[The following is a compilation of work in progress by the Option 2 work group. It represents the drafting of various authors with various understandings of how the concept might work. It represents, at this time, a number of styles of drafting. The group continues to work on making definitions more precise and on testing the concept under various alternative ways of doing it. L.W.]

D R A F T
Option 2 Report
October 8, 2003

Priority Block Concept – Description

The Priority Block concept is a method to provide for the sale of transmission capacity that is estimated to be available as a result of a flow analysis of the system. The amount of Priority Block Capacity ("PBC") is defined, for each period of time, as TTC less expected use of the system by existing contract holders and by prior purchasers of priority blocks. The amount of PBC would be divided into blocks that would be sold on short, medium and long terms

Under this concept, purchasers of transmission capacity can select a level of service that reflects their tolerance for being curtailed—and their willingness to pay for better service. For example, Priority Block 1 would be curtailed after Priority Block 2, which would be curtailed after lower-order blocks, and so forth. Priority Block 0—firm service—would be curtailed last, but, in many cases, such service is not available in a contract-path system.

The Priority Block concept is one component of Option 2's method to bridge the gap between the existing contract-path transmission service and a physics-based service based on actual power flows. That is, the contract-path methodology may show that transmission is not available when a study of transmission flows indicates that it is available—or vice versa. The Priority Block concept addresses the difference between contract-path and physical-flow availability of transmission capacity.

The notion is to divide the estimated amount of "freed up" flow-based transmission into blocks that could be sold. The sale of such blocks would be done, however, in a manner that maximizes their value—by establishing lower- or higher-probabilities of being curtailed. The highest priority blocks may be as firm as current firm service today.

Where Option 2 differs from Option 3 is in its reliance on curtailment (and subsequent market-based adjustments to obtain economic efficiency) to balance resources and loads rather than relying on a centralized operator to perform the tasks through purchases of incs and decs. While both options rely on bilateral transactions, Option 2 retains the bilateral character throughout. That is, there is no intervention by the Independent Administrator (absent a security problem) to purchase or sell power as there would be under Option 3.

Under the Priority Block concept, after all schedules have been submitted, the IA tests the system to see if they are all feasible. If not, then those low priority blocks on congested paths will be curtailed, and the schedule holder will make. This concept is discussed in more detail below.

Sale of Priority Blocks

Because the IA will identify PBC in the short and long terms, the blocks can be sold on the same terms: long and short. Thus, a transmission purchaser seeking new high-grade service may request a high-priority long-term block based on the assessments of usage of IA—or, as separately determined by its own analysis, or both.

Principles: Those who value it the most should get new Priority Block transmission rights. Transmission price should approach its marginal value to users.

Discussion: There are a number of ways that priority block transmission could be sold including auctioning them to the highest bidders and selling them at a fixed schedule that discounts the price relative to the OATT rate. For example, the first (most firm) block could be priced at 95 percent of the TO's OATT price, the second block could be priced at 90 percent, etc. Using a fixed schedule to sell priority block rights would provide price certainty in advance for both potential buyers and sellers for each priority block grade. Another advantage is that the price would never be higher than a TO's OATT rate, so current OATTs may not need to be modified to allow for prices above the tariff rate. A disadvantage with using a fixed discount schedule is that prices are not flexible and responsive to market conditions. As a result, transmission may be sold on a first come-first served basis rather than to those who value it the highest. It should be noted that under the IA approach, that you need to have the appropriate transmission rights in order to submit a schedule.

Another way to price priority blocks is to auction the blocks to the highest bidders. The advantage of auctioning the rights is that those who place the highest value on the rights receive the rights, which improves economic efficiency. A potential disadvantage is that prices could exceed the tariff rate or could be very low. [One solution is to reimburse TOs only up to their tariff rates, leaving excesses to the IA to reduce uplift or other purposes.] While exceeding the tariff rate is not a problem from an efficiency perspective (except to indicate that the tariff rate may at times be too low), it may not be allowed under current OATTs. These potential problems can be eliminated by placing a cap and floor, or minimum charge, on bids, where the cap is the tariff price.

If the priority rights are defined as either injection-withdrawal rights or path-based pseudo-physical rights the referenced tariff rate would be the flow weighted average tariff for the lines associated with each path. This complication holds for both the fixed schedule approach and the capped auction approach. If rights are defined as path-based rights the IA calculates where energy would flow for a given injection-withdrawal. Rather than an injection-withdrawal transmission right, the buyer purchases rights on each path the power flows over based on the IA's determination of flows. The pseudo-physical rights are not physical rights as currently defined since each schedule would need rights on all of the key paths that the schedule uses.

Changing the injection and/or withdrawal point likely means that rights purchased for a different schedule would not be sufficient for the new schedule.

The most appropriate pricing method may depend on the term of the rights. For example, it may be that longer-term rights (months or years in advance) could be priced based on a fixed schedule, and short-term rights would be auctioned.

The working group is considering two forms of priority blocks and two forms of their application, as is represented in the following matrix.

	Fixed Size Blocks in MW	Blocks defined by estimated probabilities of curtailment
Injection / Withdrawal	Blocks defined as below, but from injection point to withdrawal point.	IA and or utilities would provide blocks based on expected curtailment probabilities (e.g, X MW with 87 hours per year expected curtailment, Y MW with 200 hours per year, etc.), with financial consequences of curtailments above those amounts secured by financial hedges.
Injection / Withdrawal mapped to flow paths	Transmission rights and/or priority blocks (of a fixed size, say, 5-10 MW) would be required based on flows estimated from the I / W analysis of the IA.	Blocks defined as above but mapped to estimated flow path usage.

Priority Block -- Recognized Risks

While the priority blocks can be sold short or long term, there are certain risks that inhere to them. First, in the near term, there is the risk of being curtailed in advance of a higher priority block due, for example, to a) transmission or generation outages, and/or b) higher than expected service requests from existing contract-path rights holders based on their contracts at or about pre-schedule time. Second, there is a potential of long-term erosion of PBC, and therefore a risk of curtailments of lower priority blocks, due to load growth allowed under existing contract-path rights.

Methods of Estimating Short-Term PBC

One major task of the IA will be to provide an estimate of PBC on a flow basis before schedules under existing contracts or priority blocks are submitted. The levels of schedules under existing contracts likely will prove to be one of the more difficult things to estimate. What is almost certainly required is historical information on resources, loads and/or schedules to gauge what uses of the transmission system will be—for example, under a variety of load, weather and hydro conditions. Operating costs must be known or estimated by the IA. Such data may be confidential—or considered so. The analysis of such data will be a major modeling exercise. The result, of course, will be an estimate of operations for the near term and therefore an estimate of unutilized PBC available on a flow-path basis for the entire system.

The result of the estimation almost certainly not be a single number but will be a range of PBC for each major path, depending on the assumptions made about the system, informed by the history on that path and power-flow history elsewhere.

One chief issue to be decided by the IA at the outset is how conservative the determination of PBC will be, recognizing that the low priority blocks can be curtailed if conditions warrant. A more liberal interpretation of PBC will provide for more transmission available to be marketed but, as a result, a greater reliance on interruptions of the priority blocks. On the other hand, a more conservative interpretation of PBC will restrict the amount of PBC available for sale, but what is for sale will be firmer. The issue of conservatism in the selection of PBC is made less crucial if other entities have access to the same data as the IA, so that independent estimates of PBC can be made and relied upon. Thus, one difficult issue will be the release of confidential data either masked or under confidentiality covenants.

Once available PBC is determined, new requests for transmission service need to be analyzed on a injection/withdrawal flow basis and path usage estimated, so that contracts for service can be let with each of the affected TOs.

Decisions regarding flow-path usage necessarily will lead to the question of whether to ignore or to count de minimis flows. Ignoring de minimis flows will affect the quality of some or all priority blocks and will complicate potential schedule curtailment. On the other hand, requiring recognition of de minimis flows over some paths will improve priority-block curtailment estimates and allow more precise adjustment to schedules in the event of potential congestion.

Estimating PBC for the Long Term

Estimating PBC over longer terms will require some of the same methods as the estimation of short-term PBC, but with the addition of projections of loads and resource usage under existing contracts.

Of importance is the independent character of the IA's analysis of load growth and resource utilization changes, so that the estimated long term PBC can be maximized. That is, the loads projecting their growth may provide information to the IA, but the IA must determine independently the nature of load growth. Likewise, with the utilization of resources under current contracts a similar independence must be maintained.

The appropriate term of priority block transmission rights

Principle: The IA should offer priority block transmission rights that maximize the potential benefits of the transmission system to transmission users.

Discussion: Long-term transmission rights, even rights that are less than firm, allow rights owners some measure of certainly that they will be able to deliver power to customers. As such, long-term rights are more valuable than short-term rights.

Recommendation: The IA should offer long-term transmission rights as well as short-term rights.

Nature of Rights

Issue: Should the IA exclusively determine which priority block transmission rights to offer for sale, or should transmission users be able to request rights for particular injection-withdrawal pairings?

In the initial concept, a potential transmission user would identify injection and withdrawal points that the IA, through power-flow studies, would translate into "true" contract paths based on actual power flows. The transmission requestor would be obligated to purchase rights on the identified paths from the individual TO owners. An alternate concept would have the transmission user simply identify the I/W points and obtain rights for the points from the IA, which would have separately estimated where flows would be.

Discussion: The IA should be able to determine which paths are constrained and on which paths additional transmission rights are available on a flow basis. However, the rights that the IA offers may not always match the injection-withdrawal pairs desired. Allowing users to make transmission requests would ease the burden on the IA to determine what rights to offer, and it would help ensure that the rights it does offer are those desired by transmission users. In addition to particular injection-withdrawal pairs transmission requests could include the desired term of the rights. Again, this would help the IA in offering rights that potential users desire.

Recommendation: At least initially, transmission users should be able to request service for particular injection-withdrawal pairs. The IA would be under no obligation to offer rights as requested. [??]

Upgrading Rights

If a customer of the Independent Administrator (IA) requests transmission rights from an injection point to a withdrawal point and the IA determines upon application of its flow based methodology that the transaction can be granted, the application shall be enabled by the IA. This new right is a firm transmission right granted under the authority of the IA acting as the agent of the transmission owner.

In the event that there is not sufficient capacity in the transmission system to grant a firm right, the IA will inform the transmission requestor that firm rights are not available and direct the requestor to the priority blocks. In addition, the constraint(s) identified during the studies of the request will be given to the requestor. The transmission requestor may take service in the priority blocks or elect to make investments in the transmission system sufficient to create the capacity for a firm right to be granted.

The requestor may elect to make investments in the transmission facilities included in the IA's OASIS to enable creation of firm rights sufficient to allow the requested service to proceed as firm transmission service. The requestor must meet the IA's credit worthiness standard and the engineering standards of the transmission owner(s) as an initial step in the construction process to create the needed firm transmission capacity. The requestor shall also follow the Interconnection process contained in the pro forma tariffs of the transmission owner(s). The Interconnection process identifies the milestones, fees, and study procedure that will be followed. [Must open opportunity to participate in proposal. Principle: people putting in the money should get maximize reasonable rights to usage of system, but not ownership per se. TOs still own and operate system.]

Upon completion of the construction of the necessary facilities, the transmission requestor shall be granted firm rights for the injection/withdrawal points contained in its request. The term of this right will be as defined in the agent agreement between the transmission owners' and the IA.

Sales/pricing of priority block transmission

Principles: Those who value it the most should get transmission rights. Transmission price should approach its marginal value to users.

There are a number of ways that priority block transmission could be sold including auctioning them to the highest bidders and selling them at a fixed schedule that discounts the price relative to the OATT rate. For example, the first (most firm) block could be priced at 95 percent of the TO's OATT price, the second block could be priced at 90 percent, etc. Using a fixed schedule to sell priority block rights would provide price certainty in advance for both potential buyers and sellers for each priority block grade. Another advantage is that the price would never be higher than a TO's OATT rate, so current OATTs may not need to be modified to allow for prices about the tariff rate. A disadvantage with using a fixed discount schedule is that prices are flexible and responsive to market conditions. As a result, transmission may be sold on a first come-first served basis rather than to those who value it the highest. It should be noted that under the IA approach, that you need to have the appropriate transmission rights in order to submit a schedule.

Another way to price priority blocks is to auction the blocks to the highest bidders. The advantage of auctioning the rights is that those who place the highest value on the rights receive the rights, which improves economic efficiency. A potential disadvantage is that prices could exceed the tariff rate or could be very low. While exceeding the tariff rate is not a problem from an efficiency perspective (except to indicate that the tariff rate may at times be too low), it may not be allowed under current OATTs. These potential problems can be eliminated by placing a cap and floor, or minimum charge, on bids, where the cap is the tariff price.

If the priority rights are defined as either injection-withdrawal rights or path-based pseudo-physical rights that the referenced tariff rate would be the flow weighted average tariff for the lines associated with each path. This complication holds for both the fixed schedule approach and the capped auction approach. If rights are defined as path-based rights the IA calculates where energy would flow for a given injection-withdrawal. Rather than an injection-withdrawal transmission right, the buyer purchases rights on each path the power flows over based on the IA's determination of flows. The pseudo-physical rights are not physical rights as currently defined since each schedule would need rights on all of the key paths that the schedule uses. Changing the injection and/or withdrawal point likely means that rights purchased for a different schedule would not be sufficient for the new schedule.

The most appropriate pricing method may depend on the term of the rights. For example, it may be that longer-term rights (months or years in advance) could be priced based on a fixed schedule, and short-term rights would be auctioned.

Independent Administrator Operations

1 - The IA, receiving information through its OASIS, will be the administrator of all schedules. It will receive schedules proposed by holders of existing firm contracts, validate them for consistency with the provisions of their contracts and enter the points of injection and withdrawal into its power flow program data base, by hour. (Some or all of this process may be automated, e.g., the entry of proposed injections and withdrawals directly through the OASIS function). This will require the following:

- Knowledge of all the relevant existing contract provisions, akin to the catalog proposed in Option 3. If the validation is done by the contract-issuing TO, there will need to be some additional step in the process. (Resolution: IA will validate based on catalog in pre-schedule or prior time. There are questions about how to handle last-minute changes in schedule per contracts. Disputes will go to TO for resolution.)

- A detailed power flow model for the region.

2 - The IA will also receive the schedules proposed by holders of the various kinds of nonfirm rights ("priority blocks"). It will validate them itself, since it was part of the rights issuing process for these new, post-IA rights. It will (again probably automatically through the OASIS function) enter the proposed injections and withdrawals into the power flow data base.

> Issue: An open question is the representation of the rest of the West (including the operation of the phase shifters) in this program. Leaving out the rest of the West and the phase shifter operation will distort the power flow results shown for the Northwest. Putting it in raises directly the question of interaction with the other RTO/ISO entities in the West.

3 - The IA will run the power flow model to determine whether all the proposed schedules can be met without violating security constraints. If they can, they are accepted. If they cannot, the lower priority proposed schedules are stripped out, one priority level at a time, until the program solves satisfactorily. This program does not determine generation dispatch; it merely determines whether resulting flow levels are within security limits. Note the following: [Question: Can the IA use phase shifters to make schedules work prior to curtailments? Major loop phase shifters reserved for real time. Standing price for use?]

- This determination is not whether any path's scheduling limit is exceeded, but whether the set of proposed injections and withdrawals, as a whole, exceed the system's (that part of it covered by the IA) security limits in any place. [Issue: The interaction of this with path scheduling limits, control areas and WECC requirements for scheduling limits is unclear.]

- The notion of stripping out schedules in inverse priority order is not clear. For this paper, I assume there are priority orders of nonfirm rights for any given set of injections and withdrawals, but these may actually involve multiple cut planes with different duration curves of usage (the model appears to be one cut plane with a single duration curve of usage). But since the set of proposed schedules that will not meet the solution criteria includes multiple sets of nonfirm rights with multiple injection and withdrawal pairs, it is not clear how to choose the set to begin the elimination process.

4 - Assuming the above points can be clarified, those with proposed schedules that have been rejected are notified by the IA. Assuming they have not made arrangements in advance, these market participants go to the bulletin board provided by the IA to see if they can satisfy their delivery obligations in some other way. This would involve (putting aside the question of demand-side adjustments) other generation picking up to meet the load. Some generator bids clearly will not address the need; others may or may not. Market participant experience may help to reduce this uncertainty, as might information supplied by the IA.

5 - A second round (at least) of proposed schedule consideration is needed to ensure feasibility of the set of generation bids selected by those participants whose proposed schedules were rejected in the first round. This iterative process is required because the bids are made available to the individual market participants to remedy their positions, rather than to the IA as the central entity doing the power flow analysis. [If you have been approved on the first round of schedules, are you guaranteed a schedule on the second round?]

6 - When this process is concluded, the IA will be able to pass to the various control areas the set of feasible dispatches [as schedules?]proposed by the market participants, which the control areas will in turn use for reference points in operating the system. Control area checkout can be bypassed since the IA information is internally consistent already, at least for the control areas within the IA footprint.

7 - Depending on provisions of existing contracts, schedule changes may be allowed between this point and beginning of the operating hour. As changes are made (or perhaps at specific

intervals, aggregating changes to that point), those with nonfirm rights that were previously accepted may be rejected, requiring some iteration of Step 5.

8 - Whenever this step is concluded, the IA responsibility ceases and the security coordinator, working through the control areas, takes over responsibility for secure operation of the system. This task is eased by virtue of the security coordinator's knowing that the set of dispatches within the IA footprint is feasible and meets reliability constraints. It does not take account, as today, of any loop flows from outside that footprint. There could be coordination with the other RTOs in the West.

Allocation of Revenues from Sales of Incremental Transmission.

The first question that needs to be asked is, "What price should be charged for sales of incremental PBC?" While it is easy to presume that lower priority blocks would have lower value, it may not be so in all cases. For example, NorthWestern Energy frequently sells nonfirm transmission at full prices. The value of the transmission is as dependent on market spreads as it is on its firmness. Assuming that there is market price transparency (a big assumption), then one means of valuing transmission is to share the spread among transmission owners and the marketer. A way to do this would be to divide the market spread by the number of transmission systems involved plus 1. For example, a transaction between the Colorado Front Range and the mid-C may flow on PacifiCorp's, Idaho's, NorthWestern's and Bonneville's systems, thus a divisor of 5. If the market spread is $10/MWh, then the marketer would be allocated a margin of $2 while the remaining $8 would be available to pay for transmission.

The transaction revenue needs to be allocated by some means. There are three thoughts that immediately come to mind. The simplest is to allocate the revenue equally among the systems over which the transaction flows ($2 each in the example above). Another way would be to prorate the revenue according to the firm PTP rates of the systems over which the transaction is scheduled. The third way is to allocate the revenue according to the flow factors in some fashion.

The advantage to the simple alternative is that it is, well, simple. There is not a lot of ground for contention over the mechanism. On the other hand, it may not be equitable. For example, $2 is greater than Idaho's fully allocated rate while it is less than half of NorthWestern's fully allocated rate.

The second alternative allocates the revenue on a more equitable basis; i.e. every transmission owner is discounting on an equal percentage basis to enable the transaction. It eliminates the gamesmanship among TOs that goes on today over who should discount to make a deal happen and how much.

The third alternative's main advantage is that it is consistent with the concept of flow based scheduling. Because of the variability of flow distribution factors, this system is more complex, although it probably makes sense to use whatever flow factor was used to make the determination of PBC for the transaction. In the example above, it is likely that 100% of the flow occurs on both the PacifiCorp system and the BPA system with the flow dividing on the NorthWestern and Idaho systems. In that case that PacifiCorp and BPA would each receive $2 and NorthWestern and Idaho would split the remaining $4 according to flow factors. Again, however, this scheme could allow for an allocation of revenue greater than a TO's fully allocated rate as discussed in alternative 1 above.

The second alternative is likely the most equitable means of allocating incremental transaction revenue because it assures that all parties discount on an equal percentage basis. I should note here, however, that NorthWestern's fully allocated rate is among the highest in the region, so this alternative would result in NorthWestern getting a large share of revenue associated with any transaction using its system. Aren't you happy for me?

Issue: Which alternative allocation method?

Independent Administrator Functions and Characteristics

A. Governance Principles

1. The legal structure is a non-profit corporation (the "IA") incorporated in Oregon (or some other state).

2. The IA will seek 501(c)(3) status as a charity under the IRC as appropriate ("lessening the burdens of government")

3. The IA is governed by a nine-member board of directors.

4. The directors are elected by 30 stakeholder representatives (the Stakeholder Committee) from five stakeholder classes (6 representatives from each class). The classes are: TOs, TDUs, marketers and IPPs, large and small retail consumers, and public interest groups (states, provinces, tribes, environmental groups)

    a. [note: conform to stage 1 filing]

    b. [note: may need to revisit 4-2 split within class]

    c. [note: may need to revisit definition of "affiliate"]

5. The Directors must be independent of market participants as defined in the RTO West Stage 1 filing. The Stage 1 qualifications are attached.

6. You need 24 votes to be elected to the board; you can be removed with 20 votes.

7. Each director must stand for election every three years; the first terms are staggered such that three directors must stand for election every year beginning in year 2.

B. Membership in the IA

1. Anyone may join the IA for a fee of $100. [Possibility of higher fee, with waivers.]

2. Every member will be assigned to the appropriate class for purposes of electing representatives to the Stakeholder Committee.

C. Budget Limitations

1. The TOs will develop an Initial Operating Budget sufficient to permit the IA to perform its Day 1 functions. The IA may challenge the adequacy of the Initial Operating Budget before through binding arbitration with no right of appeal solely on the grounds that the budget is not adequate for it to perform Day 1 functions assigned to it under the Option 2 approach.

Question: What does it mean that the IA challenges the budget? Doesn't it propose the budget?

Issue: Should the "Stakeholder Committee" have the right to rejec IA budget proposals that exceed x%?
Issue: Do we need automatic escalators?

2. Thereafter, the IA may modify its Expense Budget after review and comment from the stakeholders as it sees fit from year to year as long as the budget does not increase from year to year more than [5%].[1]

3. Similarly, the TOs will develop an Initial Capital Budget and a Capital Budgeting Policy to guide future capital decisions by the IA. Both are subject to binding arbitration by the IA for sufficiency to allow the IA to perform its assigned duties.

4. Thereafter, the IA may modify its Capital Budget after review and comment from the stakeholders as it sees fit from year to year as long as the budget does not increase from year to year more than [5%].[2]

5. The back stop authority to contract with a third party to build needed Tx and allocate costs to benefiting TOs is not subject to these budget limitations.

D. Limiting IA Changes in Functions

1. Any "major" [to be defined] change in IA function may be effected only after public review and comment by the stakeholders in a regional process, and a decision by a majority of the Board to submit a proposed change to the Stakeholder Committee.

2. Any "major" change in policy requires a majority vote of the Stakeholder Committee.

   Note: A majority vote would require 16 votes. The subgroup does not have a consensus on whether a simple majority is sufficient protection to assure regional support for recommended changes. Some suggested requiring a super majority of 20 votes (2/3 of the Stakeholder Committee); Others suggested 24 votes should be required, effectively giving veto power to prevent change to just 7 Stakeholder Representatives.

Issue: What is the voting rule?

3. A "Major changes in policy" includes:

   a. If option 2 eliminates pancaking by adopting a "company rate"

[1] The IA may need more liberal increases for, say, the first three years, followed by more limited increases of, say, 3% annually after that—need to avoid creating an incentive to spend to the limit by allowing it to carry over increases cumulatively or it may act to spend to the cap every year out of a desire to preserve flexibility, a rational response to caps] or cumulatively.
[2] The principles for a Capital Budget and an Operating Budget are the same. The IA needs to be able to replace software and equipment that become obsolete. The Operating Budget is designed primarily to assure adequate staffing. There may be alternative ways to address the capital needs of the IA. If the IA has a tariff, it would be able to finance capital additions through debt secured by the ability to raise rates (uplift charges spread over schedules). This is a subject that could be addressed in the Capital Budgeting Policy. This seems like a workable approach.

approach involving assigning embedded fixed Tx costs to loads, a proposal to move away from company rates;

b. If option 2 does not contain an elimination of pancaking, a decision to eliminate it.

c. A significant change in the method of managing congestion management;

d. A change that mandates participation in any market by any entity;

e. A change that expands the authority of the IA over any TO, market participant, or TDU without their concurrence.

f. Amending the bylaws or articles of incorporation of the IA.

g. A "Major change in policy" does not include a voluntary, bilateral agreement between an entity and the IA to obtain services at the entity's expense from the IA acting as an agent on behalf of that entity, including:

   i. consolidating other control area functions;

   ii. buying or selling ancillary or redispatch services;

   or

   iii. otherwise performing services that may be of benefit to the requesting entity.

Issue: What approval is necessary for a major change in policy?

h. A "Major change in policy" does not include modifications to existing functions to improve them

E. Mandatory Policy Review

1. At the end of [three years of operation], the IA[3] must conduct a comprehensive review of IA and related Tx functions in an RRG-type process, and make a report to the membership, state and provincial regulatory entities of IA participants, and to FERC on changes it believes are necessary or desirable to improve the efficiency in the use of NW transmission, improve system reliability, reduced costs, reduce risk, improve markets, or recommendations on other subjects it believes are desirable. Any recommended change must also minimize cost shifts, maintain equity, and be in the best interests of the consumers within the IA footprint.

2. At any time the IA may form a technical advisory committee composed of technical experts and Stakeholder Representatives to address a subject the IA believes needs attention through a public process. The technical advisory committee shall report its findings to the Stakeholder Committee, state and provincial regulatory authorities, and FERC.

[3] An alternative approach might to empanel a "blue ribbon commission" of NW experts to prepare the report for public review and comment through an RRG-type process.

3. A Stakeholder Class may ask the IA to initiate a similar technical advisory committee to look into a matter of interest to that Class. The IA may decline to accept this request if the proposal lacks support from other Classes, unless the requesting Class agrees to pay the expenses of the advisory committee.

F. Relief Valve ????

G. Basic Contractual Structure with TOs

1. Each participating TO will sign a common "reciprocity agreement" with each other agreeing to implement the provisions of option 2.

2. Each participating TO will sign a common "agency agreement" with the IA providing for the IA to perform option 2 functions assigned to the IA.

3. Any TO, market participant, or TDU may voluntarily sign a common "bilateral agency agreement" developed by the IA for offering services the TO, market participant, or TDU may wish to obtain from the IA at the TO's, market participant's, or TDU's expense.

4. Functions to be performed by the IA pursuant to the reciprocity agreement:

    a. operates an OASIS, including a voluntary bulletin board of services available, including, but not limited to: redispatch, ancillary services, energy imbalance, day-ahead energy, forward services, financial products, demand response;

    b. determines a common method for determining PBC, ATC, OTC and TTC(?) across the IA footprint; Note: Not clear whether TTC is proper IA function.

    c. calculates system PBC, ATC, OTC, and TTC(?) using data provided by each TO;

    d. sells PBC (and ATC?) as an agent for TOs, where available, including firm Tx supported by redispatch arranged at the request, and expense, of a market participant [???];

    e. sells conditional firm Tx with specified rights (query whether the quantities of each block is determined by the IA in advance—1%, 5% 10% product). IA would set the quantity available in each block.

        Note: Not clear whether these blocks would be auctioned off or allocated according to a queue of first in time, first in right.

    f. at the request of a market participant, IA acts as agent to arrange requested services at the expense of the requestor; these can include any of the services described above, operating control areas if desired by a requesting TO, or other services;

    g. develops an annual Tx plan for the IA footprint considering non-construction alternatives, environmental factors, cost, seams, and other relevant information;

h. implements Tx back stop authority as necessary [permitted?] to cause construction of Tx that is not being built in accordance with the Tx plan;

i. prioritizes system improvements;

j. receives and approves requests for interconnection;

k. schedules all transactions involving Tx through existing control areas using an injection and withdrawal approach based on TOs' contract path schedules and new injection /withdrawal rights.

l. [provision of data base]

m. Publishes price and quantity data based on OASIS and bulletin board transactions.

Note: It may be appropriate for the IA to create a subsidiary corporation to provide fee-based services as agent (as opposed to services which are paid for through an uplift charge), to protect tax-exempt/non-profit status, to minimize liability and taxes, to avoid a conflict with its other duties, or other purposes.

H. Recovery of IA costs

Option A (IA tariff)

a. The costs incurred by the IA in responding to requests for services as an agent for market participants are paid through "service fees" established by the IA for these services

b. Remaining IA costs associated with mandatory functions (eg, OASIS, ATC, PBC and TTC calculations, etc) will be recovered through an "uplift charge" attached to schedules.

Option B (costs assigned to TOs)

1. The costs incurred by the IA in responding to requests for services as an agent for market participants are paid through "service fees" established by the IA for these services.

2. Remaining IA costs associated with mandatory functions (eg, OASIS, ATC, PBC and TTC calculations, etc) will be recovered by assigning these costs to PTOs pro rata based on loads, including external loads (export fee).

   Note: if costs are assigned to loads, there appear to be several possible methods including monthly or annual peak loads.

I. Pre-Existing Contracts

Pre-existing transmission service contracts will remain in force and will be honored by the TO and IA in a manner consistent with the contract provisions. Data base at IA will reflect what is in contracts, not to change the obligations.

J. Duties Assumed by PTO in signing the reciprocity agreement

1. [Yet to be drafted]

2. Each TO must inform the IA as to its annual maintenance plan, including planned outages.

3. Each Gen owner must inform the IA as to its annual maintenance plan, including planned outages.

K. Off Ramps

[Yet to be drafted—participants need to be able to leave the IA if it no longer meets their needs without jeopardizing the IA's ability to enter into contracts and continue to perform its functions]

L. Reliability Standards

[The Group A assumed Congress will act to give FERC authority to require the TOs and IA to meet mandatory reliability standards]

M. Liability

Major provisions:

1. **Force Majeure.** No Party will be considered in default as to any obligation under contract or IA tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

2. **Limitations of liability:** (premised on retaining WIES agreement)

Unresolved question of where these limitations are documented. Perhaps in service or integration agreement each participant must sign to schedule with IA.

a. IA liability for interruptions of service or quality of service claims limited to $[25] million, except where it is guilty of gross negligence or intentional misconduct.

b. IA liability for PBC/scheduling errors measured by cost of cover, or by actual damage.

c. No limitation of liability between TO or CAO and the customers of any other interconnected TO. (Rely on existing statutory and common law.) (Issue raised whether participation in IA materially increases risk of such claims by customers in other service areas.)

d. Any claim is limited to direct damages; no consequential damages.

N. ADR

These ADR provisions apply to all disputes that arise under the IA contract or tariff, including all disputes as to access and disputes about planning and use of backstop authority. They don't apply to disputes under an existing transmission service arrangement, which will be resolved under the terms of that contract or tariff. These provisions would be incorporated in each TO's tariff.

Process:

1. Mandatory informal settlement discussions
2. Party initiates arbitration by delivering statement of claim to IA and to other party.
3. Other party files response.
4. Parties select arbitrator from list maintained by IA of qualified, knowledgeable individuals.
5. Time limits for commencement of hearing and for decision.
6. Right of intervention for any other market participant directly affected.
7. Expedited procedures for scheduling disputes, and for generator interconnection disputes.

Decision:

Baseball or ?

Based on IA contract or tariff, applicable law and FERC precedent

Subject to appeal to FERC based on record developed before arbitrator, or right to judicial review.

Contractual Relationship Types

I. TO/IA-Mandatory
   a. Agency
      i. TO agrees to provide information
      ii. The IA determines power flows and PBC
      iii. The IA takes all new service requests and operates the regional OASIS

iv. The IA can commit the TO to sell posted ATC and/or PBC to a third party
v. The TOs commit to certain common tariff elements
  1. TO collects information from all interconnected generators
  2. Common transmission "block" products
vi. IA coordinates billing and payment

Confidentiality issue; IPPs may prefer to provide information to the IA then the TO)

b. Planning
  i. TO provides information
  ii. Single queue for transmission interconnection and/or expansion
  iii. TOs agree to pay their allocated share of any backstop facility
c. Market Monitoring
d. TO agrees to pay the IAs costs (unless there is a grid charge by the IA); define the process for managing the IAs budget
e. The IA assures common standards in the generation integration agreements between TOs and IPPs
f. IA provides ADR
  i. Define issues subject to arbitration

II. TO/IA--Voluntary
  a. IA operates TO control area

III. IA/Security Coordinator
  a. How does the security coordinator reach down to TOs and IPPs?

IV. IAs Articles of Incorporation/Bylaws
  a. Limits the functions that the IA may perform/define prohibited functions and thereby limits FERCs ability to bootstrap the IA into a more expansive role
  b. Process by which and by whom the IAs functions are modified.
  c. Functions include running a bid/offer bulletin board but the IA does not buy and sell to clear congestion

Ancillary Services Local Markets

The Independent Administrator (IA) will post on a bulletin board geographically based voluntary bids from generation willing to move in order for Transmission Customers (TC) to purchase redispatch rights that will allow transmission customers to firm up (or substitute for) transmission purchased in the priority blocks offered by the IA.

In order to indicate the locations where there is likely to be generation or load-interruption possibilities, the IA will make available information on its OASIS for the customer to satisfy its needs.

As may be allowed in some contracts between the IA and the some Transmission Owners (TO), the IA may also act as the agent on behalf of TOs to acquire ancillary services needed by the TO in the operation of the TO's control area. [Issue: Can independence be preserved?] In this process, the Interconnected Operations Services (IOS) needed by the IA for control area operations will be as general as possible and as specific as necessary. For example, the ability to raise or lower generation anywhere within eastern Washington versus the need for reactive support at the Fill-in-the-Blank 500 kV bus. In the former case, any generation owner located in eastern Washington could respond. In the latter, only generation or reactive devices connected to the Fill-in-the-Blank bus could respond.

These latter case may give rise to market power issues. The industry has attempted to resolve market power issues with price caps or controls. This is an area that needs further discussion.

Pancaked Rates

Two major alternatives are under consideration: 1) Assigning all costs to loads, thereby eliminating pancake rates, and using Company Rates and transfer payments to mitigate cost shifts, and 2) Retaining current contracts, and therefore pancake rates, for transmission charges. The following two sections outline the proposals.

Option 1 - Assign Costs to Loads

This is the opportune time for the Rate Pancaking issue to be addressed in whichever option is adopted by the RRG. Rate pancaking needs to be eliminated to solve the issues of:

1. Reduced efficiency. At times the Pacific Northwest operates higher cost resources when lower cost resources are available, but are not run as a result of transmission costs.
2. Distorted investment decisions in generation types and location. Potentially rate pancaking inappropriately favoring local, sometimes higher cost generation over distant less expensive generation.
3. In addition, eliminating rate pancaking solves many of the pricing issues associated with the Option 2 proposal.

> How does this proposal fit with potential distortions vis a vis natural-gas pipelines?

BPA realizes that a solution to rate pancaking needs to be part of an "overall" acceptable solution to a number of issues.

Principles

For the option 2 proposal, BPA would propose that the solution to rate pancaking have the following principles:

- No cost shift – propose using:
  - License plate rates (Company rates, Transfer payments, and export fees)
  - True up mechanism to ensure no (or minimize) cost shifts
- Prohibit the IA (or other independent entity) from having the authority to move region toward postage stamp rate.
- Agreement would contain a "review" clause to ensure the issue is revisited (no jump ball, maybe back to status quo).

Discussion

Under a License plate approach, transmission costs would be recovered through a combination of:

- Company rates - each company, including BPA, would set transmission rates for its native load (in BPA's case, its control area and power transfer customers) based on what they pay today.
- Transfer payments - transmission revenues received from other entities base on what they are today.
- Export Fees - transmission charges paid for deliveries out side of the RTO region. The export fee takes the place of transfer payments for entities out side of the RTO region.

If every consumer pays a portion of the fixed costs of the system comparable to what they pay today, no appreciable cost shift occurs. Under a company rate approach, every consumer would pay a charge comparable to what they pay today—but their load service entity would get access to the entire system.

In fact, the company rate proposal contained in Stage 2 of the RTO West proposal was designed to achieve the objective of minimizing cost shifts from eliminating pancaked rates. The proposal is a practical approach to eliminating pancaked transmission rates while minimizing cost shifts. This approach to minimizing cost shifts has been used by other RTOs and ISOs across the United States

How it would fit under the Option 2?

A concern with Option 2 is that if "Priority blocks" are sold at a discounted tariff price, the costs of transmission may not be fully recovered. This would lead to either rate increases, or an enforcement of some minimum floor for "Priority block" pricing.

However, if a license plate approach is used to recover transmission costs, Option 2 is greatly simplified.

As contained on Option 2, "Priority blocks" of PBC would still be calculated and sold. – Purchasers would pay for the relative firmness of the block. Since the transmission costs are already recovered, the IA would have flexibility on how the Priority blocks are priced (i.e. would not necessarily need to be a combined tariff).

> One though would be that an auction approach be used. Since the costs are already fully recovered, there would not need to be a floor at which the bidding would need to start.

The revenues from the Priority blocks could be either:

- Allocate to Tx owners,
- The IA could use it to actively resolve congestion there by increasing PBC,
- Or, other

Conclusion

Rate pancaking is a problem that results in reduced efficiency in the use of available generation. It increases costs to consumers, including those of BPA's power customers. It reduces the revenues from export sales and increases the costs of imports to the detriment of regional consumers, including those dependent on BPA power.

Rate pancaking adversely affects the type and location of new generation because these decisions are affected by pancaking of embedded costs in addition to the incremental costs of adding new generation to the system.

Finally, eliminating pancaking can be done without causing a cost shift through the adopting of company rates. This was one of the purposes for proposing company rates.

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Option 2 – Retaining existing contract charges for transmission

Currently and historically, each transmission customer (whether a utility, marketer, generator, or load) pays the applicable rate to each transmission owner for its use of that transmission owner's system. The question is whether this historical practice should be replaced by a pricing methodology (e.g. "license plate" or postage stamp rate) that charges an access fee only to loads (in conjunction with certain transfer payments) that is the same (except congestion charges) without regard to where the generation is sourced on the IA system and, thus, without regard to the transmission facilities used.

While some entities favor these new pricing methodologies, there are good reasons for not abandoning the current practice in the Northwest, certainly not as an element in the initial IA operations:

1. The historic and current practice is fair because it allocates transmission costs on the basis of benefits, i.e. all transmission customers pay, not just loads, and all customers pay for each system that it uses. It also has an implied distance component that recognizes that the further power is moved, the greater the cost burden it bears.
2. As many studies have shown, there is little societal benefit (in terms of economic dispatch) in the Northwest Power Pool area from eliminating pancake rates. At the same time there is significant institutional "baggage" in setting up a system of company rates, mechanisms for export charges or inter-company transfers and reliance on California ratepayers to make lump-sum payments to the Pacific Northwest.
3. The elimination of pancaked rates will, despite the best intentions, result in transmission cost shifts among transmission users. For example, transfer payments are imperfect because they assume future usage will be consistent with current usage, treat users differently due to the lack of consistency between uses and contract expiration dates, and usually have sunset provisions that do not recognize long-term uses of the system.

Meanwhile the incentives created by the alternatives are for greater usage without corresponding compensation to transmission owners, leading to facility expansions and higher rates to loads. Export charges will similarly be imperfect. In all of the alternatives, loads are asked to take all this risk. None of the advocates of the alternatives has stepped up to say they would indemnify loads against actual cost-shifts..

4. The distinction between facilities expansion for reliability vs. economic reasons is already blurred. The alternative pricing methodologies will increase the risk that loads on one system will pay for transmission upgrades that benefit only generators and/or loads on other systems or outside of the region.
5. The alternatives will unfairly disadvantage existing generation based upon decisions made under the historic arrangements, i.e. a plant near load but remote from its fuel source does not have its fuel transport costs socialized. Similarly, a new generator remote from load but near its fuel source could be unfairly advantaged. The historic system minimizes the distortion in new generation siting decisions or fuel choice decisions; it simply does not allow site-specific costs--the choice between fuel transport or power transmission--to be socialized. The alternatives do not provide any better generation siting decisions, allowing remote generation to place increased costs on the intervening systems without contributing anything to the cost recovery.
6. The small potential benefits from eliminating pancaked rates do not justify the cost-shift dislocations. Additionally, there is no workable method of recovering losses based on system usage in the alternative methodologies. Distance-based losses are an economic reality that should influence dispatch decisions. The current system does recover these real costs in a manner approaching cost incurrence. Imposing system-wide average losses further shifts real costs away from remote generators to local generators. The current cost recovery system, while imperfect, comes closer to recovering the true cost imposed by remote generators by charging both pancaked rates and losses, where the pancaked rates are a proxy for the distance neutral system loss factors charged on each intervening system.
7. The removal of pancaked rates will make it more economic for low cost power to be exported from the region, a politically risky proposition.
8. Ultimately, a "perfect" Company Rate proposal, with all its transfer payments, simply will replicate, in result, what we have today. So what is the imperative to change?

Planning and Expansion for Option 2

Planning

The IA will be responsible for the general planning process for the IA footprint. It will maintain common databases and a library of studies and reports. The IA will have the authority to acquire, compel and /or procure the data necessary to facilitate the sub-regional planning process. To facilitate this process, the TO's will have to provide data and run studies as requested by the IA. The IA may conduct its own studies as well. The IA will develop an open and transparent planning process that will analyze both the transmission Adequacy and Congestion problems on the system. The IA will analyze both transmission and non-transmission solutions.

It may choose to contract for this service, use TO staff, or hire its own staff. However, performing this independent function will require a certain minimum staff (4-5 people) at the IA to perform the oversight of this function to ensure independence. If the TO's support the IA's workload, the IA will not have to staff up beyond this level to fulfill its responsibility. [Have IA staff also for confidentiality purposes]

The IA will assume ultimate planning responsibility for the bulk system facilities in the sub-region. The IA's responsibility is to ensure the necessary planning work is done in an efficient manner and coordinated among all affected parties. The IA will provide a forum for sub-regional planning. The output of this planning effort will feed into the west-wide planning process.

Transmission Queue

The IA will maintain a single regional queue for generation interconnection and transmission requests. The IA will be responsible for coordinating these requests and any studies or planning that is needed to fulfill a specific generation or load interconnection request. If such a request involves only one TO's system, the IA will assign it to that TO to perform the studies. If multiple parties are involved, the IA will coordinate such a study to ensure that it is done in a timely and efficient manner.

Expansion

It is the responsibility of the TO's to recover the cost of the facilities necessary to meet their obligations from their tariffs. If a TO's system is deficient, the IA will work with the responsible TO's to implement necessary upgrades and expansion needed to resolve system deficiencies the TO's are responsible for. If that does not result in the necessary expansions, the IA is able to contract with third parties to build these transmission facilities. The TO's agree to abide by cost allocations of expansion costs assigned to them by the IA although they can access ADR to resolve disputes in this area.

Backstop Authority

The IA can invoke the backstop mechanism in the following cases.

1. Reliability Backstop.
   If a TO's system does not meet transmission adequacy standards (physical ability of the system to serve all forecast load irrespective of the cost of energy), and the TO's plans for the system are insufficient to bring it into compliance with the Standards, the IA will develop the necessary expansion plans and allocated those costs to the responsible TO. This is intended to be the same as the RTO West Stage II backstop for Transmission Adequacy.
2. Congestion Backstop.
   With Option 2, more information will be available on path usage. New products will cause a higher utilization of existing path capacity. Congestion value information will be available from the voluntary inc/dec market. The IA will facilitate consortiums getting together to expand the system. Sufficient information and facilitation should be available to ensure that needed expansion is built when congestion costs are high enough. However it is possible that situations might exist where a market power exists that is preventing necessary construction from getting built. If the market monitor function determines that a market power situation exists that is preventing system upgrades to alleviate uneconomic congestion, the IA can cause the most cost effective solution to be built and costs allocated to the beneficiaries of the solution.

   > In Stage 2, the compromise required a showing of persistent congestion and the inability to serve load irrespective of price.

3. Insufficient Assets Backstop.
   Each TO will be responsible maintaining sufficient assets to cover its obligations. Contract Path methodology does not provide a straightforward assessment of adequate assets. If a TO's assets are not sufficient for that TO to support the long term rights they have sold, the IA has the ability to cause construction of the needed facilities. The responsible TO's will recover those facility costs in its tariff.

The TO's agree to recover the costs of these expansions in their tariffs. Before the IA moves into this backstop function, the IA will give the responsible TO the opportunity to resolve the deficiencies themselves. ADR is available to resolve any disputes that arise in this process.

A. Annual Expansion Plan

IA will publish an annual expansion plan that includes all committed facilities and potentially needed facilities.