISO first defines what it understands to be the meaning of the terms "security-constrained economic dispatch." The Response describes differences in how SCED is used in Regional Transmission Organization ("RTO") versus non-RTO regions and how that relates to principles of open access transmission and the Federal Power Act's prohibition against undue discrimination and preference in the manner in which transmission services are provided. This Response also offers additional questions and responses that, in our view, focus more closely on why the topic of SCED is so relevant to other matters before the Commission. Finally, the Response provides answers to the specific questions asked by Commissioner Brownell.

A. What does "security-constrained economic dispatch" mean?

A security-constrained economic dispatch is a common, well-known tool, almost universally used by system operators in all modern electricity systems. SCED has been used by utility system operators for decades; it is not something that arose as a result of "restructuring," nor did it arise as the result of the creation of RTOs or Independent System Operators ("ISOs"). SCED is a tool that is essential for ensuring reliable operations in *any* system with multiple generators and a network of interconnected transmission and distribution facilities.

As this term is used throughout the industry, and applied at the Midwest ISO, the "dispatch" is the set of procedures the system operator uses to instruct generators as to when and how much energy to inject at their respective locations. (The dispatch may also include instructions to specific "loads" (i.e., energy consumers) that have the ability to adjust their energy withdrawals from the grid in direct response to the system operator's dispatch instructions.) For most system operators, including the Midwest ISO, these dispatch instructions are given to generators every five minutes, although there are still some system operators that use a somewhat longer dispatch interval. In each dispatch interval, the system operator gives those generators subject to the dispatch specific instructions regarding the need to increase or decrease energy output from their respective units. These instructions change dynamically as the need for energy output varies throughout the hour and day. In the Midwest ISO, generators may "self schedule" in order to limit dispatch flexibility or account for limited dispatch ability, such as that of a nuclear power plant. Self-scheduling allows the generator to provide a specified output to the system operator at which the generator will operate. This self-scheduled output is accepted as a given, and the dispatch takes into account these fixed generation resource schedules when providing the dispatch signal to other participating generators.

The performance of a security constrained economic dispatch is often considered one of the most important functions performed by *all* system operators, whether the system operators work for a vertically integrated private utility; a public, municipal or state owned utility; or an RTO/ISO, such as the Midwest ISO, PJM, ISO-New England and New York ISO. The manner in which the system operator dispatches generators ensures that the grid is operated safely and reliably. Hence, an important starting point is to clarify that the dispatch is an *essential* reliability function; it is not an option or a policy choice. *Every modern electricity system maintains reliable operations through its dispatch*.

To ensure reliable operations, the dispatch must be "security-constrained." There are several aspects to this requirement:

- First, the dispatch must keep the system in "balance." To maintain constant frequency (at 60 Hertz), the total amount of energy injected by generators onto the grid at each moment must exactly equal the total amount of energy being withdrawn from the grid by loads (consumers), plus any energy lost through the dissipation of heat during transmission and distribution. If too little energy is injected to maintain this balance, the frequency falls, with the potential to damage energy-using appliances; if too much energy is injected, the frequency rises, which can also cause damage.[1] The dispatch is thus the principal means by which the system operator provides "balancing," which is essential for safe and reliable operations. In other words, any party using the grid can obtain balancing services by gaining access to the system operator's dispatch. *In an RTO market setting, the RTO/ISO dispatch is also the means by which the RTO provides the "balancing market" required by Order 2000. System balancing occurs through the system operator's dispatch, and not through some other separate mechanism performed by some other entity.* Unfortunately, the Open Access Tariff rules of Order 888 permit non-RTO system operators to restrict access to the dispatch/balancing service. In non-RTO systems, the balancing service that all transactions need is constrained through narrow error bands and by charging uneconomic penalties for imbalances that exceed these error bands.

[1] In maintaining this balance, the system operators must also adjust the dispatch to ensure that the right amount of voltage support is being provided to maintain appropriate voltage levels, also essential for safe and reliable operations. This involves a tradeoff between the amount of "real" energy produced by generators and the amount of 'reactive" power produced. The dispatch is used to achieve a correct balance that both maintains steady frequency and sufficient voltage.

- Second, the dispatch must be arranged such that the flows across each and every element of the grid stay within (and do not exceed for any significant period) the safe and reliable operating limits specified for each element. If the system operators allowed the flows across any grid element to exceed its safe and reliable operating limits, that element could fail; depending on how serious the failure or how critical the element, the failure could jeopardize reliability across the grid and in the extreme, result in widespread system blackouts, as occurred in August 2003.

- In arranging a security-constrained dispatch, it is not enough to simply balance the system in the aggregate. The location of injections relative to loads directly determines the flows across each element of the grid; if the system operator changes the dispatch (the amount of energy injected at each location), it changes the flows. So a security-constrained dispatch is a dispatch in which the choice of which generators to dispatch (and how much) at each location results in energy flows that do not exceed the safe and reliable operating limits of any grid element.

- A security-constrained dispatch must also account for contingencies, such as unexpected line or generator failures, that could undermine reliable operations. When a contingency occurs, the electricity flows will immediately readjust to flow along all remaining paths, likely increasing the flows on some paths that might otherwise have been operating close to their safe and reliable operating limits. If a contingency is serious enough, a system operator might not have enough time to change the dispatch after the fact before the entire system would collapse. Cascading blackouts might then occur. For these very serious types of contingencies, a security-constrained dispatch must anticipate the contingency and take its effects into account to arrange the dispatch *before* the fact, so that even if the contingency occurred, and the flows redistributed, the system would still operate within safe and reliable operating limits.

- When flows actually exceed, or threaten to exceed (as in a contingency), any reliability operating limits, the system operator must quickly change the dispatch, so that the resulting flows will remain within safe operating limits. For example, "congestion" is a condition under which expected or actual flows across one or more grid elements would exceed their safe and reliable operating limits. To relieve congestion, the system operator must reduce the flows across that element, which it can do by changing the dispatch. Changing the dispatch is therefore a primary means for managing congestion. That is, the system operator can decrease the dispatch from one or more generating units whose injections are contributing to the excessive flows, while it simultaneously increases the dispatch from one or more other units that do not contribute to the excessive flows. The offsetting increases and decreases in injections at different locations keep the system in balance, while relieving the congestion. This is sometimes called "congestion redispatch," although it is not a two-step process. A security-constrained dispatch will arrange the dispatch so as to avoid congestion from overloading any transmission elements in the first place. In the Midwest ISO, this "congestion redispatch" takes place through the real-time energy market, therefore satisfying the requirement for a "market based mechanism for managing congestion" detailed in Order 2000.

- In a regional security constrained dispatch setting such as that provided by the Midwest ISO and other RTO/ISOs, a key element of the security constrained dispatch function is the internalization of loop flows. Given that electricity follows over the path of least resistance, flows on an integrated system do not stop at control area boundaries and may impact a neighboring system in a way that exceeds security limits. These flows are often referred to as "loop flows." Prior to a regional dispatch in the Midwest ISO, loop flows were managed among neighboring system operators through the use of transmission line loading relief ("TLR"). The implementation of a regional security constrained dispatch manages what were once loop flows among neighboring system operators through dispatch over a wider region, therefore reducing the amount of megawatts that must be curtailed by the less efficient TLR process.

- As a result of the regional approach to managing energy flows employed by RTOs, the tools that are used to provide the dispatch signals in light of possible contingencies and the need to manage congestion are more robust and detailed than those of stand-alone system operators. This is, in part, because of the cost associated with the development and duplication of such tools in neighboring areas and the availability of system operations data on a regional, rather than a local basis.

It is important to note here that using the dispatch to change the flows is the industry's preferred method to relieve congestion, even in non-RTO systems. It is preferred because it is the fastest (the dispatch is adjusted every five minutes) and most reliable (the generators tend to follow the system operator's dispatch instructions) means to get flows back within security limits. It is also the most precise means to relieve congestion, in that it changes the dispatch just enough to keep flows within the safe operating limits, but does not over-correct. An over correction would leave the grid underutilized and raise the cost of serving loads. This point is important for understanding why a regional dispatch operated by an RTO can achieve significant savings by allowing the grid to be more fully utilized, as is discussed further below. However, in non-RTO systems, this preferred approach is *only available for some users* (usually the local utility dispatcher's own generators when serving its own loads), but *it is not generally available to third parties* who may wish to use the same grid. Understanding how these third parties are treated is a key to understanding the main differences between RTO and non-RTO systems and how the Order 888 OATT permits this distinction.

In any system, flows across a congested line can be reduced by denying other parties the right to use the grid. If no one can use the grid, the grid would never be congested. This can be accomplished by simply declaring that there is no "available transmission capacity" ("ATC") left, given how the utility is using the grid to serve it's own customers. This allows the transmission owner (and its system operators) to deny further requests for transmission use to third parties. However, the Commission's "open access" rules seem to imply a national policy to provide open, non-discriminatory access to the nation's transmission grid.[2]

A further problem in the way Order 888 relates to the dispatch is the provision that allows non-RTO systems to schedule transactions using the "contract path" approach. Under the Commission's "contract path" scheduling approach, transmission uses are often reserved across specific paths, as though the flows only traveled across that path. In reality, electricity flows will travel across all possible paths with the distribution of flows along each path inversely related to the impedance (resistance to flows) of each path. Thus, even though a transmission schedule may not violate safe operating limits on the reserved "contract path," the actual flows can violate transmission constraints and cause congestion on other lines and systems. When this happens, another approach to relieve congestion is to simply curtail other parties' scheduled transactions after the fact, in reverse order of the "priority" of these transactions (i.e., from "non-firm" to "firm"). That is, a system operator can reduce the flows across a congested line in its dispatch area if it can order some users who have scheduled transactions on the system to get off. This curtailment system is called "TLR" for Transmission Line Loading Relief. TLR includes a set of rules developed by the North American Electric Reliability Council. The TLR rules allow a system operator (or its regional Reliability Coordinator) to require that other parties get off the system by ceasing to make injections at certain locations, when those injections and related grid uses are having a significant effect (greater that 5 percent) on the flows across a constrained grid element. When TLR curtailments are ordered, the affected system operator does not have to change its own dispatch to relieve the congestion; instead it counts on other users to get off or curtail the amount of their injections.

In contrast, RTOs offer "redispatch" to all grid users under identical terms for all. When congestion might otherwise arise because of the combined uses of the grid, the RTO will arrange its dispatch so that all proposed uses are accommodated and the resulting flows are still within the safe and reliable operating limits for every grid element. Hence, a primary difference between RTOs and non-RTOs in the use of

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[2] It is well understood in the industry that the concept of "available transmission capacity" (ATC) is deeply flawed, because one cannot determine the available capacity on any element without knowing how the system as a whole is used. Yet the dispatch determines how the system is used and determines the flows on each element and hence, whether there is any ATC "left," *in the absence of any further changes in the dispatch* (redispatch). But of course, if the dispatch is changed (via redispatch to relieve congestion), then the ATC that is "left" changes too. Calculating ATC in the abstract is thus meaningless; it is relevant only if the rule is, "we won't redispatch our system to accommodate your transaction. We'll just say 'No' to further requests for transmission service." If the ATC approach is used, it is not clear how the national policy can be achieved, even if the determination of ATC is performed by a completely independent, unbiased entity, such as an Independent Coordinator of Transmission (ICT). The current focus on unbiased ATC and other determinations by ICTs is a diversion from what is really important if the nation is to take open access seriously; the key questions are: *who controls the dispatch*, and is the dispatch equally available for balancing and congestion relief for all who wish to use the grid? When an RTO controls the dispatch, the answer is always "Yes."

security-constrained dispatch is that the RTO will *always* use the security-constrained dispatch to accommodate transactions in lieu of ordering users to get off the system via TLR curtailments, whereas non-RTO system operators seldom provide this service to accommodate transactions unless the grid users have already purchased firm transmission.

A principal reason why non-RTO system operators do not typically provide this "redispatch" service is that redispatching to relieve congestion raises the system operator's dispatch costs. To reduce flows across a constrained element, one or more higher cost units must be constrained on, while one or more lower cost units must be constrained off; the net effect is to raise costs. If these costs are not recovered from those who use the system, the system operator's utility loses money unless the costs are recovered from the utility's ratepayers. In contrast, in RTO systems, the system operators charge each grid user the marginal cost of the redispatch needed to accommodate each transaction. The marginal cost of redispatch is defined by locational marginal pricing ("LMP"). Under this system, the LMP at the point of withdrawal (sink) minus the LMP at the point of injection (source) is the marginal cost of whatever redispatch the RTO performed to keep total flows within safe operating limits. Each grid user pays the marginal costs it imposes on the system from its own grid use. An RTO can offer this service because it is fully paid for by the users or the grid and, therefore, does not result in shifting costs caused by certain users onto a local utility's rate payers or other users who did not contribute to the congestion.

B. Almost all system operators use "economic" dispatch

In addition to ensuring that the dispatch is "security-constrained," virtually all system operators also attempt to arrange and implement an "economic" dispatch. This is a common sense approach, because it would not make sense to arrange a dispatch that was "uneconomic" – that is, a dispatch that costs more than it should to maintain safe and reliable operations. An economic dispatch is simply one in which the system operator has selected the generators to dispatch in some economic "merit order" based primarily on the incremental costs of dispatching each unit at each level of output. Each plant has various cost characteristics for each level of output, based on fuel costs, heat rates and other variable costs of operations. In general, the system operator will attempt to dispatch the units with the lowest operating costs first, and then successively dispatch higher cost units as they are needed to balance the system and relieve transmission constraints. In an economic dispatch, the cheapest plants are dispatched first, more expensive plants are dispatched next, and the most expensive plants are dispatched last and only if needed to balance the system and meet security requirements.

The Midwest ISO is not aware of any credible debate among system operators regarding the merits of economic dispatch. Virtually all system operators pursue some form of economic dispatch, to the extent practical. While it is sometimes difficult to discern the most economic dispatch, because there are multiple economic factors and operational constraints that have to be considered when deciding which plants to dispatch, it is important that all responsible system operators agree on the need to pursue economic dispatch.

In recent weeks, there has been some discussion about whether the dispatch should be "economic" or whether it should be "efficient." This appears to be a false debate, a red herring based on some unknown confusion. An economic dispatch is an efficient dispatch. An economic dispatch will take into consideration all of the economic and operational factors that affect whether it is more economic to dispatch unit A before unit B or before unit C. In general, a system operator would not consider only a single factor, such as the heat rate of the units, and determine economic dispatch from that factor alone. As between any two units, it is more economic to dispatch a unit with a more efficient heat rate than a unit with a less efficient heat rate, *all other factors being equal*, but all other factors are often not equal. When all economic and operational factors are considered, the unit with the less efficient heat rate may be more or less economic to dispatch at a given moment because of these other factors.

It is possible that the confusion over "economic" versus "efficient" dispatch is a proxy for a different issue: whether a third party has fair access to a utility system operator's dispatch. If an independent power producer has a very efficient gas unit, and that unit is not allowed access to a utility's dispatch, even though the utility dispatches its own gas units with higher (worse) heat rates, and there is no other economic justification for that dispatch choice, then this issue is about discrimination and lack of open access to the dispatch. It is not about "efficient" versus "economic."

This issue can arise in non-RTO regions if the utility system operators have reasons to prefer their own units to units owned by third parties. The issue does not arise in established RTOs, such as the Midwest ISO. In RTOs, the dispatch is open to all generators on a non-discriminatory basis. The dispatch is economic, in that it selects the lowest cost, security-constrained dispatch in each five-minute dispatch interval, given the offers submitted by all the generators, and irrespective of who owns the generation. The "economic" aspects of each unit are defined by the offer prices and operating characteristics of each unit. A third party generation owner and a utility generation owner both submit their offers to the ISO/RTO using the same format and submit them at the same times under the same procedures, and the RTO/ISO dispatcher evaluates all offers on the same basis. Given this fair and open process there is no discrimination; whereas, in a non-ISO/RTO setting, the potential for discrimination may still exist.

C. What additional questions might the Commission ask relating to SCED?

The questions posed by the Commission appear to be asking whether security-constrained economic dispatch is a good idea. Does it benefit consumers? Does it improve reliability? If taken literally, these questions are easily answered. As explained above, the dispatch is an essential tool for ensuring the reliability of the system and keeping the lights on. The dispatch must be "security-constrained," in order to ensure reliable operations. The dispatch should also be economic, because it would be costly and inefficient to arrange and implement an “uneconomic” dispatch. Virtually all modern electricity systems use a form of security-constrained economic dispatch.

So what policy questions are raised that relate to the topic of SCED? The Midwest ISO believes other appropriate questions would include:

1. Should the dispatch be done on a larger, regional basis, as in the case of RTOs, or is it sufficient to continue to rely on local utility area dispatches? The Midwest ISO believes that regional dispatch provides substantial economic and reliability benefits over local dispatches. The economic benefits of regional SCED occur in the following ways:

    a. A local dispatch must rely primarily on the mix of generation available to the local utility to balance its part of the system. A regional dispatch can more readily use lower-cost units from another area in lieu of higher cost local units, to balance the system.

    b. A local dispatch must rely primarily on the same local mix of generation to “redispatch” to relieve congestion. From a regional perspective, a more cost-effective redispatch of generation to relieve congestion can often be achieved by redispatching units in different areas. A regional dispatch allows the system operator to achieve the lowest cost redispatch available across the region.

    c. The typical absence of congestion redispatch service from local, non-RTO system operators means that congestion caused by network flows must often be managed through involuntary TLR curtailments. Such curtailments are imprecise, so to ensure that flows are brought within safe operating limits, security coordinators tend to curtail too much. The result is that key transmission elements are left under-utilized. When that occurs, it means that too much higher cost generation is being used and too little lower-cost generation is used, with the net result being higher costs. In contrast, RTOs offer redispatch service in lieu of TLR curtailments. Redispatch allows the affected transmission elements to be used to the full extent of the capacity – that is, right up to the level of safe operations. This means that the dispatch can be optimized, using only as much higher cost generation as needed, and maximizing the use of lower-cost generation. In short, the RTO congestion redispatch service lowers total costs compared to reliance on TLR curtailments.

See Appendix A for a quantification of these economic benefits associated with regional dispatch.

2. Should the dispatch be open to all generators and load-serving entities on the same basis, so that any generator or load-serving entity can get open access to the

system operator's balancing services, as is true in RTOs? The Midwest ISO believes the answer should be an unqualified "Yes." Conversely, is it acceptable for a non-RTO dispatch to provide unlimited balancing to the utility's own generators when serving their own loads, while restricting and/or penalizing access to balancing for other parties? The Midwest ISO believes that where non-RTO system operators restrict access to the dispatch, they cannot claim to provide open access to transmission. Instead, the restrictions serve as barriers to trade that can raise the costs of serving consumers.

3. Should the system operator be required to offer redispatch service to relieve congestion and accommodate third party transactions in lieu of TLR curtailments, as is true in RTOs; or, is it acceptable for a non-RTO system operator to deny or restrict this service to third parties while providing it for the utility's own generators? The Midwest ISO believes that access to this redispatch service is essential for both economic commercial trading and enhanced regional reliability. Given the various problems and inefficiencies associated with TLRs, it should no longer be acceptable, at least in the highly networked Eastern Interconnection, to rely on "contract path" scheduling and TLR curtailments as the primary mechanism to keep flows within safe and reliable operating limits.

4. Since the marginal cost of providing balancing and redispatch service is defined by LMP, and LMP is used by all approved and operating RTOs, is it acceptable for non-RTO system operators to use some other pricing method to charge for balancing and redispatch? Aren't other pricing mechanisms "not economic" by definition? Given the problems that have been encountered in other regions that tried non-LMP pricing methods (e.g., California to date, New England prior to 2001, PJM prior to 1998), what other pricing system would be economically justified? Do these mechanisms discriminate or provide preferential treatment and/or result in cost shifts between grid users? Given that non-LMP prices are, by definition, inconsistent with a security-constrained dispatch, how can these other pricing mechanism support reliable operations?

D. Responses to the Commission's Questions

1. What are the benefits and costs of SCED, compared to the previous system used for dispatch, or to other potential alternatives? What specific benefits has SCED offered? Can you quantify these benefits, and if so, please do so.

Response: As explained above, SCED has always been the necessary tool for ensuring reliable operations in modern systems. Given that most system operators employ some form of SCED, whether locally or regionally, there is no comparison to be made with any "previous system." More relevant comparisons might be between RTO regional dispatch versus local dispatches and between a system that offers redispatch service to all users versus one that relies more on TLR curtailments to manage congestion. Appendix A provides a summary of the results of quantitative studies comparing RTO operations in the Midwest ISO footprint versus local dispatch operations prior to April 1, 2005.

> *2. What lessons did you learn in implementing SCED? In particular, were there unanticipated benefits or costs that should be kept in mind when considering changes or improvements to the current SCED?*

Response: Before the Midwest ISO began implementing a regional dispatch within its footprint, some observers may have assumed that it would be unlikely that the Midwest ISO dispatchers could do as good a job of dispatching local utility plants as the utility's own dispatchers had done in the past. However, results to date suggest that, after initial start-up issues were resolved, the Midwest ISO dispatchers are now doing at least as good a job as before, and in some cases better. This has surprised some observers, but not those who have seen similar experiences in other RTOs. Because the dispatch is now arranged on regional basis, local plants are sometimes dispatched differently than they were before. For example, lower-cost units elsewhere may be more often dispatched than local higher-cost units, to lower total dispatch costs. Moreover, local plants may be dispatched differently now because the RTO provides a congestion redispatch service for all users, whereas before the local dispatch relied on external TLR curtailments to relieve some congestion. The overall effect has been to improve the dispatch on a regional basis.

> *3. How does the operation of SCED relate to the operation of the regional market? How would a market operate in your region without SCED?*

Response: The RTO's regional spot market arises directly from the RTO's regional dispatch. The spot market is the process by which generators offer their output to the RTO system operators for dispatch and are paid the market-clearing prices for their output into that dispatch. Loads pay the spot prices for any energy they purchase from the spot market – that is, for any energy provided by the dispatch and not through fixed bilateral or self schedules. The spot prices (LMP) at each location also flow directly from the regional dispatch; that is, the spot prices are the marginal costs of serving an increment of load at each location, given the security-constrained dispatch and the generator offers (and load bids). Moreover, the spot prices are consistent with the security-constrained economic dispatch in each dispatch interval. This means that the spot prices each generator receives at its location provide the correct incentives to the generator to follow dispatch instructions – that is, to take the actions the system operator needs each unit to take to ensure reliable operations. Hence, the security-constrained dispatch that provides reliable operation of the grid and the spot market and prices that flow from this dispatch, are inextricably linked and support each other.

The RTO spot markets could not function without these links to the RTO's SCED.

4. What effect has SCED had on the reliability of the electric system in your region? Can you quantify the effect, and if so, please do so.

Response: Without SCED, the lights would go out, under any system. However, reliability can be enhanced if the dispatch is (1) regional, (2) open to all generators, and (3) efficiently priced so that spot prices are consistent with the SCED. Because it monitors a much larger footprint than a local dispatch, an RTO can monitor problems across the interconnection that can affect reliable operations within its footprint. If the dispatch is regional, the SCED can be used quickly (every five minutes) to solve grid problems that arise in one area before they become wide-area problems. This advantage is probably impossible to quantify. One can get a rough idea by looking at the costs of wide-area cascading blackouts, such as the one that occurred in August 2003. A regional monitoring system coupled with a regional SCED can reduce the likelihood of such events.

In addition, there has been a substantial reduction in the number of megawatts curtailed by TLRs called in the Midwest ISO region. Indeed, congestion redispatch has virtually eliminated curtailed megawatts from TLRs within the footprint, while the dispatch coordination between PJM and Midwest ISO has reduced curtailed megawatts from TLRs between the two RTOs.

The implementation of a regional SCED in the Midwest ISO has also led to the development of detailed coordination or "seams" agreements between the Midwest ISO and its neighboring entities. These agreements have a positive impact on the coordination of the interconnected grid and management of power flows across the region.

5. What effect has SCED had on the cost of electric energy in your region, after adjusting for input costs such as fuel? Can you quantify the effect, and if so, please do so.

Response: The cost of energy in any region is mostly a function of the costs of generation, the resource/fuel mix, and the costs of fuel in that region. However, a SCED will seek to minimize these costs of serving load in any region. If the SCED is regional, the cost-minimization will apply across the region and provide additional savings compared to isolated local dispatches.

Our quantitative analysis assumes a comparison between a regional dispatch with an open spot market and congestion redispatch service available to all users, versus the collection of local dispatches with no transparent spot markets and greater reliance on TLR curtailments. The results are presented in Appendix A.