IMPLEMENTATION WORK GROUP

June 9, 2000
0830-1530

Dittmer Control Center, BPA
Vancouver, WA

Meeting Minutes
Version 1 – June 12, 2000

Attendees:

Jack Bernhardsen, PNSC
John Boucher, KEMA Consulting
Douglas Cave, BC Hydro
Chris Elliot, NWPP
Jon Fisker, PGE
Jerry Garman, PRM
Richard Goddard, PGE
Bob Harshbarger, PSEI
David James, Avista
Jon Kaake, Pacificorp
Terry Kent, USBR
Robert Lewis, APX
John McGhee, BPA/TBL
Tess Park, Idaho Power
LeRoy Patterson, MP
Dave Perrino, APX
Chris Reese, PSEI
Mike Ryan, PGE
Norm Stanley, Pacificorp
Ralph Underwood, SCL
Jim Vinson, BPA/TBL
Don Watkins, BPA/TBL
Don Wolfe, BPA/PBL
Gary Wright, Sierra Pacific Resources

Calendar:

May 23, 2000	0830 - 1230	Work Group Meeting	Kingstad Center ✔
June 1, 2000	0830 - 1700	Work Group Meeting	Kingstad Center ✔
June 2, 2000	0830 - 1530	Work Group Meeting	Kingstad Center ✔
June 9, 2000	0830 - 1530	Work Group Meeting	Ditmer Control Center ✔
June 16, 2000	0830 - 1530	Work Group Meeting	Kingstad Center
June 22, 2000	0830 - 1700	Work Group Meeting	Kingstad Center
June 23, 2000	0830 - 1530	Work Group Meeting	PDX Center
July 14, 2000	0830 - 1530	Work Group Meeting	Kingstad Center
July 21, 2000	0830 - 1530	Work Group Meeting	Kingstad Center
July 28, 2000	0830 - 1530	Work Group Meeting	Kingstad Center
August 4, 2000	0830 - 1530	Work Group Meeting	Kingstad Center
August 11, 2000	0830 - 1530	Work Group Meeting	Kingstad Center
August 18, 2000	0830 - 1530	Work Group Meeting	Kingstad Center

Assignments:

Action Item	Responsible Parties	Status
Update consensus assumptions list to cover all FERC 2000 characteristics and functions	John Boucher	Due 6/16/2000
Provide spreadsheet of ancillary services operational responsibilities to AS WG	Mike Ryan	Due 6/16/2000
Define AGC hierarchical operation strawman for 6/9 meeting discussion	Bob Harshbarger (lead), Deanna Phillips, Mike Ryan, Don	Completed

	Watkins	
Outline discussion points for metering operations and retail access	Ralph Underwood (lead), LeRoy Patterson, Vern Porter, Don Watkins	Completed
Define technology requirements strawman for 6/9 meeting discussion	Don Watkins (lead), Bob Harshbarger, Dave Perrino, Mike Ryan	Completed
Outline discussion points for Support functions	Richard Goddard (lead), Jack Bernhardsen, Chris Elliott, John McGhee	Completed
Define specific control center selection parameters	David James (lead), Douglas Cave, Jon Fisker, Norm Stanley, Jim Vinson	Completed
Define issues concerning AGC hierarchical operation including identifying responsible work groups	Bob Harshbarger (lead), Deanna Phillips, Mike Ryan, Don Watkins	6/16/2000
Define issues concerning metering including identifying responsible work groups. Review IndeGO meter specifications and update as required.	Ralph Underwood (lead), LeRoy Patterson, Vern Porter, Don Watkins	6/16/2000
Define issues concerning technology requirements including identifying responsible work groups	Don Watkins (lead), Bob Harshbarger, Dave Perrino, Mike Ryan	6/16/2000
Define issues concerning support functions including responsible work groups	Richard Goddard (lead), Jack Bernhardsen, Chris Elliott, John McGhee, Chris Reese	6/16/2000
Complete assessment questionnaire for Avista, PGE, and BPA	David James (lead), Douglas Cave, Jon Fisker, Norm Stanley, Jim Vinson	6/16/2000
Provide a 30 minute overview of IndeGO operations and staffing, including driving forces and short-falls.	LeRoy Patterson, Jon Kaake	6/16/2000

Summary of Consensus:

1. Agreement was reached on specific control center assessment criteria.

2. Note that in any case where consensus is reached that later proves inconsistent with decisions made by work groups responsible for a specific policy, such as Ancillary Services, then the Implementation work group will bring its consensus into conformance with those decisions.

Highlights of Meeting by Agenda Item (Agenda Attached)

Agenda Item 1: AGC Hierarchical Operation

Two strawmen for discussion were presented and discussed. The general view is that the RTO will form a control area while allowing other control areas to exist. See attached. This task team will create an issues list showing the responsible work group. In the cases where the Implementation work group is the responsible party, any prerequisites from other work groups will be defined.

Agenda Item 2: Metering Operations and Retail Access

Questions arose including: 1) What are the metering specifications? And 2) Do we require meters at the RTO-controlled facilities transition interfaces? This task team will create an issues list showing the responsible work group. In the cases where the Implementation work group is the responsible party, any prerequisites from other work groups will be defined.

Agenda Item 3: Technology Requirements

Strawman was presented and discussed. See attached. Questions arose regarding the withholding of certain equipment at Dittmer for BPA's use. Will this impact the functionality and information available to the RTO? Will this compromise the independence of the RTO? Also there was the question of whether or not ESCA would allow BPA to transfer its software licenses to the RTO. This task team will create an issues list showing the responsible work group. In the cases where the Implementation work group is the responsible party, any prerequisites from other work groups will be defined. BPA will propose any conditions as part of the lease offer.

Agenda Item 4: Support Functions

Strawman was presented and discussed. See attached. This task team will create an issues list showing the responsible work group. In the cases where the Implementation work group is the responsible party, any prerequisites from other work groups will be defined. BPA will propose any conditions as part of the lease offer.

Agenda Item 5: Control Center Selection Parameters

Strawman was presented and discussed. See attached. Some items were added. The questionnaire will be completed for all candidate sites including Dittmer. Avista, PGE, and Dittmer will be assessed first.

Agenda Item 6: Tour and Assessment of Dittmer Control Center

The work group appreciated the one hour tour. The assessment will take place as per item 5 above.

Agenda Item 7: Concept of Scheduling Coordinator

The need for a scheduling coordinator(s) will be defined jointly by the Ancillary Services and the Congestion Management work groups. The need is likely.

Agenda Item 8: Impact of Non-Power Hydro Commitments

Fish operations and flow restrictions, among other issues, must be kept in mind in defining the operations. Such constraints may be bundled within the definition of the unit or plant.

Next Meeting:

The next meeting will be held at the RTO West facilities at the Kingstad Center on Friday, June 16, 2000. John Buechler will join the beginning of the meeting to answer questions ranging from NY ISO staffing to NY ISO hierarchical control operation. The IndeGO overview will be presented. Each task team will present the results of their action item, including the assessments of three of the control centers.

Implementation Work Group
Meeting – June 9
Agenda

Task Team Led Discussions	0830 – 1100

1) AGC Hierarchical Operation
2) Metering Operations and Retail Access
3) Technology Requirements
4) Support Functions
5) Control Center Selection Parameters

Tour of Dittmer Control Center	1100 – 1200
Lunch	1200 – 1300
Assessment of Dittmer	1300 – 1400
Creation of a Questionnaire for Back-Up Control Centers	1400 – 1430
Other Issues	1430 – 1500

1) Concept of Security Coordinator
2) Impact of Non-Power Hydro Commitments

Task Team Assignments	1500 – 1530

RTO West
Implementation Work Group
AGC Issues
Ramblings, Version 1.0

AGC – Automatic Generation Control classical definition includes the calculation ACE (Area Control Error), determination of generation adjustments to move ACE to zero, and the generation adjustment implementation.

Calculation of Area Control

Within the RTO control area, the calculation of ACE should be the classical method – the comparison of actual and scheduled interchange and the comparison of scheduled and actual frequency plus a time error component. What presents the challenge is the determination and adjustment of generation to move ACE to zero.

Determination of generation adjustments to move ACE to zero

Once ACE is found to be non-zero (or outside of a deadband around zero), text books would have you proceed to the Economic Dispatch subroutine to determine new desired generation values for the units participating in direct control. This was very appropriate for thermal based systems where incremental cost curves were known and available. Even in some hydro-thermal systems, incremental water use curves are used with a "value of water" for fuel costs. Also, traditional ED used penalty factors to bias generation adjustments based on losses (i.e., remote generation wasn't valued as much as local generation due to losses).

RTO West may have units on direct control that do not have incremental cost curves available or that even apply. How the ACE correction is allocated to the units would be the question. Also, losses are real, yet do penalty factors still factor in?

The RTO will probably have a market that will produce a set of units who will participate in AGC – could be two sets – flutter units and trendy units. Flutter units need direct control links. Trendy units could be direct or indirect control.

Implementation of generation adjustments to move ACE to zero

Under ideal conditions, the control area's AGC would include direct digital control of generation units (e.g., raise and lower signals would actually close contacts on the unit's control system or MW set-points would be transferred to the unit's control computer). A "sufficient" amount of generation would participate in AGC. Unit response rates would be known. What is attractive (from a control system view) is that there is some reasonable amount of predictability of this control loop. Once the new desired generation levels are determined, one could count on the units responding.

However, we faced with a reality that does not offer ideal conditions from a classical AGC perspective. Many would say that sending-out price signals is preferable to direct control. Theoretically it makes sense. However, it introduces an unpredictability to the AGC control model – unit response becomes market driven where the unit operator's judgement of the price is capricious at best. And can the response be counted on every 4 to 10 seconds? Guess it boils down to reaching an arrangement that allows for direct control and generator is adequately compensated.

Ancillary #3 – does it help?

Under the 888 pro forma tariff, providers had to make available Ancillary Service #3, Regulation and Frequency Response to those transmission customers using transmission service to serve load within the provider's control area[1]. By this service's name and through some of the narrative text within the tariff, it would seem that a customer taking this service would be constantly balancing their load variations with generation. However, it is measured by hourly comparisons of actual versus scheduled quantities. Variations within the hour could be netted-out. Load pick-up is averaged over the hour. This service does not provide for the moment-to-moment balancing the AGC function is attempting to perform.

Example – at 9:00 a customer's load is 50 MWs. At 10:00 it is 150 MWatts. For that hour, the customer scheduled 100 MWs. Ignoring the ramping and random load variations, the system must absorb the excess generation for the first half hour and then deliver a like amount for the last half hour.

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[1] SCHEDULE 3

Regulation and Frequency Response Service

> Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The charge for Regulation and Frequency Response Service provided by the Transmission Provider under this Tariff will be computed for each day as the product of (i) $0.1234 per kilowatt multiplied by (ii) the highest hourly positive deviation of actual amounts of power and energy from scheduled amounts of power and energy.

The point here is that Ancillary Service #3's measurement provision is too course to provide all of the regulation services a control area requires. It seems the control area must acquire regulation services even if its customers are self-providing. A question is - how are the costs associated with this service recovered

Some Scenarios

Scenario A – the RTO provides for transmission service only and does not operate a control area. It could be viewed as taking the transmission provider function from ever utility in the RTO and combining them into a one stop shopping function. All the existing control area operations would remain the same (and the RTO would not worry about it).

Scenario B – the RTO assumes the operation of an existing control area. This would require the establishment of relationships between the RTO and generation under its control. However, let's assume that most of the units that were on direct control remain that way. In addition, a process for adding units wanting to participate in the RTO's direct AGC control would have to be developed.

Scenario C – same as B but now a second control area X is dissolved in to the RTO control area. Any interchange metering between the RTO control area and control area X is no longer included in the ACE calculations (it may remain for other purposes). Metering between control area X and other adjacent control areas would have to be transferred to the RTO's ACE calculations. Units previously participating in control area X's direct control could follow the process established above for adding new units to the RTO's direct control, should they choose to.

Scenario D – Same as C except several old control areas have been assimilated in to the collective. Rather than redirect all the control communication paths to the RTO control center, determine and send correction factors to the old control centers. Then the AGC system in the old control centers use the correction factor as their ACE.

Control Area Issues – RTOW IWG

Don Watkins – June 9, 2000

Reliability

Who will perform identified functions

Why?

How?

Assumptions:

- The RTO will have reliability authority over all member control areas.
- All use of the transmission of the RTO members will be arranged through the RTO including determination of OTC/TTC/ATC. Posting of capacity on the OASIS, accepting reservations, hedging arrangements, scheduling, and reconciliation/billing.
- The RTO is responsible for all management of schedules and fulfillment of reliability and commercial obligations for its system.
- The RTO will be a supplier of and provide an RTO region wide Ancillary Services/Market (others can be contracted to supply these), i.e. must assure coordination/oversight of all controls areas in TRO
- The RTO must assure access to real-time balancing.
- There will be multiple control areas at the RTO Startup. These control areas will continue to accept schedules for entities within their control area boundaries.
- The RTO must do Congestion management and ancillary services that effectively account for zones of impact on congestion. These zones do not correspond to set (including existing) control area boundaries.
- The anticipated and preferred end state is a single control area for all members
- The preferred end state is contiguous control areas.

Requirements:

- RTO ready to supply AS for balancing, non-performance, or other real-time demand for AS.

Questions/Issues:

1. Will there be one OASIS for the RTO at start up?
    - If so, who will accept reservations, the RTO or each control area?
    - How will information be transferred between the RTO and the CA?
2. Who will accept schedules? Who will manage schedules in the real time day? Do each need to stay informed? If so, how will they?
3. Will the RTO start as a control area? Whose?
4. Will the RTO start as one control area? Can it?
    - What are the administration costs of each control area vs. the administrative cost of combined control areas?
    - What are the costs of **not having one control area**, keeping in mind required and expected services that have to be applied RTO wide. What provisions must be made? If multiple control areas exist in the RTO for a time will each do their

own pre-scheduling (accept their own tags)? How will this be coordinated with/through the RTO? Will CA's get set points or schedules? Will load, interchange, and AS be handled the same or differently in dispersed control areas?

- What are the costs/issues of **implementing one control area** at start up? What phasing should be continued?

5. How do the RTO and the CA's interface with non-RTO members.
6. How will the RTO accommodate special optimization or control requirements of generation owners that are associated with the control function (hydro optimization, etc)?
7. Will the RTO participate in a wider (than the RTO) reserve sharing program?
8. If you collapse control areas, present performance standards will have to be relaxed. Current practice assumes at least 10 CA's for the randomness needed to arrive at present standards.
9. Can market participants/competitors in the commercial market be CA's?
10. Is there a way, before a single control area, to allow for one (control/monitoring) connection for a generator that can supply AS to any of the RTO member control areas?

00606 RTOW IWG Control Area Issues

RTO IMPLEMANETATION DATA/TECHNICAL ISSUES (DRAFT JUNE 7, 2000)

Don Watkins – BPA (Terry Doern – BPA (360)418-2341 tldoern@bpa.gov
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Bob Harshbarger - PSE (425)882-4643 bharsh@puget.com

What are the issues for technology and data for creating a NW RTO?

WHAT are the basic functional needs for the RTO?

STAGE 1 most urgent or easiest to implement	**STAGE 2** less urgent or more difficult to implement	**STAGE 3** difficult or could stay with utility
➢ Scheduling	➢ DISPATCH	➢ RTO Training Simulator
➢ OASIS	➢ AGC	➢ Statistical analysis
➢ E-Tags	➢ SCADA	➢
➢ OUTAGE Coordination	➢ Mapboard	➢
➢ Communications – Voice	➢ Logging	➢
➢ Telephone Systems	➢ WSCCNet messages	➢ System Planning
➢ Communications – Data	➢ EHV data pool & ICCP	➢ Remedial Action Schemes
➢ Backup power	➢ Metering	➢
➢ HVAC	➢ Communications monitoring	➢
➢ Physical Security	➢ Operational Planning	➢
➢ Network - critical systems	➢ Powerflow study tools	➢
➢ IT e-mail, word processing, internet	➢ Advanced applications/ on-line powerflow study tools	➢
➢ (Security Coordinator?)	➢ Backup site	➢
➢ Support-legal, payroll, financial, etc. ➢ Business systems	➢ Critical Path Nomograms for arming RAS (BPA IPS)	➢ Other

1. Should facilities be shared between utilities and RTO?

- Dispatch Floor? *Probably not but could share for BACKUP purposes.*
- Operational Computer Systems? *Use utility systems if needed to meet schedule then transition to RTO systems if cost effective.*
- Communications Systems? *Yes. Lease as needed.*
- General Purpose Systems? *Share if cost effective. (e.g., telephone system)*
- Office Space? *No power marketers! Some support staff from host utility may reduce cost.*

a.

2. What are communications needs? What is available? What is best for NW RTO?

3. For basic systems (SCADA, AGC, Telephone, MAPBOARD), which type is best for RTO?

- New? purchase and develop?
- Lease from utilities or commercial?
- Existing from one of utilities? (e.g., use BPA Mapboard)
- Copy from utility? New hardware, same software.

4. How is real time data shared between RTO, Control Areas, Utilities, Generators, and Marketers?

5. Should the RTO directly monitor and control Substations and Generation?

- Access through utility SCADA/EMS only? Interim or always?

- Shared access to data with utility? Shared control with utility?
- Access and control only by RTO? (e.g., CAL ISO Remote Access Gateway)
- What has worked for CAL? Ask CAL ISO, PG&E, SCE, SDG&E
- What is the most cost effective?

6. Support STAFF for critical and general purpose systems
- Who should maintain? RTO staff? Utility staff? Contractor?
- What level of support? 5X8? 7X24? Define for each system
- What is the most cost effective?

7. SECURITY COORDINATOR ISSUES
- Stay independent of utilities and RTO? Become part of RTO?
- PNSC runs online power flow? RTO runs online powerflow?
- Overrules marketing decisions if reliability is a problem?

8. BACKUP requirements for RTO and BPA:

Functions in BOLD needed at BACKUP SITE

STAGE 1 Most urgent or easiest to implement	**STAGE 2** less urgent or more difficult to implement	**STAGE 3** difficult or could stay with utility
➢ **Scheduling**	➢ **DISPATCH**	➢ RTO Training Simulator
➢ OASIS	➢ **AGC**	➢ Statistical analysis
➢ **E-Tags**	➢ **SCADA**	➢
➢ OUTAGE Coordination	➢ **Mapboard**	➢
➢ **Communications – Voice**	➢ Logging	➢
➢ **Telephone Systems**	➢ **WSCCNet messages**	➢ System Planning
➢ **Communications – Data**	➢ **EHV data pool & ICCP**	➢ Remedial Action Schemes
➢ **Backup power**	➢ Metering	➢
➢ **HVAC**	➢ Communications monitoring	➢
➢ **Physical Security**	➢ Operational Planning	➢
➢ **Network - critical systems**	➢ Powerflow study tools	➢
➢ IT e-mail, word processing, internet	➢ Advanced applications/ on-line powerflow study tools	➢
➢ **(Security Coordinator other SC sites)**	➢ **Backup site**	➢
➢ Support-legal, payroll, financial, etc. ➢ Business systems	➢ **Critical Path Nomograms for arming RAS (BPA IPS)**	➢ Other

Backup site issues:

a) Must backup site be in a geographically different area? 10 miles? 600 miles?
b) Which functions must have full time staff at BACKUP SITE (7x24 hours)?

9. Who pays?
10. How are costs allocated to RTO for shared equipment
11. How are RTO costs allocated to RTO members, customers, Marketers or All.

000609 RTO IMPLEMANETATION TECH DATA

Talking Points for RTO West Support Functions

1. Human Resources and Training

The Human Resources staff would include those who deal with general employee issues. The following tasks have been identified for this functional area:

- RTO West staff orientation and training
- RTO West compensation and benefit program administration and training
- Support employee selection process
- Track applicants
- Maintain employee records.

2. Information Systems

The Information Systems staff would include those responsible for all computer infrastructure activities. The Information Systems staff will support all computer and communications activities within RTO West including operations, accounting, billing, and administrative operations. The following tasks have been identified for this functional area:

- Accounting and Billing Applications
  - Develop, maintain, and upgrade RTO West settlement and associated accounting and billing software
  - Ensure the security and integrity of the accounting and billing data
- Operations Applications
  - Develop, maintain, and upgrade application software
  - Conduct factory and field acceptance testing
- Business Services and Other Applications
  - Support customer relations
  - Support RTO West staff training
- Database
  - Maintain power system models used for real-time operations, planning, and training simulator
  - Build and maintain EMS displays
  - Manage the archiving and retrieval of historical information for auditing and dispute resolution
- Communications
  - Monitor the performance of communications interfaces to the ISN, public Internet, and RTO West intranet
  - Identify requirements for any new communications services and interfaces
- Hardware and Software Platform Support

- Maintain servers for OASIS node
- Maintain external communications interfaces
- Maintain RTO West PCs, LANs, and peripherals
- Maintain and upgrade software platforms
- Provide shift technical support.

3. Customer Services

The Customer Services staff handles issues related to customer contacts. The following tasks have been identified for this functional area:

- Administer and register transmission customer applications for RTO West services
- Prepare procedural manuals for transmission customers
- Conduct transmission customer training
- Coordinate customer visits and meetings
- Coordinate transmission customer dispute resolution.

4. Financial Services and Accounting

The Financial Services and Accounting staff handles the bookkeeping, billing, settlements, and accounting functions for RTO West. The following tasks have been identified for this functional area:

- Process payroll and benefits for salary and hourly employees
- Define the processes and procedures for transmission service settlement
- Administer general ledger
- Prepare financial, regulatory, and management reports
- Administer asset accounting, depreciation, amortization, and tax reporting
- Support annual operating and capital budgeting process
- Administer accounts receivable, accounts payable, billing, and invoice payment processes and procedures.

5. Regulatory and Contract Administration

The Regulator and Contract Administration staff would include those responsible for FERC and State Regulatory Authority filings. The following tasks have been identified for this functional area:

- Review and interpret FERC and State Regulatory Authority filings for RTO West
- Prepare FERC and State Regulatory Authority filings and proceedings
- Administer RTO West contracts

- Analyze RTO West contracts
- Administer OASIS web site
- Monitor transmission tariff compliance
- Monitor FERC 888/889 compliance.

6. Legal

The Legal staff is responsible for providing legal counsel to RTO West.

- Represent RTO West in legal proceedings
- Administer dispute resolution process.

7. RTO West Implementation

The RTO West Implementation staff would include those responsible for major implementation activities during startup. The following tasks have been identified for this functional area:

- Administer RTO West implementation
- Work closely with transmission owners/control areas to define requirements, interfaces, and data models
- Define processes and procedures
- Review and approve specifications for the communications infrastructure
- Enter into contracts for the communications infrastructure
- Enter into contracts for RTO West primary and backup facility construction/remodel activities
- Review and approve operator training program
- Participate in factory and field acceptance testing
- Conduct field trials in preparation for RTO West commissioning.