Northern Tier Transmission Group

2008-2009 Accomplishments and Progress Report

The Hemingway Substation under construction in Idaho. Three planned projects will connect here.

December 1, 2009

Approved: December 8, 2009

Preface

This report describes the Northern Tier Transmission Group (NTTG or Northern Tier), a sub-regional group formed to meet the needs of an evolving electricity industry and to comply with the direction of the Federal Energy Regulatory Commission as set forth in its Orders 890 and 890-A. It describes the many processes, communications, analyses and reports undertaken by Northern Tier during its first biennial planning cycle.

Northern Tier provides a forum and platform for collecting and analyzing the load, resource and transmission information provided by members, stakeholders and participants to establish a coordinated outline of future transmission development across the transmission footprint of member balancing authorities. The design, siting, permitting, financing, construction and cost recovery of transmission projects remains the responsibility of the projects' sponsors. At the end of each biennial planning cycle, Northern Tier's Planning Committee produces a Final Report on its planning work, separately reviewed and approved by the Northern Tier Steering Committee, which is attached to this report.

In addition to coordinated planning, Northern Tier provides recommendations on cost allocation among customer classes and regulatory jurisdictions, in order to enhance transparency, provide comparable treatment of projects, and help expedite the construction of needed transmission. Northern Tier's Cost Allocation Committee also produces a report at the end of each biennial cycle with its recommendations on cost allocation for the projects included in the transmission plan. That report, also separately approved by the Northern Tier Steering Committee, is attached as well.

A third Northern Tier committee, the Transmission Use Committee, provides a forum for developing, discussing and making available information on the use of the existing transmission systems of member Transmission Providers with respect to congested paths. While the charge of the Transmission Use Committee requires publication of data, a formal report is not mandated. However, an extensive overview of the committee's work is provided in this document.

In the course of Northern Tier's coordination among members and with other sub-regional organizations, it became evident that a number of initiatives would benefit from a broader reach and geographic scope and could provide substantial value to the Western Interconnection. This led to the formation of a Joint Initiative undertaking and the initiation of several projects. Description of these projects and their benefits is included in this document.

To ensure efficient, effective, coordinated use and expansion of the members' transmission systems in the Western Interconnection to best meet the needs of customers & stakeholders.

Figure 1: Map Illustrating Northern Tier Members' Principal Transmission Lines

The extensive high-voltage transmission network of the Northern Tier Transmission Group's Transmission Providers reaches to all states of the US Western Interconnection.

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The Northern Tier Transmission Group

The Northern Tier Transmission Group began its work in 2007 as the next step in a series of regional and sub-regional organizations working to evolve a coordinated inter-utility and stakeholder-involved transmission planning process.

One founding principle of Northern Tier is to fulfill FERC Order 890 requirements that local Transmission Providers participate in regional and sub-regional planning. Additional detail on the history underlying the current organization is available in the 2007 Annual Planning Report published April 2, 2008 and accessible[1] on the Northern Tier web site.

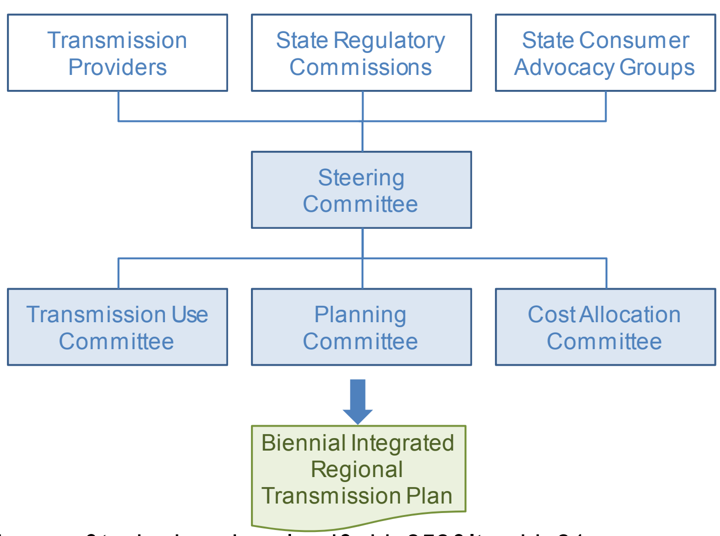
Northern Tier focuses its efforts on the evaluation of transmission projects that move power across the sub-regional bulk electric transmission system, servicing load in its footprint. The transmission providers belonging to Northern Tier serve over four million customers with nearly 3,000 miles of high voltage transmission lines. These members provide service across much of Utah, Wyoming, Montana, Idaho and Oregon, and parts of Washington and California.

Northern Tier works with the Western Electricity Coordinating Council's (WECC's) Planning Coordination Committee for reliability planning, the WECC Transmission Expansion Planning Policy Committee (TEPPC) for economic planning, and has established a framework for cooperation with neighboring sub-regional planning entities.

Northern Tier Members and Committees

The Northern Tier Transmission Group's organizational structure has multiple levels, as shown in Figure 2. Overall direction for Northern Tier is provided by the Steering Committee, whose membership at the end of 2009 numbered 12 and consists of state regulatory commissions, state customer advocacy groups, public utilities and consumer-owned utility organizations that are parties to the Northern Tier funding agreement. The Transmission Use Committee is charged with increasing the transparency and efficiency of the transmission systems of member utilities by analysis and communication of transmission system usage. The Planning Committee is responsible for coordinating transmission planning within the Northern Tier footprint, coordination

Figure 2: Northern Tier Structure and Hierarchy



[1] http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=353&Itemid=31

with other sub-regional planning groups and the WECC planning committees. The Cost Allocation Committee is charged with applying the Cost Allocation Principles consistently, openly and fairly in the analysis of cost allocations that accompany transmission project proposals developed in the Northern Tier planning process, and making recommendations on cost allocations to the Steering Committee.

Table 1: Northern Tier Members and their Committee Participation

Organization	Steering Committee	Trans. Use Committee	Planning Committee	Cost Alloc. Committee
Black Hills Power			●	
Deseret G&T	●	●	●	●
Horizon Wind			●	
Idaho Office of Energy Resources			●	
Idaho Power Company	●	●	●	
Idaho Public Utilities Commission	●			●
Montana Consumer Counsel	●			●
Montana Public Service Commission	●		●	●
NorthWestern Energy	●	●	●	
Oregon Public Utilities Commission	●	●		●
PacifiCorp	●	●	●	
Portland General Electric	●	●	●	
TransCanada			●	
UAMPS	●		●	●
Utah Public Service Commission	●			●
WY Office of Consumer Advocates				●
Wyoming Public Service Commission	●		●	●

Coordination within the Northern Tier Footprint

Each of the Transmission Providers belonging to Northern Tier is also responsible for transmission planning for its own service area and for any Balancing Authority Areas it administers. This local transmission planning process is, for each Transmission Provider in Northern Tier, designed to parallel and interact with the planning done at Northern Tier.

The local planning process is conducted in greater depth than the sub-regional process, both in terms of its analysis of finer detail (lower voltages and system dynamics), and more extensive construction detail, as the Transmission Provider is responsible for path ratings, project financing, permitting and approvals, and execution of the build.

Northern Tier provides a mechanism for coordinating appropriate load and resource data and for coordinating the analysis of the existing sub-regional transmission system augmented by a number of proposed transmission projects that impact the planning decisions, system adequacy and operation of multiple Transmission Providers. These are commonly high voltage projects. Throughout 2008 and 2009, efforts were made to ensure proper coordination among the Northern Tier Transmission Providers' transmission plans.

Angle Structure installation Ben Lomond to Terminal

Coordination with Others in the Western Interconnection

NTTG is committed to coordinating sub-regional planning efforts with adjacent sub-regional groups and other planning entities. In addition to working directly with the ColumbiaGrid and WestConnect sub-regional planning groups, Northern Tier relies on the data collection, validation and transmission modeling work done by the Western Electricity Coordinating Council (WECC, the Regional Reliability Organization) and the Northern Tier biennial transmission plan reported here is consistent with the work of the WECC.

The WECC provides valuable service to transmission planners across the Western Interconnection through its role in regional reliability planning and facility rating, and by providing economic planning data and analysis to its members through its Transmission Expansion Planning Policy Committee.

Relationships among Planning Entities in the West

Transmission planning in the Western Interconnection has evolved to incorporate three distinct organizational levels of activity: Transmission providers, sub-regional transmission groups, and regional planning entities.

Individual Transmission Providers were once (for the most part) fully-integrated generation, transmission and distribution utilities that, with deregulation, have now changed focus to provide equal access to all markets and customers.

The Transmission Providers each develop and maintain an Open Access Transmission Tariff process that receives and acts on requests for transmission service in accordance with a well-defined procedure. The Transmission Providers also assess future load and resource developments to plan the evolution of an efficient transmission system, and undertake reliability analysis and improvements.

Where service requests and other identified needs call for the development of transmission that involves participation of multiple Transmission Providers within a sub-regional transmission group's footprint, the planning and analysis of improvements are coordinated at the sub-regional level. 2008 was a startup year for sub-regional planning groups and as Northern Tier and others undertook their first sub-regional planning cycles, relationships and coordination were forged among Transmission Providers in the sub-regional groups.

At the regional level, establishment of the WECC's Transmission Expansion Planning Policy Committee provided a foundation for coordination on regional issues and completes a framework that addresses regional, sub-regional and local issues.

Regional Participation

Regional activities were performed by and for member Transmission Providers during the 2008-2009 biennium to adhere to the Federal Energy Regulatory Commission's Order 890 planning principles, to meet its requirements regarding planning and coordination, and to advance the common interests of Northern Tier stakeholders. These activities originated with and involved many interrelated organizations, from federal agencies to other sub-regional groups and to various convocations of organizations focused on important issues in power system development and planning.

Interconnection-Wide Coordination

Transmission Expansion Planning Policy Committee

TEPPC is a substantial organization within the Western Electricity Coordinating Council that, among other things, develops and maintains a voluminous database of transmission, load and resource information. TEPPC uses the database to operate a sophisticated security-constrained hourly power system commitment and dispatch model with an extensive transmission representation. The model provides detailed assessment of transmission congestion and production cost impacts due to alternative generation, load and transmission futures. WECC staff facilitates database development and creation of a core set of studies, which Northern Tier and others rely on as the foundation of their own economic congestion studies.

Representatives of Northern Tier and its precursory organizations helped to develop and implement TEPPC's structure to meet FERC Order 890 requirements, including the researching and authoring of a Western System Planning Roadmap document (explaining to stakeholders how various transmission planning groups interrelate and how they might get involved with transmission planning for the Western Interconnection) and the development of TEPPC's Protocol and Planning Processes.

Northern Tier actively participated in WECC's Long Term Planning and Supersizing Seminar and organized and chairs the Long Term Planning Work Group.

Northern Tier representatives also co-chair TEPPC and chair the TAS Data Work Group.

Northern Tier representatives participated actively in TEPPC and its many subordinate groups, including the Technical Advisory Subcommittee, Studies Work Group, Modeling Work Group, Data Work Group, and Hydro Modeling Task Force. Northern Tier representatives also participate on WECC's Variable Generation Subcommittee and took part in a review of regional planning responsibilities of two major WECC organizations, TEPPC and the PCC (Planning Coordination Committee).

Sub-Regional Planning Group Coordination

Late in the biennium, Northern Tier led the creation of a Sub-Regional Coordination Group to better coordinate the development and integration of sub-regional plans into an interconnection-wide plan for the West. This included the development of a draft charter and process timeline.

Northern Tier also took a leadership role in development of a new Western Interconnection planning process and its incorporation into a response by the WECC to a US Department of Energy Funding Opportunity Announcement. This includes the concept of a sub-regional planning group foundation reliability plan, to provide WECC a foundation 10-year transmission reliability plan to serve as a basis for a WECC regional transmission plan.

Northern Tier representatives coordinated with other sub-regional planning groups, including WestConnect and its member sub-regional groups, the California Independent System Operator and ColumbiaGrid, both directly and via their interactions at the WECC Transmission Expansion Planning Policy Committee forums.

Northern Tier representatives attended and participated in meetings of the ColumbiaGrid Board and its Planning Committee, providing input and promoting coordination between the two closely-interconnected sub-regions. Northern Tier also monitored the ColumbiaGrid Reliability Services and OASIS (Open Access Same-time Information System) activities.

Northern Tier joined with ColumbiaGrid in forming and co-chairing the Wind Integration Study Team (WIST) to help implement the Northwest Wind Integration Forum's action plan, carrying forward the work started by the Northwest Transmission Assessment Committee. WIST's goals are to develop dynamic schedule limits for critical paths within and between Balancing Authority Areas in the Pacific Northwest to facilitate the exchange of reserve products, to analyze the relative merits, in terms of delivered costs, of local and remote wind generation, and to develop planning criteria appropriate to renewables and to define their representation in simulations and other studies.

Northern Tier also participated in meetings of the Northwest Power Pool's Transmission Planning Committee and of the Transmission Coordination Work Group, which is coordinating the WECC Path Rating Process among a number of large transmission projects that electrically affect or interconnect near a point of geographical convergence in Northeastern Oregon (close to the Boardman coal-fired power plant). The WECC Phase II Rating Process requires the determination of impacts of a new transmission project on other transmission, and doing such an analysis simultaneously with other projects is a complex task requiring considerable coordination. Northern Tier-studied projects involved in the TCWG include Boardman-Hemingway, Cascade Crossing, Hemingway-Captain Jack, and Walla Walla-McNary.

Federal and State Initiatives

FERC Compliance and Coordination

Northern Tier and its member Transmission Providers worked during the biennium to continue implementation of FERC's Order 890 and its subsequent Compliance Orders, including coordinated revisions to providers' Open Access Transmission Tariff Attachments K, and participation in FERC's Planning Technical Conference on Order 890 Compliance and its follow-on activities.

Department of Energy Activities

Northern Tier prepared data for and reviewed analysis produced in the US Department of Energy's 2009 Congestion Study to help ensure a robust and useful report. Northern Tier also participated in and worked diligently to help assemble the WECC's proposal in response to the DOE's Funding Opportunity Announcement related to electricity planning, helping to frame the role and responsibilities of Northern Tier within a multi-level interconnection-wide planning process.

State Commissions and Agencies

Northern Tier made presentations of Northern Tier's organization and activities and of regional planning to state organizations including the Washington Utilities and Transportation Commission, the Oregon Public Utilities Commission, the Committee on Regional Electric Power Cooperation, the Western Interconnection Regional Advisory Body, the Western Interstate Energy Board, the Wyoming Public Service Commission, and the California Energy Commission.

Western Renewable Energy Zones

Northern Tier also participated on various Western Renewable Energy Zone committees, including the Modeling and Transmission Cost subcommittees. Northern Tier representatives on the Transmission Cost Subcommittee collected and prepared line-mile and substation costs estimating guidelines for use in WREZ analysis and simulation models.

Populus to Ben Lomond – Pole setting in Idaho

Western Electricity Industry Leaders

The WEIL conducted a renewable energy resource analysis, aided by Northern Tier's preparation of cost estimates for transmission connecting resource-rich areas to load centers.

ACE Diversity Interchange Initiative

Each Balancing Area is required to maintain a balance between the load and generation within its area. Deviation from this balance is called Area Control Error (ACE). In real time, some control areas are surplus and some are deficit. By sharing ACE data between control areas, the diversity of the ACEs can be better managed to control system frequency.

In 2007, PacifiCorp, Northwestern, Idaho Power (members of Northern Tier) and British Columbia Transmission Corporation developed communication and software so that the system's participants can share the diversity of their Area Control Errors, thereby reducing the participants' regulating requirements and more easily meeting NERC Balancing Area Standards. ADI was developed using a free-standing open agreement among the initial parties which permits additional parties to join the ADI control program at each additional party's incremental cost for development and integration and subsequent responsibility for its pro-rata share of on-going operational costs.

Following the successful implementation of ADI, a number of additional balancing areas have signed the ADI agreement (Arizona Public Service Company, British Columbia Transmission Corporation, Bonneville Power Administration, El Paso Electric Company, NaturEner Glacial Wind Energy, NV Energy, Inc, Public Service Company of New Mexico, Public Service Company of Colorado, Puget Sound Energy, Seattle City Light, Salt River Project, and Tucson Electric Power Company). Six of these additional balancing areas have ADI operational and three more are expected to be operational before the close of 2009. The remaining participants plan to be connected in 2010. Other balancing areas also have expressed interest in joining ADI.

Joint Initiatives - Summary

The Joint Initiative (JI) is a collaborative effort of the Northern Tier Transmission Group, ColumbiaGrid and WestConnect to encourage and facilitate development and implementation, by parties within the western interconnection, of high-value, cost effective regional projects. Facilitation of the Joint Initiative is provided by the three sub-regional groups, but participation is not limited to membership within those groups.

The goal of the Joint Initiative is to identify processes that would benefit from a broader reach and geographic scope and to develop business cases for identified products or projects that explore the technical feasibility, potential costs and opportunities attendant to implementation. Those parties who decide to move forward with implementation of the projects will do so pursuant to an Implementation Agreement among such parties.

To date, the Joint Initiative has focused on the development of three initiatives. These are summarized here and reported in greater detail later in the report.

Dynamic Scheduling System

The Dynamic Scheduling System (DSS) will allow participants to take advantage of load and resource diversity by facilitating a more efficient one-time system setup for implementing dynamic scheduling. The participating Balancing Authorities set up communications and make Energy Management System modifications once for any number of future dynamic schedules. Additionally, the contract negotiations for each transaction can follow the same process for striking deals for block energy, taking minutes rather than months.

Just as dynamic scheduling works today, the DSS would facilitate the dynamic transfer of energy through a common communications protocol using ICCP links sending a telemetered value to the Net Scheduled Interchange portion of the ACE equation. Generating units of participating entities supplying or receiving the transacted energy will be on Automatic Generator Control (AGC) and respond automatically based on 2-4 second signals.

Unlike dynamic scheduling of today, the DSS will allow participants to exchange dynamic schedules with any number of participants simultaneously for both short term and long term transactions. Participants are free to exchange commodities as they are needed or become available on an hourly, daily, weekly, or monthly basis.

Consistent with today's practices, the bilateral transactions will still be established contractually between the buyer and seller irrespective of the DSS, but the terms of the agreement would be communicated via approved Dynamic e-Tags. The e-Tags would be approved using existing processes and practices and it is anticipated that no tariff or e-Tag specification changes would be required to implement the DSS.

Nineteen diverse parties, representing 20 balancing authorities, a power marketing and trading company and a generation and transmission association have executed the DSS Agreements. Signatories include Arizona Public Service Company, Bonneville Power Administration, British Columbia Transmission Corporation, Idaho Power Company, Imperial Irrigation District, NaturEner Power Watch, LLC, Northwestern Energy, NV Energy, Inc., PacifiCorp, Portland General Electric, PowerEx, Public Service of New Mexico, Public Utility District #2 of Grant County, WA, Puget Sound Energy, Salt River Project, Seattle City Light, Tri-State Generation and Transmission, Western Area Power Authority (WAPA), and Xcel Energy.

DSS implementation has been initiated and is expected to be in production by September 2010.

Intra-Hour Business Practices

To address unanticipated generation patterns and better accommodate within-hour changes in loads and resources, the Joint Initiative has recommended that Transmission Service Providers (TSPs) accept within-hour schedule changes to the extent the schedules can be accommodated within the TSP's existing infrastructure and without negatively impacting reliability of its system.

The flexibility to purchase or schedule transmission within the hour will be achieved through TSP business practices or OATT amendments (as deemed appropriate by the individual TSP) or corresponding Balancing Authority operating procedures, without the need for new transmission products.

Intra-Hour Transaction Accelerator Platform

I-TAP is a tool to facilitate and reduce the workload burden and time required to initiate and finalize within-hour and other transactions. In simple terms, I-TAP will be an internet accessible bulletin board 'hub', or meeting place, that links existing systems (e.g. OASIS, e-tag author, e-tag approval, deal-capture, trading platforms, etc.) as spokes, via new I-TAP hub software and hardware, to enable high-speed real-time transactions via a single port of entry.

While individual market participants may already have trading systems with many of the I-TAP features (except for the power products bulletin board), the I-TAP system will provide an enhanced level of transaction speed and efficiency while providing a unique and broad view of power products available throughout the Western Interconnection.

Stakeholder Participation and Regional Support

In addition to the development of the three projects discussed above, the Joint Initiative continues to conduct quarterly “Think Tank" stakeholder meetings to provide a forum for information sharing and guidance from stakeholders on other projects that would benefit the region.

This collaboration among regions and the resulting opportunities to provide additional flexibility to the existing transmission grid have been well received by all stakeholders. The Joint Initiative continues to receive encouragement and support from regional entities such as the Western Electric Coordinating Council (WECC), the Committee on Regional Electric Power Cooperation (CREPC), the Federal Energy Regulatory Commission (FERC) and the Western Governors Association (WGA).

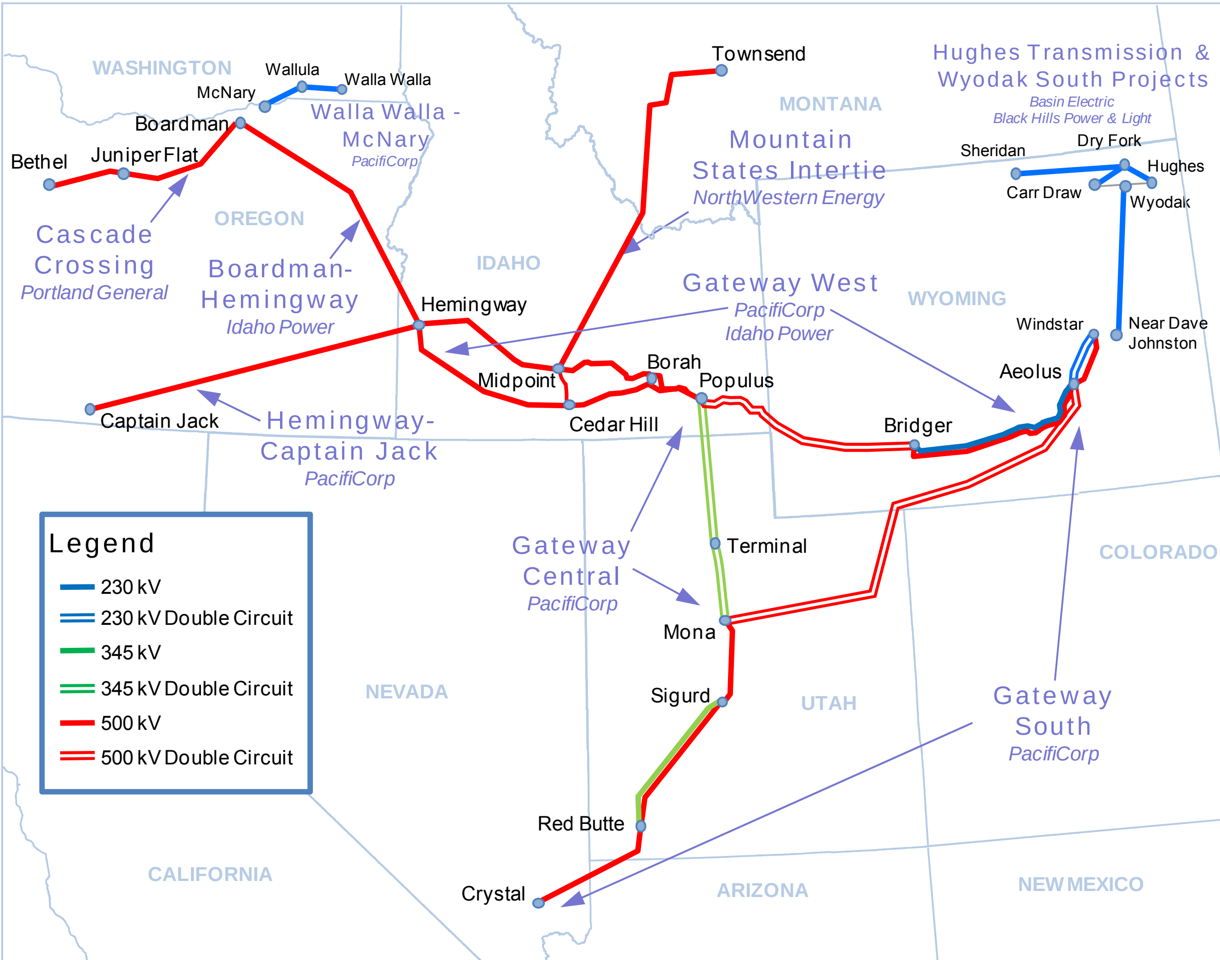
Committee Report Summaries

Northern Tier’s Planning and Cost Allocation Committees are required by their charters to adopt and post separate reports on their activities and products. While produced as independent reports, for convenience they are summarized here.

Planning Committee

The Northern Tier Transmission Group’s 2008-2009 biennial transmission expansion plan was produced through its public processes in conjunction with related activities of the NTTG Cost Allocation Committee and NTTG Transmission Use Committee. Technical studies have demonstrated the resulting plan to be capable of reliably meeting the identified needs established in the study plan.

Figure 3: Northern Tier Transmission Group Planned Transmission Additions



Planning is an iterative process and must work in concert with local transmission plans and Integrated Resource Plans, where they exist. This Northern Tier transmission plan is a result of a 'bottom-up' load service process to ensure that the transmission planned for the Northern Tier footprint can reliably serve forecasted load growth and conditions established by data submittals and stakeholder input during the process. There may be broader regional needs outside of the Northern Tier footprint unmet by this plan, which are expected to be addressed as part of regional, interconnection-wide efforts reconciling 'bottom-up' and 'top-down' study efforts.

This plan establishes the baseline main grid transmission configuration for the Northern Tier footprint for the planning horizon ending in 2018. This planned transmission should be used as a 'base plan' to inform other planning processes. While Northern Tier cannot assure the plan will be implemented as designed, it represents the best information available during the current planning cycle. Changing needs or new information will be accommodated through appropriate data submittals during the next planning cycle.

This plan identifies a number of specific projects. However, the technical analysis was performed on the premise that the entire transmission plan is in service in 2018. Path and project ratings are determined separately through Western Electricity Coordinating Council (WECC) processes and are the responsibility of each project's sponsor(s). Commercial subscription and capacity commitments are administered by each Transmission Provider under their Open Access Transmission Tariff (OATT).

The full final report of the Planning Committee is a separately developed and approved document.

Cost Allocation Committee

The Northern Tier Transmission Group created the Cost Allocation Committee ("Committee"), which primary purpose is --

> *"To apply the Cost Allocation Principles consistently, openly and fairly while conducting analyses of cost allocation that accompany transmission project proposals developed in the NTTG planning processes and to make recommendations on cost allocations to the Steering Committee based on those analyses."*

There are sixteen projects studied as part of the 2008-2009 Biennial Plan, each representing a single or multiple-owner transmission segment identified by the project sponsor(s). These projects are planned for a variety of reasons, which include support of retail and wholesale network load growth; maintenance and improvement of reliability; meeting requests in the transmission providers' queues; access to new and existing generation resources and markets; and support of projected, but non-specific, transfers of power from regions rich in renewable resource potential to regions with concentrated loads.

Project 1: Hughes Transmission Project

Project 2: Wyodak South Project

Project 3: Mountain States Transmission Intertie

Project 4: Gateway South, Mona – Crystal

Project 5: Gateway South, Aeolus – Mona

Project 6: Gateway Central, Populus – Terminal Segment

Project 7: Gateway Central, Mona – Oquirrh Segment

Project 8: Gateway Central, Sigurd – Red Butte – Crystal Segment[2]

Project 9: Gateway West, WindStar – Bridger

[2] Consolidated with Project 4: Gateway South, Mona-Crystal

Project 10: Gateway West, Bridger – Populus

Project 11: Gateway West, Populus – Midpoint

Project 12: Gateway West, Midpoint – Hemingway

Project 13: Boardman – Hemingway

Project 14: Hemingway – Captain Jack

Project 15: Walla Walla – McNary

Project 16: Cascade Crossing[3]

On behalf of the Committee, the chair, Lou Ann Westerfield, sent a letter to each transmission project sponsor formally requesting specific information related to the development of a draft cost allocation recommendation. Each project sponsor responded to the Committee's data request.

Each project was assigned a liaison from the Committee to review the information supplied by the project sponsor, to coordinate clarification and augmentation of the sponsor's initial response, and to complete a standard project template utilizing the information supplied by the sponsor. Each project was discussed at length on the Committee's conference calls. Based on review and consideration of the information supplied by the project sponsor, in particular its proposed cost allocation methodology, the Committee has either (i) made a recommendation with respect to a project or (ii) determined that there is insufficient information or the project is too immature to recommend a cost allocation. The Committee's actions with respect to each project are summarized below. In several instances the action is not "final" and may be modified as new information is received regarding the project's scope, purpose, configuration, or participation by other parties.

Table 2: Committee Action on Proposed Projects

Project Segment	Project Cost	Estimated In-Service Date	Action
Project 1: Hughes Transmission Project (Basin Electric Power Cooperative)	$82.9 million	4th Quarter, 2009	Recommend cost allocation as proposed: rolled-in to all transmission customers

[3] Formerly designated as Southern Crossing

Project Segment	Project Cost	Estimated In-Service Date	Action
Project 2: Wyodak South Project (Black Hills Power)	$53 million (2008 dollars)	The first component of the project is in-service. The estimated in service date of the second component is November 2010	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 3: Mountain States Transmission Intertie (NorthWestern Energy)	$1.0 billion	2013	No recommendation: Costs will be borne by subscribers
Project 4: Gateway South: Mona-Crystal (PacifiCorp)	$745 million (nominal dollars)	Not Available	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 5: Gateway South: Aeolus-Mona (PacifiCorp)	$782 million (nominal dollars)	Not Available	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 6: Gateway Central: Populus-Terminal (PacifiCorp)	$815 million (nominal dollars)	Not Available	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 7: Gateway Central: Mona-Oquirrh (PacifiCorp)	$569 million (nominal dollars)	Not Available	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 8: Gateway Central: Sigurd-Red Butte-Crystal (PacifiCorp)	Consolidated with Project 4: Gateway South, Mona-Crystal	Not Available	Project 8 is now the same as Project 4: Gateway South, Mona-Crystal
Project 9 and 10	$1.37 billion	Not Available	Recommend cost allocation as proposed: rolled-in to all

Project Segment	Project Cost	Estimated In-Service Date	Action
Gateway West: Windstar-Populus (PacifiCorp and Idaho Power)	(nominal dollars)		transmission customers
Project 11 and 12 Gateway West: Populus-Hemingway (PacifiCorp and Idaho Power)	$821 million (nominal dollars)	Not Available	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 13: Boardman – Hemingway (Idaho Power)	$600 million (2008 dollars)	2015	Recommend cost allocation as proposed: rolled-in to all transmission customers
Project 14: Hemingway – Captain Jack (PacifiCorp)	$931 million (nominal dollars)	Not Available	No action: Final project configuration TBD
Project 15: Walla Walla – McNary (PacifiCorp)	$87 million (nominal dollars)	Not Available	No action: Final project configuration TBD
Project 16: Cascade Crossing* (Portland General Electric) * Formerly designated as Southern Crossing	$610 million (direct costs, 2008 dollars)	2015	Recommend cost allocation as proposed, rolled-in to all transmission customers

As part of the Cost Allocation Committee's evaluation, consideration was also given to the impacts of the NTTG Planning Committee's 2009 economic studies assessment to determine if proposed projects in Northern Tier's footprint will meet future load requirements. Subsequently, the Cost Allocation Committee acknowledged the NTTG Planning Committee's Economic Congestion study as an effective test of NTTG processes and concluded that neither 2009 NTTG study results nor logical model refinements sufficiently impact current cost allocation evaluations to require modifications to the existing NTTG Cost Allocation Committee conclusions.

Committee recommendations are non-binding on Committee members, the entities they represent, and the NTTG Steering Committee, pursuant to the Committee's Charter. Thus, the following disclaimer pertains to this entire Report:

This Cost Allocation Recommendation is created on behalf of the Northern Tier Transmission Group Cost Allocation Committee in conjunction with the Northern Tier Transmission Group's Biennial Draft Transmission Plan per the Cost Allocation charter. This is a recommendation only and not binding upon committee members or the Northern Tier Transmission Group Steering Committee.

If the state commission's designated representative (or alternate) is a member of the Committee, with respect to the Committee said individual will not be acting as a representative of a state commission. No action or position taken by the individual or the Committee will preclude a state commission from taking contrary actions or positions in proceedings before it or other regulatory bodies.

The Committee's recommendations shall not be framed as decisions binding on individual state members and shall state clearly that each state retains its decision-making prerogatives. No action or position taken by a state commission's representative or by NTTG shall preclude a state commission from taking conflicting action consistent with its jurisdiction or constitute prejudgment of any issue in a proceeding before it.

The full Final Report of the Planning Committee is a separately developed and approved document.

Transmission Use Committee

Overview

The Transmission Use Committee is established to increase the efficiency of existing member utility transmission systems through commercially reasonable initiatives and to increase customer knowledge of, and transparency into, the transmission systems of the member utilities. The Transmission Use Committee satisfies this purpose by accomplishing a set of recurring deliverables as well as completing special assignments based on stakeholder input or needs identified by the committee and supported by the Steering Committee of the Northern Tier Transmission Group. The deliverables and work products of the committee are discussed in more detail below.

Membership

The Transmission Use Committee is comprised of representatives appointed from the transmission provider function of each utility or utility cooperative who is a party to the funding agreement of the Northern Tier Transmission Group. Membership can be extended to include: (1) staff representatives from state regulatory utility commissions appointed by each state's respective regulatory utility commission in the Northern Tier footprint, and (2) representatives appointed by state customer advocacy groups within the Northern Tier footprint. Membership of the committee currently consists of representatives from Idaho Power, Deseret Power Electric Cooperative, Northwestern Energy, Portland General Electric, PacifiCorp, and the Oregon Public Utilities Commission. The diversity of membership allows for technical support of the committee work products and informed membership regarding the current environment of evolving operating standards and practices relative to the usage and efficiency of the transmission system.

A Chair and Vice-Chair are elected annually prior to the Northern Tier Transmission Group's annual stakeholder meeting. For more information regarding membership in the committee and its leadership selection process, please see the Transmission Use Committee Charter dated October 21, 2009 located on the Northern Tier Transmission Group's website at:

http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=857&Itemid=31

Meetings

Meetings of the committee are held on a recurring basis, typically bi-monthly and more often as needed. Project reports detailing the committees work and timelines are available on the Northern Tier Transmission Group website. The Transmission Use Committee also participates in a public stakeholder meeting at least twice per calendar year.

Work Products

The following is an overview of some of the activities and work products prepared by the Transmission Use Committee.

Annual Products

On an annual basis each transmission provider committee member provides an updated list of annual system impact study and facility study activity for the prior year as well as updated transmission service queue activity for the point of delivery and point of receipt combinations. This provides a summary of activity related to studies conducted on the system and potential demand on certain paths for transmission service. This information can be found at:

http://nttg.biz/site/index.php?option=com_content&task=blogsection&id=10&Itemid=57

Additionally, a significant piece of work has been completed historically on an annual basis to graph on a rolling two year period, historic scheduled long term firm network and point-to-point customer use of paths with zero Available Transfer Capability. One graph provides an annual view of the hourly scheduled use data and a second graph is a chronological duration curve graphing the data points on an hourly basis over a year period. While a transmission customer considering purchasing capacity on any of these paths must go to each transmission providers' Open Access Same-Time Information System for the source of accurate and current information regarding available capacity, the graphs provide in visual form an indication of limitations on firm capacity availability for certain paths. Graph information can be found at:

http://nttg.biz/site/index.php?option=com_docman&task=cat_view&gid=148&Itemid=31

Semi-Annual Products

On a semi-annual basis, the transmission provider committee members provide updates to transmission path information including updating and explaining changes to a map showing point of receipt and point of delivery for rated paths in the Northern Tier footprint with a corresponding list of transmission providers and common names for the receipt and delivery combinations. The transmission provider committee members also update a summary matrix of paths with zero Available Transfer Capability that compares amounts on a seasonal basis along with a narrative list of paths with a change in monthly or yearly Available Transfer Capability due to a change in Total Transfer Capability of 10% of greater. These deliverables provide a consolidated source of information regarding scheduled paths and their transfer capability on a regularly updated basis. Information on these deliverables can be found at:

http://nttg.biz/site/index.php?option=com_content&task=blogsection&id=10&Itemid=57

Economic Study Requests

In addition to the recurring deliverables described above, the Transmission Use Committee also plays a key role in the economic study request process as described in Attachment K of the transmission provider's Open Access Transmission Tariffs. Specifically, the Transmission Use Committee has established a process to prioritize and submit to the Northern Tier Transmission Group's Planning Committee up to two sub-regional economic congestion studies per biannual planning cycle as well as to submit local, sub-regional and regional customer requests for economic congestion studies once per calendar year to the Western Electricity Coordinating Council.

Ad Hoc Work Assignments

Based on customer and stakeholder input received at its public meetings, the Transmission Use Committee may develop work plans aligned with its purpose and per approval by the Steering Committee that outline a course of work including scope, milestones and estimated resources and costs to complete. By way of example, in 2008, the Transmission Use Committee conducted a review of each of its transmission provider committee member's business practices. The committee developed an inventory of over 150 total business practices and learned that historically, business practices were developed not only for compliance purposes but also based on customer expressed need to clarify a provision of the transmission provider's Open Access Transmission Tariff resulting in unique and targeted business practices among providers. The committee continues to be open to future opportunities to develop common or consistent business practices as appropriate.

In addition to work plans, the committee also follows and participates (primarily on an individual transmission provider basis), on developing reliability requirements related to the calculation of Available Transfer Capability.

Summary

In summary, the Transmission Use Committee in conjunction with the other committees of the Northern Tier Transmission Group plays a key role in providing timely and cohesive information regarding the transmission system in the Northern Tier footprint. In support of principles evolved from the Steering Committee of the Northern Tier Transmission Group, the committee maintains focus on actively delivering information that helps increase transparency of the working of the existing transmission system for the benefit of electric transmission and end use customers.

Appendix : Joint Initiative Details

The Joint Initiative (JI) is a collaborative effort between the Northern Tier Transmission Group, ColumbiaGrid and WestConnect to encourage and facilitate parties within the western interconnection to develop and implement high-value, cost effective regional projects. Facilitation of the JI is provided by the three sub-regional groups but participation is not limited to membership within those groups.

The goal of the JI is to identify opportunities that would benefit from a broader reach and geographic scope and develop business cases for identified products or projects that explores the technical feasibility, potential costs and opportunities of implementation. Those parties who decide to move forward with implementation of the projects will do so pursuant to an Implementation Agreement among such parties.

To date, the Joint Initiative has focused on the development of the following three initiatives.

Dynamic Scheduling System

The Dynamic Scheduling System (DSS) is a common dynamic communication infrastructure/protocol that will allow participating entities to purchase or sell capacity and energy on a dynamic basis between any number of participating balancing authorities at any scheduling granularity, depending upon need and capability. The DSS allows participants to more easily and readily take advantage of load and resource diversity by replacing the month's it takes today to negotiate and make system changes required to establish a dynamic schedule with a one-time implementation of the DSS that can accommodate any number of future dynamic schedules.

Current Use of Dynamic Schedules

Historically, Balancing Authorities (BAs) have used dynamic schedules for a number of different purposes, including but not limited to:

1. Remote resource or load integration,
2. BA to BA dynamic support, and
3. Load following and regulation transactions.

Presently, there are very few inter-BA dynamic schedules since regulating reserves are traditionally held within BA boundaries. As new variable generating resources are built, the need for additional low cost and effective regulation services between BAs has and will continue to increase.

Today, dynamic scheduling between BAs is typically established under long term agreements. These agreements identify specific generators or plants, portions of generators or plants, or system capacity and energy quantities to be dynamically exchanged.

Currently, there is not an efficient mechanism to transact short-term regulation or load-following deals between BAs. These types of dynamic schedules require communications infrastructure, Energy Management System modifications, energy accounting system modifications, and associated transmission capacity. Dynamic schedules take weeks or months of lead time to negotiate and modify energy management systems to facilitate such a transaction. Because of this, only long term deals are done which leaves weekly, daily, or hourly deals impractical.

For example, a typical transaction which will use dynamic scheduling may include the following implementation process steps:

1. A resource planner identifies the need for an additional resource of a certain capacity.
2. A purchaser begins shopping for the new resource which may be a generator, plant, wind farm, etc. or another entity providing Balancing Authority functions that has the ability or obligation to provide the resource.
3. A bilateral contract is subsequently negotiated between the parties. The purchaser normally bears all costs for both the acquired resource and the dynamic schedule communication and implementation costs.
4. Long term firm transmission is acquired for the full capacity of the resource.
5. Energy Management Systems and energy accounting systems are modified by both source and sink Balancing Authority.
6. Communication systems and links are established between parties for both real time and metered data exchange.
7. Dynamic e-Tags are submitted containing the maximum expected instantaneous MW quantity in the transmission allocation and average hourly energy quantity in the energy profile.
8. Dynamic e-Tags are adjusted to reflect expected operations (as per Transmission Provider's business practice requirements and reliability standards of the North American Electric Reliability Corporation).
9. After the operating hour, the actual metered values are exchanged between source and sink for energy accounting purposes and compliance with NERC standards.
10. The e-Tag energy profile is updated with the actual integrated or metered quantity by one of the parties.

11. On contract expiration, the Energy Management System and energy accounting systems are modified to remove the resource and the associated communications.

Today this process can take three to twelve months or longer to implement each transaction.

Need for a Quicker and Easier Dynamic Scheduling Tool

There is an increasing amount of variable generation coming on-line and projected to come on-line in future years to meet growing load demands. The ability to secure adequate regulating reserve services to satisfy load obligations is critical.

The Dynamic Scheduling System (DSS) will provide increased flexibility for exchange of these commodities, supporting increased access and optimization of these resources. The system has been designed to be flexible and scalable to accommodate a variety of transactions among participants. For example, Independent Power Producers (IPPs) working through its host BA could dynamically schedule the output of their generators for any duration of time. The implementation of the interface between participants and host BA's is left up to those entities.

The DSS will provide a standardized methodology to facilitate regulating, load-following, and reserve transactions. These transactions may be of any duration (hourly, daily, weekly, monthly, and yearly) depending on the participants' needs and capabilities.

The DSS Proposal

The DSS will facilitate a more efficient one time system set up for implementing dynamic scheduling. The participating BAs set up communications and make EMS modifications once for any number of future dynamic schedules. Additionally, the contract negotiations for each transaction can follow the same process for striking deals for block energy, taking minutes rather than months.

Just as dynamic scheduling works today, the DSS would facilitate the dynamic transfer of energy through a common communications protocol using ICCP links sending a telemetered value to the Net Scheduled Interchange portion of the ACE equation. Generating units of participating entities supplying or receiving the transacted energy will be on Automatic Generator Control (AGC) and respond automatically based on 2-4 second signals.

Unlike dynamic scheduling of today, the DSS will allow participants to exchange dynamic schedules with any number of participants simultaneously for both short term and long term transactions. Participants are free to exchange commodities as they are needed or become available on an hourly, daily, weekly, or monthly basis.

Consistent with today's practices, the bilateral transactions will still be established contractually between the buyer and seller irrespective of the DSS, but the terms of the agreement would be communicated via approved Dynamic e-Tags. The e-Tags would be approved using existing processes and practices and it is anticipated that no tariff or e-Tag specification changes would be required to implement the DSS.

Proposed DSS Implementation Process

Participants who use the DSS have the option to set up communications and make EMS modifications once. Any subsequent transaction which utilizes dynamic scheduling via the DSS would be implemented using a procedure similar to the following:

1. Resource planners, day ahead traders, or real time schedulers identify the need for or availability of dynamically scheduled commodities.
2. Purchasers and sellers make contractual arrangements with another DSS participant, just as they do today for energy transactions.
3. Transmission is obtained for the transaction.
4. Dynamic e-Tags are submitted in compliance with existing business practices and reliability standards.
5. The DSS receives the e-Tag and implements the transaction between the participants using ICCP.
6. Dynamic e-Tags are adjusted to reflect expected operations.
7. After the operating hour, the actual integrated values are supplied to all participants to the transaction by the DSS in an e-Tag adjustment for energy accounting purposes and compliance with NERC standards and WECC business practices.

Note that the steps 1 through 4 occur outside DSS and reflect process efficiencies from common communication links and protocols.

Anticipated Benefits

1. DSS facilitates the development of intermittent resources
2. Improves use of Dynamic Schedules

   2.1. The system will provide the ability to assemble and execute dynamic transactions with shorter lead times by using pre-existing infrastructure and common protocols. Today, a Dynamic Schedule transaction can be time consuming to arrange among participating entities. Establishing the terms of the agreement as well as the ability to automate signals to facilitate the dynamic transfer of energy and use of transmission capacity are key components of the process. With the use of the DSS, the lead time required to establish and execute a Dynamic Schedule transaction will be shortened because a common communications protocol will be pre-established and alleviate the need for technology modifications as part of the transaction. In turn, this reduction in elapsed time needed to establish and execute a transaction will increase the viability and application for use of Dynamic Schedules as they can be more readily applied on shorter time frames up to the hour.

2.2. DSS provides access to transact business between multiple parties through the use of a common infrastructure, resulting in lower cost of implementing dynamic schedules

2.3. DSS allows participants to capture of more economical resources for regulating services.

2.4. DSS allows participants to take advantage of load and resource diversity

3. More efficient use of generating resources:

   3.1. Potential reduction in movement of uneconomic generating resources that provide regulating services (frequency reserve response and regulation service) and replaced by Dynamic Schedules that are backed by more responsive and more economic generating resources.

   3.2. Deferral or potential avoidance of capacity additions for regulation and load following

   3.3. Better match the available resources to the required need

4. Potential reduction in imbalance charges:

   4.1. Allows participants a way to reduce balancing area imbalance charges with the use of a Dynamic Schedule e-Tag to balance their loads and or resources.

5. Creating potential market opportunities that may result in lower portfolio costs:

   5.1. LSE's will naturally migrate to the lowest cost dynamic schedule commodity available

   5.2. Permits more efficient dispatch of units

6. DSS facilitates NERC and WECC standards and business practices, for example:

   6.1. enforces e-Tag curtailment limits

   6.2. automates ATF schedule adjustments

   6.3. automates the utilization of dynamic schedules based on marketer priorities

   6.4. automatically enforces contractual constraints such as maximum MW, MWh and minimum MW

DSS Status and Accomplishments

From the conceptual brainstorming session at the first JI Think Tank meeting held in Reno, Nevada in August of 2008, to today, considerable progress has been made towards establishing the Dynamic Scheduling System as a viable option for participants. Key accomplishments include:

1. August, 2008: Joint Initiative kick off meeting and brainstorming session with regional participants to identify potential products and services that would benefit from broad regional participation.
2. April 1, 2009: DSS business case published identifying infrastructure requirements, system design specifications, potential costs and value and participant implementation protocols for the proposed Dynamic Scheduling System.
3. May, 2009: An Agreement of Interest was distributed to determine if there was sufficient interest within the region to proceed with issuing a Request for Proposal (RFP) from vendors. Consequently, over 16 parties signed and submitted Agreements of Interest and an RFP was developed and distributed to vendors and posted on the JI website.
4. June, 2009: A comprehensive evaluation of the vendor responses was conducted and based on functionality, risk factors and pricing, OATI was selected as the preferred vendor.
5. October, 2009: Parties participated in extensive negotiation processes that resulted in Agreements between participants that established the rights and obligations of parties, including cost sharing, the establishment of a Management and Operations Committee and the hiring of OATI as the vendor to create and operate a dynamic scheduling system. In addition, Idaho Power Company was established as the finance agent responsible for collecting monies from the parties and paying vendors. The agreement also establishes Comprehensive Power Solutions, as the project manager responsible for management of DSS going forward. Agreements between OATI and the participants were also negotiated for operational purposes.
6. November, 2009: Diverse parties, representing 20 balancing authorities, a power marketing and trading company, and a generation and transmission association executed the DSS Agreements.

In December, 2009 DSS implementation was initiated and cut over to production is targeted for September 2010.

Intra-Hour Business Practices

To address unanticipated generation patterns and better accommodate within-hour changes in loads and resources, the JI has recommended that Transmission Service Providers (TSP) accept within-hour schedule changes to the extent the schedules can be accommodated within the TSP's existing infrastructure and without negatively impacting reliability of its system.

Purpose and Need

The purpose of the proposed within-hour purchase and scheduling business practices is to more efficiently use the existing electric system without sacrificing reliability, and assist with the integration of non-dispatchable resources.

Mechanism

The flexibility to purchase or schedule transmission within the hour will be achieved through TSP business practices or OATT amendments (as deemed appropriate by individual the TSP) or through corresponding Balancing Authority operating procedures, without the need for new transmission products.

Intra-Hour Business Practices and Accomplishments

Efforts to implement intra-hour business practices have progressed well. As of late November, 2009:

1. Avista Corporation, Bonneville Power Administration, NV Energy, Inc, PacifiCorp, Portland General Electric and Puget Sound Energy have posted either draft or final business practices.

2. As of December 1, 2009, PacifiCorp will operate under its intra-hour transmission business scheduling practices

3. Bonneville Power Administration has announced a pilot project starting in December, 2009, to accept new schedules for wind on the half hour.

4. Portland General and Puget Sound Energy are taking steps to seek tariff amendments required to allow them to initiate intra-hour scheduling, and

5. WestConnect members are proceeding with the development of common business practice that can be adopted among all WestConnect transmission owners.

Intra-Hour Transaction Accelerator Platform

I-TAP is a tool to facilitate and reduce the workload burden and time required to initiate and finalize within-hour and other transactions. In simple terms, I-TAP will be an internet accessible bulletin board 'hub', or meeting place, that links existing systems (e.g. OASIS, e-tag author, e-tag approval, deal-capture, trading platforms, etc.) as spokes, via new I-TAP hub software and hardware, to enable high-speed real-time transactions via a single port of entry.

Current Environment

Currently, within-hour transactions, to the extent they occur in the Western Interconnection, are not transparent or automated. There is no visibility as to resource opportunities; in most instances a market participant with a real-time need must identify a willing and acceptable seller by making a series of telephone calls. After locating a willing seller, the deal must be put together, and the parties must determine whether there is available transmission and whether that transmission can be scheduled in the required timeframe. Because there may not be sufficient time to identify and finalize transactions, opportunities may be lost.

Need for I-TAP

Market Participants need to be able to identify and enter into real-time transactions faster and more easily than they can today in order to:

1. Better use the existing system by optimizing existing capacity;
2. Manage the integration (and integration cost) of variable renewable generation (in particular, tools are needed to address significant unexpected ramps in generation within an operating hour);
3. Meet reliability standards, including recovering from an ultimate contingency event within the prescribed timeframe when there are not sufficient reserves avoiding expensive sanctions;
4. Mitigate the need for imbalance energy and minimize imbalance energy charges; and
5. Fully use other Joint Initiative Products (Dynamic Scheduling System and Within-Hour Transmission Purchase and Scheduling Business Practices).

Joint Initiative I-Tap Proposal

In simple terms, I-TAP will be an internet accessible bulletin board „hub", or meeting place, that links existing systems (e.g. OASIS, e-tag author, e-tag approval, deal-capture, trading platforms, etc.) as spokes, via the new I-TAP hub software and hardware, to enable high-speed real-time transactions via a single port of entry. While individual market participants may already have trading systems with many of the I-TAP features (except for the power products bulletin board), the I-TAP system will provide an enhanced level of transaction speed and efficiency while providing a unique and broad view of power products available throughout the Western Interconnection.

While I-TAP will coordinate and cooperate with existing systems by linking them together via the

I-TAP hub and providing a new electronic bulletin board for the posting of power products available throughout the Western Interconnection, I-TAP is not intended to be a centralized market.   All participation would be voluntary, and all transactions would be bi-lateral deals between the individual parties.

I-TAP will be administered and operated by a "Host."   The Host will physically maintain the software, hardware, and telecommunications links within a secure facility. The Host will also administer the software, with respect to updates, upgrades, maintenance, backup, and security.

The Host will manage the contract with the software vendor and, depending upon the final payment arrangement with the software vendor, might also act as a payment agent for I-Tap users. It will act as the moderator amongst the I-TAP parties. Additional roles for the Host will be discussed and determined through the RFP process (including maintaining the enabling bilateral agreements amongst I-TAP users), and may evolve as I-TAP is implemented.

I-TAP is intended to help facilitate a needed market. In order to succeed, among other things, any market must have the following elements:

1. Ease of trading and low cost of trading;
2. Diverse group of buyers and sellers to produce liquidity and volatility; and
3. Price transparency and price discovery.

The ITAP platform, while not being directly responsible for ensuring these elements, will support them by allowing users to easily:

1. Broadcast the availability and price of capacity and energy for both economic purposes and to address unexpected changes in loads or resources;
2. Identify the products they are looking to buy or sell, both the quantity and the quality;
3. View bids and offers, both quantity and price;
4. Post bids and offers with a minimum of keystrokes;
5. Ascertain the availability of transmission; and
6. Make the tagging process easier.

Anticipated Benefits

As a value proposition, I-TAP"s facilitation of within-hour transactions will likely

1. lower the cost of integrating variable generation,
2. help meet reliability standards and avoid expensive sanctions, and
3. lower the need for imbalance energy and associated charges.

The following list summarizes additional anticipated benefits of the I-TAP:

1. More efficient use of existing system resources;
2. Visibility of capacity and energy needs and availability of resources to meet those needs;
3. Greater ability to take advantage of load and resource diversity;
4. Provides access to more economical resources for balancing services;
5. Greater opportunity to use evolving within-hour transmission purchase and scheduling opportunities;

6. Possible lower portfolio costs as LSEs will naturally migrate to the lowest cost commodity available with increased market opportunities;

7. Permits more efficient dispatch of units;

8. Less reliance on Balancing Authority to provide energy for imbalance;

9. Scheduling efficiencies that maintain and enhance reliability based upon system conditions (cuts only done if necessary);

10. With respect to events which are non-DCS events but use reserves to respond, facilitates a market to respond in order to avoid ultimate contingency event;

11. Realization of some of the benefits of an RTO or centralized market without the structure and overhead of an RTO;

12. Provides information as to how market participants use the system and opportunities, informing NERC discussion (white paper) on the need for 10-minute markets;

13. Allows the market to determine the value of capacity; and

14. Facilitates the development of variable resources.

I-TAP Status and Accomplishments

Advancement continues to receive support from regional parties. Key accomplishments to date include:

1. April 2009: Request for Information (RFI) distributed to vendors to validate the technical feasibility and understand the cost and timing considerations associated with implementation of I-TAP

2. October 2009: Business case distributed for consideration by interested parties and solicitation of parties to sign an Agreement of Interest

3. November, 2009: 16 parties signed the Agreement of Interest including Bonneville Power Administration, Chelan County PUD, Columbia Energy Partners, Grant County PUD, Grays Harbor PUD, Idaho Power Company, NaturEner Power Watch, LLC, NorthWestern Energy, PacifiCorp, Portland General, Puget Sound Energy, Seattle City Light, Snohomish County, Tri-State Generation and Transmission, WAPA - CRSP-EMMO, and Xcel Energy.

4. November 2009: Request for Proposal distributed to vendors

Contract signing and execution is scheduled for March 31, 2010 and will trigger I-TAP implementation activities.