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Efficient implementation of inter-regional transactions

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Abstract

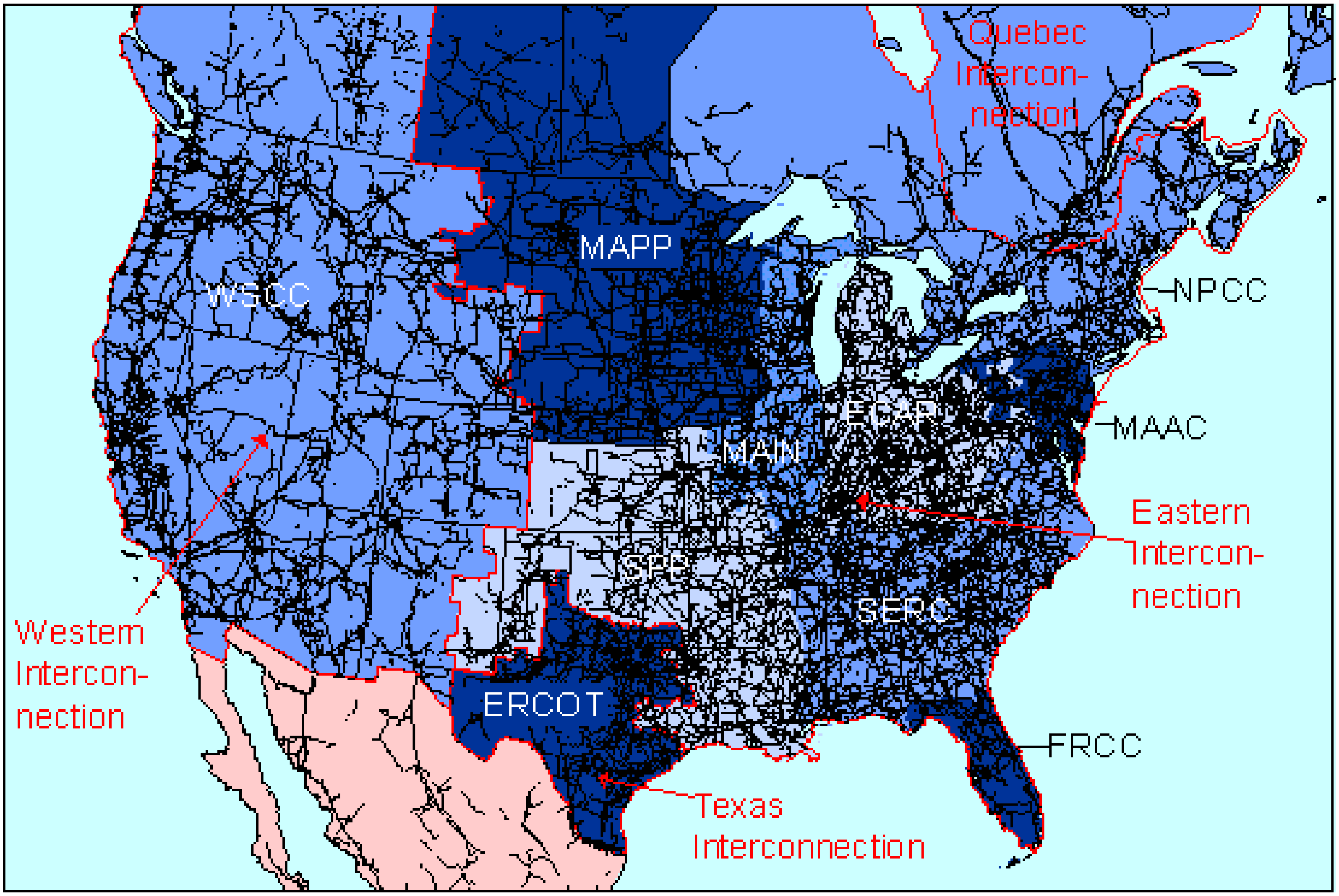
In this paper we describe the provision of transmission in the multiple regional setting. In each region it is assumed that a separate market structure and tariff system exist.

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

I. Introduction

Figure 1 shows the three transmission systems serving the entire U.S., part of Canada and part of Mexico: (1) the Eastern Interconnected System, covering the eastern United States and some of the Canadian Provinces; (2) the Western Interconnected System, consisting of the western United States and the northern portion of Mexico; and (3) the Texas Interconnected System. The North American Electric Reliability Council (NERC) regions in Figure 1 refer to ten administrative areas established across North America in order to promote the reliability of the electricity supply following the systemwide blackouts on November 9, 1965 [12]. From the perspective of transmission network development it is important to note that the boundaries of NERC regions are defined by aggregating 152 regional control areas into appropriate electrical geographic sizes rather than by being limited to the administrative utility boundaries. A control area is an entity that is electrically bounded through tie-line metering and telemetry, who is responsible for maintaining its interchange schedule with other control areas and participating in frequency regulation of the interconnection through scheduling, dispatching and controlling generation within its area. The Eastern Interconnection is comprised of 109 control areas, the Western of 33, and the Texas of 10.

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. Related 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. The IOS are the essential functions needed for the continuous balancing of generation and demand, transmission system security, and emergency preparedness under uncertainties [9]. On one hand, if the TP fails to acquire the adequate level of the IOS by underestimating the uncertainties, then the reliability of the network operation is jeopardized. On the other hand, if the TP attains excessive level of the IOS by overestimating the uncertainties, then the efficiency of the network operation suffers. Thus, 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



NERC Regional Councils

ECAR	–	East Central Area Reliability Coordination Agreement
ERCOT	–	Electric Reliability Council of Texas
FRCC	–	Florida Reliability Coordinating Council
MAAC	–	Mid-Atlantic Area Council
MAIN	–	Mid-America Interconnected Network, Inc.
MAPP	–	Mid-Continent Area Power Pool
NPCC	–	Northeast Power Coordinating Council
SERC	–	Southeastern Electric Reliability Council
SPP	–	Southwest Power Pool
WSCC	–	Western Systems Coordinating Council

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Fig. 1. North American Transmission Systems and NERC Reliability Council Regions

efficiency. These already difficult tasks become even harder to deal with 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.

We first describe the advantages and disadvantages of having the interconnections with neighboring control areas. Then, 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

Consider the 5-bus electric power network as shown in Figure 2. The network is composed

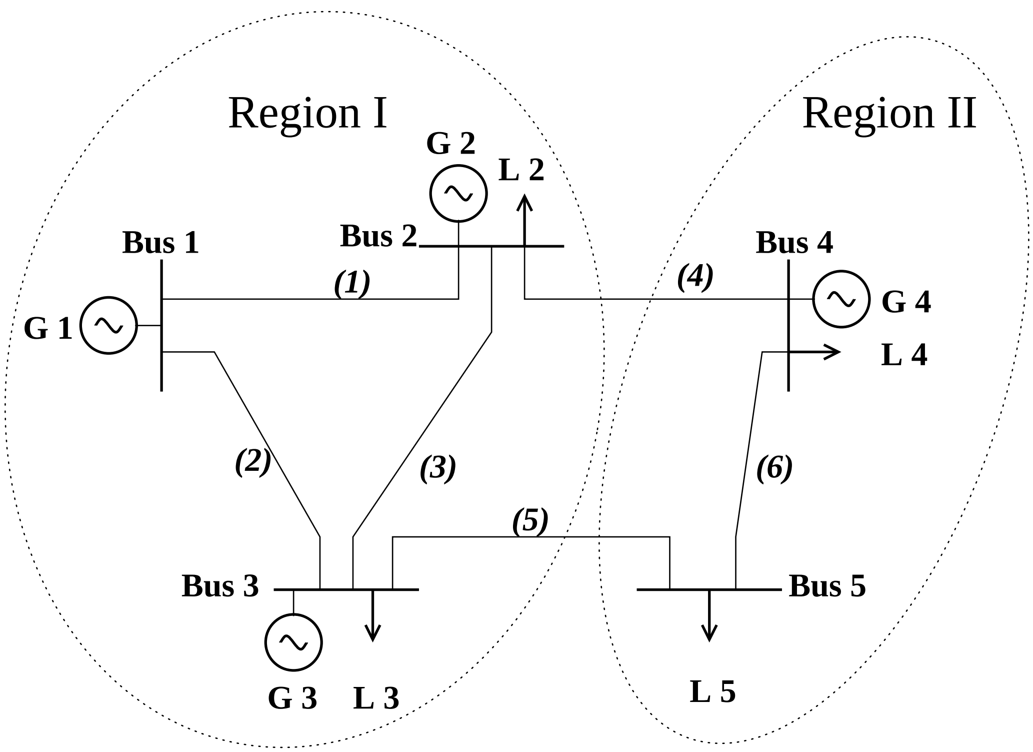


Fig. 2. One-line diagram of 5-bus electric power network

of two regions with each region having enough generation to meet its own loads. The network lines between the regions are called tie-lines, i.e., the lines 4 and 5.

For illustration purposes, assume that at some hour k the generators in the network are dispatched by the respective TP's to meet the load as described in Table I. By continually

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

matching the supply and demand, the network is running within the normal operating limits including the acceptable range of voltage and the typical frequency (of 60Hz in the US).

Suppose the demand at bus 3 suddenly increases from 157.25MW to 207.25MW a few minutes after the beginning of hour k, 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. The area-wide frequency continues to drop until this drop in frequency is detected by the generators participating in the IOS and these generators react by increasing their generation to bring the frequency back to the level before the load increase. This particular service is often referred to as the regulation service, of providing generation response capability, under automatic generation control (AGC), in order to continually balance the supply with minute-to-minute load variations with the control area [9]. Figure 3 shows the change in the area-wide frequency in region I following the unanticipated load increase if region I is isolated from region II.

If region I is interconnected with region II, then the same unanticipated load increase in region I affects the network-wide frequency, instead of only the area-wide frequency, in a similar way. That is to say, following the load increase, the network-wide frequency initially drops by 1.8×10^{-3}Hz and continues to drop until the deviation in frequency is detected by the generators participating in the IOS, and these generators react by increasing their

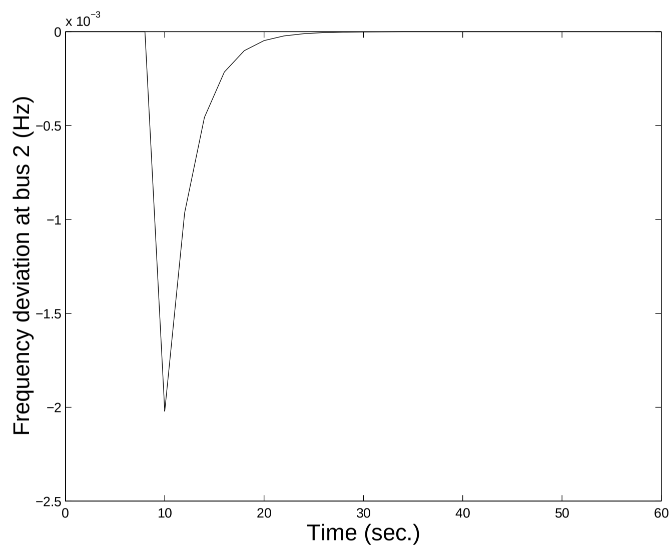


Fig. 3. The change in the area-wide frequency deviation in region I measured at bus 2 following the unanticipated load increase if the region I is isolated from region II

generation to bring the frequency back to the level before the load increase. Figure 4 shows the change in the network-wide frequency in region I following the unanticipated load increase when region I is interconnected to region II.

However, it is evident from comparing Figures 3 and 4 that 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. Plus, the recovery of the frequency is also much easier in the interconnected network than in the isolated system because the responsibility of recovering the frequency is shared among more generators. This is one of the biggest advantages of having an interconnected network.

In case of more severe deviations in nominal operating conditions such as equipment outages, sharing of IOS among many control areas 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

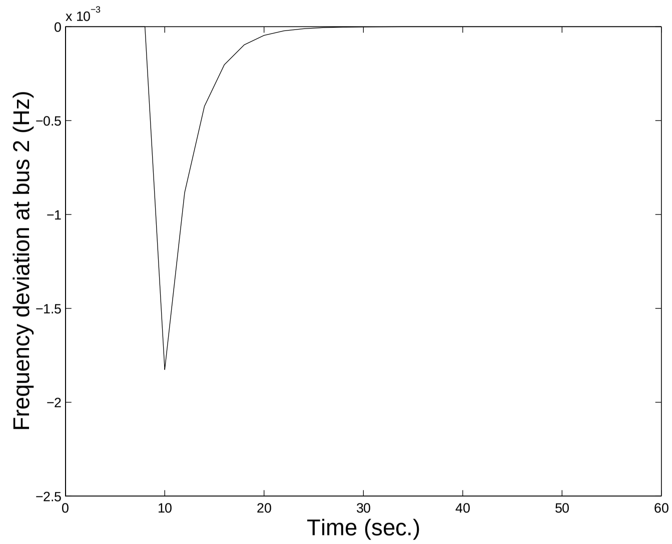


Fig. 4. The change in the network-wide frequency deviation in region I measured at bus 2 following the unanticipated load increase when the region I is interconnected to region II

50MW stand-by generation each, region I is fully operational 91.85%, i.e.,

$$0.9185 = 0.9^5 + \binom{5}{1} 0.1 \cdot 0.9^4 \tag{1}$$

and region II is fully operational 99.00%, i.e.,

$$0.9900 = 0.9^2 + \binom{2}{1} 0.1 \cdot 0.9 \tag{2}$$

If region I does not have the stand-by generation of 50MW, then the region is only operational 59.05%, i.e., $0.5905 = 0.9^5$. Similarly, if region II does not attain the stand-by of 50MW, then the region is only operational 81.00%, i.e., $0.8100 = 0.9^2$. 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, i.e.,

$$0.8503 = 0.9^7 + \binom{7}{1} 0.1 \cdot 0.9^6 \tag{3}$$

The savings from requiring only 50MW of stand-by generation may be tremendous when compared to that of 100MW. Incidentally, the stand-by generation service that makes additional capacity available to immediately serve customer demand should a contingency occur is often called reserves. [9].

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. For example, suppose that the supply functions at the various buses are as shown in Figure 5 based on the individual marginal costs of the generation units. At hour k let the demand of the loads at different

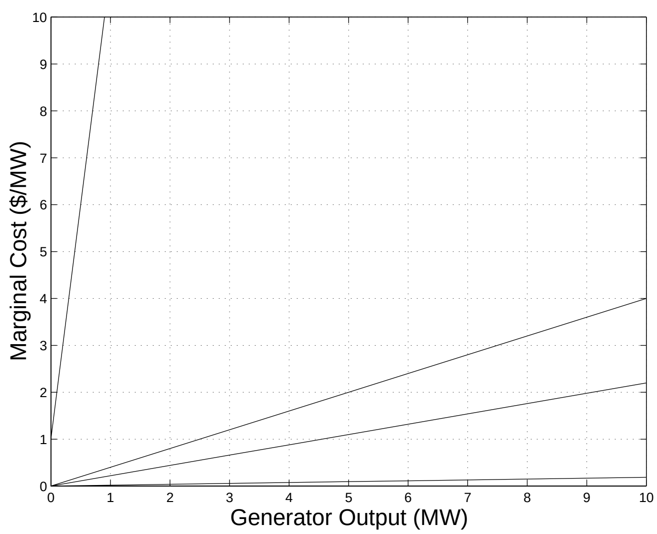


Fig. 5. The supply functions at buses 1, 2, 3 and 4 based on the individual marginal costs of the generation units

buses be inelastic and be given as $Q_{d_2}[k] = 0MW$, $Q_{d_3}[k] = 157.25MW$, $Q_{d_4}[k] = 0MW$ and $Q_{d_5}[k] = 160MW$. Table II summarizes the dispatch schedule determined through the market mechanism if the regions I and II are isolated from each other. The difference in prices in region I is due to the *binding network constraints* on transmission line 3 of 80MW limit. In comparison, Table III represents the dispatch schedule if the regions belong to the same market within a single control area. The result in Table III 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 characteristic, however, the result in Table III is neither likely feasible nor necessarily optimal. Nevertheless, comparing the total costs of generation in Tables II and III, 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.

Generation at bus #	1	2	3	4
For region I				
Output (MW)	74.50	82.75	0	·
Price ($)	16.38	1.55	31.20	·
For region II				
Output (MW)	·	·	·	160.00
Price ($)	·	·	·	64.00
Total cost of generation ($): $15,588.57 = 1,348.57$ (region I) $+10,240.00$ (region II)				

TABLE II

Generation dispatch schedule if the regions I and II are isolated

Generation at bus #	1	2	3	4
Output (MW)	156.39	78.84	0	82.02
Price ($)	34.37	1.47	67.27	32.81
Total cost of generation ($): $8,182.10 = 5,491.02$ (region I) $+2,691.08$ (region II)				

TABLE III

Generation dispatch schedule if the regions I and II belong to the same energy market of a single control area

Therefore, an argument may be made that the major advantages of interconnection are the improved reliability and efficiency through the sharing of IOS and the further increased efficiency through the cost savings in generation.

Suppose in order to take advantage of inexpensive generation cost, the loads at bus 5 enter into an energy contract with the supplier at bus 2 for 50MW. Then, using the DC load flow approximation, the electric power flows through different network lines can be computed as shown in Figure 6. It is interesting to note that a significant amount of electric power (more than a half of the entire transaction amount) flows through the tie-line 5 despite the availability of a closer tie-line, line 4 that could handle the entire transaction. From this example it may be deduced that if there are more than two control areas, then even

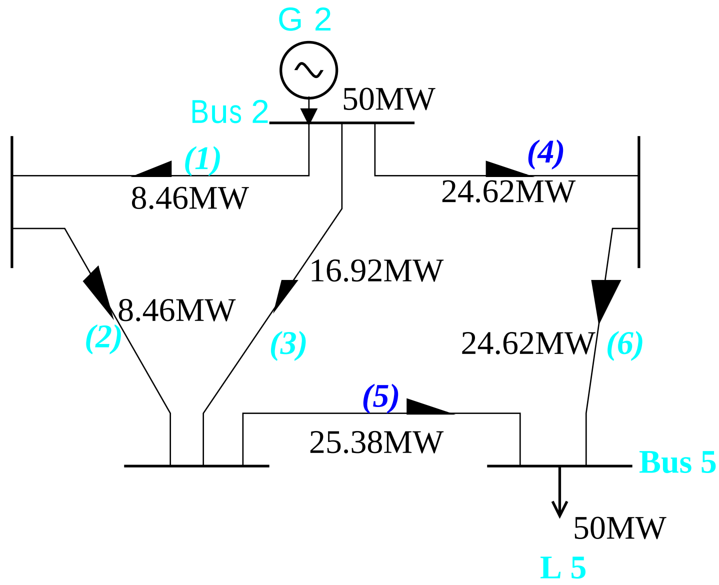


Fig. 6. Electric power flows through network lines caused by 50MW transactions between the suppliers at bus 2 and the loads at bus 5

if the proposed transaction takes place between two adjacent control areas, the rest of the interconnected network is affected by the transaction. 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 [11]. We consider this as the first of two types of loop flows and it relates to the inability of the market participants to control the transmission path.

The second type of loop flow is related to the inability of each individual TP to control the transmission path. For example, when the dispatch schedule is made by individual TP's as given in Table II the markets at regions I and II are conducted completely separate from each other and no transaction between the two regions are committed as shown in Figure 7. However, due to the presence of the tie-lines between the regions, the actual electric power flows through the network are realized as shown in Figure 8. We note that the actual flow through line 3 exceeds the operational limit on power transfer. This difference is quite significant since the network is being operated in a hazardous regime where the reliability of the system is no longer assured.

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

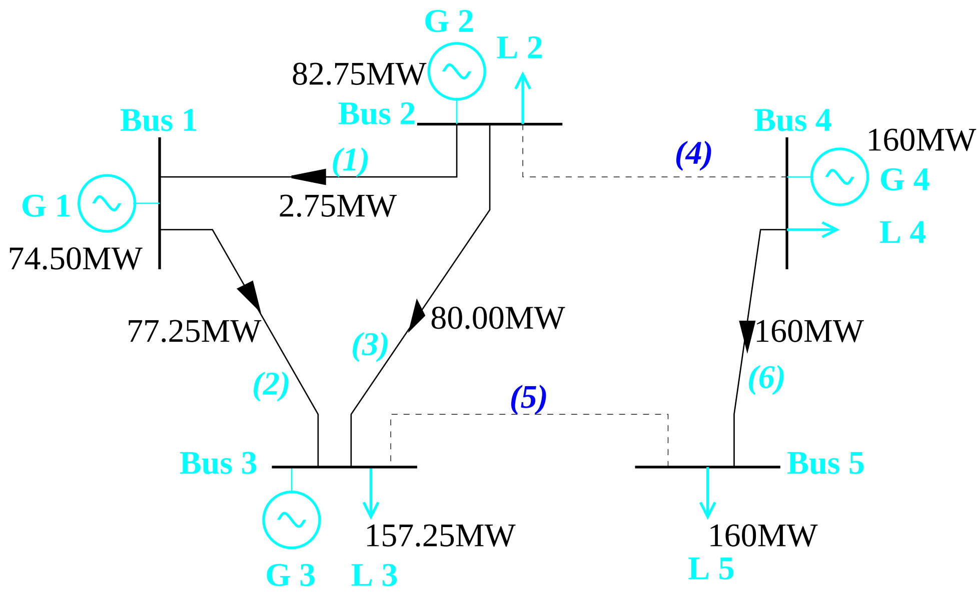


Fig. 7. Electric power flows based on the supply and demand determined through the market mechanisms separately between regions I and II

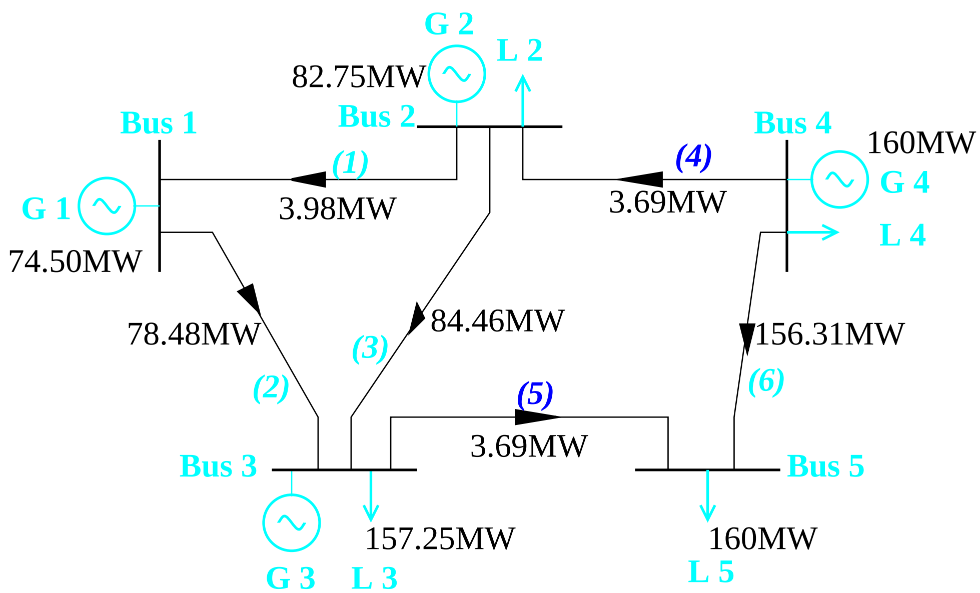


Fig. 8. Actual electric power flows through the network determined based on the supply and demand of regions I and II

breach in the reliability, the systemwide coordination 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.

Figure 9 shows the change in the frequency measured in *region II* following the unanticipated load increase when the region I is interconnected to region II. Even though the

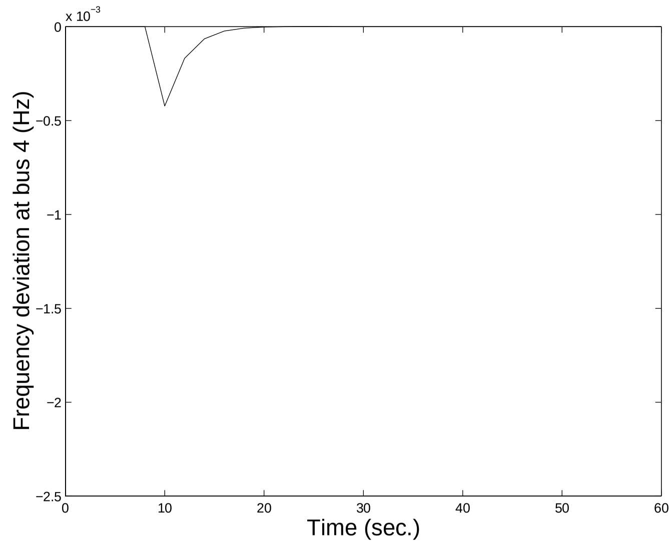


Fig. 9. The change in the network-wide frequency deviation in region II measured at bus 4 following the unanticipated load increase when the region I is interconnected to region II

deviation in frequency in region II is not as severe as in region I, the effect of the load increase at bus 3 is still being felt there according to Figure 9.

There are a number of network related controllers within the system, other than generators, also reacting to the deviations in frequency. These controllers are typically tuned around some anticipated operating conditions. Suppose following the disturbance in frequency as shown in Figure 9 several network related controllers, as well as the generators in region I, are activated in order to restore the frequency back to the pre-disturbance level. If the result of the generators reacting to the deviation in frequency significant alters the operating conditions in region I, the operating conditions in region II are also modified due to the loop flow of second type. This is reflected in change in flows caused by the different electric power flows entering into or leaving out of region II through the tie-lines. The change is due exclusively to the effect of different operating conditions created outside of region II since here we assume no generator in region II reacts to the deviation, and once the frequency is restored, the network related controllers are deactivated. Thus, from the perspective of region II, no change is made other than the electric power flow through the tie-line, and consequently the area-wide flows according to the loop flow of second kind. The next time region I undergoes similar kind of disturbance, the network related controllers in region II might not work properly because the controllers are initially tuned for certain operation conditions which may be quite different from the post-disturbance operating conditions.

To make the matters worse, it is not easy to tune the controller for the new operating conditions since the change in system conditions is entirely external. The TP in region II might not be exactly aware of the effect of the new operating condition without the full knowledge of the operating conditions in region I. The only way to insure the proper functioning of the network related controllers in region II, therefore, is to restore the tie-line flows back to pre-disturbance level so that the effect from the loop flow of second type is minimized and the only change in operating conditions in region I is observed by the TP in region I only. The TP in region I can restore his own control area to a state of readiness for other contingencies since the full knowledge of the operating conditions in region I is assumed to be bestowed with the same entity. Incidentally, because of the difficulties in defining the controller settings based on numerous off-line reliability studies with respect to the *outside of its own region*, it is often implied that tie-line flows may change only once or twice within a day.

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 [5].

Therefore, an argument may be made that the major disadvantages of interconnection are the reduced reliability through the loop flow of first and second types.

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

In the following section, we briefly describe the newly proposed market mechanisms in the U.S. patent filed by Ilić and Yoon (2000) for implementing the inter-regional transactions.[1]

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

The overall 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. Roughly speaking, the auction mechanisms are designed such that the apparent 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 allow the effect of loop flow of first and second types to be minimized. 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) [5]. Under the proposed market mechanism in the patent the IRTO is a for-profit entity created solely to support the inter-regional transactions.

In the Northeast market, for instance, the IRTO will be on a scale large enough to embrace the Mid-Atlantic States and the Northeast Power Coordination Council (NPCC). Through an iterative auction, the IRTO clears the market for inter-regional transactions based on bids from RTOs - including Transmission Providers, Control Areas and Independent System Operators (ISO) - and marketers interested in inter-regional transactions. The IRTO coordinates the activities of market participants as they maintain strict control of tie line flows

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

for the duration of the transaction. This design of the IRTO makes the framework essentially independent of the type of market and the transmission tariffs in the regions within its boundaries.

In terms of hierarchical power system controls [6], the IRTO operates at the tertiary level. Based on preferences of marketers, he establishes the optimal tie-line flow for a given period. Other market participants operate at the primary and secondary levels - not much different from present operation of the power system. These marketers implement their transactions while ensuring that tie line flows remain at the levels determined by the IRTO.

Consider the 5-bus electric power network example presented in Figure 2 in the beginning of the paper. Due to the reasons explained earlier, 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 IV. The elastic portion of the demand is created by the loads

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

TABLE IV

Inelastic portion of demands in regions I and II

at bus 5 only. Given that there is a significant price differential between region I and region II as shown in Table II this elastic portion of the demand is suggested to be satisfied through the inter-regional transactions from the suppliers at bus 2.

A. Auction mechanisms

At the beginning of the day, the TP's in regions I and II, first, submit bids for utilizing tie-lines 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. If the vertically integrated utilities in regions I and II had a limited exchange between them ranging between 13MW and 23MW through tie-line 4 and between 16MW and 22MW through tie-line 5, then it is reasonable to infer that the existing network has evolved to perform at the highest reliability level when the exchange is within that range. For example, the network in region I is built to support the operating conditions where the exchange between the regions is 15MW through tie-line 4 and 20MW through tie-line 5. Similarly, the network in region II is constructed to support the operating conditions where the exchange between the regions is 21 MW through tie-line 4 and 18MW through tie-line 5. Hence, the reliability level of the entire network comprising regions I and II is first-class with minimal IOS if the exchange between the regions is within the ranges typical under the vertically integrated utility structure. As the exchange deviates from these ranges, in order to maintain a similar level of reliability, in the short term, the TP's may have to acquire more of the IOS or in the long term, enforce the network to support the operating conditions with new exchange schedules. Thus, the cost associated with the exchange from the perspective of TP's in terms of reliability may be as shown in Figure 10 for tie-line 4 and Figure 11 for tie-line 5. The negative costs in Figures 10 and 11 indicate the benefit of the

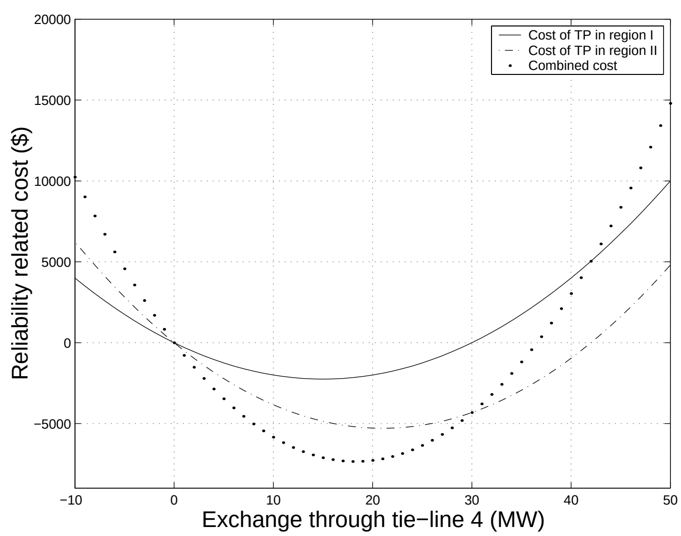


Fig. 10. Cost associated with the exchange through tie-line 4 from the perspective of TP's in terms of reliability

TP's in terms of improved reliability by having the interconnected network rather than two isolated systems. Based on the combined costs the network-wide reliability level is highest

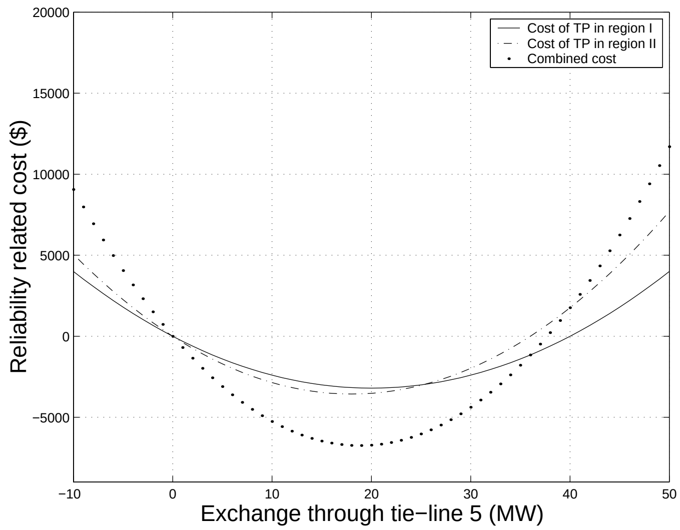


Fig. 11. Cost associated with the exchange through tie-line 5 from the perspective of TP's in terms of reliability

with the minimal IOS if the exchange is scheduled at 17MW through tie-line 4 and at 20MW through tie-line 5. Thus, if there is 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 *without* considering the transmission network as given in Table III where the exchange is around 37MW through tie-line 4 and 41MW through tie-line 5.[2] 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 bids to the IRTO at the beginning of the day n. The bid is based on the benefit associated with cost savings from 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 5, 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

[2]The comparison is not entirely accurate since the result given in Table III not only assumes the inelastic demand of loads at bus 5 but also considers only one hour snap shot whereas here the exchange schedule is over a day composed of multiple hours. Nevertheless, a few key concepts may be conveyed by comparing the examples.

transaction between bus 2 and bus 5 may, then, be as shown in Figure 12. The benefit

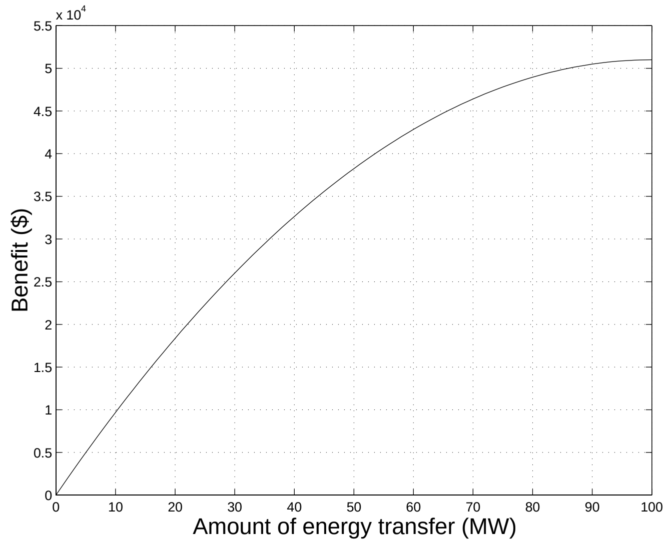


Fig. 12. Benefit associated with the transaction between the suppliers at bus 2 and the loads at bus 5 in terms of cost savings

function given in Figure 12 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 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 13 and 14. The transmission

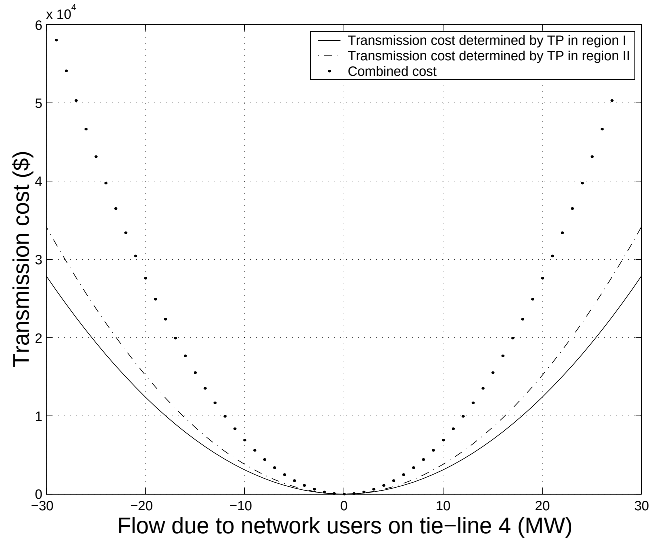


Fig. 13. Transmission cost to be levied on the network users involved in the inter-regional transactions using tie-line 4

costs shown in Figures 13 and 14 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 auction 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" [8]. Pancaking refers to the multiple transmission rates levied on the transactions spanning several regional markets. This is due to inaccurately charging for transmission based not on flows but on membership (in case of access fee scheme) or on injection (in case of injection tax scheme).

Once the bids are submitted, the IRTO can determine the tie-line schedules by minimizing the 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

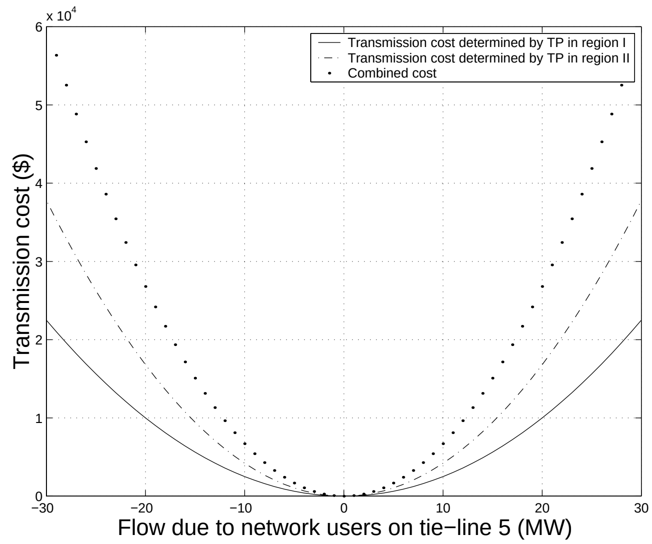


Fig. 14. Transmission cost to be levied on the network users involved in the inter-regional transactions using tie-line 5

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 depends prominently on 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. Since the net of 91.6MW is scheduled to be delivered from region I and region II, the generation dispatch following the overall market activities in region I produces 91.6MW of surplus in generation. Similarly, the generation dispatch results in 91.6MW of shortage in generation. The surplus and the shortage are due to the inter-regional transaction between the suppliers at bus 2 and the loads at bus 5. Suppose the overall market activities produces the dispatch schedule shown in Table V. 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

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 V

Dispatch schedule for regions I and II at hour 1 on the day n

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 systemwide coordination and strict tie-line flow control so that the actual flows through tie-lines match the scheduled flows.

This can be accomplished by implementing the tertiary level control along with the secondary level control and the primary level control [6] [3]. The primary control refers to the fast stabilization at the individual generator level with respect to disturbance of fast dynamics nature. 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 by momentarily offsetting generator frequencies [3]. 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 VI. It can be seen from Table VI 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

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 VI

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

tie-lines.

Figure 15 shows the result of employing the tertiary level control to reinforce the flows through the tie-lines between regions I and II throughout day n. Although it is not shown

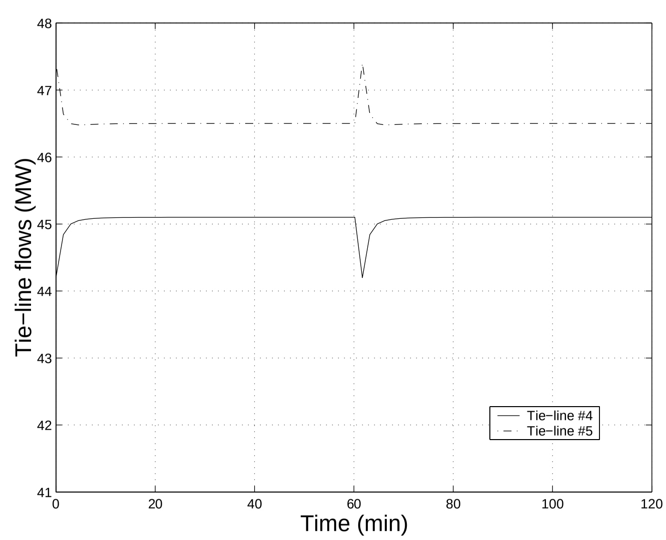


Fig. 15. Actual tie-line flow throughout the day n with the use of tertiary level control

here, the tertiary level control is used throughout the day and not only when the some regional markets are conducted in order to maintain the flows through the tie-lines. So, in case of a sudden occurrence of plausible contingency[3] 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.

[3]The occurrence of contingencies, such as a natural disaster causing the loss of 75% of transmission lines, leading to systemwide blackout needs to be excluded from the discussion.

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. As described in the previous section, the principal reasons for having an interconnected network through tie-lines are more reliability related than economics driven. Thus, the amount of the transactions does not fully reflect the possible cost savings by importing electric power from the inexpensive regions to the expensive regions.

The electric utilities are established as (regulated) vertically integrated natural monopolies serving captive markets in a cost-plus business. Utilities function more as colleagues than competitors, since the very nature of the business prevents competition. With the assurance that costs can be passed on to the rate-payers, the utilities build extensive and fairly reliable systems with the main aim of moving power from the generating plants to the consumers with an appreciable level of reliability. With no need for competition, utilities trade power primarily to help meet acceptable levels of reliability, which limits the scale of inter-regional transactions.

The goal of maintaining reliability also means that vertically integrated utilities do not have to trade power over long distances. It is sufficient to import (or export) enough power from (or to) adjacent regions for reliability purposes. Inter-regional transactions are therefore limited in scope.

Additionally, utilities do not strictly control tie-line flows, but agree on, and monitor the net inter-change between regions. The flows on the lines are then somewhat loosely regulated and at the end of an agreed-upon period (a day, month or season), the deviation from the flows are paid back *in kind* as net. This means that a utility that experiences a net export for a number of hours within a particular operating period (peak or off-peak, say), would have to export to the other utility for the same number hours during a similar operating period, and vice versa.

With the introduction of competition the characteristics of inter-regional transactions have changed, as market participants attempt to take advantage of cheaper power in distant locations by transporting power over longer distances and across several regions and market structures. This has led to an increase in both the scope and scale of inter-regional transactions, making the management of transactions through voluntary cooperation insufficient.

There are several identifiable reasons for the change in management systems. 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. This means that the participants in the transaction will have to deal with one or more intermediary regions in addition to the source and sink regions. Therefore a more structured approach to managing the transaction will be required than the selling and purchasing regions simply agreeing to a net scheduled interchange.

Second, the amount of energy involved in the transactions desired by marketers for economic reasons may exceed the amount assessed by the utility as necessary for optimal reliability. As mentioned earlier, the utilities design the tie-lines with a view to accommodating interchange quantities close to that assessed for optimum reliability. To accommodate the increased level of transaction will then mean incurring additional cost to purchase IOS or to reinforce the transmission network. This will require a balancing of these costs and the economic benefits of implementing the transactions.

Third, the tie-line flows can 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 [10]. The SC is responsible for the safe and reliable operation of the interconnected network including several control areas managed by the respective TP's.

First, the network users enter into various energy contracts for trading electricity across multiple regional boundaries. Of these contracts, the users involved in physical transactions determine the shortest transmission path possible between the injection point and the withdrawal point of each transaction. This transmission path is then used for accounting the usage of the network for carrying out the trade as specified by the contract. Because the transmission path decided by the users is only for the contractual purposes and is not related to the actual usage of the transmission system, it is called the contract path [11]. The users can reserve the transmission capacity necessary for the transaction along the contract path with the respective TP's. There are 7 priority levels of transmission capacity reservation defined by NERC, at the time of writing. Once the necessary transmission capacity reservations are made over the specified period of time according to the preference, the suppliers (and loads) involved in the transactions may inject (and take out) the specified amount of power by the contract into (and from) the interconnected network.

Then, while the various inter-regional transactions take place as specified by the respective contracts, any TP's may call for so-called *transmission loading relief* (TLR) procedures to be implemented by the SC in case of any violations in the operating security limits, typically network related limits such as transfer limits on *flowgate*[4], believed to be caused by inter-regional transactions. It is assumed that if any of the operating security limits *defined by the individual TP* in each region is violated, the reliability of the entire interconnected network is in danger of being lost. The TLR procedure is a method for mitigating potential or actual operating security limit violations [11]. When particular operating security limits are violated, requiring the implementation of the TLR procedures, the SC identifies the

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

likely inter-regional transactions causing the violations based on simple computation using the interchange distribution calculator. The identified transactions are then curtailed in the order of lowest level of transmission capacity reservation until the system conditions are again within the operating security limits. The details of the TLR procedures may be found in [11].

There are several inefficiencies associated with the inter-regional transactions managed by the SC because of the improper placement of incentives and responsibilities [5]. We discuss a few of the rather major inefficiency issues here.

First, one of the major problems under the SC scheme is that the TP in each region has no strong incentives for establishing well-defined operating security limits related to the inter-regional transactions. Suppose some TP's define several flowgates in the interconnected network without carefully considering the projected inter-regional transactions scheduled to take place. Then, operating within the security limits of these flowgates may not ensure the reliability of the system because of the effect of the inter-regional transactions. Similarly, the violation of the security limits may not mean the degradation in reliability, either. Given that the TP's are only responsible for the safe and reliable operation of their respective networks, the security limits defined on flowgates are likely to be highly conservative without thoughtful concern given to the economic aspect of the inter-regional transactions. 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.

Then, the other major problem is related to the passive nature of the SC. Upon TP's request for implementing TLR procedures, the SC identifies the likely inter-regional transactions causing the violations and then curtails those transactions in the order of lowest level of transmission capacity reservation until the system conditions are again with in the operating security limits. Before the implementation of TLR procedure is requested, however, the SC is not in any way involved in the inter-regional transactions. Given that the SC may be most familiar with the operation of the interconnected network, the SC can support the network users to identify the truly economical inter-regional transactions which result in savings not only in generation costs but also in systemwide IOS costs, etc. by avoiding the transactions which may cause the implementation of the TLR procedures. Under the proposed market mechanisms in the patent 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 not reactively by implementing TLR procedure *after* the reliability related problems are identified.

Finally, there is another major problem linked with the restoration of the interconnected network back to within the operating security limits. With a number of curtailments implemented by the SC following the TLR procedures the operating conditions may no longer violate the security limits on the flowgates at the moment. However, as the system conditions are constantly evolving this type of rigid process of restoring the network can hardly be optimal. In some cases it may be more reliable not to implement the TLR procedures immediately following the violation of the security limits because the system condition may soon be changed so that carrying all of the inter-regional transactions supports the overall network better than curtailing some of the transactions. 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. Plus, 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 reactionary TLR procedure with the proactive bidding process. In the following section we describe the implementation of the inter-regional transactions under other proposed market mechanisms, for further comparison purposes.

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 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 [1] and [7]. 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. Only a brief description of the method is given here for discussion purposes, and the detailed explanation of the method is deferred to [1] and [7].

In this approach each control area performs a system-wide economic dispatch. However, the operator in each area considers only the constraints in his area as binding. Constraints on lines outside of his control area are accounted for as an added cost in his objective function.

In an iterative process each operator reports the net loads and locational congestion costs arising from constraints in his region that would apply to adjustments in the net loads at any location in the grid. Each control area operator then adjusts the energy prices and schedules and recalculates the new transmission prices in his area based on the adjusted nodal prices.

To illustrate with the 5-bus system in Figure 2, first the operators will each balance their respective markets and arrive at their desired operating levels. It is assumed that tie-lines belong to one of the 2 regions, for instance line 4 may belong to region I and line 5 to region II. If the schedules are feasible considering the interconnected system, no redispatch will be required. However redispatch will be required if the schedule in one region causes a violation in another when implemented simultaneously. For example the simultaneous dispatch may result in a line flow on line 3 that is in excess of the 80MW limit.

If a redispatch is necessary, then regions I and II will exchange information on their net loads and adjustment bids for generators. Region I will then perform a system-wide economic dispatch using the net loads from region II, and the adjustment bids to price generation in region II. In this case the operator explicitly models the actual limits on lines 1, 2 3 and 4 only, and assumes that lines 5 and 6 are limitless. Region II does the same, including limits on line 5 and 6 only, meaning that it ignores the 80MW limit on line 3.

Based on the resulting solution each operator can determine the locational congestion costs arising from its own constraints that would apply to adjustments in the net loads at any location in the grid. The operators exchange information on net loads and adjustment bids and congestion costs, update estimates of net loads, reformulate their economic dispatch problem to include the adjustment bids and the associated congestion costs from the other regions, and perform a new redispatch.

This process continues until there is no significant change in the dispatch of either region.

There are several inadequacies associated with the method of coordinated OPF across multiple regions because of the impracticality in implementation. We discuss a few of the major issues relating to its impracticality here.

First, one of the major problems under the coordinated OPF method is that there are inherent difficulties in defining security limits for the network. As described earlier, the security limits are defined as a result of numerous off-line reliability studies. This entails, at the minimum, establishing a few system operating conditions around which the regional network is usually being managed. These operating conditions are often referred to as *nominal conditions*. Although it is not trivial, establishing nominal conditions is a doable task for an individual TP so long as the uncertainties to be considered are contained within its own region. Thus, often times, the uncertainties associated with interactions outside the region are accounted for by modeling several possible exchanges through tie-lines. If the exchanges through tie-lines are expected to vary extensively, then the the security limits may need to be time varying as well or, at the least, may mean quite different levels of reliability. If there is a minimum level of reliability to be achieved, then this requires procuring different amounts of IOS. Since under the coordinated OPF method the security limits need to be defined by the TP's without reflecting the change in actual reliability level due to the outside regions through the different amount of the IOS to be procured in the respective regions, the security limits are either very conservative or time varying as the system conditions change. Given that the TP's are only responsible for the safe and reliable operation of their respective network, the security limits are likely to be defined as highly conservative rather than time varying, 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.

Then, the other major problem is related to the inability to convey the regional characteristics of individual control areas in deciding the transfer across multiple regions. Some control areas may have more expensive transmission network due to many peculiarities in the region, such as higher property cost and so on. By treating each line in the entire interconnected network in the same way, the regional tariff structures developed to be best suited for the respective regions by the market participants are completely ignored in implementing the coordinated OPF method. Under the proposed market mechanisms in the patent 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 IV 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 interregional 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.

B. Flowgate rights allocation method across multiple regions

The flowgates right approach to inter-regional transaction management is representative of the link-based approach [2]. 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.

The flowgate method is a system of flow-based transmission rights that, unlike the contract path approach, attempts to match scheduled transactions with the actual power flow by using the power transfer distribution factors (PTDF) derived from Kirchhoff's laws to translate the physical effects of each energy transaction into requirements of transmission rights.

The underlying market structure assumed for the flowgate rights is rate of return regulation imposed on the transmission owners and operational authority assigned to a non-profit independent system operator (ISO). Under this market structure, market participants submit bids to purchase flowgate rights once at the beginning of the year (or season). The ISO then determines the price and amount of flowgates to be made available, and allocates the network capacity corresponding to the flowgate rights based on the bids. Each flowgate right issued to participants specifies, at least, the designated flowgate (i.e. the line that is likely to be congested), and the capacity offered on that flowgate.

The flowgate rights grant the holder a capacity reservation or scheduling priority for using specific transmission links. If the holder fails to use the right by scheduling power transactions, the scheduling priority expires and the right reverts to the system operator. The holder can therefore not use it to prevent others from accessing the unused transmission capacity.

Once the allocation of flowgate rights is concluded, two separate markets, the forward and spot markets, are conducted sequentially. First, participants in the forward market arrange for transactions and acquire the flowgate rights necessary to implement the transactions from the current holders. If a participant arranges a transaction (backed by a flowgate) that reduces congestion on another flowgate, then he becomes the holder of the newly created flowgate rights in the amount by which the congestion is reduced. The process continues until all the transactions arranged are covered by flowgate rights. The network capacity of unused flowgate rights are returned to the ISO who then conducts the spot market.

Some marketers who choose to participate in the spot market can submit bids to that market. The ISO clears the spot market by solving the OPF problem subject to the network capacity limits redefined to incorporate the unused flowgate rights. Again, as a result of the market clearing process, the combined price of the energy and transmission portions of the electric services are determined by the nodal prices at each bus. The ISO collects and distributes revenue that is determined by the product of the injection into the bus and the corresponding nodal price. Part of the revenue is used to compensate holders of unused flowgate rights.

One of the major problems under the flowgate rights allocation scheme is that the TP in each region has to define the amount of rights available exclusively for inter-regional transactions ahead of time. For the 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 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.

In the situation where the TP needs to estimate the available flowgate rights, strong incentives are required for properly projecting the usage of flowgate rights at the energy market within the region. Suppose it is found after conducting the spot market that some TP's overestimate the usage of the available capacity through the flowgates. Then, the flowgate rights offered to the network users involved in inter-regional transactions may not insure the scheduling priority as desired.

In the situation where the TP needs to conduct the auction process once for the market participants within the region and for the inter-regional transactions together, 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 [4], 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.

On top of the problem mentioned above, the problem still exists for accurately assessing the total amount of the flowgate rights to be offered by the individual TP's with 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, there is a problem linked with the change in amount of flowgate rights available in a region due to the evolving operating conditions in the rest of the interconnected network. For example, when the operating conditions in one region changes, some operating conditions believed to be secure may no longer be the case in some other regions. Then, the operating security limits for certain links in those regions need to be adjusted. If the link on which the flowgate rights are issued happens to undergo an adjustment, then the amount of the flowgate rights available on that link also changes [4]. Because of this problem the amount of flowgate rights offered may be highly speculative and may require a continual adjustment depending on the evolving operating conditions of the entire 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.

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.

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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