Efficient implementation of inter-regional transactions

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Abstract—

In this paper we describe the provision of transmission in the multiple regional setting. In each region it is assumed that a separate market structure and tariff system exist.

It is shown that the new structure is essential for fostering the operation and planning of the interconnected electric power network while ensuring reliability.

Keywords—

open access interregional transactions, reliability, tie-line flow control, markets.

I. Introduction

The North American Electric Reliability Council (NERC) was established following the systemwide blackouts on November 9, 1965 to promote the reliability of the electricity supply and prevent the recurrence of such a blackout [1]. The NERC regions comprise ten administrative areas, made up of over 100 regional control areas.

Several publications focus *de facto* on the role of the transmission provider (TP) in a single regional control area *isolated* from other control areas. The TP is assumed to have the sole operational authority of a control area and to alone be responsible for short term reliability. The TP conducts numerous off-line reliability studies so that the probability of network failure is below the acceptable limit. Based on the reliability studies the TP decides on the adequate level of interconnected operations services (IOS) required by the regional network [2].[1] The task of determining the adequate level of IOS and subsequently the task of accurately assessing the area-wide uncertainties are quite arduous and, at the same time, are very important for reliability as well as for efficiency. An underestimation jeopardizes the reliability of the network, while excessive levels results in inefficient operation of the network. The task is even more difficult when there are interconnections among neighboring control areas and transactions taking place across several market boundaries encompassing multiple control areas. This paper describes the market mechanisms necessary for implementing inter-regional transactions while maintaining a high level of reliability and efficiency.

Examples of practical problems that this mechanism could be used to address are: (1)The 1200MW limit to imports on a DC line from Canada to New England, due to potential problems in PJM; and (2) Certain (impractical) limits such as those imposed by the transmission line in Northwest Wisconsin and the transformer as described in [13].

[1] Specifically we are interested in the stand-by reserves in this paper.

We first describe the advantages and disadvantages of having the interconnections with neighboring control areas. Then, we describe the newly proposed market mechanisms (and transmission provision) for implementing inter-regional transactions. The proposed mechanisms are then contrasted to the methods under the vertically integrated utility scheme and under the present restructuring process. Finally, the mechanisms are compared to the other methods recently proposed in the industry.

II. Objective of interconnections with neighboring control areas; advantages and disadvantages

Interconnections between neighboring control areas improve both reliability and efficiency. This is achieved through the sharing of IOS and the cost savings in generation.

Consider the 5-bus electric power network as shown in Figure 1. The network is composed of two regions con-

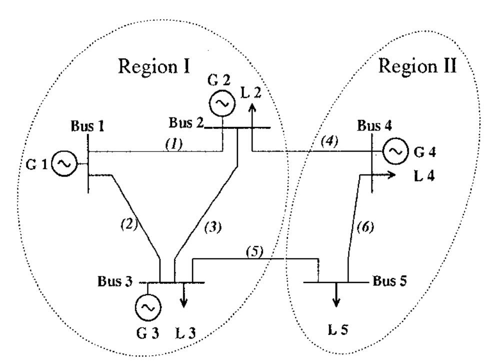

Fig. 1. One-line diagram of 5-bus electric power network

nected with two tie-lines, i.e., lines 4 and 5. The dispatch schedule is as shown in Table I.

The charateristics of the generators are as shown in Table II.

Suppose the demand at bus 3 suddenly increases from 157.25MW to 207.25MW, deviating from the anticipated when scheduling dispatch. If region I is isolated from region II then, the area-wide frequency in region I initially drops by 2×10^{-3}Hz following the sudden load increase, before being corrected to the level before the load increase through AGC [2].

Generation at bus #	1	2	3	4
Output (MW)	77.25	100	0	100

Demand at bus #	2	3	4	5
Demand (MW)	0	157.25	0	120

TABLE I

NOMINAL DISPATCH SCHEDULE FOR THE 5-BUS ELECTRIC POWER NETWORK AT HOUR k

Generator	Droop	D
1	5 percent	5
2	5 percent	4
3	5 percent	4

TABLE II

GENERATOR DROOP AND DAMPING COEFFICIENT (D)

If region I is interconnected with region II, the same unanticipated load increase in region I affects the network-wide frequency, instead of only the area-wide frequency. The network-wide frequency initially drops by 1.8×10^{-3}Hz. The temporary deviation in frequency is smaller (by about 2×10^{-4}Hz or about 11%) when regions I and II are interconnected. This is due to the higher inertia carried within the interconnected network than in the isolated system, and also because the recovery of the frequency is shared among more generators.

In case of more severe deviations from nominal operating conditions such as equipment outages, sharing of IOS becomes even more significant. For instance, suppose that each generator within the network has 10% probability of failure while being dispatched equally at 50MW. Further suppose that in region I there are five generation units while in region II there are two generation units all together. If the reliability criterion specifies that no loss of load should occur at least for 85% of any operating conditions during an outage of at most one generation unit, then the isolated regions I and II are each required to have an additional 50MW of stand-by generation (a total of 100MW network-wide). With 50MW stand-by generation each, region I is fully operational 91.85%, i.e.,

$$0.9185 = 0.9^5 + \begin{pmatrix} 5 \\ 1 \end{pmatrix} 0.1 \cdot 0.9^4 \qquad (1)$$

and similarly, region II is 99.00%.

Without the stand-by generation the values are 59.05% for region I and 81.00% for region II. For the interconnected network of regions I and II, however, a total of 50MW stand-by between the regions is necessary in order to meet this particular reliability criterion, the value in the case being 85.03%. The savings from requiring only 50MW of stand-by generation, or reserves [2], may be tremendous when compared to that of 100MW.

Beside the savings from sharing the IOS through the interconnected network, additional savings may be possible if the control areas linked through the tie-lines are significantly different in terms of the cost of available generation resources. In that situation, power can be imported from the lower cost to the expensive region. Consider the load in Table I and the supply functions in Figure 2. If the two regions are isolated, total generation cost is $15,588.57 (1,348.57 in region I and 10,240.00 in region II). If they are in the same market the corresponding figure is $8,182.10 (5,491.02 in region I and 2,691.08 in region II).

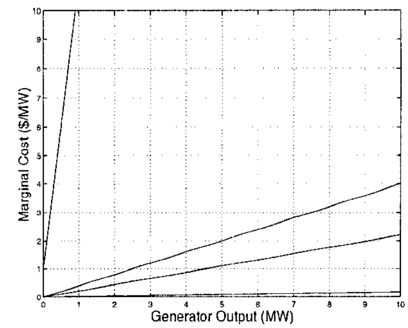

Fig. 2. The supply functions at buses 1, 2, 3 and 4 based on the individual marginal costs of the generation units

The latter assumes that the transmission charge levied on the market participants are only the congestion price without any additional costs such as *ex ante* flow tax. Given that there typically exist transmission charges other than the congestion price and that the market mechanisms vary from one region to another based on the regional characteristics, however, it is neither likely feasible nor necessarily optimal. Nevertheless, comparing the total costs of generation, it is plausible to expect some savings if the control areas linked through the tie-lines are significantly different in terms of the cost of available generation resources.

The disadvantages of the interconnection are mainly related to the reduced reliability resulting from the impact that external disturbances have on the region. Of particular significance are loop flows[2]. We identify two kinds of loop flow.

The first is related to the inability of the market participants to control the transmission path. If two (neighboring) regions schedule an interchange, the power flows will affect other regions within the interconnection, but not involved in the transaction. The second is related to the inability of each individual TP to control the transmission path. If two neighboring regions conduct their markets separately, in such a way that each meets its demand and there is no transaction between the regions, power still flows on the tie-lines because the regions are connected.

Since no single TP has complete control over the flows throughout the interconnected network as demonstrated through the loop flow of second type, in order to avoid serious breach in the reliability, the systemwide coordination

[2]The so-called loop flow refers to the effect of electricity flowing not according to the possibly contracted transmission path (based on the corresponding energy contract) but rather according to the physical law [3]

becomes necessary in an interconnected network of many control areas. Moreover, if we revisit the earlier example on increased reliability through the sharing of IOS, the need for systemwide coordination and strict tie-line flow control becomes even clearer.

The unanticipated load increase in region I also affects region II when the two regions are interconnected. Even though the deviation in frequency in region II is not as severe as in region I, the effect is still felt.

There may be network-related controllers that react to the deviation in frequency. These are tuned for certain operating conditions. If the post-disturbance conditions are different from the initial, these controllers may not operate properly when the next disturbance occurs. It is not easy to tune the controller for the new operating conditions since the change in system conditions is entirely external. The only way to ensure the proper functioning of the network related controllers in region II, therefore, is to restore the tie-line flows back to pre-disturbance levels.

Further, if the disturbance described above occurs, and the generators in region II react to the deviation in frequency by increasing their generation, instead of the network related controllers, at the time of electricity scarcity, there is also significant economic consequences in terms of "stealing electric power" as explained in [4].

Therefore, an argument may be made that the major concerns about operating interconnection under open access are the reduced reliability through the loop flow due to the separate operation of individual regions as well as due to the inter-regional transactions.

Given the advantages and the disadvantages of interconnected network described above, the market mechanisms necessary for implementing the inter-regional transactions must have the following characteristics:

- They should maximize the improvement in reliability and in efficiency realized through sharing of IOS
- They should maximize the further increase in efficiency realized through the cost savings in generation
- They must include the regional characteristics in providing transmission when determining the optimal transactions
- They should minimize the effect of loop flow of first and second types through the systemwide coordination and strict tie-line flow control

III. Market mechanisms for implementing the inter-regional transactions as proposed in U.S. patent filed by Ilić and Yoon (2000) [3]

The market mechanisms for implementing the inter-regional transactions as proposed in the patent are composed of two parts, the auction mechanisms and the control mechanisms. The auction mechanisms are designed such that the inter-regional transactions, as reflected in the tie-line flows, maximize the improvements in reliability and in efficiency through sharing of IOS and, at the same time, maximize the benefit achieved through the cost savings in generation while reflecting the appropriate regional characteristics in transmission provision by each control area. The control mechanisms minimizes the effect of loop flows. Here we give a brief description and illustrate the proposed market mechanisms through a simple example. Refer to the patent for a detailed description of the algorithm.

The main driver of the auction process is the so-called inter-regional transmission organization (IRTO) [4]. Under the proposed market mechanism in the patent the IRTO is a for-profit entity created solely to support the inter-regional transactions.

Consider the 5-bus electric power network example presented in Figure 1 The tie-line flow schedules are assumed to be adjusted no more than once a day. For simplicity without loss of generality assume that a day is composed of 2 hours and that the demand of loads in regions I and II consists of elastic and inelastic portions. On a typical day n, the inelastic portion of the demand is given as summarized in Table III. The elastic portion of the demand is created by the loads at bus 5 only. Given that there is a significant price differential between region I and region II this elastic portion of the demand is suggested to be satisfied through the inter-regional transactions from the suppliers at bus 2.

Demand at bus #	2	3	4	5
Day n, hour 1				
Demand (MW)	0	107.25	0	68.4
Day n, hour 2				
Demand (MW)	0	157.25	0	68.4

TABLE III
INELASTIC PORTION OF DEMANDS IN REGIONS I AND II

A. Auction mechanisms

At the beginning of the day, the TP's in regions I and II, first, submit bids for supporting tie-line flows for the reliability purposes to the IRTO. Suppose that the two TP's in the network are created from the respective vertically integrated utilities through the functional unbundling process, as is usually the case in US. It is reasonable to suppose that the network operates efficiently with minimal IOS when the exchange is within the range expected by the vertically integrated utilities. In this case the nominal exchange is taken as 15MW and 20MW through lines 4 and 5 respectively for region I, and correspondingly 21MW and 18MW for region II. As the exchange deviates from these ranges, the TP's may have to acquire more of the IOS or reinforce the network to support the operating conditions with the new exchange schedules. The cost to the TP's in serving native customers may be shown in Figures 3 and Figure 4 for tie-lines 4 and 5 respectively. The negative costs indicate the benefit to the TP's in terms of improved reliability by having the interconnected network rather than two isolated systems. The combined costs indicate that the network-wide

[3] For convenience the patent in the paper refers to this particular patent.

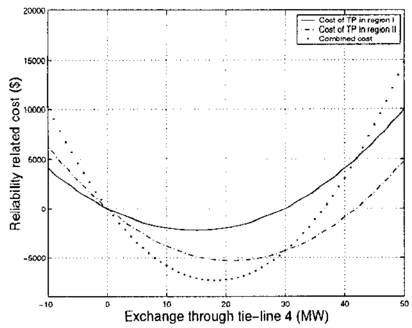

Fig. 3. Cost associated with the exchange through tie-line 4 from the perspective of TP's in terms of reliability

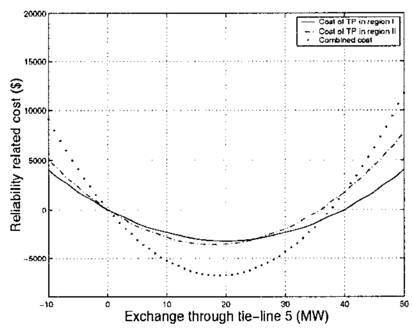

Fig. 4. Cost associated with the exchange through tie-line 5 from the perspective of TP's in terms of reliability

reliability level is highest with the minimal IOS if the exchange is scheduled at 17MW through tie-line 4 and 20MW through tie-line 5. Thus, if there are no economically motivated transactions scheduled by market participants, then the IRTO may schedule an exchange between regions I and II at 17MW and 20MW for the entire day n. It is interesting to note that the level of exchange here is much lower than what is expected as the systemwide optimal.[4]. The main factor for this difference is the lack of network support inherited from the vertically integrated utility era.

Similar to the bids submitted by the TP's, the network users also express the intent to use the tie-lines for inter-regional transactions in the form of demand bids to the IRTO to use tie-line flow capacity at the beginning of the day n. The bid is based on the benefit associated with cost savings by purchasing from less expensive generation sources.

Suppose that the demand of the load at bus 5 is elastic. Given the higher cost of generation in region II as shown in Figure 2, the load at bus 5 may want to satisfy some of its demand by making a purchase from the suppliers at bus 2. The overall benefit from realizing the transaction between bus 2 and bus 5 may, then, be as shown in Figure 5. The benefit function given in Figure 5 is typical, and the demand function for the desired transaction can be constructed by taking the first derivative of the benefit function.

When the actual tie-line schedule is determined, some

[4]The comparison is not entirely accurate since the inelastic demand of loads is assumed at bus 5 in addition to only one hour snap shot in the analysis even though in the paper we are more interested in the exchange schedule is over a day composed of multiple hours. Nevertheless, a few key concepts may be conveyed by comparing the examples.

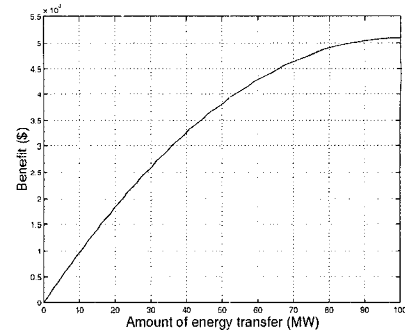

Fig. 5. Benefit associated with the transaction between the suppliers at bus 2 and the loads at bus 5 in terms of cost savings

parts of the flows are due to the TP's utilizing tie-lines for reliability purposes while the rest are because of the network users carrying out the economically beneficial transactions. Thus, the difference between the flows due to the TP's and that due to the network users needs to be accounted for, and appropriate charging mechanisms need to be developed. The charging mechanisms are due to two factors. On one hand, the difference in flows results, from the perspective of the TP's, in the deterioration of the reliability level if no further action is taken, and in order to maintain the same level of reliability as before, the TP's may have to incur additional costs in reinforcing the network and/or in purchasing more of the IOS. On the other hand, the difference in flows reflects the usage of the individual networks in regions I and II by the network users involved in inter-regional transactions. Under the open access principle, the market participants and the network users must be subject to the equivalent transmission charges for employing the transmission system in order to satisfy the energy need using the resources within the region and through the inter-regional transactions, respectively. By differentiating the usage of the tie-line by the TP's and by the network users, the TP's can correctly impose network related charges to the proper participants. Under the *ex ante* flow tax and congestion pricing scheme, the transmission costs levied on the network users involved in the inter-regional transactions may look as Figures 6 and 7. The transmis-

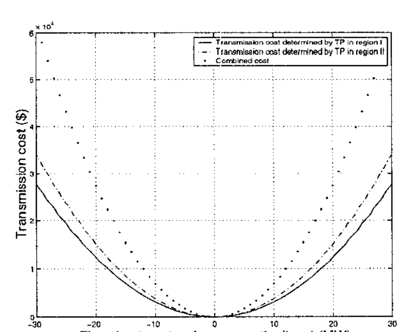

Fig. 6. Transmission cost to be levied on the network users involved in the inter-regional transactions using tie-line 4

sion costs shown in Figures 6 and 7 are used to compute the supply bids to be submitted to the IRTO by the TP's, so that the transmission charges reflecting the regional characteristics in providing transmission are included in the auc-

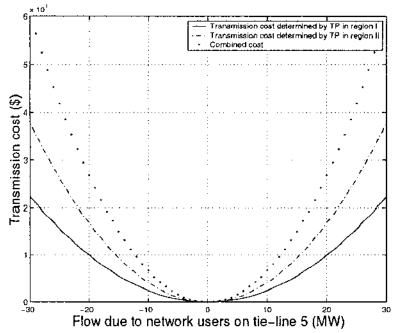

Fig. 7. Transmission cost to be levied on the network users involved in the inter-regional transactions using tie-line 5

tion mechanisms. It is interesting to note that in case the *ex ante* access fee and congestion pricing scheme or the *ex ante* injection tax and congestion pricing scheme is used instead, then the transmission charge levied on the network users involved in inter-regional transactions result in the so-called "pancaking" [6].

Once the bids are submitted, the IRTO can determine the tie-line schedules by minimizing the tie-line flow transmission cost as well as the cost associated with the exchange from the perspective of TP's in terms of reliability while maximizing the benefit associated with cost savings from purchasing from less expensive generation sources. For the 5-bus electric power network example above, the cleared bids result in the scheduled flows of 45.1MW through tie-line 4 and 46.5MW through tie-line 5 and the inter-regional transaction between the suppliers at bus 2 and the loads at bus 5 of 91.6MW for *both* hours 1 and 2 on the day n.

B. Control mechanisms

Since the TP in region I is affected by the change in operating conditions in region II (and vice versa), if and only if the tie-line flows into or out of the region I (or region II) deviate from the tie-line schedule, the ability for the individual TP in each region to operate its own network more or less independently from the other region is prominently subject to how well the tie-line flows can be maintained at the scheduled level.

At the beginning of hour 1 on day n the TP's in regions I and II conduct the respective regional markets in order to schedule generation dispatches to balance the supply and demand. Region I produces 91.6MW of surplus in generation, and the generation dispatch in Region II results in 91.6MW of shortage in generation, since a net of 91.6MW is scheduled to be delivered from bus 2 in region I to bus 5 in region II. Suppose the resulting dispatch schedule is as shown in Table IV. Then, because of the loop flow of second type, the flows are 44.2MW through tie-line 4 and 47.4MW through tie-line 5, which are different from the scheduled flow of 45.1MW through tie-line 4 and 46.5MW through tie-line 5. Thus, in order to ensure reliable operation of the interconnected network, there is a clear need for minimal systemwide coordination and strict tie-line flow control so that the actual flows through tie-lines match the scheduled flows.

For hour 1 on the day n				
Generation at bus #	1	2	3	4
Output (MW)	167.51	91.6	0	68.4
Demand at bus #	2	3	4	5
Demand (MW)	10.26	157.25	0	160

TABLE IV
DISPATCH SCHEDULE FOR REGIONS I AND II AT HOUR 1 ON THE DAY n

This can be accomplished by implementing the tertiary level control along with the secondary level control [5] [7]. The secondary control refers to the automatic generation scheduling for frequency regulation at the control area level. The tertiary level control refers to the compensation for inadvertent flows between control areas [7]. With the network assistance provided by the TP's at the regional level, the IRTO can utilize various controllers, both the generator related and the network related (flexible AC transmission systems (FACTS), in particular), participating in inter-regional transaction support.

At the beginning of hour 2 on the same day, the TP in region I is required to conduct the regional market for the second time in the day because of the significant change in the demand of the loads at bus 3. In contrast, the TP in region II has no need for any further market activities since the demand of the loads at bus 5 remains unchanged from that of the previous hour. The dispatch schedule following the market activities at hour 2 is summarized in Table V. It can be seen from Table V that the net generation is 91.6MW surplus in region I and 91.6MW shortage in region II. As before, due to the loop flow of second type, the tertiary level control is needed for matching the actual flows to the scheduled flows through tie-lines.

For hour 2 on the day n				
Generation at bus #	1	2	3	4
Output (MW)	67.51	131.34	0	68.40
Demand at bus #	2	3	4	5
Demand (MW)	0	107.25	0	160

TABLE V
DISPATCH SCHEDULE FOR REGIONS I AND II AT HOUR 2 ON THE DAY n

Figure 10 shows the result of employing the tertiary and secondary level control to reinforce the flows through the tie-lines between regions I and II throughout day n. Let the day consist of two hours, each 360 seconds long. In case of a sudden occurrence of plausible contingency in a particular region within the interconnected network, the tertiary level control ensures that the other regions may operate without being affected except for a few minutes following the contingency.

To test the response of the system to disturbances, such as unexpected deviations in load, load deviations by 0.2 p.u., -0.2 p.u. and 0.2 p.u. are simulated at bus 3 at 60 seconds, 240 seconds and 480 seconds, respectively, as shown in Figure 8.

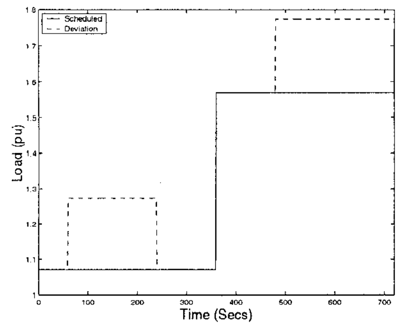

Fig. 8. Load Profile at Bus 3

Figure 9 shows the change in output of generators as the system parameters change. Starting at 15 seconds, generator governor settings are adjusted every 15 seconds to return tie-line flows, if deviations have occurred, to values preset by the IRTO.

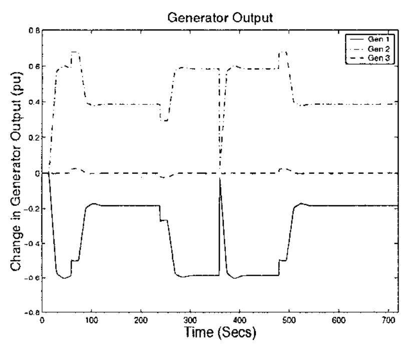

Fig. 9. Change in the output of generators at buses 1, 2, and 4 due to unexpected deviations in load at bus 3 and clearing of market at midday

Figure 10 shows the resulting tie-line flows. It is observed

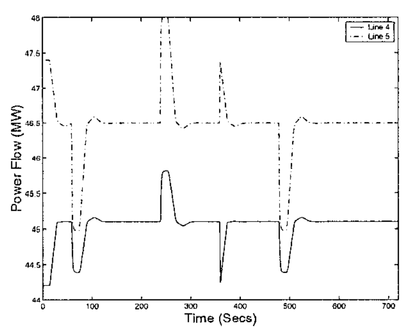

Fig. 10. Power flow on tie-lines 4 and 5

that except for the brief periods following the clearing of the market(s) and the deviations in load at bus 3, the tie-line schedules remain strictly as determined by the IRTO. This ensures that the disturbances originating in region I have minimal impact on region II.

Therefore, with the market mechanisms composed of the auction mechanisms and the control mechanisms, as proposed in the patent, the inter-regional transactions may be implemented while maximizing the advantages and minimizing the disadvantages of the interconnected network. In the following section we describe the implementation of the inter-regional transactions under the vertically integrated utility structure and under the current development, for comparison purposes.

IV. Implementation of inter-regional transactions under the vertically integrated utility structure and under the current development

Under the vertically integrated utility structure the implementation of the inter-regional transactions is limited in scale, and tie-lines are not designed to handle the import and export of large amounts of electricity over long distances that marketers would like to see in a deregulated electricity market. Competition has however led to an increase in both scale and scope of inter-regional transactions. See [14] for further analysis.

There are several reasons regarding a change in management systems is necessary. First, the tie-line interchange can no longer be agreed upon by two adjacent system operators because they (1) do not have any incentives to do so and (2) the people who actually have the incentives to drive the inter-regional transfers often request the transfers that take place over multiple regions.

Second, the tie-line flows should no longer be regulated loosely since there are already examples of riding on neighbors to acquire power at the high price hours and to return in-kind payment at the low price hours; this is stealing since the price at each hour is different. Rather, there is the need for strict tie-line flow control. This will not only help to minimize the effects on regions not on the contract path (which are affected due to loop flows of the second kind), but will facilitate the assignment of the costs involved to the appropriate agents involved in the transaction. It is important to note that implementing control mechanism according to the proposed market mechanisms in the patent is not very different from the industry practice under the vertically integrated utility. The only addition is the tertiary level control for strict tie-line flow, which does not require any additional equipment to be installed in the interconnected network.

Under the current development the inter-regional transactions are managed by an entity called *security coordinator* (SC) independent of any merchant functions [8]. The SC is responsible for the safe and reliable operation of the interconnected network including several control areas managed by the respective TP's.

Network users enter into various energy contracts for trading electricity across multiple regional boundaries, and reserve a *contract path* [3] for the transaction. If, while implementing the transaction, there is the threat or an actual violation of the operating security limits, typically network related limits such as transfer limits on *flowgates*[5], believed to be caused by inter-regional transactions, the TP's may call for so-called *transmission loading relief* (TLR) [3] procedures to be implemented by the SC.

[5]Flowgate refers to the transmission link associated with the likely network congestion.

There are several inefficiencies associated with the inter-regional transactions managed by the SC because of the improper placement of incentives and responsibilities [4]. The proposal in the patent covers some issues that the SC scheme is not designed to address.

First, with limited knowledge of systems external to its area, the security limits the TP defines on flowgates are likely to be highly conservative rather than economically efficient. In comparison, the proposed market mechanisms in the patent instigate the TP's to carefully consider the effect of inter-regional transactions through the bids associated with the reliability cost and the transmission cost.

Second, given the SC's familiarity with the operation of the interconnected network, the SC can support the network users to identify the truly economically efficient inter-regional transactions. However, the SC is not involved until a TLR is required. Under the proposed market mechanisms the IRTO, which effectively carries out the functions of the SC, participates proactively in the market process of realizing the most efficient inter-regional transactions by clearing the bids *before* the reliability is threatened, and not reactively by implementing TLR procedure *after* the reliability related problems are identified.

Third, operating conditions following a TLR may no longer violate the security limits on the flowgates, but may also not be optimal. In comparison, the restoration of the interconnected network under the proposed market mechanisms in the patent is based on the fundamentally sound technical criteria and utilizes mostly the *existing* controllers to constantly adjust around the evolving system conditions.

Therefore, with the market mechanisms proposed in the patent, many issues related to the current SC scheme are resolved because the implementation is based on the technically sound fundamentals while incorporating the proper economical incentives.

Figures 11, and 12 show the results of applying the current method of implementation of inter-regional transactions to the exchange between regions I and II. Secondary control reschedules the output of the generators everytime there is a disturbance that causes the frequency to deviate from 60Hz. This returns the system frequency to the

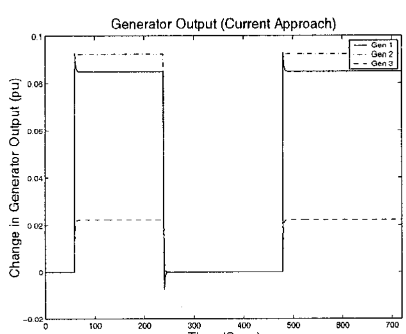

Fig. 11. Change in the output of generators at buses 1, 2, and 4 due to unexpected deviations in load at bus 3 and clearing of market at midday

desired value of 60Hz.

Unlike tertiary control, secondary control does not reset the tie-line flows, therefore tie-line flows tend to drift from the scheduled.

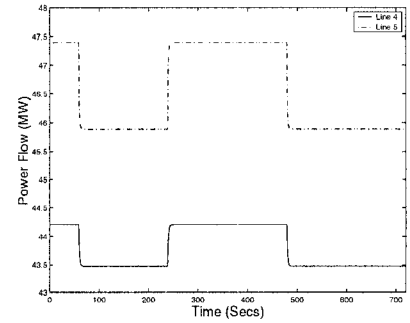

Fig. 12. Power flow on tie-lines 4 and 5

V. Other proposed market mechanisms for implementing the inter-regional transactions

At the time of writing, there are currently two main proposals for replacing the SC scheme in implementing inter-regional transactions. For convenience we refer to them as (1) coordinated optimal power flow method and (2) flowgate rights allocation method across multiple regions.

A. *Coordinated optimal power flow method across multiple regions*

The coordinated optimal power flow (OPF) method is mainly based on the analyses given in [9] and [10]. The method is based on the nodal pricing paradigm and seeks to attain the system-wide cost-based OPF using a coordinated, distributed method. The price of transmission is calculated from the differences in prices of energy at the various nodes. Detailed explanation of the method is deferred to [9] and [10].

The proposal in the patent covers some issues that the coordinated OPF scheme is not designed to address.

First, due to the inherent difficulties in defining security limits for the network, the security limits are likely to be highly conservative and consequently a significant efficiency loss is expected. In comparison, based on the proposed market mechanisms in the patent the process of defining actual security limits are internalized by the individual TP in each region while the change in reliability level (or the different amount of the IOS to be procured) is allowed to be directly communicated to the network users through the bids so that a higher efficiency is achieved.

Further, each line in the entire interconnected network is treated the same way, although some regions may, for instance, have more expensive transmission networks. Under the proposed market mechanisms these regional characteristics are respected by allowing the TP's to submit separate bids accounting for the usage of their respective transmission networks.

Finally, there is a problem linked with the restoration of the interconnected network as the operating conditions change. If any one of the regions goes through a significant change in operation, then the operating conditions for the rest of the interconnected network need to be modified in order to accommodate this change. For instance, in the example discussed in Table III when the energy market in region I is conducted to meet the significant change in the demand of loads at bus 3, the energy market in region II also needs to be conducted again to make certain that no security limits are violated in region II due to the change in region I. If the continuously evolving operating conditions are considered due to the plausible contingencies as in the case in the electric power network, this implies that the various energy markets in the *entire* interconnected network needs to be synchronized so that any change in operating conditions in one region does not result in violation of the security limits in other regions. In comparison, under the proposed market mechanisms in the patent the effect from any changes in operating conditions in one region is contained within the region once the tertiary level control mechanism restores the interconnected network following any plausible contingencies.

Thus, in order to properly implement the coordinated OPF method for managing inter-regional transactions, a significant number of modifications must be made to the network, the least of which is synchronizing the market activities throughout the entire interconnected network. It is quite the contrary with the proposed market mechanism which requires only minor modifications to the network.

Figures 13 and 14 show the results of implementing the exchange between regions I and II using the coordinated OPF approach. Secondary control reschedules the output of the generators everytime there is a disturbance that causes the frequency to deviate from 60Hz. This returns

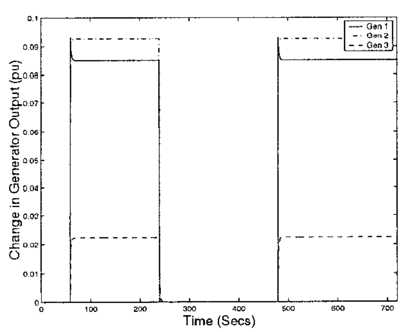

Fig. 13. Change in the output of generators at buses 1, 2, and 4 due to unexpected deviations in load at bus 3 and clearing of market at midday

the system frequency to the desired value of 60Hz. Similar to the SC scheme, tie-line flows are not reset, and so tend to deviate from the scheduled, as shown in Figure 14.

B. Flowgate rights allocation method across multiple regions

The flowgates right approach to inter-regional transaction management is representative of the link-based approach [11]. Although the term flowgate may refer to any transmission line in the system, in general it refers to the links in the network that are likely to be congested. Refer to [11] for a detailed description of the method.

Some issues that the flowgate approach is not designed

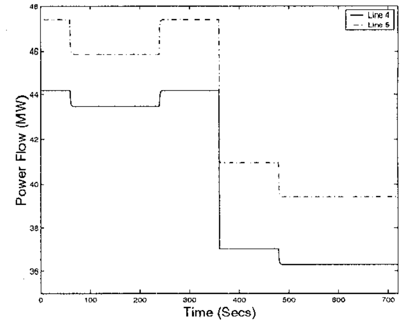

Fig. 14. Power flow on tie-lines 4 and 5

to address are incorporated in the patent proposal.

First, there is the need to accurately assess the total amount of the flowgate rights to be offered by the individual TP's who have very limited knowledge about the operations in the other regions. In comparison, based on the proposed market mechanisms in the patent, the network users involved in the inter-regional transactions are handled completely separately from the market participants due to the proactive participation by the TP's. Plus, instead of defining the rigid amount of flowgate rights available, the individual TP in each region may reach a higher efficiency by communicating to the network users the change in reliability level through the bids.

In addition, the amount of flowgate rights available in a region have to be adjusted constantly due to the evolving operating conditions in the rest of the interconnected network. Under the proposed market mechanisms in the patent, this problem is resolved by minimizing the effect of any disturbances from propagating throughout the interconnected network by the IRTO performing the systemwide coordination and strict tie-line flow control.

Some other issues related to the flowgate scheme may be considerd. The first is that the TP in each region has to define the amount of rights available exclusively for inter-regional transactions ahead of time. This requires strong incentives to properly project the usage of flowgate rights in the energy market. An overestimation implies some transactions may not receive the desired scheduling priority.

Additionally, the markets for the entire interconnected network need to be conducted in a synchronized fashion with the majority of transactions being taken care of through this market process leaving only the unanticipated balancing to the spot market in each region. However, as it is pointed out in [12], many of the transactions in the current electricity markets still rely heavily on the spot market process. So long as this is the case, the markets under the flowgate scheme may not achieve high efficiency.

Furthermore, for reasons related to the maximum possible number of scheduling of tie-lines being only once or twice per day as discussed earlier, it is often implied that inter-regional transactions need to be handled separately from the energy markets for the trades within the region. Then, when a TP offers the flowgate rights for inter-regional transactions only, either the TP needs to estimate the flowgate rights needed for the trades within the region, or the

TP needs to conduct the auction process once for the market participants within the region and for the inter-regional transactions together.

Therefore, with the market mechanisms proposed in the patent, many issues related to the flowgate rights allocation method are resolved because of the IRTO's presence. By having an entity solely responsible for handling the inter-regional transactions, the regional energy markets can be conducted separately from these transactions and may co-exist while having very different characteristics from one another. This is important since in order to achieve higher efficiency, the well functioning markets need to reflect the unique features of the respective regions. Plus, the systemwide coordination and strict tie-line flow control allows for further independence of each regional market.

VI. Conclusion

This paper has presented a method of managing transactions involving multiple regions, based on the patent filed by Ilić and Yoon. The proposed method is independent of the market structure in the regions, and requires minimal modification to the existing markets. It is also unique in that it accounts for reliability explicitly by allowing each market participant to include his preferred level of reliability in his bid to sell or purchase power.

It is not very difficult to implement the proposed mechanism since the underlying structure is already in place. That is to say, the only necessary improvements are replacing the SC with the for-profit IRTO and substituting the TLR procedure with the proactive bidding process. Moreover, committee-based approaches, such as currently considered Memorandum of Understanding (MOU) [15] are not suited for effective on-line management of inter-regional transactions.

To implement this mechanism, a regulatory structure will have to be designed for the coordinating, for-profit IRTO, who remains a regulated entity. However, this should not pose any unusual difficulty since the structure will likely be similar to that required for the proposed Regional Transmission Organizations (RTO).

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