The documents entitled, "The RTO West Control Area Model" and "Appendix A: Example Only of One Possible Approach for Multi-tier Operational Functionality" meet the criteria below:

> All correspondence, including emails, discussing or concerning the combination or consolidation of BPA control area operations with the control area operations of any other electric utility, between any of the **BPA officials identified in item number one and any representative of PacifiCorp, Idaho Power Company, British Columbia Hydro Corporation, Powerex or Montana Power Company (a.k.a., Northwestern),** for the period of January 1, 2000 to the present (November 26, 2003).

The remaining correspondence meet the criteria below:

> All correspondence, including emails, discussing or concerning RTO West, the formation of an RTO in the Pacific Northwest, or the formation of an RTO in the Western interconnection **between officials of the United States Department of Energy and Bonneville officials: Steven Wright, Administrator; Steven Hickok, Deputy Administrator; Mark Maher, SVP; Vickie Van Zandt, VP,** for the period of January 1, 2000 to the present (November 26, 2003).

To. Vickie Van Landt
360-418-8433
From: Carol Opatrny

To Vickie VE

The RTO West Control Area Model

~~[August 18, 2000 Draft]~~ Final CHCA Draft

Canadian Hierarchial Control Area.

Introduction and Terminology

This document provides an overview of the duties and relationships of the Control Area Operator (CAO), Area Control Centers (ACCs) and Scheduling Coordinators (SCs) in the RTO model. It describes the ways in which the CAO acquires the Interconnected Operations Services (IOS) capacity that the CAO needs in order to securely operate the grid, how the CAO operates the grid through the deployment of Ancillary Services (AS), and the roles of the ACCs. The document also describes the various mechanisms, including "self-provision" of AS and "self-tracking" of AS, by which SCs, through their management of Generation Control Centers (GCCs), can control the dispatch of their resources and their exposure to RTO charges for Balancing Energy and other AS.

To enable Canadian transmission owners to become Participating Transmission Owners (PTOs) in the RTO in the event that sovereignty requirements prevent them from formally giving up their control areas, this document also includes a Canadian Hierarchical Control Area (CHCA) option. Under this option, Existing Canadian Control Areas (ECCAs) that separate their transmission functions from other functions in a way that meets FERC Order 2000's independence standards could opt to become part of the RTO but would retain control area operation responsibilities, including participation in the deployment of ancillary services, as described in this document.[1]

Overview of Market Structure

[1] In BC, the Canadians intend to form an Independent Grid Operator (IGO) that will be independent of all market participants. The IGO will take no position in the capacity or energy market and its primary functions are to implement the terms and conditions of the tariffs and commercial models for ancillary services and congestion management, as defined by the RTO. This function will require receiving from the RTO all of the necessary information (in digital form or otherwise) to safely operate the grid in BC and implement the terms and conditions of the RTO-wide tariff in BC. The relationship between the IGO and the RTO will be codified in the form of a contract formally defining their respective commitments and functions.

The IGO preserves Canadian Sovereignty and control over the reliability of their facilities. As such, it will be regulated by the British Columbia Utilities Commission. It is not designed to reduce the commercial opportunities or compete with the for profit functions of scheduling coordinators. Nor, it is designed to give any advantage to the BC PTO over other Canadian or US PTO's.

The functions of the ACC are contained within the IGO. Unless otherwise noted, the entities in BC (Scheduling coordinator, IGO and transmission owner) will fully conform to the principles and market operations described in this document.

The basic structure of the RTO control area model is as follows:

1. There will be a single NERC-certified CAO for the entire RTO region. The RTO will be the CAO. Those entities owners who become Participating Transmission Owners (PTOs) will turn over some of their present CAO duties to the RTO. Other duties will be distributed to ACCs and to SCs.[2]

2. Entities which are currently CAOs but do not choose to become PTOs - whether those entities are "islands" within the RTO region or located at or beyond the boundaries of the RTO region - would continue to operate their own control areas, just as today. Those entities would be entitled to obtain transmission services from the RTO (because they would be Eligible Customers under the RTO Tariff) by designating SCs to interface with the RTO for transmission services.

3. Every entity wishing to receive transmission service from the RTO must do so by becoming, or by designating, an SC. I.e., generators and loads receive transmission services from the RTO through their RTO-certified SCs. (The roles and responsibilities of SCs are described in other Ancillary Services Working Group documents, including the working draft of "Appendix J - Scheduling Coordinator Certification.")

4. The CAO will be independent of all market participants. It will not own any IOS resources. It will obtain IOS resources through the procurement mechanisms described in this and subsequent documents.

5. The ACCs will be independent of all market participants (although the degree of separation between the ACCs and affiliates of the entities that own the ACCs has not yet been discussed). The ACCs will not control the deployment of any IOS resources, except in certain emergency situations.[3]

6. The SCs will be responsible for the management of their individual portfolios of resources.[4] The SCs may offer IOS resources to the CAO (although in certain cases, in which the CAO procures IOS resources through long-term agreements, the resources may, at their option, individually contract with the CAO) and will control the deployment of their portfolios of resources in response to commands from the CAO.

7. Each SC must operate a GCC.[5] A GCC is a 7 * 24 operations center[6] that is maintained by each SC which schedules energy and/or ancillary services capacity into, out of, or through

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[2] <u>An exception to this would occur if a Canadian control area operator became a PTO under the CHCA option.</u>

[3] <u>Under the CHCA option, the RTO, ECCAs and SCs would jointly deploy the IOS resources.</u>

[4] Note: throughout the document, "resources" should be understood to include both generation resources and dispatchable demands, unless the context dictates otherwise.

[5] Note: if an SC is not responsible for any resources - for example, the SC simply purchases energy from other SCs, sells energy to non-dispatchable loads, and sells no IOS to the RTO - then the SC's duties are much smaller and its "GCC" is responsible for fewer functions. However, the SC must still in most cases have a GCC in

the RTO grid. Through the GCC, the SC controls all generation and dispatchable demand for which the SC has responsibility. Depending on the circumstances and the technical requirements, this communication may be verbal, by computer, or through Direct Digital Control (DDC).

Description of Roles of the Parties

1. How are the duties of Control Area Operators handled?

CAO duties can be placed into five categories: energy balancing, grid security monitoring, redispatch of resources to maintain secure operation of the grid, switching operations, and response to system emergencies.

- Energy balancing duties will be transferred to the RTO and the SCs. The RTO will be responsible for balancing the entire grid to meet NERC control performance standards. To perform this duty, the RTO will acquire the authority to send dispatch signals (through SCs) to IOS resources that have been provided to the RTO either through self-provision or through SC offers of such IOS resources to the RTO. The RTO will decide which resources to dispatch by creating stacks of the IOS resources which have been provided for the RTO's use (through self-provision by the SCs and through the RTO's procurement processes). SCs will dispatch their resources consistent with the RTO's dispatch signals and the contractual commitments that the SCs have made to the RTO. Each SC will have the flexibility to operate its resources on a portfolio basis (provided that the changes in the resource schedules do not increase congestion unless permitted by existing contracts or licenses), and each SC will also be permitted to use those portions of its resources that have not been committed to other purposes to "self-track" the SC's loads.

- Grid security monitoring will be the responsibility of the RTO and the ACCs. The ACCs will be under the direction of the RTO in this regard. The types of system status data (voltages, line loadings, status of switches, etc.) which will be brought into the RTO control center vs. the types of data that will be managed at the ACC level needs to be determined.

- Redispatch of resources to resolve congestion (i.e., congestion management pursuant to the RTO's congestion management rules): the redispatch of resources in response to contingencies will be managed by the RTO and the SCs, under a structure similar to that described for energy balancing. The switching of transmission facilities in response to contingencies is described in the next category below.

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order to respond to real-time orders from the RTO regarding curtailment of transmission rights, emergency curtailments, etc.

[6] Note: the RTO's certification requirements for such operations centers have yet to be determined.

- Switching operations, including the switching of transmission facilities in response to contingencies, the switching of facilities for forced outages and for maintenance outages, and the switching of facilities that affect the TTC of grid facilities, will be handled by the RTO and ACCs. In general, the RTO is responsible for approving all switching operations and the ACCs are responsible for carrying out the actual operations. (In some cases, and depending on how independent the ACCs are from the operations of their affiliated generation and load-serving functions, the ACCs may be responsible for routine switching activities without RTO intervention.) i.e. voltage control

- Response to system emergencies is the joint duty of the RTO and the ACCs. The RTO will be the NERC-approved Security Coordinator for the region and as such must have authority over certain aspects of emergency response.[7] Emergency response duties at the lower voltage levels and emergency response duties in the event of catastrophic events would be delegated between the RTO and ACCs pursuant to pre-defined agreements.

2. What is the relationship between RTO and Existing Control Areas?

As a condition for becoming a Participating Transmission Owner, an entity must turn over its CAO duties to the RTO and to the SCs who will assume responsibility for the entity's resources.[8] Existing NERC-certified control areas will no longer exist within the portions of the grid that are controlled by Participating Transmission Owners.[9]

As noted above, the RTO will have operating relationships with SCs and through that, with each SC's Generation Control Center. Each SC will, through its GCC, have the ability to adjust generation as needed to meet the SC's power, non-power and legal obligations, including the obligations between the SC and the RTO. Communications between the RTO and the SC's GCC may range from phone calls to direct digital control between the RTO and GCCs, depending on the nature of the function.[10]

3. What IOS are acquired by the RTO and what AS are provided by the RTO?

[7] The RTO will either be the NERC-approved Security Coordinator or contract with an entity to perform these functions.

[8] Under the CHCA option, an ECCA would participate in the deployment of ancillary services. From a technical perspective, this would require electronic links between the RTO and the ECCA to communicate the real time status of the RTO's Operating Plan and to deploy resources through the RTO. From a contractual perspective, each ECCA would in effect become an agent of the RTO, would take on a duty to the RTO to perform its grid operations role in the best interest of the RTO (rather than operate in the interest of the ECCA's affiliated functions), and must require the ECCA's employees to follow the same Code of Conduct as would apply to any RTO employee.

[9] Note that existing control area boundaries might continue to exist to the extent they define an SC's self-tracking area. This issue will require further discussion in the context of how a self-tracking SC would meter its loads and resources. The boundaries of ECCAs that exercised the CHCA option would also continue to exist.

[10] In the CHCA case, there will also be a need to coordinate the flow of information from the RTO to the IGO. This should in no way interfere with or inhibit the commercial relationship between the SC's and the RTO.

The table below lists the IOS and AS that are currently being considered by the Ancillary Services Working Group. The details (definitions, technical requirements, certification, deployment, compliance monitoring, compensation, billing determinants, etc.) are being developed by the Working Group.

Working List of Possible RTO IOS and AS[11]

Group	Interconnected Operations Services ("Raw Materials" Purchased by RTO)	Ancillary Services ("Finished Products" Provided by the RTO)
1	Regulation	Regulation
2	Load Following Up Load Following Down Spinning Reserve Supplemental Reserve "Non-Spin" Replacement Reserve	Load Following Up Load Following Down Spinning Reserve Supplemental Reserve "Non-Spin" Replacement Reserve
3	Supplemental Energy Congestion Redispatch (Forward)	Congestion Redispatch (Forward) Balancing Energy (and RT congestion mgmt)
4	Black Start Voltage Support (Gen & Non-gen) Area Control Center Support to RTO	Black Start Voltage Support Scheduling & Dispatch

4. Who defines the requirements - quantity/capacity, location and technical (certification, response time, metering, telecommunications, etc.) - for IOS and AS?

The RTO will define these requirements for all of the IOS Groups and all of the AS Groups. The RTO will post these requirements (for example, x MW of Spinning Reserve per 100 MW of an SC actual demand-plus-exports) on the RTO website well in advance (weeks or more) of the Operating Day. The RTO's standards will at a minimum meet those established by NERC and the WSCC.

5. Who will procure IOS resources?

For IOS Groups 1-3: There are three mechanisms through which IOS resources are acquired under normal conditions: self-provision by the SC, self-tracking by the SC, and procurement by the RTO. Based on the requirements posted by the RTO on its website, each SC will know the quantity of each IOS resources for which it will be held responsible. Self-provision and self-tracking are optional - i.e., an SC is not required to do either of these, and may rely upon the RTO to acquire the SC's allocated share of IOS by simply purchasing AS from the RTO.

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11 In addition to the above, a fifth category of possible IOS services is being considered. This category might comprise some or all of the following services: Load Curtailment, Under-Frequency Load Shedding, Under-Voltage Load Shedding, Generation Dropping for RAS, Load Tripping for RAS, Transient Excitation Boosting for RAS, and Frequency Responsive Reserve. The costs of procuring these possible IOS services might be included in the transmission ratebase or they could be allocated through an unbundled charge for an Ancillary Service designated as "System Dynamic Response."

- Self-provision

Under self-provision, an SC would acquire IOS resources by virtue of being the SC that is responsible for such resources and/or by acquiring from other SCs the rights to schedule such resources (through inter-SC trades of such resources made bilaterally or through external-to-the-RTO exchanges). The SC would turn over to the RTO the authority to request the dispatch of specified amounts of capacity from such resources.

Self-provision exempts the SC from paying the RTO for the RTO's procurement of the quantity of IOS resources that was self-provided by the SC. Self-provided resources are deployed by the RTO for community use, and not for SC-specific contingencies or imbalances. Thus, through self-provision, the SC avoids the payment of capacity reservation charges for the IOS resources.

The SC will remain responsible for real-time Balancing Energy charges or credits, to the extent that the SC's injections in each Congestion Zone, adjusted for transmission losses, do not equal the SC's withdrawals from the Congestion Zone. However, an SC that closely manages its generation/load balances over the Settlement Interval (for example, energy integrated over a 10-minute interval) may mitigate a portion of its exposure to Balancing Energy charges.[12]

As outlined earlier, the RTO will define the standards and certification processes for self-provision.

- Self-tracking

Self-tracking is an alternative to self-provision of certain ancillary services resources (Load Following and Regulation)[13] to the RTO. Under self-tracking, an SC contractually commits to the RTO that the SC will use the generation resources in the SC's portfolio to closely match the loads in the SC's portfolio, pursuant to performance requirements that will be consistent with the NERC CPS criteria. (This will require the SC to track its loads on a much more precise basis than simply matching integrated production to integrated consumption over a ten-minute period.) In return for relieving the RTO of the burden of following the SC's loads, the SC is exempted from all, or a part of,[14] the SC's pro rata requirement to self-

[12] I.e., it is not necessary for an SC to conduct "self-tracking" in order to manage its exposure to Balancing Energy charges.

[13] Self-tracking of reserves has also been discussed. Under self-tracking of reserves, the SC's operating reserves would be deployed only for the SC's own contingencies. The SC would not be a participant in the RTO's reserve sharing program and therefore would be required to protect against its own single largest contingency. It does not appear to be a feature that anyone desires at this time. Thus, while it is agreed that the RTO will not prohibit self-tracking of reserves, the consensus is that the Working Groups should not spend much effort trying to define the concept at this time.

[14] Details of the self-tracking concept, including performance requirements, remain to be developed. For example, the SC would still be responsible to the RTO for some share (on a yet-to-be-determined basis) of the costs associated with the RTO's obligation to the interconnection for provision of the frequency bias component of Area Control Error.

provide - or have the RTO procure on the SC's behalf - Load Following and Regulation resources. Therefore, the self-tracking SC does not pay the RTO for some or all of the SC's share of Load Following and Regulation AS. Note however, that the self-tracking SC must dedicate capacity to this function from either its own resources or third-party resources that it has procured for this purpose.

Under self-tracking, the SC would deploy its own Load Following and Regulation resources for the SC's own use only. Each SC will remain responsible for its residual energy imbalances over the Settlement Interval,[15] just as would be the case for an SC that did not self-track. As is the case for all SCs, a self-tracking SC may net its energy imbalances with those of other SCs prior to the RTO's final calculation of imbalance energy charges or credits. As is the case for self-provision, the RTO will define the standards and certification processes for self-tracking.

How does this work?

Additional discussion of self-tracking is included in the Appendix to this document.

- RTO procurement

  After adjusting for the self-provision and self-tracking commitments of SCs, the RTO will determine whether it needs to procure additional IOS resources in its role as the AS "provider of last resort." The RTO will acquire such resources through purchases from the marketplace, which may include one or more external-to-the RTO ancillary services exchanges. The RTO's costs of procuring such IOS will be allocated to SCs based on their residual (after self-provision and self-tracking) AS obligations.[16]

For IOS Groups 4-5: because these IOS are generally acquired through longer-term contracts or other longer-term commitments, and because generators and loads can change their SCs on short notice, the longer-term contractual commitments may be made directly (without required intervention of an SC) between the generator/load and the RTO through competitive solicitations or other contractual arrangements.

Under abnormal or unusual situations (for example, upon the loss of IOS resources or the loss of transmission capacity that is used to deliver IOU services) or unanticipated situations (for example, real-time demand far in excess of that which was anticipated by the RTO), the RTO will: (i) if time permits, allow SCs to procure and provide additional IOS resources to the RTO; (ii) procure additional IOS resources from ancillary services exchanges; (iii) as a last resort, exercise any backstop authority under the Tariff to order SCs to provide IOS resources.

6. Who sets the prices of IOS capacity and AS capacity?

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[15] The length of the Settlement Interval - for example, 10 minutes, 60 minutes, etc. - will be defined in the ongoing work of the Ancillary Services Work Group.

[16] Note that, as stated earlier, an SC may use its resources to both self-track and to bid into the AS marketplace. The SC would then only be charged for the amount of AS not self-tracked and not self-provided.

For IOS Groups 1-3:

- For self-provided IOS resources: The capacity prices of the resources (i.e., the prices for the "capacity call options" that have been passed on to the RTO by the SCs) are determined in private exchanges and/or through bilateral arrangements, and the RTO will neither know nor care about such prices. The energy prices of such resources (i.e., the "strike prices" at which the IOS resources will be dispatched) will be provided to the RTO by the SCs who self-provide the IOS resources.

- For self-tracking SCs: Because the RTO does not dispatch the associated IOS resources (that being the self-tracker's duty), the RTO does not set the prices for such resources. Any excess or deficit of energy produced by resources which are used for self-tracking purposes will contribute to the SC's energy imbalance account for the Settlement Interval and the SC will therefore be credited or charged for such energy at the RTO's Balancing Energy price for the location and Settlement Interval.

- For resources acquired by the RTO through ancillary services exchanges: The capacity prices and energy strike prices are determined in the exchange. The capacity costs (plus the RTO's transaction costs for procuring the resources, including any associated software development and hardware costs) will be allocated to those SCs who are deemed to be responsible for the RTO's procurement.

For IOS Groups 4-5: the capacity prices are determined by the RTO through the RTO's longer-term procurement processes and/or other contracts. The associated costs are allocated to all SCs who are deemed to be responsible for the RTO's procurement.

7. Who develops the prices for real-time Balancing Energy and how?

From the IOS resources self-provided by SCs and procured by the RTO as described above, the RTO will create "stacks" of available sources of Balancing Energy. The RTO will create a "Balancing Energy stack" for each congestion zone, comprising the applicable IOS resources that are located in the congestion zone and resources outside the zone with FTRs which in effect provide the IOS resource with access to the zone. As Balancing Energy is needed (and/or as residual congestion is cleared by the RTO) the cheapest resources in that stack are called upon, and the final resource that was dispatched in that zone will set the Balancing Energy price in that zone for that Settlement Interval.

These Balancing Energy prices are used to charge or credit each SC to the extent that the SC has a net imbalance during the Settlement Interval. This is true whether the SC self-provides, self-tracks, or procures its Ancillary Services from the RTO.

The Ancillary Services Working Group must still address many details, including how Balancing Energy will be dispatched (e.g. through a traditional bid stack or through permissive dispatch), duration of the Settlement Interval (e.g. 10 minutes), treatment of operating reserves (e.g., are they used only for contingencies or also for system energy balancing), and pricing and payment during Settlement Intervals in which resources may be both incremented and decremented.

8. Who creates the Operating Plans for the RTO grid?

The RTO will be responsible for developing the Operating Plan for the entire RTO grid. The Operating Plan includes the day-ahead plan for the deployment of IOS and AS and the creation of the Balancing Energy stacks that will be used for the dispatch of AS, and may include aggregated information from self-tracking SCs. The RTO will update its Operating Plans as system conditions change between day-ahead and real-time, based on input provided from the SCs and other sources.

9. Who determines which IOS resources will be deployed (dispatched)?

For the resources under the RTO's control - i.e., those IOS resources that have been self-provided or have been procured by the RTO - the RTO will issue operating instructions to SCs per the RTO's Operating Plan. Each SC will have the flexibility to select and/or distribute the response among its projects via the SC's Generation Control Center, consistent with the RTO's specifications for the IOS and assuming operating conditions allow. To the extent that the output of different plants would have the same effect in meeting an SC's commitment to the RTO and to the extent that shifts of responsibilities between such plants would not violate security limits, the SC can treat the those plants as a single "virtual resource."

For resources that are not under the RTO's control - i.e., that resource capacity that is being used to self-track and any other resources which have not been committed to the RTO through the self-provision or RTO procurement processes - the SC may dispatch such capacity as it desires, limited only by congestion limitations for which it has not provided FTRs and those RTO operating protocols that are needed to ensure that such dispatch would not violate any congestion management protocols.[17]

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17 Under the CHCA option, the RTO, an ECCA (or IGO hereinafter)-and SCs would jointly deploy the IOS resources as follows:

(i) The RTO and the ECCA would agree on the intra-hour ramping requirements for the ECCA and each of the Congestion Zones within the ECCA. Because the boundaries of Congestion Zones and ECCAs are not the same, this will require coordination by the RTO to ensure that flowpaths and other branches in the network will not be overloaded. The RTO would determine which resources should be ramped using the RTO's knowledge of the requirements for the ECCA and each Congestion Zone and the costs of the resources in each of the RTO's Balancing Energy stacks. The RTO may choose to issue orders to ramp resources within the ECCA and/or create dynamic schedules between the RTO and the ECCA, which it will telemeter to the ECCA. In this way, the RTO would ensure efficient coordination between the RTO and each of the ECCAs, ensure that system constraints are met, and ensure that each ECCA receives - through actual ramping of IOS resources and/or through dynamic schedules between the RTO and the ECCA - the energy needed to keep the ECCA's Area Control Error (ACE) within NERC performance standards. The RTO would contact the SCs whose IOS resources are to be ramped. These SCs are responsible for implementing the ramps through their GCCs.

(ii) The same basic process would be used for shorter-time frame response (i.e., the use of Regulation IOS). Instead of sending Direct Digital Control (DDC) signals from the ECCA to the computer system of the local GCC (i.e., the pre-RTO approach), DDC signals would be sent electronically from the ECCA to the RTO's real-time computer, where they would be automatically processed and distributed to the GCCs of the appropriate SCs and/or result in the creation of real-time dynamic schedules between the RTO and the ECCA which are sent back to the ECCA's computers.

10. Who deploys/dispatches the IOS resources?

Under the direction of the RTO, the SC will dispatch IOS resources over which the RTO has been granted dispatch authority (through self-provision or through RTO procurement of IOS), but only for the amounts of capacity over which the RTO has been granted dispatch authority.[18] A self-tracking SC will dispatch its IOS resources.

11. Who conducts the settlement function?

The RTO will settle with SCs for IOS capacity purchased by the RTO and for AS capacity costs charged to the SCs. The RTO will settle with SCs for Balancing Energy charges. The RTO has no involvement with the settlement of SC to SC transactions.[19]

12. Who monitors performance and enforces penalties for noncompliance?

The RTO will perform the monitoring functions specified in the RTO Tariff to ensure that IOS providers deliver and perform pursuant to the RTO-defined standardized product and performance standards, and to ensure that treatment of providers of IOS resources will be consistent and non-discriminatory. Enforcement issues addressed in provisions in the RTO

(iii) For most contingencies requiring the dispatch of reserves , the ECCA (which would remain responsible for real-time monitoring of grid conditions) would contact the RTO, which would deploy the appropriate resources from the RTO's Balancing Energy stack. For the most-serious system emergencies, the ECCAs would be given direct access to the Balancing Energy stacks and would be allowed to make deployment decisions, consistent with the emergency plans developed between the RTO (in its role as Security Coordinator for the grid), ECCAs and the ACCs of the other pre-RTO CAOs.

This hierarchical control concept would: (i) comply with Canadian sovereignty requirements; (ii) allow the ECCA's existing computer systems to continue to be used; (iii) allow multiple SCs to compete to provide IOS to each Congestion Zone in the RTO - including those in the ECCA ~~-without fear of discrimination~~; (iv) allow the ECCAs to deal with multiple ~~GCCs (something that they would have to do as soon as a single IPP entered the market for IOS)~~; (v) create efficient coordination between all controls areas, including the ECCAs; (vi) allow each ECCA to maintain its ACE requirements in compliance with NERC CPS; and (vii) leave each SC with the control that it needs to manage its portfolio of resources (just as resource owners have today). Implementation will, of course, require the definition of redundant systems and fallbacks in the event of loss of telemetry.

[18] Under the CHCA option, the Canadian control area would request incremental and/or decremental energy from the RTO, which would provide such energy from IOS resources and/or RTO-ECCA dynamic schedules. The ECCA's communication will be through ACE signals to the RTO (for Regulation), inter-computer ramping requests from the ECCA to the RTO (for Load Following, Supplemental Energy, Voltage Support and elimination of congestion), and ECCA-RTO computer or voice communication (for deployment of Spinning Reserves, Non-Spinning Reserves, Supplemental Reserves and Black Start capacity).

[19] ~~Under the CHCA option, there is no need for any settlement process between the ECCAs and SCs (except possibly for paying for the embedded costs of the grid through the basic Grid Access Charge), or between ECCAs, or between ECCAs and the RTO, because the ECCAs are never the purchasers or sellers of either capacity or energy.~~

Tariff will be the duty of the RTO and regulatory agencies. Other monitoring and enforcement duties may be the responsibilities of, or may be coordinated with, FERC, NERC/NAERO and WSCCWIO.

13. Who is responsible for inter-RTO tie-line schedules?

As a NERC-certified CAO, the RTO will be responsible for managing all schedules between itself and any other CAO, pursuant to applicable criteria for control area operation.

14. Who is responsible for intra-RTO tie-line schedules?

The RTO will operate a single, NERC-certified control area, and as such there are no intra-RTO tie-line "schedules," as the term "schedule" is used to define interchanges between CAOs. Instead, the RTO will manage ~~flowgates~~ within the RTO.[20]

injections & withdrawls ~~of~~ from congestion zones.

15. Who is responsible for managing flowgate schedules?

The RTO manages all flowgate schedules.

16. Who is responsible for managing congestion?

Most congestion is self-managed through the scheduling process by the SCs through the purchase, sale and scheduling of FTRs. Residual congestion, under both normal and emergency conditions, is managed by the RTO, through the protocols in the RTO Tariff.

17. When does the RTO acquire IOS resources (timeline from day-ahead to real-time)?

For Groups 1-3 IOS and AS:

a) The RTO will forecast the requirements for the ancillary services that may be self-provided on a long-term forward basis and will communicate these requirements to the marketplace through the RTO website, to promote SC self-provision.

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20 Under the CHCA option, the RTO would be responsible for validating SC schedules, determining the net schedule for each ECCA, managing the stacks of IOS inputs that will be used to manage contingencies and imbalances over the intra-RTO tie-lines (including those within the ECCA), and maintaining the RTO-ECCA dynamic schedules. As such the RTO would be responsible for the intra-RTO tie-line "schedules." The operation of the IOS market does not preclude the ECCA or IGO from also receiving all schedules to maintain the security and reliability of their control area facilities.

b) Prior to the day-ahead prescheduling process, the RTO will adjust the forecast to reflect system conditions. The RTO could either: (i) base final ancillary services requirements on the original per-unit forecasts and actual load, acquire the residual IOS, and charge the costs out as an uplift; or (ii) deem the revised requirements to be the obligations of the SCs and allow SCs an opportunity to self-provide additional IOS resources. There are pros and cons to each of these alternatives, and they will be discussed in the Ancillary Services Work Group.

   Note: While self-tracking SCs would not be directly affected by this step, they would probably see the same effects indirectly, since the resources that they would need to dedicate to meet their self-tracking performance requirements would likely change in a similar fashion.

c) Through the day-ahead pre-scheduling process, the SCs will submit schedules and self-provision commitments to the RTO. SCs that self-track will inform the RTO of their proposed operating plans, to enable the RTO to determine whether or not those plans would create transmission congestion.

d) The RTO will procure the difference between the RTO's forecasted requirement and the amounts supplied by SCs through self-provision and self-tracking, as described earlier.

e) In the post-day-ahead scheduling process, SCs may submit additional schedules, provided that they meet any incremental AS demands, through self-provision or self-tracking, that may be created by the additional schedules.

f) Throughout the period between the close of the day-ahead scheduling process and real-time, the RTO will update its IOS requirements, based on changes in system conditions and input from the SCs and other sources.

g) In real-time, the RTO will, as described in Q&A #9, deploy the appropriate resources to meet the RTO's needs, by communicating with the SCs that are responsible for those resources.

The SCs are responsible to comply with the terms of their contractual obligation to the RTO (portfolio response or unit specific, quantity, response time, etc., depending on the service).

18. What obligations do the RTO and SC's have to offer AS?

Pursuant to Order 2000, the RTO must offer AS as a provider of last resort. This requirement is met fully through the process described above, in which the RTO acts as the agent for SCs who have not self-provided IOS resources (and for all SCs, in the case of non-self-providable ancillary services) by procuring Group 1-3 IOS resources through external-to the-RTO markets and procuring Group 4-5 IOS resources through longer-term procurement arrangements.

Each transmission owner (but not existing control areas per se) currently has an obligation under its FERC Order 888-compliant tariff to offer ancillary services to Eligible Customers who serve load connected to the transmission owner's grid. The SCs which become responsible for the generators that were affiliated with the transmission owner would inherit this obligation to the extent that they are required to do so by contracts and/or regulatory entities. Beyond these requirements, the pricing authorities of formerly-affiliated generators will be determined by the FERC. There is no intention that the transmission owner's participation in the RTO should expand the obligations of such formerly-affiliated generators.

19. How is market power mitigated?

- Designating the RTO as coordinator of grid-wide ancillary services processes mitigates market power by creating grid-wide IOS markets and consolidating the split of markets into subregions that are based on TO boundaries. Physical system constraints rather than historical control area boundaries will now determine market boundaries, creating larger markets in which there is more competition.

- Allowing SCs to transfer ancillary services across flowgates with FTRs further reduces market power by allowing transfer even across those physical constraints.

- Allowing SCs to self-provide and self-track, as an alternative to RTO procurement, creates a much more robust marketplace with many purchasers and with opportunities for continuous forward market deals to procure IOS resources. This mitigates against the market power of sellers of IOS resources.

- The RTO requirement that an efficient electronic trading exchange be put into place (at a minimum, as a mechanism for the RTO to use in its provider of last resort procurement process) will create liquidity and efficient and visible pricing, further mitigating market power.

- The RTO's use of grid-wide standards for certification and performance of IOS resources will make the services more portable.

- To the extent that limited transfer capability into portions of the RTO grid and concentration of generation ownership in those areas prevent the creation of a workably-competitive market for ancillary services in those areas, the RTO may require additional tools to mitigate market power. These might include bid caps, recourse obligations, and administrative pricing tied to the prices in competitive areas of the grid.

20. Who is the IOS provider and who is the AS customer?

For Groups 1-3, the SCs are IOS resource providers and the AS customers. Other entities (PSEs, LSEs, Customer Aggregators, Loads) either become SCs or interact with the RTO through their designated SCs. The RTO is the "Transmission Service Provider" for the RTO grid, and its role is described throughout the document. The Transmission Owners and the Local Distribution Companies play no role in the IOS/AS markets for Groups 1-3, except to the extent that their bundled affiliates are required to make IOS resources available to the SCs and RTO under the terms described in the answer to Question 18.

For Groups 4-5, the IOS resource providers are the generators, dispatchable demands and wires owners that are capable of providing the IOS resources. The AS customers are, once again, the SCs, who are billed for these IOS resources through a grid uplift charge, through payments of the TOs' Annual Transmission Revenue Requirements, or other mechanism specified in the RTO tariff.

Finally, for Scheduling and Dispatch service, the provider is the RTO. The customers are the SCs.

21. How are existing contracts treated?

IOS that are made available by a party pursuant to an existing contract would, if they meet the RTO's technical standards and do not impose limitations on the RTO's use of the IOS, be qualified to be submitted to the RTO by the SC (as self-provision) or to be offered to the ancillary services markets.

Obligations to provide or sell AS under existing contracts would have to be honored by the SC that is responsible for the obligations, pursuant to the terms of the existing contract.

22. How is "native load" treated?

"Native load" is treated no differently than any other load from the RTO perspective. From the RTO's perspective, "native load" is simply a group of bundled consumers that have a pre-designated SC. The RTO treats all SCs identically, regardless of whether the SCs represent bundled loads, unbundled loads, generators, wheel-throughs, or any combination thereof.

23. How will the answers above change under retail access?

Very little changes under retail access, because the SC model which is proposed for use in all of the RTO's relationships with grid users does not distinguish in any way between bundled and unbundled retails loads. The only thing that does change under retail access is that the formerly-bundled retail loads may have a choice of changing their SCs. This flexibility will need to be accommodated in the RTO's settlements and meter data acquisition protocols.

Settlements for Balancing Energy require resource and load data that reflects the "granularity" of the RTO's Balancing Energy markets. The Settlement Interval may be ten-minutes or shorter, and there will in general be different Balancing Energy prices for each Settlement Interval. This may require that existing interval meters (which may provide data on an hourly basis) either be replaced with meters which can provide data on a Settlement Interval basis, or that some form of interpolation be used to develop "deemed" data for each Settlement Interval.

Retail access extends this problem from that of determining ten-minute loads from hourly meter data, to that of determining ten-minute loads from monthly load data. Under some states' retail access programs, "load profiling" processes have been developed to convert data from monthly cumulative meters to more-granular hourly data. This type of approach may also be considered for use in the RTO's settlements process. Details of settlement processes and the sources of data for use in those processes will be discussed by the Ancillary Services Working Group.

[NWRTO-ControlAreaModel-081800.doc]

Additional Discussion of Self-Provision and Self-Tracking

Under the proposed models for Ancillary Services procurement and for the roles of Scheduling Coordinators, an SC is responsible for managing its portfolio of resources and loads by submitting to the RTO balanced schedules (i.e., injections equal withdrawals plus deemed losses). An SC may "self-provide" its allocated shares of various ancillary services resources to the RTO (by offering dispatch authority to the RTO for capacity from the SC's resources or from the resources of another SC with whom the first SC has a bilateral agreement); or the SC may elect to have the RTO procure, on behalf of the SC, part or all of those quantities of ancillary services resources (in which case, the RTO would charge the SC for the full purchase price of the resources plus the RTO's procurement costs). The RTO dispatches those resources (whether self-provided or RTO-procured) for the collective benefit of the SCs, using the resources to balance the Area Control Error for the RTO grid and to respond to contingencies. To the extent that an SC has real-time energy imbalances[21] in its portfolio, it sells excess energy to the RTO at the 10-minute Balancing Energy price or purchases energy from the RTO at the 10-minute Balancing Energy price.

An SC can manage its exposure to real-time Balancing Energy charges by closely matching its real-time generation to its real-time demand (integrated over a ten-minute interval). The SC has the ability to move its generation resources in real-time to match changes in its demand; and it also has the ability to make bilateral deals with other SCs to provide/consume energy in real-time (in which case, the two SCs' countervailing imbalances would be netted out against one another before the RTO charged the SCs for Balancing Energy based on any residual imbalances).

In addition, each SC is responsible for the managing the portfolio of resources (which can be generation or demand-side resources) that it has committed to the RTO's ancillary services stacks. Except for emergency situations , the RTO does not issue commands directly to the SC's resources. Instead, the RTO issues such commands to the SC, which is responsible for maintaining a 7 * 24 operations center (or "Generation Control Center") that is capable of providing the RTO with the IOS resources that the SC has committed to provide. Thus, each SC possesses the flexibility to offer to the RTO ancillary services from groups of resources which are located in electrically-similar locations; and to manage the SC's response to the RTO's ancillary services deployment orders on a group basis. This allows each SC the flexibility to manage resources on a watershed, to manage groups of dispatchable demands in accordance with the contracts struck between the SC and the demands, etc.

With these basic features, each SC has the ability to fully manage its resources. Each SC may also mitigate its exposure to charges for real-time Balancing Energy to the extent that the SC is able to match its loads and resources over each ten-minute window while at the same time meeting any commitments that the SC has made to provide the RTO with IOS resources.

Self-Tracking

Some participants may desire to more-completely remove themselves from the RTO's ancillary services and Balancing Energy processes, and to have their retail merchants (which are simply SCs)

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[21] Note: "Imbalance" is the difference between the SC's actual generation and actual demand (i.e., scheduled quantities are irrelevant), calculated on a zone-by-zone basis.

operate their resources to match their loads in the same manner as would a vertically-integrated utility that is a control area operator.[22] I.e., the SC would agree to match its loads and resources on a much more refined basis (consistent with NERC Control Performance Standards), relieving the RTO of this burden and thereby relieving the SC from its obligation to self-provide (or have the RTO procure) Load Following and Regulation resources.[23] This functionality can be provided through the concept of "self-tracking."

Self-tracking is an alternative to self-provision of certain ancillary services resources (Load Following and/or Regulation) to the RTO, under which an SC would contractually commit to the RTO that the SC would use the generation resources in the SC's portfolio to closely track the loads in the SC's portfolio. In return for relieving the RTO of the burden of following the SC's loads, the SC would be exempted from all (or a part of) the SC's pro rata requirement to self-provide (or have the RTO procure on the SC's behalf) Load Following and/or Regulation resources.

Some of the features of self-tracking are as follows:

- An SC which has committed to self-track would not have those parts of its resources which it is using for self-tracking called upon by the RTO to meet the RTO's requirements to balance ACE on the RTO grid, or for any other reason except to deal with residual congestion management when there are no other alternatives, or pursuant to the RTO Tariff's rules for the management of system emergencies. (Actually, the reason for this is not related for self-tracking, but is because the SC would not have committed to provide those resources to the RTO, either through self-provision or through bidding them into the RTO's ancillary services procurement process.[24])

- In order to qualify for self-tracking, the SC must demonstrate that it has the capability to perform self-tracking. The SC would also be obligated to provide data to the RTO (on a 2-4 second basis rather than an integrated 10-minute basis) to enable the RTO to monitor and verify that the SC did indeed meet its obligation to self-track and to settle for undergeneration or overgeneration by the SC.[25]

- Performance standards need to be defined for how closely the SC must match its loads and resources. For an SC to either receive a reduction in or be exempted from Load Following and

22 Note: The concept of control area operator is currently undergoing a major overhaul at NERC to completely separate the role of managing grid security from commercial functions. Under that overhaul, an integrated utility's retail merchant arm would be separated from the entity (known as a "Balancing Authority") which is responsible for managing the control area's ACE and for dealing with other grid security issues. The Balancing Authority must be independent of all market participants - including the retail merchant - in order to ensure that it does not leverage its grid security responsibilities to provide preferential treatment to its affiliates (including the retail merchant).

23 It is difficult to conceive of many, if any, situations in which an SC would be better off under this alternative to self-provision. But, under the proposal in this discussion paper, that decision would be left to each SC.

24 Note: The RTO's ancillary services procurement process is intended to be a simple, external-to-the-RTO process. For example, the RTO could annually contract with an operator of an ancillary services exchange, in which case the RTO would procure by submitting its quantity bids into the exchange.

25 This data would include energy imbalance data (e.g., similar to ACE) for the group of loads and resources in the SC's portfolio and real-time generation data.

Regulation charges, the standard would probably be similar to that in the NERC CPS and as a result may require additional certifications for GCC operators over and above the operators of an SC that chooses not to self-track. (If a second level of self-tracking was developed, under which an SC would be exempted from Load Following capacity charges but would self-provide Regulation resources as described in the introduction, the standard might be looser - e.g., integrated imbalance must be less than a specified tolerance for every 2-minute period.)

- Tolerances need to be developed in order to define acceptable performance. For example, the SC's imbalance must be less than x MWh during every 2-minute period. The SC could exceed this value by z% no more then i times per day.

- Charges need to be defined for non-performance. This could be addressed in several ways. A ratcheted "backup charge" could be developed ($J for exceeding the tolerance the first time, $K for exceeding it the second time, etc.). The purpose of this charge is to prevent the SC from leaning on the RTO. Alternatively, a percentage of the SC's responsibility under self-provision could be charged (e.g., 20% of the self-provision requirement) in return for a looser set of self-tracking performance requirements.[26]

- To the extent that the SC does not precisely match its loads and resources over a ten-minute interval, the SC would be charged (or would receive) the Balancing Energy price for the excess energy taken from (or provided to) the RTO grid. (This is equivalent to paying for inadvertent energy under the old-world control area model.)

- The question of how the SC would real-time meter its loads and generation in order to keep its imbalance close to zero in real-time needs more thought. In the case of a self-tracking SC which desires to rely on the real-time metering of an affiliated transmission or distribution wires entity, this issue needs to be addressed in a way that is equitable to both the self-tracking SC and any SCs who are responsible for generators or loads (whether wholesale loads or unbundled retail loads) within the geographic boundaries of the wires entity.

Conclusion

The concept of self-tracking, together with the other basic features of the ancillary services and SC models, provides an SC with the capability to match its loads and resources, with no interference from the RTO, no new exposure to imbalance energy prices, and no exposure to the RTO's charges for Load Following and Regulation ancillary services. The concept allows an SC to be treated almost as if it were a traditional control area (the primary differences being that: (i) the SC is not responsible for transmission security functions; and (ii) the SC – since it would not actually be a control area operator – could not leverage a role in the transmission arena[27] to gain preferential treatment over SCs).

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26 In addition, some residual charges for RTO Load Following and Regulation capacity might still be appropriate since the RTO would be responsible to the non-RTO portions of the Western Interconnection for a share of the interconnection's frequency bias response, whereas the self-tracking SC would have been absolved of such responsibility.

27 Examples include preferential access to real-time data as to the status of the grid, control over the dispatch of ancillary services for the grid (rather than for its own use), control over the resources and loads of other SCs in

the control area, ability to park and lend (while other SCs could not), and ability to lean on other control areas for real-time energy (while other SCs could not).

Attachment H

Facsimile Cover Sheet

BONNEVILLE POWER ADMINISTRATION

Transmission Business Line
Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666

To: John Kaake
Company:
Phone:
Fax: 503-813-5233

From: Vickie VanZandt
Routing:
Phone: 360-418-8459
Fax: 360-418 8433

Date: 3/22/02
Pages Including Cover Page: 9

Comments:

Appendix A: Example Only of One Possible Approach for Multi-tier Operational Functionality

Terms and Acronyms:

ATC: Available Transfer Capability
CBM: Capacity Benefit Margin
NERC: North America Electric Reliability Council
Open Access Path: Interconnections of commercial interest, i.e. posted paths
TIER 1: Pertains to regional grid operator characteristic or functional responsibility
TIER 2: Pertains to the local grid operator characteristic or functional responsibility, i.e. control area or utility level.A Multi-Tier RTO is one where responsibility for some of the functions of the RTO would be passed/contracted to sub-regional organizations that meet the independence criteria established by FERC. Such an arrangement may work where certain RTO participants must preserve local or regional sovereignty over transmission operations. This structure could include both TransCo (like the ITC) and ISO (like RTO West) elements, and independent grid operators (IGO), who, as operating entities, would collectively perform all of FERC's requirements for an RTO.

The Multi-Tier Model envisions some functions of the RTO being performed by RTO West (Tier 1) and other functions performed, within Canada, by a Canadian Independent Grid Operator (Tier 2) (possibly one IGO in each province, recognizing jurisdictional distinctions between provinces). With both Tier 1 and Tier 2 exhibiting characteristics required by FERC for RTO-related entities, RTO functions can be shared and distributed between the two tiers as necessary, with the two tiers together encompassing the single collective RTO. For the purposes of this document, Tier 2 entities are each assumed to be a single control area (CA) but there is no apparent reason that a Tier 2 component couldn't be made up of several CAs.

In a Multi-Tier Model, Canadian transmission facility owners would deliver control over the operation of their transmission facilities to the Canadian IGO. This can be accomplished by agreement or by legislation, and might be done that way in some provinces, creating a legislative paradigm directly. Canadian IGO(s) would carry out specified RTO West functions in Canada as necessary to accommodate Canadian legal and regulatory matters. Agreements(s) between Canadian IGO and RTO West would encapsulate the division of RTO functions as between them. Such agreements(s) would be the enabler for the business deal, and would embody the commercial arrangements(s) with RTO West and Canadian IGO to provide RTO operation that accommodate different legal/regulatory regimes.

T/M: Transmission
TTC: Total Transfer Capability
TRM: Transfer Reliability Margin
TRR: Transmission Revenue Requirement
WSCC: Western Systems Coordinating Council

Listed below is a final draft allocation of how FERC's characteristics/functions could be undertaken in a multi-tiered RTO.

PART A: Characteristics	Responsibilities	Objective/Justification
A.3 Operational Authority		
• Operate the Control Area • Maintaining energy balance • Interchange schedules • Maintaining system frequency	TIER 1: Develop standards for and ensure compliance with both overall grid reliability and operation of the system. TIER 1: Provide energy scheduling services (E-tag); determine (inter- and intra-RTO) net in/outs and advise Tier 2 TIER 1: Develop consistent terms and conditions for deployment of ancillary services within RTO region TIER1: Within the RTO region, Operates overall control area – performs AGC and ACE function – responsible for net inter-RTO tie line schedules and security measures. Is the provider of last resort and ensures adequacy of self provided ancillary products coordinated. TIER2: Operate a control center and provide self tracking and self provision of ancillary services, (AGC and ACE functions), TIER2: Responsible for implementation of energy and ancillary services schedules as authorized by Tier 1. TIER2: Settles (the tier2) energy imbalances with Tier 1.	Removes intra-TIER 1 seams issues and facilitates inter-RTO resolution of seams issue Complex issue in debate; utilize existing processes until A/S management is resolved

• Schedule and implementT/M Outages	Transmission Owner: Provides list of planned outages to Tier 2. Tier 2: Provides to TIER 1 a list of planned outages that affect facilities under the functional control of TIER 1.~~Open Access Paths to Tier 1. (as defined by Tier 1)~~ TIER 1: Authorizes transmission and contracted generation (i.e. must-run generators) outages that affect facilities under the functional control or TIER 1. TIER 2: Authorize and implement all other transmission and contract generation outages TIER 2: Operates circuit breakers and disconnect switches to isolate equipment and issues safety guarantees.	Maximized TTC/ATC across a contiguous multi-control area/utility path via high level coordination. Domestic load provided by Tier 2
• Respond to Forced Outages	TIER 1: Approves operating procedures for timely response to forced outages that affect facilities under the functional control of Tier 1 and coordinates ultimate response to the outage. TIER 2: Incorporates operating procedures (including implementing scheduling curtailment instructions) into operating orders and informs TIER1. TIER 2: Develops and implements operating procedures and orders for response to contingencies not affecting facilities under the functional control of Tier 1. TIER1: Determines new path limits based on forced outages.	Restoration best handled at local level but using TIER 1-wide protocols. TIER 1 needs to be kept in the picture to facilitate its ATC/TC posting and congestion relief obligations.

A.4 Security Coordination		
• Security Coordinator Function	TIER1 : Provides Security Coordination services for the RTO region. TIER 1: Working in conjunction with Regional Reliability Authority and others, develops and communicates standards to TIER 2. TIER 2: Incorporates standards into its operating practices. Reports to TIER 1.	TIER 1, as umbrella organization, is in the best position to police TIER 2 compliance with reliability standards. Most practical for TIER 2s to continue to ensure that their system's operate reliably and within region wide standards.

PART B: Functions		
B.1 Tariff Administration and Design		
Not the responsibility of the Adjunct Committee Technical Team		
B.2 Manage Congestion		
• Congestion Relief/Redispatch Process • Compliance Monitoring • Business Practices	TIER 1: Develops and administers congestion management procedures for facilities under the functional control of TIER 1. Tier 2: Implements congestion management procedures (redispatch) under the direction of TIER 1. TIER 1: Provides a Dispute Resolution process	TIER 1: Provides efficient and independent congestion management & dispute resolution.

B.3 Parallel Flow Issues		
• Rules for Compliance Monitoring • Operations Mitigation • Planning Mitigation	TIER 1: Develops procedures and administers inter- and intra-RTO parallel flow management Unscheduled Flow Mitigation Plan would be implemented by Tier 1. TIER 2 follows TIER 1 directions regarding Tier2 facilities which mitigate loop flow.	Provides an independent and efficient regional perspective to most effectively deal with loop flow that reduces TTC.
B.4 Supplier of Last Resort for Ancillary Services		
• Regulation and Frequency Response • Operating Reserve • Supplemental Operating Reserve • Energy Imbalance • Losses • Reactive Supply/Voltage Control	TIER 1: Develops/administers the provision of ancillary services. Is the provider of last resort. TIER1 will provide ancillary services that are not self tracked or self provided by TIER2. TIER 2: Dispatches the ancillary services as determined by TIER 1. TIER2: May self provide, self track or arrange bilateral provision of ancillary services products.	Tier1 Facilitate the provision of ancillary services. (self provision, bilateral contracts, market) In order to meet Tier 2 regulatory requirements to operate local facilities in a safe and secure manner, Tier 2 needs the ability to effectively maintain the security and control of the system.

B.5 Operate Single OASIS Site for T/M Under TIER 1 Control		
• Administer Single Site – real time, hourly, daily, monthly, yearly T/M reservations • Calculate ATC	TIER 1: Responsible for establishing and administering uniform business practices for reserving transmission TIER 1: Provides OASIS site and calculates ATC. TIER 1: calculates OTC / TTC or approves OTC / TTC as calculated by TIER 2. If OTC / TTC is in dispute then the more conservative limits will be used until the dispute is resolved.. TIER 1: Provides Dispute Resolution Process	Removes Inconsistencies across multiple areas within the TIER 1 Allocation of responsibility based on: ATC (Tier 1) = TTC (Tier 2) - T/M Reservations/Contracts (Tier 1) - TRM (Tier 1) - CBM (Tier 1/Tier 2)- Domestic/Grandfathered Contracts (Tier 2) Tier2 does TTC calculation due to local requirement for adequacy and security.
B.6 Monitor Markets Not the responsibility of the Adjunct Committee Technical Team		
B.7 Plan and Coordinate Necessary T/M Additions and Upgrades Not the responsibility of the Adjunct Committee Technical Team		

B.8 Conduct Interregional Coordination		
Not the responsibility of the Adjunct Committee Technical Team		

The Canadian Adjunct Technical Committee has concluded that the TIER 1 / TIER 2 concept can work operationally. The sub committee has prepared a draft matrix that describes the functional division between TIER 1 and TIER 2.

This technical subcommittee did not address planning, tariffs and market monitoring issues. We feel these issues are best addressed by other RTO West work groups or a newly appointed subcommittee of the Adjunct Committee

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

NOV 3 2000

In reply refer to: CE-1

MEMORANDUM FOR THE DEPUTY SECRETARY

FROM: Judith A. Johansen /s/ Stephen J Wright
Acting Administrator and Chief Executive Officer

SUBJECT: INFORMATION: Letter of Appreciation

As Bonneville has moved forward over the past year to participate in the formation of an RTO, one area of critical focus has been employee transition issues. Our goal has been to minimize the transition impacts for employees who may want to work for the RTO, as well as for those employees who choose to remain Bonneville employees. We have worked with our employees and the Unions in a highly collaborative process to identify and propose solutions to employee transition issues. Over 30 issues and proposed solutions were identified.

The two issues that needed to be addressed early in the RTO West formation process were:

1. The need for the RTO to be able to provide any of its new employees who were formerly Bonneville employees with the option of retaining their current federal retirement coverage; and
2. The need for the Administrator to be able to detail employees to the RTO to assist in the initial start-up and operation of the RTO.

Bonneville sought and received excellent assistance from the Department in the development, review and coordination of RTO legislative bill language to address these two key issues. The Department's legislative proposal was developed in such a manner as to cover all the PMAs.

Particular thanks goes to Pam Jeckell, Supervisory Management Analyst in the Workforce and Planning Division, Office of Human Resources Management; Bob Rabben, Assistant General Council for Legislation, Office of the General Counsel, and Rich Glick, Electricity and Energy, Senior Policy Advisor to the Secretary of Energy.

Pam Jeckell provided us with information regarding how the Department addressed similar issues across the complex and especially at closure sites. She shared past experience in crafting legislation to address employee transition issues and offered Office of Personnel Management (OPM) advice and council the Department had received in the past. In this manner she helped to insure that our legislative proposal was in keeping with the spirit and direction of the Department.

Bob Rabben thoroughly reviewed our proposed legislative language a number of times, made a number of very valuable suggestions, and worked closely with Mr. Harry Wolf, Director of Legislative Affairs at OPM. He helped move the draft bill language through Departmental and OPM review process and then pushed to get the proposal through an expedited interagency review process at the Office of Management and Budget (OMB). All of this effort was accomplished over a very short period of time at the end of the legislative session of the 106th Congress.

Rich Glick provided valuable advice as the draft bill language moved through the Department and OPM review processes and very important support for placing the draft legislation into the expedited OMB review process.

Unfortunately, the press of issues pending resolution at the end of the last session of the 106th Congress the Conference on Energy & Water was such that we were unable to include this bill language in the FY 2001 appropriations bill. We did, however, make substantial progress and will seek to include this bill language in the President's Budget for FY 2002. Again, we appreciate all of the DOE staff's efforts to make this possible and to support the RTO goals you expressed in your May 16, 2000, memorandum.

bcc:
Adm. Chron. File – A
T. Esvelt – C-4
S. Wright – K-7
J. Stier – KN/Wash
B. Evans – KR-7-C
Official File – CE (EX-15-12-3)

VLWilliams:3031:10-30-00 (h:Thankyou DOE legislation)

The Deputy Secretary of Energy
Washington, DC 20585

RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG #: 2000-0223
RECEIPT DATE: 5·16·00
DUE DATE: 5·30·00

May 16, 2000

MEMORANDUM FOR POWER MARKETING ADMINISTRATORS

FROM: **T. J. GLAUTHIER**

SUBJECT: **FERC Order No. 2000**

ASSIGN: KR-7C
cc: A3, K, KE, KN, L, P, T, C, KC-Mahar, KC-Mosey

On December 20, 1999, the Federal Energy Regulatory Commission (Commission) issued its Final Rule, Order No. 2000, on Regional Transmission Organizations (RTOs). In Order No. 2000, the Commission found that independent, regionally operated transmission grids will be necessary in order to promote the continued development of competitive electricity markets. The Commission also found that to meet this objective, all transmission owners, including the Federal power marketing administrations (PMAs) should be included in RTOs.

The Department of Energy fully endorses the Commission's goals, as enunciated in Order No. 2000. Pursuant to the Secretary's request, I hereby direct the PMAs to fully participate in the process contemplated by Order No. 2000 with the objective, if possible, of joining an RTO. As the RTO process continues to unfold, I look forward to maintaining a close dialogue with you regarding these objectives.

Order No. 2000 specifically requires all public utilities that own, operate, or control transmission facilities to file with the Commission by October 15, 2000, or January 15, 2001, as appropriate, a proposal for an RTO to be operational by December 15, 2001. Alternatively, Order No. 2000 requires all such utilities to file a description of their efforts to participate in an RTO, any obstacles to RTO participation; and any plans to work toward RTO participation. I direct the PMAs to make such filings with the Commission by October 15, 2000.

\- BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT
November 28, 2003

I. Schedule

[redacted]

II. Key Departmental News

Northwest Making Significant Progress Toward Unified Transmission: On December 10-11, 2003, a Regional Representatives Group (RRG) will meet to confirm its acceptance of a single platform for unifying Northwest transmission operation and planning, and developing a plan to move forward. The RRG tentatively accepted the platform last week, formed a drafting team to fill in remaining gaps and identify items for subsequent development. The platform calls for three phases. Each would proceed when proved beneficial to participants. The first phase would begin with voluntary control area consolidation. Bonneville, PacifiCorp, Idaho Power Company and B.C. Hydro have expressed interest in taking this first step together. Additional utilities could join, as they perceived benefits.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (14-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

Nothing to report.

VI. FOIA Requests

[redacted]

[redacted]

VII. Grants, Economic Announcements and Publications

Nothing to report.

VIII. Climate Changes

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

January 3, 2003

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

[redacted]

Federal Energy Regulatory Commission (FERC) Clarifies Stage 2 Ruling: On December 20, 2002, FERC issued its decision on the RTO West Filing Utilities' petitions for rehearing or clarification of its September 18, 2002, Stage 2 ruling. Filing Utilities were concerned about protecting critical components of the Transmission Operating Agreement (TOA) from future FERC-mandated changes. FERC recognized "that the willingness or ability of some entities to participate in the RTO may hinge on particular agreed upon provisions in the TOA" and agreed to consider providing protection to a list of TOA provisions that the Filing Utilities would file in the future. The Order also removed the uncertainty about the eight-year Company Rate Period by removing the requirement in the September 18, 2002, order that the Market Monitor evaluate and make recommendations concerning the length of the Company Rate Period. The Commissioners further said, "We do not intend to revisit these prior approvals [of RTO West design elements] upon issuance of the Standard Market Design final rule." FERC reiterated the importance of the Seams Steering Group – Western Interconnection's (SSG-WI) work to address any seams issues that may be created where RTO West proposes different solutions from adjacent Regional Transmission Organizations. It said, "Our approval of any individual RTO market design solution is based on our expectation that the parties will continue to identify and work towards a successful resolution of any resulting seams issues."

Media Interest: No.
Program Contact: Jeff Stier, 202-586-5640.

FERC Chairman Praises Bonneville and RTO West: In an open Commissioners' meeting December 18, 2002, FERC Chairman Pat Wood applauded the RTO West proposal. He said RTO West is doing top quality work, setting the mark for what RTOs should look like. He said he read "with gratitude" a speech that Bonneville's Vice President for Industry Restructuring Allen Burns made before the Northwest Public Power Association in mid-December describing Bonneville's strategy for moving RTO West forward. Wood said Bonneville's strategy is pragmatic, supportive, and clear about what the agency is asking for from FERC.

Media Interest: Yes.
Program Contact: Jeff Stier, 202-586-5640.

III. Upcoming Events or Matters of Secretarial Interest (7-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

Nothing to report.

VI. FOIA Requests

Nothing to report.

VII. Grants, Economic Announcements and Publications

Nothing to report.

VIII. Climate Change

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

January 17, 2003

I. Schedule

[redacted]

II. Key Departmental News

Regional Transmission Organizations (RTO) Submit Report on Joint Effort to Resolve "Seams" Issues: On January 29, 2003, representatives from RTO West Filing Utilities, the California Independent System Operator, and WestConnect will brief the Federal Energy Regulatory Commission (FERC) on the progress under the Seams Steering Group-Western Interconnection (SSG-WI) at a FERC Commission meeting in Washington, D.C. Last week SSG-WI filed a status report in compliance with FERC's orders (in all three RTO dockets) to formalize a process to resolve seams issues between the three Western RTOs. The report describes a memorandum of understanding the entities signed in December on how they'll work together. SSG-WI told FERC it will operate as an advisory group to the three RTOs, producing recommendations on specific issues that each RTO will then decide whether to adopt and submit it to FERC.
Media Interest: No.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

[redacted]

[redacted]

III. **Upcoming Events or Matters of Secretarial Interest (14-day advance)**

[redacted]

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

Nothing to report.

VI. FOIA Requests

Nothing to report.

VII. Grants, Economic Announcements and Publications

Nothing to report.

VIII. Climate Change

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

February 21, 2003

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

Comments to Federal Energy Regulatory Commission (FERC) on Standard Market Design (SMD): Bonneville will provide comments to FERC on its SMD Notice of Proposed Rulemaking by FERC's deadline of February 21, 2003. Northwest investor owned utilities participating with Bonneville in RTO West will file their SMD comments with FERC separately.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

[redacted]

Regional Transmission Organization (RTO) Development Plans Will Take Time: Bonneville and the eight other utilities involved in RTO West filings have told the FERC they need time to develop and launch RTO West. All the utilities, including Bonneville, are carefully controlling investments. The current financial picture points to the need to hold off on significant investments until at least fiscal year 2005. At the same time, the utilities said, they need time to shape an RTO proposal that works for the Northwest. On this timeline, RTO West startup would be in 2006 or 2007.

Media Interest: Some.

Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

[redacted]

III. **Upcoming Events or Matters of Secretarial Interest (14-day advance)**

Nothing to report.

IV. **Work on Secretarial Initiatives**

Nothing to report.

V. **Press Inquiries**

Nothing to report.

VI. **FOIA Requests**

Nothing to report.

VII. **Grants, Economic Announcements and Publications**

[redacted]

VIII. **Climate Change**

Nothing to report.

IX. **Disaster Assistance**

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT
July 4, 2003

I. Schedule

[redacted]

[redacted]

[redacted]

II. Key Departmental News

[redacted]

[redacted]

Bonneville and Others Offer New Vision For RTOs: Bonneville and other regional utilities working to develop a Regional Transmission Organization (RTO) are offering a new vision intended to ensure that the RTO West proposal is shaped to respond to the region's needs. The draft vision was first introduced at a June 26, 2003, meeting of the RTO West Regional Representatives Group, which is made up of delegates from utilities, end use customers, public interest groups, states, and other stakeholders affected by transmission service and infrastructure in the Northwest. The new vision for RTO West calls on all participants to unify transmission management to maintain reliability, improve efficient use of the system, and provide the Region's customers with access to diverse, widespread, wholesale energy alternatives. The vision is still a work in progress. The RTO West Regional Representatives Group plans to meet again on July 9, 2003, to approve a final product.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640

[redacted]

[redacted]

[redacted]

Northwest Senators Send Request to FERC: All eight Northwest senators signed a letter to FERC June 12, 2003, requesting that it hold one of its technical conferences on Standard Market Design (SMD) in the West. The senators say that the Commission's proposed rulemaking on SMD and its recent white paper on market design have significant implications for the region. They request that the region's stakeholders have a chance to discuss their concerns directly with the Commission.
Media Interest: No.
Program Contact: Jeff Stier, 202-586-5640

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (14-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT
October 31, 2003

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

[redacted]

[redacted]

[redacted]

Regional Transmission Organizations (RTO) Identify Expansion Needs for Western Grid: Working together, transmission planners, stakeholders and State representatives from 13 western states and two Canadian provinces have defined generally where the western power grid may need expansion. The new "SSG-WI Transmission Report" lays out broad transmission additions needed to support potential natural gas, coal or renewable-based additions to the west's power resources through 2008 and 2013. All the results are consistent with Bonneville's plans for its own grid. The report also identifies a process for coordinating westwide and subregional transmission planning with work by utilities and states on integrated resource planning or resource adequacy standards. The report is the product of the Seams Steering Group of the Western Interconnection (SSG), made up of technical experts from RTO West, the California Independent System Operator, and West Connect, to address seams issues between the three RTOs proposed for the western grid interconnection.

Media Interest: No.

Program Contact: Jeff Stier, 202-586-5640.

III. Upcoming Events or Matters of Secretarial Interest (14-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

[redacted]

VI. FOIA Requests

[redacted]

VII. Grants, Economic Announcements and Publications

Nothing to report.

VIII. Climate Changes

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT
November 14, 2003

I. Schedule

[redacted]

II. Key Departmental News

Consensus Proposal on Unified Transmission Planning and Operations Expected: Eight individuals representing a range of interests met all this week to develop a straw proposal that could become the foundation for getting to a widely supported approach to unifying Northwest transmission planning and operation. The group is working from concepts produced by the RRG and are to present their consensus proposal to the RRG the week of November 17, 2003.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. **Upcoming Events or Matters of Secretarial Interest (14-day advance)**

Nothing to report.

IV. **Work on Secretarial Initiatives**

Nothing to report.

V. **Press Inquiries**

[redacted]

[redacted]

VI. FOIA Requests

Nothing to report.

VII. Grants, Economic Announcements and Publications

[redacted]

VIII. Climate Changes

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT
November 21, 2003

I. Schedule

[redacted]

II. Key Departmental News

Bonneville to Release Statement on Region's Efforts Toward Unified Transmission Planning: In the next three weeks, Bonneville expects to roll out its current thinking on alternatives for a unified Northwest transmission grid next week. The white paper will outline the agency's "must haves" and encourage those working on the proposals to make a concerted push through work that has at times seemed daunting. Since June, a Regional Representatives Group (RRG) has reached consensus in areas that had resisted progress for years. Following the Federal Energy Regulatory Commission's (FERC) favorable response to Northwest concerns, RTO West filing utilities convened the RRG and asked it to develop options that would work for the Northwest's unique hydro system. Bonneville believes that the RRG's "hybrid" option promises to fulfill many of the criteria set by FERC, Bonneville and others as necessary for success.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (14-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

[redacted]

VI. FOIA Requests

Nothing to report.

VII. Grants, Economic Announcements and Publications

Nothing to report.

VIII. Climate Changes

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

January 25, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

[redacted]

RTO West Prepares to File Proposal: The week of February 4, RTO West will distribute to stakeholders a draft proposal to form a Regional Transmission Organization (RTO). RTO West plans to file the proposal March 1 at the Federal Energy Regulatory Commission (FERC). The utilities will hold a two-day public meeting February 11 and 12 to get input on the proposal. Comments from the session will help shape the final proposal. In addition, preliminary results from the RTO West benefit-cost study will be shared with stakeholders beginning February 4. A final benefit-cost study should be completed by February 22.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (7-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. Press Inquiries

Nothing to report.

VI. FOIA Requests

Nothing to report.

VII. Grants, Economic Announcements and Publications

Nothing to report.

VIII. Climate Change

Nothing to report.

IX. Disaster Assistance

Nothing to report.

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

February 1, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

RTO West Prepares to File Proposal: RTO West filing utilities will hold a two-day public meeting February 11 and 12 to get input on a draft proposal to form a RTO in the Pacific Northwest. RTO West plans to file the proposal March 1 at the Federal Energy Regulatory Commission (FERC). Comments from the session will help shape the final proposal. Stakeholders are particularly

interested in the benefit-cost study. Preliminary results should be available the week of February 4. The study should be finalized by February 22.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (7-day advance)

Nothing to report.

IV. Work on Secretarial Initiatives

Nothing to report.

V. **Press Inquiries**

Nothing to report.

VI. **FOIA Requests**

Nothing to report.

VII. **Grants, Economic Announcements and Publications**

[redacted]

VIII. **Climate Change**

Nothing to report.

IX. **Disaster Assistance**

Nothing to report.

DEPARTMENT OF ENERGY

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

IN REPLY REFER TO: BPA-KR

February 6, 2002

MEMORANDUM FOR THE SECRETARY

FROM: Stephen J. Wright
Administrator and Chief Executive Officer

SUBJECT: 30-60-90 Day Report

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Projected Benefits and Costs of Regional Transmission Organization (RTO): RTO West expects to release a final benefit-cost study Feb. 28 on the proposed RTO. An independent consultant is producing the report, which will look at the benefits and costs of the proposed RTO West organizational structure and its impacts on the region. Preliminary results were released Feb. 4 and widely distributed among customers and other stakeholders, as well as the Northwest congressional delegation, as a critical step in gaining regional consensus to move forward with the proposed RTO West.

No Secretarial action requested.

March
Next 60 Days

Regional Transmission Organization (RTO) Filing Due: In March, Northwest transmission owners plan to submit a Stage Two filing to the Federal Energy Regulatory Commission (FERC) providing remaining details and contractual concepts for RTO West. Among the issues addressed in the filing will be congestion management, ancillary services, planning, scheduling coordinator terms, security coordination, and an analysis of the benefits and costs of the proposed RTO West. The filing is being developed through a collaborative public process involving all stakeholders in the region. RTO West has made several filings with FERC under Order 2000. The Stage Two filing is expected to be the most comprehensive and address most of the remaining issues with RTO formation in this region.

No Secretarial action requested.

[redacted]

[redacted]

[redacted]

[redacted]

April
Next 90 Days

[redacted]

[redacted]

Ongoing

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

February 8, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

Report Estimates Costs and Benefits of Regional Transmission Organization (RTO): The preliminary results of an independent benefit-cost analysis of RTO West, released February 4 for public review and comment, shows nearly $350 million energy savings across the RTO West grid. The report, prepared by Tabors-Caramanis and Associates (TCA), indicates that other significant benefits exist, but TCA does not quantify them in the report. A range of $125 million to $145 million annual cost is estimated for startup and operations. RTO West representatives shared the results with stakeholders and the Northwest congressional delegation this week. The presentation (a 126-page PowerPoint document) is posted on the RTO West Web site at http://www.rtowest.org/Stage2BenCstMain.htm.

Media Interest: Some.

Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (7-day advance)

RTO West Prepares to File Proposal: In preparation for filing a proposal for RTO formation March 1 at FERC, RTO West filing utilities will hold a two-day public meeting February 11 and 12. Comments from the session will help shape the final proposal. Stakeholders are particularly interested in the benefit-cost study that was released this week. The study should be finalized by February 28.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

IV. Work on Secretarial Initiatives

[redacted]

V. Press Inquiries

[redacted]

VI. FOIA Requests

[redacted]

VII. Grants, Economic Announcements and Publications

[redacted]

VIII. Climate Change

[redacted]

IX. Disaster Assistance

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

February 15, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

[redacted]

Regional Transmission Organization (RTO) West Prepares to File Proposal: RTO West filing utilities are preparing to file a proposal for RTO formation at the Federal Energy Regulatory Commission (FERC). A benefit-cost study, which is of particular interest to regional stakeholders, should be finalized February 28. The utilities held a two-day public meeting this week to get comments on the final proposal.

Media Interest: Some.

Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. **Upcoming Events or Matters of Secretarial Interest (7-day advance)**

[redacted]

IV. **Work on Secretarial Initiatives**

[redacted]

V. **Press Inquiries**

[redacted]

VI. **FOIA Requests**

[redacted]

VII. **Grants, Economic Announcements and Publications**

[redacted]

VIII. **Climate Change**

[redacted]

IX. **Disaster Assistance**

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

February 22, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

[redacted]

RTO West Delays Filing: RTO West utilities have agreed to delay filing a proposal for RTO formation at the Federal Energy Regulatory Commission (FERC). The delay is not expected to last more than a month. RTO West intended to file a proposal on March 1, 2002, but will now wait until Regional stakeholders have time to better understand the proposal and the results of the RTO West benefit-cost study. The benefit-cost study will be finalized February 28. RTO West hosted a two-day stakeholders meeting last week to receive comments on the draft proposal. Stakeholders were able to provide feedback and requested a follow-up meeting to understand how their comments will be incorporated into the final proposal. The Northwest Energy Caucus plans to invite RTO West representatives and stakeholders to an informal hearing in Washington, DC, in mid-March.

Media Interest: Some.

Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

III. **Upcoming Events or Matters of Secretarial Interest (7-day advance)**

[redacted]

IV. **Work on Secretarial Initiatives**

[redacted]

V. **Press Inquiries**

[redacted]

VI. **FOIA Requests**

[redacted]

VII. **Grants, Economic Announcements and Publications**

[redacted]

VIII. **Climate Change**

[redacted]

IX. **Disaster Assistance**

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

March 1, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

[redacted]

Public Discussions Continue on RTO Proposal: RTO West utilities will meet with stakeholders on March 5, 2002, to go over remaining issues regarding the RTO filing at the Federal Energy Regulatory Commission (FERC.) The Northwest Energy Caucus has also scheduled an informal hearing on March 13, 2002, in Washington, D.C. on RTO West. The RTO West filing at FERC, originally set for March 1, 2002, was pushed back until the end of the month to allow time for regional stakeholders to better understand the proposal and the results of the RTO West Benefit-Cost Study.

Media Interest: Some.

Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (7-day advance)

[redacted]

IV. Work on Secretarial Initiatives

[redacted]

V. Press Inquiries

[redacted]

VI. FOIA Requests

[redacted]

VII. Grants, Economic Announcements and Publications

[redacted]

VIII. Climate Change

[redacted]

IX. Disaster Assistance

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

March 8, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

Discussions Continue on RTO West Filing: The Northwest Energy Caucus has scheduled an informal hearing March 13, 2002, in Washington, D.C. on RTO West. The RTO West filing at the Federal Energy Regulatory Commission (FERC), originally set for March 1, 2002, has been pushed back until the end of the month to allow time for regional stakeholders to better understand the proposal and the results of the RTO West benefit-cost study.

Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

Study Shows RTO West Yields Reliability Benefits: A Northwest regional transmission organization would offer at least five advantages to maintaining system reliability, according to a new study done under contract for Bonneville. Ed Schweitzer, president of Schweitzer Engineering Laboratories, and Roy Billinton, with the University of Saskatchewan, conducted high-level analyses of the impacts of RTO West on transmission system reliability. In addition to identifying critical areas covered in the RTO West proposal that could affect reliability, they suggested actions that would help reduce the risks. The reports by Billinton and Schweitzer are part of an overall effort to assess benefits and costs of an RTO.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

Utilities Express Concerns About RTO West: The Washington Public Utility District Association and the Public Generating Pool have written to the Administrator asking that Bonneville not participate in RTO West. In their letters, the utility Association states that Bonneville already provides the kind of open, non-discriminatory transmission access advocated by FERC. As a result, they say, RTO West may be unnecessary. The Association also raises concerns about RTO costs and whether increased costs might fall on Bonneville customers. Bonneville continues to work with its customers and constituents to assure that the RTO West filing now being developed meets Northwest needs and Bonneville's own principles.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

[redacted]

III. Upcoming Events or Matters of Secretarial Interest (7-day advance)

[redacted]

IV. Work on Secretarial Initiatives

[redacted]

V. Press Inquiries

[redacted]

VI. FOIA Requests

[redacted]

VII. Grants, Economic Announcements and Publications

[redacted]

VIII. Climate Change

[redacted]

IX. Disaster Assistance

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

March 15, 2002

I. Schedule

[redacted]

II. Key Departmental News

[redacted]

Regional Transmission Organization (RTO) Filing Approaching: Bonneville intends to join the Northwest investor-owned utilities in filing a RTO West proposal at the Federal Energy Regulatory Commission (FERC) by the end of March. The final RTO West benefit-cost study was released this week by the independent consultant. The final results indicate the formation of RTO West will provide substantial benefits in the Northwest. The consultant is providing Bonneville with more analysis, which will be shared with Bonneville's public utility customers soon. The proposal remains highly controversial with many of Bonneville's customers and their representatives in Congress.
Media Interest: No.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

III. **Upcoming Events or Matters of Secretarial Interest (7-day advance)**

[redacted]

IV. **Work on Secretarial Initiatives**

[redacted]

V. Press Inquiries

[redacted]

VI. FOIA Requests

[redacted]

VII. Grants, Economic Announcements and Publications

[redacted]

VIII. Climate Change

[redacted]

IX. Disaster Assistance

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

March 22, 2002

[redacted]

II. Key Departmental News

Regional Transmission Organization (RTO) Filing Expected Next Week: Bonneville intends to join the Northwest investor-owned utilities in filing a RTO West proposal at the Federal Energy Regulatory Commission (FERC) by the end of March. Bonneville believes the proposed RTO West filing represents a framework for a Northwest RTO that has the potential to provide benefits to Northwest electricity consumers. However, there are significant unresolved issues that could cause Bonneville to reconsider its support for RTO West. The filing is still highly controversial among Bonneville's public utility customers. Last week Washington State Governor Gary Locke sent a letter to the Administrator asking that Bonneville clarify with FERC that its participation in the filing is not a final decision to join RTO West.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

March 29, 2002

[redacted]

II. Key Departmental News

Regional Transmission Organization (RTO) Proposal Filed: On March 29, 2002, Bonneville and the Northwest investor-owned utilities filed the RTO West proposal at the Federal Energy Regulatory Commission (FERC). The filing asks FERC for a declaratory order finding that the RTO West proposal satisfies the minimum characteristics and functions of an RTO per FERC's Order 2000, pending subsequent filings refining RTO West concepts and details. Significant unresolved issues remain to be addressed.
Media Interest: Some.
Program Contact: Jeff Stier, 202-586-5640.

[redacted]

[redacted]

Public Utilities Start Campaign on RTO: The Washington Public Utility District Association (WAPUDA) has initiated a "grassroots" campaign to suggest alternatives to the RTO West proposal that was filed at the Federal Energy Regulatory Commission (FERC) March 29. The campaign reportedly will involve working with members of the Northwest Congressional delegation as well as influential state representatives. WAPUDA is concerned that an RTO will adversely affect their members' historical relationship with Bonneville and Bonneville's role in the region's transmission system. The Director of WAPUDA recently wrote to the Administrator asking that Bonneville not participate in the RTO filing.

Media Interest: Some.

Program Contact: Jeff Stier, 202-586-5640.

[redacted]

BONNEVILLE POWER ADMINISTRATION WEEKLY REPORT

April 26, 2002

[redacted]

May 9: The Administrator will meet with public utility commissioners from the four Northwest states. The commissioners are very interested in the progress on the Northwest's Regional Transmission Organization (RTO) proposal.

[redacted]