WESTERN AREA POWER ADMINISTRATION OPERATIONS STUDY REPORT

MIRACORP

Western
AREA POWER
ADMINISTRATION

DISCLAIMER: The views expressed herein are solely the opinions of the MIRACORP team.

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Team Biographies

Brian Haney is a Senior Consulting Engineer at Utility System Efficiencies, Inc. He has over 26 years of experience with electric utilities, including power transmission system planning and operations, NERC Compliance, benchmarking, generator bid evaluation and siting, load forecasting, area assessment, long-term planning, power flow studies, voltage collapse and stability studies, and project management. This experience has provided him with a thorough understanding of transmission issues, and he has worked on transmission system and generation interconnection studies for projects across the country. He holds a B.S. in Electrical Engineering from the Massachusetts Institute of Technology, and has been a registered Professional Electrical Engineer in the State of California since 1994.

Edward F. Hulls is a registered Professional Engineer with over 37 years of experience as an electrical engineer and manager in the electric utility industry. His experience spans a variety of areas including power system operations, transmission planning, power system maintenance, WECC and NERC Standards and Compliance activities, as well as negotiating a variety of transmission and ancillary service agreements. He chaired the WECC Operating Committee (OC) and Joint Guidance Committee (JGC), as well as numerous other subcommittees and task forces. He also chaired the NERC August 14, 2003 Blackout Investigation Team that was responsible for analyzing the standards and compliance issues concerning the blackout.

Mr. Hulls led numerous efforts within the Western Area Power Administration (Western) to help improve efficiencies across all of Western's four Regions, including a recommendation to consolidate two of Western's Operations and Transmission Planning offices into a single organization. After approval, Mr. Hulls was responsible for implementing the new consolidated operations organization, including meeting operating reliability and compliance requirements, as well as operating the WACM and WALC Balancing Authorities and associated transmission systems.

Casey Reed is Executive Vice President of MIRACORP. He is a degreed mechanical engineer with over 20 years of executive level and program management experience supporting both federal and commercial customers. Mr. Reed effectively and efficiently managed several highly complex construction and technical projects prior to joining MIRACORP. His experiences enabled him to master the art of planning, managing, and executing multi-million dollar contracts with simultaneous operations at multiple geographically separate locations.

Bob Riehl is a Functional Specialist. Mr. Riehl began his career in a special studies group, developing annual operating plans with Western's Upper Great Plains (UGP) Region when it was formed in 1978. He later moved to electric power contracts, where he worked for 11 years. Mr. Riehl moved to the Rates group in 1990, and shortly became the Rates Manager responsible for the repayment of the Pick-Sloan Missouri Basin Program and Joint Transmission System (now known as the Integrated System). Later, he managed three departments as the Power Marketing Manager for the UGP. He has worked many years with key customer groups within the seven states of the Upper Missouri Region of Western.

Mr. Riehl was also the lead contact in several audits and responded to the Federal Energy Regulatory Commission (FERC) on marketing, transmission, and operational issues. He performed extensive work in the development of UGP's Integrated Transmission System and Western's Transmission Tariff and Rates. After retiring in 2008, Mr. Riehl continued supporting Western under contract on projects relating to rates and repayment.

Acronyms

ACC – Alternate Control Centers
AEP – American Electric Power
AGC – Automatic Generation Control
APPA – American Public Power Association
APM – Aces Power Marketing
ARRA - American Reinvestment and Recovery Act
ATC – Available Transmission Capacity
BA – Balancing Authority
BANC – Balancing Agency of Northern California
BUCC – Backup Control Center
CAISO – California Independent System Operator
CCO – Conditional Curtailment Option
COTP – California-Oregon Transmission Project
CPUC – California Public Utilities Commission
CRSP – Colorado River Storage Project
CSO – Corporate Services Office
DOE – Department of Energy
DSW – Desert Southwest
EIM – Energy Imbalance Market
EMS – Energy Management System
EPTC – Electric Power Training Center
ERCOT – Electric Reliability Council of Texas
FERC – Federal Energy Regulatory Commission
FES – Firm Electric Service
FTE – Full Time Employee
GBAS - Generation Based Ancillary Services
IAM – Integrated Asset Manager
ICP – Internal Compliance Program
IS – Integrated Transmission System
ISO – Independent System Operators
LBA – Local Balancing Authority
LSE – Load Serving Entity
MCG – Minneapolis Consulting Group
MID – Modesto Irrigation District
MISO – Midwest Independent System Operator
MOD – NERC's Modeling, Data, and Analysis Standards
MRO – Midwest Reliability Organization
NASB – North American Standards Board
NATF – North American Transmission Forum
NERC – North American Electric Reliability Corporation
NITS – Network Integrated Transmission Service
OASIS – Energy Software
OATI – Energy Software
OATT – Open Access Transmission Tariff
OCI – Operations Consolidation Implementation
OCP – Operations Consolidation Project
PACI – Pacific AC Intertie
PCM – Preemptive and Competition Module
PER – Personnel Reliability Standards
PM – Project Manager
PRC – Protective Relay and Control
PSOC – Power Systems Operations Council
PSOM – Power Systems Operations Manual;
Power Systems Operations Training Plan
RC – Reliability Coordinator
RMR – Rocky Mountain Region
RMRG – Rocky Mountain Reserve Group
RRO – Regional Reliability Organizations
RSMO – Reliability Standards Management Office
RTO – Regional Transmission Organizations
SCADA – Energy Software
SIS – System Impact Study
SMUD – Sacramento Utility District
SNR – Sierra Nevada Region
SPP – Southwest Power Pool
SRSG – Southwest Reserve Sharing Group
SSW – Simultaneous Submission Window
TEP – Transmission Expansion Planning
TIP – Transmission Improvement Program
TOP – Transmission Operations
TP – Transmission Planning
TSO – Transmission Switching Operations
TSP – Transmission Service Provider
UGP – Upper Great Plains
USBR – United States Bureau of Reclamation
WACM – Western Area Colorado Missouri Balancing Authority
WALC – Western Area Lower Colorado Balancing Authority
WAPA – Western Area Power Administration
WASN – Western Area Sierra Nevada Sub-Balancing Authority
WAUC – Western Area Upper Colorado Balancing Authority
WAUE – Western Area Upper Missouri East Balancing Authority
WAUW – Western Area Upper Missouri West Balancing Authority
WECC – Western Electrical Coordinating Council
Western – Western Area Power Administration
WIT – Western Interchange Tool

1 Executive Summary

In August 2011, Western entered into an agreement with MIRACORP to provide expert analytical consultant services concerning Western's power system operations and transmission functions. These services included assessing the current situation, reviewing the lessons learned from OCI, benchmarking Western with similar utilities, and recommending any organizational changes.

Based on the internal benchmarking, OCI lessons learned, the External Benchmarking Study, and projected industry changes, a list of alternatives is included in this report. A common theme arose from this analysis that indicated a tendency to form larger, more consolidated organizations with standardization of functions and processes. If the past is an indicator of the future, the electric industry will continue to change and evolve. While it is difficult to predict specific outcomes, several trends are likely to continue.

Industry restructuring, which started in the 1980s, was a catalyst for an increase in mergers that lead to larger, more concentrated utility companies. This trend is expected to continue, with Standard & Poor's Ratings Services recently estimating that it expects 25 new mergers over the next five years.

Widespread power outages, both in the Western and Eastern Interconnections, were the drivers for the development of the mandatory NERC Reliability Standards in 2007. Enforcement of these standards has resulted in a trend towards standardization of all electric utility functions. The recent San Diego outage reinforced the need for this trend to continue.

The formation of ISOs and RTOs is another industry trend that was spawned by deregulation and support by FERC. ISOs and RTOs increased the span of control for the transmission grid and resulted in consolidation of rates and services over larger geographic areas. FERC Order 1000 is expected to continue this trend.

The External Benchmarking Study in Section 6 provides insight into the four organizations that participated in the study. The general trend is toward central management of the various NERC functions, but not always the geographic centralization of the employees who perform these functions.

Two other entities, Duke Energy and Progress Energy, were not able to participate in the study due to an ongoing merger. After their merger, these companies expect to have somewhere in the neighborhood of 15 operations centers spread over the Eastern Interconnection, which will all be overseen by a centralized management.

Standardization of tools and centralization of management structure were the most commonly used strategies for ensuring compliance with NERC standards and preparing for future changes in the electric industry.

The views expressed herein are solely the opinions of the MIRACORP team.

2 Study Summary

This study was performed using a multi-dimensional approach. First, internal benchmarking was performed between the four Western operations centers. Secondly, an analysis of the lessons learned from the Operations Consolidation Implementation was conducted during on-site interviews. A third portion of the study was an external benchmarking analysis, which included Western and three other major electric utility companies. A fourth portion of the study is an analysis of future industry changes and initiatives. All of the information gathered from the various analyses was combined to develop a list of potential alternatives for Western.

2.1 Internal Benchmarking Recommendations Summary

Data was collected along with written responses to a series of questions. After the data was organized, more than 70 people representing Western's management and staff were interviewed during site visits to clarify answers and provide additional input. Notes from those meetings and the information received provided the material that was organized into the findings and alternatives developed in Section 4 of this document.

The findings and alternatives were organized into four categories: Standardization; Compliance; Strategic Participation in External Organizations (WECC, MRO, NERC, etc.); and East-West Separation and Consolidation Challenges. In total, 17 recommendations for alternatives to address these findings are included in Section 8.

2.1.1 Standardization

In this category, the team recommends that Western develop a common tools program that would define the process for evaluation and selection. This is generally software used by the staff to automate their work and documentation. However, the principle would be carried over into hardware, etc.

Training consumes considerable time for Operations, both in maintaining certifications and training switchmen. The cost of training and tracking could be reduced by using common tools to perform the routine portions of these tasks.

Western may already be addressing the issue of OASIS sites. However, from the websites, it is apparent that these sites need to be more consistent and informative. This report suggests moving to one site, as Western has only one Tariff.

Performing Transmission Settlements is structured differently at each of Western's offices. This function needs definition and structure, both in performing the function and tracking the costs.

Treatment of Ancillary Services is inconsistent across Western. As customers move from one Western BA to another, they are encountering different treatments for Ancillary Services, even though the service is under the same Western Tariff in each BA.

The terms and conditions for Tariff and Rates, much like Ancillary Services, can vary even within a single Western BA. Our recommendations here suggest a single rate within a BA and a goal to remove pancaking beyond the BA.

Many opportunities to restructure Western's operations offices may exist. However, one of the limiting factors is the path operator activity currently performed by the WACM office. Western should initiate discussions with WECC and the other path operators to encourage WECC to have the RC take over path operation.

2.1.2 Compliance

No business reason was presented to justify why Western is using multiple approaches to perform Operations Office Compliance. Staffing and structure vary from office to office. Removing the duplication would reduce the risk for compliance violations and the cost of undertaking a monitoring program.

2.1.3 Strategic Participation in External Organizations

A strategic plan for Western's participation in these organizations and committees should be developed to address the need to be involved economically and effectively.

2.1.4 East-West Separation and Consolidation Challenges

Western operates in both the Eastern and Western Electrical Interconnections, which have different methods of operation. It is important that the differences be considered as Western develops a standard that may be expected to operate on both sides of the separation.

2.2 Lessons Learned from OCI Summary

Beginning in 2007, the DSW and RMR operations and transmission functions began a program to consolidate into a single organization under the Rocky Mountain Regional Manager. This effort was known as the OCP. In March 2010, the OCI phase was initiated to fully implement the project. Western requested that MIRACORP include an OCI Lessons Learned within this report, the results of which are included in Section 5.

An overview of the lessons learned from the review includes the following:

- ***Leadership*** *– If management is not on board, it is less likely that employees will buy into the change.*
- ***Justification*** *– Drivers for change must be clearly identified, as well as projected savings.*
- ***Communications*** *– Communication must be consistent, honest, and frequent.*
- ***External Impact*** *– Impacts outside of the reorganized groups must be considered and addressed early in the process. Human resources consultants and change management consultants would be helpful.*
- ***Roles and Responsibilities*** *– Must be clearly defined before, during, and after.*
- ***Tools Selection*** *– Process and justification for standardizing tools should be addressed early, with an emphasis on cost impacts and life cycle costs. Choices should not be based on politics, but on facts.*
- ***Budget and Cost Allocation*** *– Costs of the reorganization should be budgeted. Short-term resources should be utilized since employees cannot be expected to have time to implement change while performing their existing duties.*
- ***Culture*** *- Cultural differences between regions must be taken into account.*

Section 5 also includes recommendations that Western should consider for any contemplated future organizational changes. These recommendations are not included in the alternatives listed in Section 8.

2.3 External Benchmarking Study Summary

In order to benchmark Western with other, similar utilities, Western was compared with three partner utilities that operate systems with large geographic areas, have multiple operations centers and/or deal with multiple RROs, and have undergone major reorganizations or mergers. The NERC functions and supporting activities performed are very similar for each of the partners. The three partner utilities agreed to provide their data as long as it was anonymous and considered proprietary. One of the partners declined to have its data separately identified in a public document, so data from only two of the companies is included in this report. For purposes of establishing normalizing factors and averages, the undisclosed data from the third company was included.

Option 1, which was only identified at Western, is the most autonomous structure. The positions that performed specific NERC functions, such as Transmission Operations, report to Regional Managers who are responsible for all of the NERC functions for that region. Since this structure is the most autonomous, it allows for independent decision-making. In order to promote consistency, Western has several committees that meet regularly to promote standardization where applicable. Since these committees do not carry the same authority as a centralized manager or director, it is sometimes difficult to reach a common ground to promote standardization. Western RMR and DSW have moved to Option 2 with the consolidation of operations and transmission functions under OCI.

Option 2 is a middle ground between Options 1 and 3. In Option 2, the supervision is centralized, but the positions are not. Employees are still located on the "front lines" and have firsthand knowledge of the issues that are important to customers. However, a centralized authority is present that can decide what standardization is the best alternative.

Option 3 is the least autonomous option. In this case, both management and employees are centralized. Since this allows for the least independent decision-making, it is better suited for areas that have strict procedures and criteria. Such areas would also not require much independent decision-making.

Despite these common structural elements, this analysis identified the following variations for improving efficiency, which should be considered by Western:

- ***Organizational Structure at the Vice President / Regional Manager Level*** – *Two of the companies had a single Vice President of Transmission, with a majority of the BA, TOP, TSP, and TP functions under that position.*

  Another common structure is to have two Vice Presidents (Transmission and Operations). The real-time BA, TSP, and TOP functions report to the Vice President of Operations, while the other TSP and TP functions report to the Vice President of Transmission.

  Western was the most unique organization in this regard, since the BA, TOP, TSP, and TP functions primarily report to a Regional Manager instead of a centralized Vice President.

- ***Centralized Management*** – *A definite trend emerged towards centralized management (Options 2 and 3). Centralized management of employees who perform the same NERC functions in geographically dispersed operations centers (e.g., having these employees report to the same supervisor, manager, director, or vice president), improved consistency in procedures and methodologies.*

Companies 1 and 2 have centralized management (Option 2 or 3) for all of the benchmarked activities. Western has moved in this direction with its Operations Consolidation Implementation.

- ***Geographical Centralization*** *– As shown by several of the partners, geographical centralization (Option 3) is also a possibility. If the electric systems are too large to combine desks, it is possible that multiple desks for multiple areas can be located at the same operations center. Since relocation is a costly alternative, both from logistical and human resources perspectives, the "lessons learned" that were described in previous sections would obviously apply to geographical centralization.*

- ***Desk Staffing*** *– The most common operation desks in this analysis are the Transmission Switching (TOP) desk, Transmission Scheduling (TSP) desk, and Balancing Authority (BA) desk. Because the responsibilities of these desks may vary by the time of day, some innovative strategies for staffing were observed.*

- ***Operations Support*** *– Support positions such as training, outage coordination, and EMS support were common to almost all of the organizations. Except for Western, these support activities report to an Operations group that reported to a centralized Operations director (Option 2).*

  With regard to EMS support, it was more common for this role to be performed by a group that is not under the Operations director or under the Vice President of Transmission. At Western, a similar situation existed for DSW, RMR, and SNR, where a separate group for EMS support was under the Regional Manager and not the Operations director.

- ***Long Term Planning and Operations Engineering*** *– There was some minor variation for these activities, but also many commonalities:*

  - *Long-Term Planning and Operations Engineering are generally performed by two separate groups. SNR and UGP were the two exceptions to this rule.*

  - *The Operations Engineers report to the Operations Manager or Director.*

  - *Except for Western, Long-Term Planning was centrally supervised and reported to the Vice President of Transmission.*

  - *Company 1 geographically centralized Long-Term Planning. This function may be more suitable for geographic centralization, since it is focused on a common set of NERC criteria and requires less independent decision-making.*

- ***Tariff Administration and OASIS Sites*** *– All of the companies operated from a single OATT. A few variations were noted.*

- ***Transmission Settlements*** *– This activity had significant variation in staffing levels and organizational structure. Two companies have centralized this function from a management and geographical perspective (Option 3). One company has the settlements positions reporting to the operations center managers, who report to a centralized director of System Operations (Option 2). At Western, the Settlements positions are completely autonomous.*

- ***Renewable Generation*** *– Renewable generation is having significant impact on all of the systems, except for SNR. The percentage of new requests that are renewable resources ranged from 65% to 100%.*

- ***Compliance*** *– All of the partners were concerned about compliance and had a significant number of positions dedicated to that issue. All partner companies had a separate compliance group that reports directly to the upper levels of management. Western's compliance team reports to each Regional Manager individually, but coordinates through a committee that includes the General Counsel and the Reliability Compliance Manager located at CSO.*

Based on the partners in this analysis, centralization of the management of the BA, TOP, TSP, and TP functions appears to be the trend. Geographical centralization of the employees who perform these functions is less common and was focused on activities that had specific criteria or focus (such as long-term planning, operations engineering, or tariff administration). Balancing (BA) and Transmission Service (TSP) desks were more likely to be combined. Transmission Switching (TOP) desks were more difficult to combine, depending on the complexity of the system, but could be moved to geographically centralized operations centers with multiple desks.

The participants in this study and the other industry participants all agreed that they have seen significant changes in the electric utility industry and will probably continue to see significant changes for the foreseeable future. The trend will be towards larger markets that include energy imbalance, hourly, day-ahead, and capacity markets. Regional planning will become the norm. Organizations need to be structured for consistency over large geographic areas, yet remain nimble on the front lines of customer service.

2.4 Future Industry Changes and Strategic Initiatives Summary

The future of the electric industry is ever-changing. But those changes are shaped by the policies and initiatives developed locally, regionally, and nationally. In preparing for this report, policies and initiatives that were recently promulgated or under current consideration were reviewed. For Western to be prepared and flexible to address industry changes and strategic initiatives economically, it needs to standardize more of its tools and functions. More standardization would allow Western to reduce the workload of maintaining multiple systems performing the same tasks, and to staff correctly to move on industry changes and prepare for strategic initiatives.

In evaluating the changes on the horizon, initiatives coming from DOE and regional options being proposed for the Western Interconnection were reviewed. This report focuses more on the Western Interconnection, as most of Western is in the WECC. UGP operates predominately in the Eastern Interconnection, and although it is separated from the rest of Western by this separation, most of the principles of preparing for the future should apply.

As an agency under the DOE, Western is assigned some goals from DOE. As the executor of marketing the generation from the Federal Hydro Projects, Western is governed by many pieces of legislation relative to marketing and delivering federal power, even as it may be specific to just one project. In addition, Western is operator of a large, loosely-connected network of transmission. This transmission is or could be key to the development of a system that could benefit the Western United States. Western should be a leader in the effort to strengthen the transmission system in the West.

Although the generation resources and project loads may be limited by the individual legislation of the projects, it is believed the transmission and interconnections with neighboring systems are minimally affected by the project legislation. Historically and today, the transmission system has been operated and modified to address more than just service to the projects.

In Section 7, this report may have asked more questions than it answered, but to address challenges, Western must question, plan, and build on what it has to reform and overcome those challenges.

The keys to addressing challenges in the future are planning, staffing, and training. Western must plan and develop leaders up and down the ranks to allow it to be flexible and form its own future. An organizational culture that is open to change should be cultivated.

2.5 Assessment of Alternatives Summary

Section 8 of this report summarizes all of the alternatives included herein, except for the recommendations in Section 5, Lessons Learned from OCI. Section 8 is divided into five groups of alternatives, including: Structural Changes, Regional Changes, Tool Changes, Other Non-Structural Changes, and Alternatives Considered but Not Recommended. The alternatives were developed based on Western's strategic goals, DOE's strategic goals for Western, Western site visits, recommendations from employees who were interviewed, industry partner observations, FERC and NERC outage recommendations, and future industry changes and strategic initiatives. All of the alternatives range in complexity and impact and will take further study to fully evaluate the impact and cost, as well as the final structure to implement.

Some of the alternatives could build on one another, and some could probably not be implemented without affecting other alternatives. A majority of the alternatives under Structural Changes are various options of merging several transmission functions into a more centralized manner instead of by region, as is currently done. This report does not recommend specifically what the organizational structure should look like (except for Alternative 8.1.1) and leaves that for Western to determine, depending on what alternatives it chooses to pursue. Several options include assigning the new combined organizations under an existing Regional Manager or the Chief Operating Officer.

Alternative 8.1.1 is the most comprehensive structural change, and it assigns all transmission functions (including operations) to a new Senior Manager who would be responsible for all of Western's transmission functions. Western and partner utility experience has shown that major changes in organizations are very difficult to achieve – even under a single management structure – and almost impossible without a single management structure. Alternative 8.1.1 would give Western the greatest opportunity to prioritize and implement the other recommendations contained in this report.

Another notable alternative, Alternative 8.1.6, would establish a single Operations Engineering Support group responsible for running all next-day and short-term studies. This is an area where Western appears to be very short on resources and has a high risk. This recommendation would minimize the number of resources in this area for all of Western.

The alternatives listed under Regional Changes would initially apply to a single or possibly two regions. Alternative 8.2.1 is of special note in this section. This alternative has Western's RMR office transferring its path operator and associated TOP-007 responsibilities to the WECC Reliability Coordinator or another transmission organization. Western having responsibility for this operation contains a high risk and hinders RMR from pursuing a number of alternative organizational structures.

Alternatives listed under Tool Changes could greatly benefit Western in the long term. Western has attempted to standardize operations/transmission tools and processes for a long time, but has had limited success. Alternative 8.3.1 would set out a program that would aggressively pursue this with strict boundaries on what exceptions or regional preferences would be allowed. Again, Western and partner utility experience has shown that lack of "compelling drivers" to move to common tools and procedures may even lead to building barriers for future cooperation. Again, Alternative 8.1.1 could lead to the greatest success in implementing this alternative.

Alternatives listed under Other Non-Structural Changes were designed to be alternatives Western could pursue that would not require any organizational changes. Alternative 8.4.1 would be for Western to clarify what is meant by "one Western." This was a common phrase that the team heard on the site visits, but various definitions were espoused on what it meant when implementing a new tool or process. This alternative would seek to clarify that definition and could help with future cooperation between regions.

The last group of alternatives included changes that the team considered but does not recommend pursuing for various reasons.

Although it was outside the scope of this study, Appendix C-5 includes an alternative organizational chart that would consolidate similar functions across all of Western.

3 Study Process

In August 2011, Western entered into an agreement with MIRACORP to provide expert analytical consultant services concerning Western's power system operations and transmission functions. The analysis performed by MIRACORP included the following four elements:

- *Assessment of the current situation;*
- *Identification/development of benchmarking and other evaluation criteria on which to measure the performance/effectiveness of a power operations organization;*
- *Recommended organizational changes; and*
- *Analysis of the potential impacts associated with any organizational and/or staffing changes identified under Element 3 of this scope/task.*

MIRACORP's strategy to provide this service was to utilize MIRACORP expert staff that had previous experience with Western in these areas, and also contract with other experts who had not previously worked for Western. This strategy resulted in a balanced approach for the study.

MIRACORP developed a project plan and schedule, along with three comprehensive questionnaires that were presented to Western to gather background data and information. Following the receipt of information from the initial two questionnaires, the MIRACORP team initiated site visits to Phoenix, AZ; Folsom, CA; Watertown, SD; Lakewood, CO; Loveland, CO; and Billings, MT. The purpose of the site visits was to better understand how each of the

Western Regions functioned in these areas, as well as to clarify and ensure consistency between regions in the data provided in response to the questionnaires.

The assessment included a review of Western's Power System Operations, Transmission Services (including Transmission System Planning and Open Access Transmission Tariff Administration), and after-the-fact Transmission Settlement activities.

The assessment of the current situation included collecting multiple sets of data from Western, and also visiting each of the operations centers.

In order to benchmark Western with similar electric utilities, MIRACORP developed a short list of potential partners that included companies that operate systems with large geographic areas, have multiple operations centers, and/or deal with multiple RROs. This list was developed using the NERC Compliance Registry. This process resulted in the identification of six potential partners who received invitations to participate in the detailed benchmarking study. Of those six, three companies elected to participate in the study. The overall structure of one other partner was included by utilizing publicly available information.

In addition to the companies that were identified via the NERC Registry, a general questionnaire was sent to all of the members of the NATF Operators Group.

Per Western's request, included in this report is a "lessons learned summary" of the Operations Consolidation Implementation and considerations that Western could take into account when preparing for additional future changes.

The team also assessed future industry changes and strategic initiatives that Western is presently engaged with or will be confronted with in the near future. These industry changes will impact the way Western and other utilities do business in the future. The issues include: FERC transmission service including Order 1000, a memo from Secretary of Energy Chu dated March 16, 2012 on Power Marketing Administration's future roles, and WECC initiatives. This section, along with the alternatives, includes some thoughts on how Western can position itself to face these future challenges.

Each alternative is evaluated on how it impacts organizational structure, regions and customers, compliance, BA and footprint, human resources, integration of renewable resources, anticipated industry changes, risks, costs, and pros and cons.

4 Internal Benchmarking

4.1 Background

The MIRACORP study group collected significant data from Western's Operations and Transmission Offices. After reviewing the available data, a series of site visits and follow-up telephone conversations were used to interpret the information and arrive at the assessment.

Western currently has four operations centers (Watertown, Loveland, Phoenix, and Folsom). These centers operate four Balancing Authorities (WAUE, WAUW, WACM and WALC) and one Sub-Balancing Authority (WASN) using one Open Access Transmission Tariff and seven different transmission and ancillary service rate packages among them. These seven rate packages recover in excess of $240 million[1] per year for Western. It should be noted that WALC has four different transmission and ancillary service rate packages (Pacific NW-SW Intertie Project, Central Arizona, Parker-Davis, and Salt Lake City Area Integrated Projects); WACM has two (Loveland Area Projects and Salt Lake City Area Integrated Projects); WAUE and WAUW share one between them (Pick-Sloan Missouri Basin-Eastern Division aka Integrated Transmission System); and WASN has one (Central Valley). It should also be noted that Western operates on both sides of the East/West electrical separation. WAUE operates in Eastern Interconnection under the MRO, and WAUW, WACM, WALC and WASN operate in the Western Interconnection under WECC. These two reliability organizations do not cross the electrical separation of East and West.

In interviews with employees and managers, many stated that Western could improve its work product with more standardization. Common practice in the Power Operations and Transmission Services industry is to use standards for consistency and ensure a more secure system operation with many operators, as can be seen from the NERC and reliability organizations. Common tools, procedures, and policies across Western would provide savings in many areas, such as operating costs, training, and compliance costs, and would reduce errors in operation and liability due to mistakes.

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[1] See page 18 of the Statistical Appendix to Western's FY 2010 Annual Report. This number represents Western's Revenue from Transmission and Ancillary Services for FY 2010.

To allow the organization to be more flexible and nimble to respond to industry changes, the default should be to standardize unless there is a good business reason to do otherwise. Territorialism appears to be a barrier to flexibility. Opportunities for Western to standardize would include: common tools, procedures, compliance activities, and field practices that can be duplicated.

One of the items that came from the on-site interviews was the need for a plan to address the challenges Western will face:

- *Western as an organization should adopt medium- and long-term strategic plans;*
- *Regional plans should be assessed annually and updated as necessary to adapt to an evolving industry with a goal of creating a single plan with attachments/sections for each region;*
- *Create a Standing Business Practices review team that will assess and evaluate Western's functional areas (X0000, X1000, X2000, etc.), on an annual basis;*
- *Utilize the results of the previous three elements to perform an annual assessment and provide recommendations to create an annual plan for accomplishing strategic goals. The annual plan would incorporate a 10-year planning horizon.*

4.2 Standardization

4.2.1 Common Tools

Operation and Transmission use many automation and support tools. The most significant is the SCADA system in each region. RMR and DSW have the most recent experience of attempting to make two systems, which should have been compatible, mirror each other. Even though the systems were provided by the same vendor, choices made over time by the regions created significant differences between them. As an example, the displays chosen by each office used different standards of presentation for simple things like representation of open and closed switches. These things affect training and understanding the display even more than selecting the system vendor. If Western were to move toward a standard tool for SCADA systems, it would require significant planning.

SCADA is a costly item, which may prohibit establishing a common SCADA platform. Basic SCADA systems have been around for a long time, and the optimal tool should be available. Other non-SCADA functions may require automation, and the optimal tool may not yet exist.

Choosing a common tool is a task that should not be taken lightly. If it is to be functionally capable, easy to use, and cost-effective, the comparative analysis must be complete. The analysis must also include a review of all other tools and systems that integrate into the tool being considered. A functional analysis of the tools frequently does not completely quantify costs. In-house tools need to consider cost of maintenance and life cycle costs when compared to off-the-shelf tools. Off-the-shelf tools need to consider cost of modifications to perform in the field. Sales or promotional statements do not indicate performance without modification, sometimes at great expense. Users of software should participate in software demonstrations to ensure that all of the required capabilities are adequate.

Alternative: Develop a common tools program with strong project management using professional facilitation. Subject matter experts, financial analysis, and software expertise will also be necessary for the selection process. (See Alternatives 8.3.1 and 8.3.2.)

In our interviews, the dispatchers indicated that they interact with many pieces of software as part of their daily work. In order to have access to these programs during their shift, they must log in separately to each package at the beginning of a shift. This takes considerable time and effort.

Alternative: Develop a secure method allowing a simplified login to these multiple products to reduce the time involved, yet maintain security. (See Alternative 8.3.3.)

4.2.2 Training

In discussions with staff, two areas of concern were raised: one is training staff to meet NERC certification, and the other is training switchmen – internal staff and external non-Western personnel.

Standard tools, procedures, processes, and policies will simplify training and increase consistency across Western. Standardized training will also help employees understand the direction and intent of each of the above.

4.2.2.1 NERC Certification Training

Most of the NERC certification training is provided in-house, but in some offices, individuals are responsible for tracking their own hours. In other offices, this is tracked by supervisors with various pieces of software. Spring training is conducted for every dispatcher – one week of training done four or five times in a row. UGP does this by itself, while other regions share the responsibility with other companies.

Alternative: Develop a program using common tools to track and perform routine training. (See Alternative 8.4.7.)

A need for a new dispatcher's intern program appears to exist. Notably, RMR has a program, while other regions do not. This is another example of regions not well-coordinated for development of dispatcher staff. Some regions simply use Chapter 7 of the Western-wide operations training manual to test skills of applicants to prepare for in-house on-the-job training. While this may be effective in developing local staff, it may not be the most cost-effective method across the regions.

Alternative: Review the operations training manual and determine the most cost-effective method to develop a consistent intern training program. (See Alternative 8.4.8.)

4.2.2.2 Switchmen Training

Some offices with remote switching locations use non-Western personnel to perform switching. To be prepared for this, they train many people – both Western employees and non-Western personnel – to perform switching. In addition, Western trains USBR and Corps of Engineers staff on switching, which may or may not be used by Western for switching. SNR has cut back on training. It found that it was training many people who have never been, or may never be, used for switching.

Alternative: Review records to see who is actually used for switching, and prepare a program that addresses the need. (See Alternative 8.4.9.)

4.2.3 OASIS Sites

The OASIS sites for each of Western's Transmission offerings are inconsistent. Although Western has one tariff, it has multiple OASIS sites and rates for each of the separate transmission systems it operates. On the WALC site, there are Transmission rates for four different Transmission systems. The rates for Transmission Service on the site are mixed in with the Wholesale Firm Power Service rates. Why are Firm Energy rates for preference power customers listed on the OASIS site? Even the naming convention of the OASIS sites is different. "WALC" is the BA that offers transmission on the Parker Davis, Intertie, Central Arizona, and a portion of the Salt Lake transmission systems. The WACM BA operates three OASIS sites, which are separately named "LAPT" offering transmission on the Loveland Area Projects Transmission system, "CRCM" offering transmission on the Colorado River Storage Project, and "BEPW" offering transmission service under a separate Basin Electric Power Cooperative Tariff on the Stegall DC tie. However, the rates for transmission service cannot be found on any of the three sites. Several pre-decisional documents were provided that address these concerns, and Western may currently be moving to address this issue.

Alternative: Reduce the number of OASIS sites. Standardize the format of the website and include all appropriate data. Review OASIS sites of other companies to develop a format that is consistent with industry practices. (See Alternative 8.1.2.)

4.2.4 Transmission Settlements

In the interviews, it appeared that the Transmission Settlement function was not consistently defined, and each office structured its transmission settlement effort differently. To help with this, the interviews started with two questions: (1) "What is transmission settlement?" and (2) "Where does settlement stop and billing start?" Several items rose to the top: 1) "After-the-fact" agreement with the counter-party on data; and 2) Determination of the final data before preparing the bill. The RMR staff had the cleanest separation of its transmission settlements staff, since it did only minimal merchant settlements. SNR had a very detailed flow chart for its processes. If all groups had similar flow charts, these would be helpful for comparing and standardizing processes across Western.

The types of products used on a specific transmission system can assist in blending settlement efforts. Point-to-point service is a reservation-defined billing unit and therefore not dependent upon schedules or power meters, except to ensure that the schedules are met, load is served, and reservation is not exceeded. Network service is a different matter. It is totally dependent upon the load served from the transmission system and is charged as a prorata share of the revenue requirement of the transmission system cost. This requires significantly more involvement of the load metering, and its calculation can be significantly affected by a load billing/metering error. In the case of Network Service, it is the typical "chicken and egg" argument; e.g., once you "settle" on the load amounts, you have the transmission settlement amounts. Some of the ancillary services are simple; however, Loveland Area Projects does significant calculation/settlement of regulation service, which is meter- and staff-intensive. If other offices were also doing that, it is expected that Transmission Settlement staff would increase, or at least more of the settlement staff effort would be recognized as transmission settlements. Currently, several projects in WECC are using only limited amounts of network service. As they move to more usage of network service, staff work for transmission settlements could become more clouded.

In addition, expense charging for the settlement staff was reviewed and found to be inconsistent across Western as well. For those cases where the transmission settlement function is performed by staff associated with the TSS Desk, the expenses are recorded in SOLDM. However, some offices charge all of the settlement/bill staff time to BILLM, and that is not broken out to SOLDM vs. MKRTM, which would separate the settlement expenses between transmission/operations and merchant.

Alternative: Clearly define the transmission settlements function and transmission settlement processes, and track transmission settlement expenses more closely for appropriate cost recovery. (See Alternative 8.1.8.)

4.2.5 Ancillary Services

Interpretation and application of Ancillary Services is inconsistent across Western. Even though transmission service rates are set for each transmission system across Western, the ancillary services rates are generally set per balancing authority. For example, in WALC, transmission rates are set for four different transmission systems, but ancillary services for the BA have only one set of rates.

Alternative: Develop one set of transmission rates for each BA. (See Alternative 8.4.4.)

Western has drafted a Generation-Based Ancillary Services Policy (GBAS), which is concerned with the relationship between the transmission-based operation of the system and the ancillary services that must be provided by the generation or merchant offices within the BA. This paper suggests that "Each BA that utilizes Project resources should have a defining document in place that identifies the terms and conditions of such use." Such a document should be an agreement between the Power Marketing and Operations Functions operating the BA.

Alternative: Operations Manager and Power Marketing Manager enter into an agreement that would allow the merchant function of Western to adequately plan for and obtain, if necessary, resources for the BA to support transmission service with the necessary GBAS. (See Alternative 8.4.10.)

Energy Imbalance and Regulation Service puts the federal generation resource most at risk. All of the rate schedules for these services allow financial settlement of energy deviations. However, only the WACM BA requires financial settlement of energy deviations. Prior to enforcing financial settlement for imbalance, some transmission customers were taking high-cost energy and returning low-cost energy. After enforcement, energy imbalance was not abused. This may be occurring in the other BAs to some extent. Financial settlement of energy imbalance accounts sends the appropriate price signal to reduce the abuse of this ancillary service. In addition, it is the responsible method, protecting the federal generation resource, and is most fair to all parties involved.

Some may question whether the benefits and savings exceed the cost of implementation and enforcement, but RMR's experience suggests that it is extremely beneficial.

Alternative: Require all BAs to settle energy imbalance accounts financially. (See Alternative 8.4.11.)

If LSE generation schedules are not adjusted over the hour, Regulation Service can commit a significant amount of federal generation capacity to operation of the BA. This can be magnified by LSEs with both scheduled and non-scheduled generation. Intra-hourly resource scheduling can reduce the impact on federal generation capacity for providing regulation service.

Alternative: Evaluate the current commitment of federal generation capacity to regulation service and assess whether moving to intra-hourly resource schedules could reduce the commitment significantly. (See Alternative 8.4.12.)

4.2.6 Tariff and Rates

From project-to-project or Sub-BA within a BA, transmission system services and rates are combined or pancaked. Under Western's single tariff, these should be consistent.

For example: In the WAUE, BA Western's UGP and a few RMR facilities are included in the IS along with the facilities of Basin Electric Power Cooperative, Heartland Consumer Power District, NorthWestern Energy (NWE). NWE has its own tariff, but no one uses it since they are surrounded by Western). NWE takes NITS from Western and receives facility credits to recover its revenue requirements. Missouri River Energy Services transmission facilities, and loads are treated the same as NWE's. Transmission service across all of the IS facilities is sold under WAPA tariff without a rate pancake.

Yet, the WALC BA has four separate federal transmission systems. Although these facilities are all interconnected and can provide support for each other, they have separate rates that can be pancaked for any transaction crossing more than one system.

Alternative: Set a goal and milestones to achieve one set of transmission rates per BA, and include the transmission facilities of customers and others that support transmission within the BA. (See Alternative 8.4.3.)

It also seems that in the WECC area, very little load is served with NITS. NITS should, by design, be the most effective and economical method of transmission service for resource to load within a system. If it is not, then the proper pricing signals for transmission rate design may not be used, or current pricing methods are allowing loads and resources to game the system and avoid paying for benefits received from facilities needed to sustain the transmission system.

Alternative: Develop a white paper on rates methodology and identify the barriers to combining transmission systems and un-pancaking of rates within each BA. (See Alternative 8.4.4.)

4.2.7 Operations Desk Activities

UGP has combined the TSS and BA desks into a 13-person rotation. This rotation has three people on during the day and two people on at night. During the day, one person does AGC, one does TSS, and the third does OASIS tags work. At night, AGC has the same responsibility, while TSS has both numbers and OASIS responsibility. However, two workers are on duty to back each other up if an emergency arises. SNR is considering a similar combination.

One complicating factor on the TSS desk in WACM is that it is a path operator with TOP-007 responsibility. Currently, in the East, the RC has curtailment responsibility for the whole MRO. In WECC, several BAs act as path operators with that responsibility. This could change if the RC were to take over control from the path operators. This could happen with enhanced curtailment software and RCs accepting that responsibility. Thus, at this time, it may be difficult to combine the BA and TSS desks in WACM. However, it may be feasible to combine the WACM and WALC BA desks, and perhaps the TSS desk from WALC.

Combining TSS and AGC can provide efficiencies. Cross-training would be beneficial, and a manager could be eliminated. A concern could be that the different work and volume of work could spread dispatchers thin, with the AGC desk approximately 50-60% busy and 1.5 dispatchers estimated workload on TSS. If tools work well, this would make the system work more easily and could allow the BAs to be merged. A phone system would be necessary that allows phone calls to be re-routed depending on who is performing the function (Phoenix office or Loveland office). If Western merges BAs, it will not have a dispatcher available for a hot back-up (Phoenix/Loveland), as only one AGC dispatcher is on at a time. If BA and TSS duties were combined, a hot back-up could be immediately available. Benefits could include sharing reserve and ACE. ACE could be shared with BAs separately, as is currently being done, using pseudo tie. Reserve sharing is more difficult.

The TOP desks at Western already perform switching functions over large areas today. Further consolidation might make the areas too large and risk switching errors due to complexity and situational awareness across the systems. As an example, MISO is the BA, but all of the systems inside MISO do their own switching. (See Alternative 8.5.1.)

Alternative: Initiate discussions with WECC and other path operators in WECC for WECC RC to take over responsibility for path operations. Western does not have a NERC obligation for path operation. This function hinders Western's ability to reorganize its operation to be more efficient. Continuing to perform this task increases Western's liability from non-compliance with NERC Reliability Standards. (See Alternative 8.2.1.)

4.3 Compliance

The compliance function is working on Western-wide consistency, but is not there yet. Multiple software programs are being used for compliance across Western. No business reason has been presented for these multiple approaches. Although the optimal tool may not yet exist for some functions, a standardized tool to make compliance easier for the technician at the equipment level may be a significant cost benefit to Western. Several well-developed compliance tools do exist, however, so Western should investigate the applicability of this software.

Currently, each office is incurring duplicative costs to implement its NERC Compliance Program. These costs could be reduced by a single effort, perhaps even to the point of hiring a contractor to get the staff through the labor-intensive documentation effort. As an example: Each of the four regions has a separate task list for PER-005. Each region took time and completed the tasks without coordinating the effort. Thus, the results are not common. To perform these tasks, each office has a slightly different organizational structure for its Compliance Manager and support staff for the subject matter experts. These structures and support efforts are inconsistent from region to region. If a need exists to have a Compliance Manager at each site, the best practice is the structure used in the SNR office, where the Compliance Manager reports directly to the Regional Manager. If compliance monitoring for Western could be done from a central location, each region would save on duplicative staff. Each of the partners indicated that it had established a single external compliance organization to the operations group.

Recommend–Move to implement a single compliance program and develop a compliance staffing and structure based upon the best practices in the benchmarking study. (See Alternative 8.1.9.)

4.4 Optimize Participation in External Organizations

A significant amount of time is dedicated to participation in external organizations (e.g., WECC, MRO and NERC committees). Some offices have reduced their commitments to NERC and WECC to save time and money. Western has 17 registrations in NERC. Some offices have acknowledged that benefits and detriments exist to this number of registrations and multiple participations in committees. Western will definitely lose influence in the industry if it does not participate and address its positions among its peers. However, there must be an optimal point for each of these efforts.

Alternative: Review and develop a strategy for Western's registrations and committee participation that is both effective and economical. (See Alternative 8.4.13.)

4.5 East-West Separation and Consolidation Challenges

Even with the implementation of the NERC Standards, some differences exist between the operations methodologies of the Eastern and WECC Interconnections. These differences make common practices across Western difficult. East and West have different NASB interests; for example, transmission line-loading relief in the East and path management in the West. In developing standards for the East, the MRO defines the risks and monitors; however, in the West, the WECC finds, fixes, and tracks. For determination of available transmission capacity systems in the East, the "Flow-based" model is used, while most systems in the West use the "Contract Path" methodology. WECC, MISO, SPP, and MRO do not want to deal with issues that may cross the East-West separation; therefore, this seems like a natural separation for Western to use as it begins to standardize its operations. There are several anomalies; e.g., RMR has some facilities in the East with some exposure for compliance since they are not registered in the MRO. UGP operates a small BA in Montana. Those facilities do not have the same risks as the RMR East facilities, but they are across the separation from most of UGP's facilities and do provide generation resource to the East.

Alternative: Consider the differences of East and West in developing Western standards, and appropriately reduce any compliance risks resulting from separated facilities. (See Alternative 8.4.14.)

5 Lessons Learned from OCI

5.1 Background

Beginning in 2007, the DSW and RMR operations functions were scheduled to be consolidated into a single organization under the Rocky Mountain Regional Manager. This effort was known as the Operations Consolidation Project (OCP). From January 2008 through Jan 2010, staff in both RMR and DSW worked on organizational structure and plans to implement the OCP. By February 2010, major milestones were achieved, including the reorganization, and the OCP phase was considered complete. In March 2010, the Operations Consolidation Implementation (OCI) phase was initiated to fully implement the project. Appendix A includes a timeline for the major OCP and OCI milestones.

5.2 Operations Consolidation Project (OCP) Decision Process

5.2.1 Leadership

Everyone interviewed agreed that change is necessary to stay competitive and believed that OCP was the right thing to do. Management led change with a clear vision, and senior management took an active role in this leadership. The plan included leaving both offices staffed, and the organization was well thought out.

5.2.2 Justification

Most agreed that OCP was valuable and will save resources down the road. OCP allows for a single high-level manager to preside over all Operations and Transmission functions. Some felt that drivers for this change were not clearly identified, and the projected savings were very subjective.

Early on, FES customers asked how OCP would impact rates, but this could not be forecast with acceptable certainty. Enough detail was not available to know what tools or time frames would be necessary to achieve OCP goals. Customers were told that OCP was not originated to save money at the present time, but would avoid future costs. It is not clear whether the customers (and some employees) were aware of this. Plans to finance OCP were not in place when the decision was made to proceed.

5.2.3 Communications

An e-mail containing Senior Manager notes, sent before Christmas 2007, announced that Western was moving forward with plans to consolidate the DSW and RMR operations functions. It stated that primary operations would be at RMR, and DSW would be the back-up. Staffing of each location, including organizational structure and responsibilities, was still being developed, although this plan envisioned that "some staffing at the back-up operations center was initially thought to be covered by 24-hour by 7-day coverage." The announcement stated that the implementation process would define the actual staffing and functional requirements. It also noted that a final decision would not be made until Western's customers had an opportunity for comment.

The initial announcement left some DSW employees in turmoil, and some had decided to resign. Dispatchers and other operations personnel stated that they didn't know whether they still had a job. Local communications were inadequate, and some "first-level supervisors were the worst about spreading rumors." After the holidays, employees began to see what OCP meant and were able to review organizational charts. A handful of people at DSW felt that

DSW was the “loser.” Some interpreted the announcement as an indication that the senior managers wanted to combine the RMR and DSW regions. Management believed employees had been assured that they would continue to have positions with Western, but a number of employees apparently had not understood this until later.

Some employees felt there was a lack of communication with too much secrecy, and that the plans could have been better communicated, with more details provided. Some interviewees did not always trust that the communication was open and honest. Others expressed that management could have been more open to listening from the bottom up. Since management couldn’t give them a detailed analysis, employees and customers had significant apprehension because they could not project what the future would hold.

When details of future plans have not yet been identified, it is difficult for management to be open and share information it does not have. Employees then assume they are being excluded, which leads to much uncertainty. On the other hand, if management waits to share information after the details have been worked out, employees feel that management has not been open and honest with them.

5.3 Pre-Implementation Planning

5.3.1 Early Planning

5.3.1.1 Pace and Communications

Once a decision was made to move forward with OCP, a very aggressive schedule was set. Additional resources and/or time could have allowed OCP to be better planned prior to implementation, and additional impacts could have been identified. The pace was very fast, which didn't leave much time to consider the impacts. Other necessary work continued to be required, which resulted in an increase in employee workloads. Accelerating OCP was not necessarily a bad idea, but consequences included issues with budgeting, negative impacts on customer and employee relations, and an atmosphere of secrecy and rumors.

Although some supervisors and managers communicated quite well with their employees, others did not, which led to additional rumors. Some supervisory positions were vacant, which also left a void in communications with employees and only exacerbated the perception of secrecy.

5.3.1.2 Impacts Outside of Operations/Transmission Services

Implementation decisions were made without identifying impacts on other groups outside operations and transmission services. Many technical issues were identified early on, but other impacted organizations were not brought in until much later.

A human resource consultant could have helped to identify internal customer impact that only received consideration late in the process. Such a consultant could also have helped with implementing a timeline that included HR activities. The OCP implementation focused on the technical side and did not give much consideration to the “soft side.” Identifying “soft side” impacts earlier in the process would have been very helpful. HR could have helped identify and develop a plan to train supervisors and managers on:

- Remote supervision;
- Improved communication skills;
- Importance of supervisors and managers knowing all of their employees;
- Increased travel requirement issues;
- Sensitivity to the other office’s culture and modifying cultures; and
- Increased supervisors’ responsibilities with remote supervision.

Both offices had property, inventory, and warehouse items associated with operations and transmission services. Determination of the value of these items and which office would own them after consolidation could have been resolved prior to the consolidation.

Procurement had two contract officers, and it was not clear which one would be responsible after the consolidation.

Security policies and procedures were different between the two facilities. It was not clear which office’s policies and procedures should be followed when RMR employees were located in a DSW office. It would have been helpful to decide this up front.

5.3.1.3 Roles and Responsibilities

Roles, responsibilities, and job and functional boundaries could have been better identified early on. Some of these issues are still not well-defined or implemented. Implementation could have been facilitated if the following areas had been addressed:

- Space issues were not clearly defined up front. Who was responsible for construction and the associated cost of facility modifications? Federal and contract employees were impacted by OCP and not all space considerations were outlined in advance.

- Responsibility for record management (such as official records, mailing and employee lists) was vague.

- Contract support issues were not identified in advance. Do the DSW contract employees support the RMR employees working in Phoenix, or does RMR modify its support contract to cover the RMR employees in Phoenix? This decision impacts the support contract employees acting as back-up for other support contractors.

- A better line could have been drawn between operation and planning horizons.

- A better understanding of responsibilities for various NERC standards could have been specified.

- Each of the offices handled Western customer contact differently. In DSW, all customer contact was handled through the power marketing office; in RMR, the transmission customer contact was on the operations side. Customer contact after implementation of OCP should have been clearly spelled out.

- Local IT groups support the transmission settlements groups in both DSW and RMR. OCP created a seams issue because the settlements groups were not included in OCP, and their support structure is different between the two offices. The IT groups in both offices are continuing to work this out.

5.3.2 Tools Selection

Impacted tools were identified early on, but the following issues could have been better addressed:

- No clear process was established as to how the tools would be selected. Teams of experts from both offices were assembled, but these teams were not always balanced with both technical users and information technology experts familiar with each tool.

- Significant "turf" battles took place in this area. Some interviewees felt that the committee approach was not always effective for reaching agreement on standardization.

- Some felt that the "best" method was not always selected. Instead, "one region's method" was preferred and adopted over "another's region's method."

- Functional analysis for tools did not include a complete study of costs. In-house tools often didn't consider maintenance and life cycle costs, and off-the-shelf tools didn't consider the cost of modification. Once a tool was selected and a thorough analysis was performed, short falls were identified that required significant additional FTEs, time and expense.

- Also, vendor tools that were not used in either office were not given much consideration since no budget had been established to purchase outside tools.

- In tool selection, competition and efforts to preserve a favorite tool prevented some team members from being open to looking for the best tool for the job and led to misrepresentation of different tools' functionality.

- Timelines were built based on dependencies between the tools. Implementation of various tools was delayed due to the many dependencies and unexpected modifications that had to be made to those tools. The CRSP consolidation project had also been added, which increased workload and required further modification of tools.

5.3.3 Budget and Cost Allocation

5.3.3.1 OCP Budgeting

OCP was implemented within a timeframe that did not allow for normal budgeting methodologies. Western's budget process requires a three-year forecast for future needs, and this makes it difficult for management to proactively plan for unknown changes in the deregulated electric utility environment. The budget for this implementation required other organizations' funds to be reprogrammed. The following items complicated the implementation process:

- RMR had budgeted for approximately 42 FTE out of 45 positions; DSW had budgeted for 39 FTE out of 54 positions. The extra positions were considered "over-hires" and were not factored into the original plan.

- DSW had six to seven people for Independent Power Producer (IPP) contracts, which were 100% non-federally funded. Immediately prior to OCI and during the initial implementation, 75% of the IPP funding disappeared, so six to seven FTEs needed funding. Maintenance and other DSW organizations made up the difference for two years, until the budget could be updated. This would still have been an issue without OCI.

- DSW's and RMR's budgeting policies were inconsistent concerning FTE "float" or "over-hires."

- Capitalization methods differ between the two regions. For example, DSW capitalizes total SCADA, whereas RMR capitalizes SCADA piece by piece.

- Overhead cost did not change, so DSW has a higher employee hourly overhead rate because it has fewer employees, while the RMR employee hourly overhead rate has been reduced because it has an increased number of employees.

5.3.3.2 OCP Cost Allocation

DSW has nine projects within its boundaries to allocate operations costs, while RMR has three projects to allocate its costs. After OCP was implemented, costs were apportioned using a five-year historical average. Several attempts were made to negotiate a new allocation methodology that would be seen as fair to both regions and their customers. After some frustrating attempts were made, an unbiased leader facilitated a new allocation methodology that is now seen as very fair for both entities and their customers. The new cost allocation went well, customers felt they had input, and most are satisfied with the outcome. Some cost-shifting took place, but this was seen as correcting issues not related to OCP. The methodology utilized both generation nameplate and transmission line miles and will become effective in 2014.

5.4 Operations Consolidation Implementation

5.4.1 Things Working Well

Although OCI is still in process, everyone agreed that it was necessary and will better position Western for the future. The following items were noted as positive:

- Coordination of Operations and Transmission Services appears to be effective.

- Transmission settlements process in RMR appears to be well-defined.

- Compliance appears to be working well, based on the recent audit results that were presented.

- Conducting quarterly manager meetings in Loveland and Phoenix has been a very positive experience.

- OCI has eliminated any differences in the way that the Transmission Tariff is administrated.

- DSW and RMR maintenance are working well together and doing as much as they can to coordinate and create common practices.

- Ability to focus on Transmission Provider services has been a benefit of OCP. Transmission Services has been able to concentrate on its required tasks.

5.4.2 Impacts

Workload is high on those who were impacted by OCP. Supervisors and managers, along with impacted employees, have increased responsibilities, and their positions are seen as quite stressful. OCI is a big driver, but other contributing factors include:

- Retirement of knowledgeable staff;
- NERC compliance activities, including audits;
- Increased FERC scrutiny;
- Western's TIP;
- Western-wide issue coordination;
- NERC's proposed revision of MOD standards; and
- CRSP consolidation.

Few additional resources were added to keep the system operational while implementing OCP and CRSP consolidation.

RMR managers also face challenges interfacing with their "bosses." They directly report to an RMR manager, and at the same time, they must also meet the expectations of the DSW and CRSP managers.

5.4.3 Culture

Distinct cultural differences exist between RMR and DSW. These differences have impacted the timeline to complete OCI. Outside of operations and transmission services, each region has a tendency to continually pursue its own interests. This has sometimes included sacrificing Western's overall best interests for decisions more in line with a region's interests. Some employees have also embraced change more quickly than others.

Operations and Transmission Services employees in both Phoenix and Loveland appear to have bridged these differences. They are more apt to look at the transmission system they are responsible for as a whole, rather than as individual regional systems.

Meetings have increased due to greater responsibilities, and some feel that DSW has no representation in certain areas. For instance, the PSOC appears to have two RMR representatives, with an operations manager and a transmission services manager on the council.

Culture outside of operations has also impacted OCI. Questions have arisen about procedures, such as why RMR employees in Phoenix would need to go to RMR HR personnel when DSW HR personnel are locally available.

5.4.4 Areas of Improvement

Several potential areas of improvement with OCI include:

- RMR should notify DSW when personnel changes are being made. This includes temporary changes, such as "acting supervisors."
- Communication between the regions needs improvement – early, often, and well-timed.
- Regional meeting attendance requirements should be clarified. Some feel that operations and transmission service should be represented in all regional meetings. The operations and transmission service managers did not necessarily disagree, but felt that workload prohibits this.
- A “winners and losers” attitude was felt by some, although this was primarily expressed by those outside of operations. Some employees felt that the "north" (RMR) came down and told the "south" (DSW) how things should be done. Others felt that the RMR let DSW’s tools be selected to compensate for the perception that RMR had "won.” Something of an attitude of “us versus them” continues to remain, and although this has improved, it would benefit the organizations to continue to work on this attitude to alleviate employees’ feelings that there were “winners and losers.”
- Time and resources to conduct process improvement is limited because of the high workload.
- Western's TIP was initiated during the implementation of OCP, and the associated workload is impacting OCP.
- Team building exercises should continue to be utilized to build trust among the two organizations.
- Results of OCP should be tracked and communicated to show that the desired results from the changes have been achieved.

5.4.5 General Western-Wide Observations

It will be difficult for Western to implement standard processes and achieve common tools until it is a single organization. OCP has demonstrated that it is very difficult to standardize processes and achieve common tools even within a single organization that has a single management chain. Western's regional independent culture leads to teams that are frequently not open to what is best overall for Western. Members of teams continue to support their regions' best interests. Western should have a priority of becoming more common among the regions with practices and tools.

If Western developed common practices and tools prior to change, the changes would occur much more smoothly. It is recognized that this would be a difficult challenge. It may help Western to focus on doing similar things, rather than on the organizational structure. Standardizing sets the stage for later change, if so desired. Often Western-wide tools or standards lead to different implementation practices. Western has been sensitive to customer desires and regional flexibility, but this is not necessarily consistent with "open access" transmission policy, and Western should strive for uniform implementation of its OATT.

The following are examples where Western has had challenges in implementing common practices and tools:

- DSW and RMR had identical SCADA systems, including the same version number, but these were implemented differently. It has taken more than two years to reach compatibility for further consolidation into a single system.

- An example that came up during discussions with personnel was the recent decision that Western would move to a single billing program. Some were disappointed that the power billing program will end up with "one program," but this is being implemented differently in each region. For example, NITS is calculated differently between regions, and some are using other tools to supplement the new billing program. Some felt that more agreement could have been reached to eliminate the differences that were not required due to project legislation or the regional marketing plans.

- Each of Western's operations offices are preparing to meet the new PER (personnel) reliability standards. Although each of Western's operations offices is required to implement and meet the same standards, they are independently preparing to meet those standards. This does not mean the offices have no desire to work together, however; rather, it is seen as being quicker and easier for each region to do it on its own. Although most would agree that in the long run, it would save resources to jointly develop the implementation material, additional resources would be expended initially, and the offices do not feel they have those resources available at this time.

Limited resources will continue to challenge Western's regions to meet new and changing industry requirements individually.

5.5 Recommendations for Future Changes

- Management should lead change with a clear vision and with senior management taking an active role.
- Identify justification and drivers for the change as clearly as possible. Projected cost savings should be tracked to ensure that they are realized. This information should be well communicated to ensure that the employees see the benefit of their efforts.
- Communication is critical, and should be early, frequent, and well-timed. It is understood that early communications often do not have the details that employees and customers desire; more defined communications take more time, leading to employees and customers believing that "secret studies" are being performed and that management is not being honest. Frequent communication, even without new information, is desirable and keeps employees abreast of the latest plans. This will help supervisors that do not communicate frequently to their employees and alleviate misinformation that may be given.
- Define budgets, resources, cost allocation, and cost recovery issues early.
- Define program changes for other organizations that are not directly involved in the consolidation but will be impacted.
- Consider using a change management consultant to help lay out a process.
- Regional cultural differences must be considered, and training on implementing cultural change should be provided to management and staff.
- Consider time frame to implement and take into account additional workload that the involved employees will be expected to handle. Consider adding short-term resources to address the additional workload of implementing the change.
- Clearly spell out who is responsible for communications to customers. This is especially important when offices handle them differently prior to the consolidation.
- Identify specifically which resources and associated FTE will be transferred to the new organization.
- Identify a project manager who will facilitate and track the changes. Standard project management practices should be utilized.

- If standard processes and tools, including similar implementation, could be achieved prior to the consolidation, consolidation could be achieved much more efficiently. The tool selection criteria shown below could help in this endeavor.

Some additional things to consider that may have helped with OCI include:

- Involving rate managers early in the process to identify rate impacts to customers.
- Involving budget managers early in the process to identify budget impacts.
- Involving human resources early in the process to lay out HR and other "soft side" issues.
- Involving administrative officers early in the process to identify property, inventory, warehouse, procurement, and contract officer issues.
- Identifying space issues and responsibilities.
- Identifying who is responsible for contract support activities.
- Involving security managers to define consistent parameters.
- Identifying reliability standards, roles, and responsibilities as clearly as possible.
- Clearly spelling out IT roles and responsibilities, especially when functional changes occur.
- Tool selection:
    - Utilizing an outside (non-impacted) facilitator.
    - Establishing tool parameters, including budget and timelines.
    - Defining tool requirements carefully. Facilitating discussion on differences to make certain they are justified and not just an office preference.
    - Identifying dependencies of each tool.
    - Identifying flexible team members who are open to the best Western solution, and who are experts in either the technical function of the tool or the information technology and other system dependency side of the tool. Ideally, this will be a balanced team with representatives from all areas.

6 External Benchmarking Study

6.1 Purpose and Scope

The external benchmarking study was performed to provide information to both Western and its benchmarking partners regarding structural changes and lessons learned from reorganizations that resulted from mergers or positioning for the future as a result of industry changes. The focus of this benchmarking study is primarily on the Balancing Authority, Transmission Operator, Transmission Provider, and Transmission Planning functions, as those terms are defined in the NERC Functional Model. Transmission Settlements activities were also included.

6.2 Methodology

Since Western is unusual in the respect that it deals with large geographic areas, has multiple operations centers, and deals with multiple RROs, the primary purpose of this study was to focus on utilities in similar situations.

A short list of potential partners was developed that included companies that operate systems with large geographic areas, have multiple operations centers, and/or deal with multiple RROs. This list was developed using the NERC Compliance Registry.

This process resulted in the identification of six potential partners who received invitations to participate in the detailed benchmarking study. Of those six, three companies elected to participate in the study, but one of these three companies was only agreeable to providing its data as long as that data was considered proprietary and not included in the report. The two companies that were willing to anonymously include their proprietary data will be referred to as Companies 1 and 2. The third company's data did not significantly change the recommendations, and for the most part, supported the information provided by Companies 1 and 2. The overall structure of one other company, American Electric Power (AEP), will be discussed using publicly available information.

In addition to the companies that were identified via the NERC Registry, a general questionnaire was sent to all of the members of the Operators Group at the NATF. This survey included three questions regarding the following topics:

- Response to planned or future industry changes;
- Company reorganizations; and
- Participation in an RTO or ISO.

No additional companies were identified for the detailed study as a result of the general NATF survey.

Partner companies that elected to participate in the detailed benchmarking study received a questionnaire and provided data regarding the following topics:

- Organization Charts for the BA, TOP, TSP and TP Functions
- Drivers for Mergers and Reorganizations
- Impact of Mergers and Reorganizations
- RTOs and ISOs
- Future Changes
- Back-up Control Centers
- NERC Compliance
- Tools Standardization
- Tools Used
- System Information

The following section will provide a comparison of the data that was provided by the detailed questionnaires and through subsequent phone interviews.

6.3 Organizational Structure

Western was formed in 1977 when the DOE was formed. The power production and power marketing activities that were under the Bureau of Reclamation were transferred from the Department of the Interior to the Department of Energy.

Companies 1, 2, and AEP were all formed by mergers that occurred within the last 25 years. These transactions triggered the need to integrate operations centers that perform in more than one geographic area, and in some cases, under more than one RRO.

These mergers and significant changes in the electric utility industry have required organizations to make changes in the structure of all of the functions that are within the scope of this study. The following subsections will discuss specific issues regarding the changes that were made and an assessment of the current structure of the partner organizations.

6.3.1 System Overview

With regard to the general structure of the merged organizations, the spectrum of potential options ranged from allowing the pre-merger organizations to remain completely autonomous on one side, to requiring them to be completely centralized with standard procedures on the other side. The rise of RTOs and ISOs also impacted the manner in which the subject NERC functions were performed for the companies that joined RTOs or ISOs.

Table C1 summarizes some of the general organizational issues for each organization, including their involvement with RROs, RTOs, and ISOs.

Table C1 – Summary of Operations Centers, RRO's, RTO's, ISO's and NERC Functions Performed

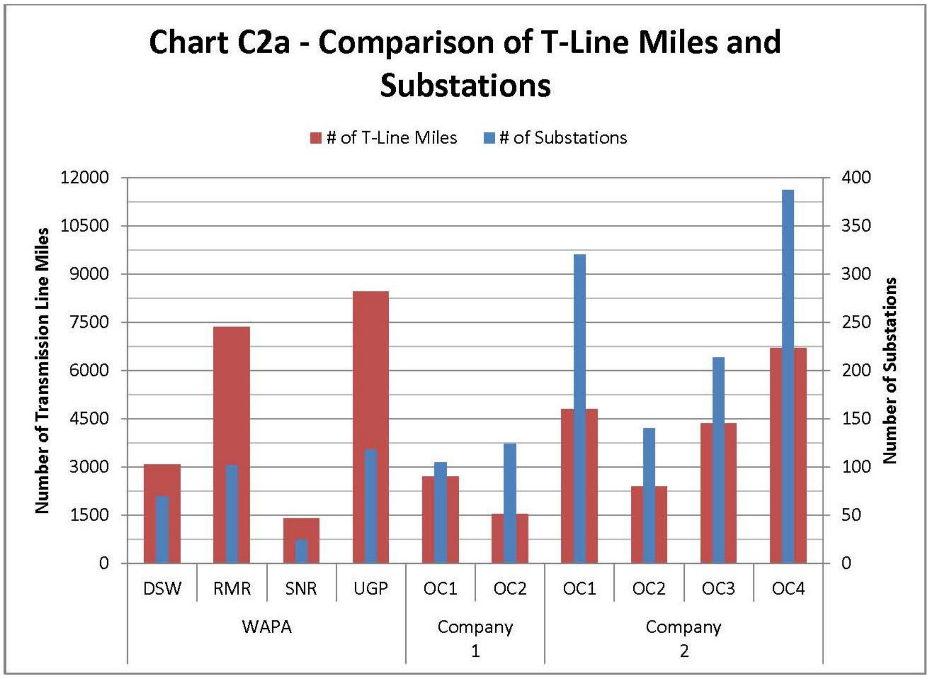
Metrics	WAPA	Company 1	Company 2	AEP
# of Operations Centers	4	2	4	5
# of RROs involved	2	1	3	3
# of RTOs or ISOs involved	0	0	2	3
Performs the TOP function?	Yes	Yes	Yes	Yes
Performs the BA function?	Yes	Yes	Limited	Limited
Performs the TP function?	Yes	Yes	Yes	Limited
Performs the TSP function?	Yes	Yes	Yes	None

6.3.2 Normalizing Factors

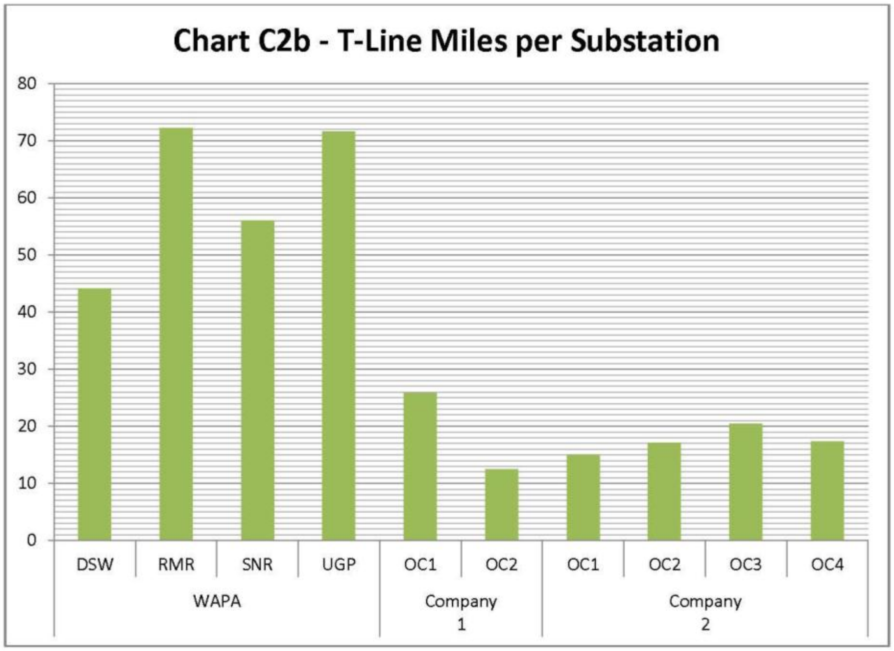
In order to account for differences in system size, data was collected to develop normalizing factors, including the connected generation capacity, peak load, total transmission line miles, and number of substations for each operations center. For purposes of establishing normalizing factors and averages, the undisclosed data from the third company was included.

Except for the number of substations, the other three metrics varied significantly. The average standard of deviation for the transmission line miles, generation, and peak load were 1805, 995, and 1129, respectively, while the average standard deviation for the number of substations was only 58. This is the average of the absolute deviations of data points from their mean. Therefore, the number of substations was assumed to be the best normalizing factor.

For areas where the transmission line miles and the number of substations were not proportional, the partners were contacted to ensure that the appropriate data was submitted. Variations were found to be consistent with the density of the population for each operations center's area. Chart C2a shows the correlation between the number of substations and the number of transmission line miles for each operations center.



Because some of the operations centers control large rural areas with no metropolitan areas, the ratio of transmission line miles per substation varied significantly. Some areas had a very high substation density, while others were very low. While data was not readily available to capture the number of breakers per substation, it was felt that substations in high density areas would have more breakers and thus be more complicated to operate.



Other factors that might add to the complexity of operations may include the number of System Operating Limits (e.g., Path Ratings that are required to be monitored), the number of neighboring Transmission Operators, loop flow impacts of neighboring systems, and Special Protection Systems. Special Protection Systems are automated systems that may drop load or generation for various outages, depending on system conditions.

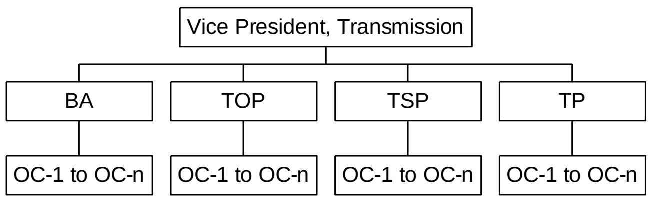
6.3.3 Overall Structural Comparison

One of the primary questions addressed in all of these mergers is whether to centralize functions or keep them decentralized, as they were before the merger. Centralization may be implemented by centralizing management organizationally, or by physically centralizing the employees. There are many pros and cons for both options, which resulted in some hybrid solutions.

In any case, the partners agreed that the decisions needed to be clearly justified and well communicated. It was also noted that Western and Company 1 are currently in the process of organizational changes that are meant to position their organizations for future industry changes.

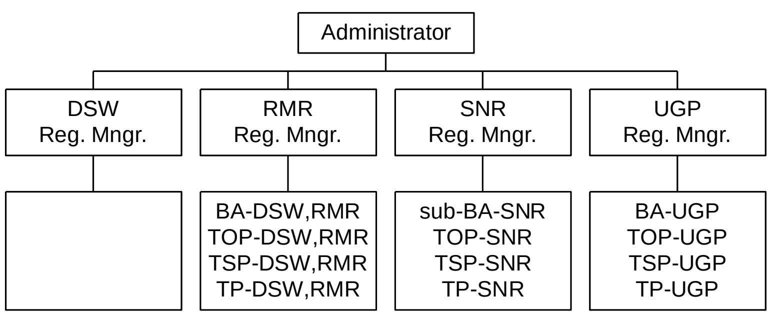
Companies 1, 2, and AEP have all maintained separate operations centers, but have centralized the management of the functions between those operations centers, as shown in the simplified organization chart (C3a). There are some variations on the geographical distribution of the employees that perform these functions, which will be discussed in later sections. All three of these companies have Directors or Managers under the Vice President, who are responsible for the NERC functions across the different Operations Centers (shown as OC “1” through “n”). The simplified diagram set forth below shows one Director or Manager for each function. In reality, however, there was some variation as to how the functions were assigned to those positions (e.g., real-time functions for BA, TOP, and TSP are often under one Director). These variations will be discussed later in the report.

Chart C3a



Western has merged and eliminated some of its operations centers in the past, especially in the UGP region. UGP merged the Fort Peck, MT, and Jamestown, SD, operations centers into the Watertown, SD, operations center in the 1980s. Western's transformation program in the 1990s eliminated the Montrose, CO, operations center and associated WAUC BA, and merged the functions into the Phoenix and Loveland operations centers and their associated BAs.

Chart C3b



Western’s current organizational structure is different from the other partners’, as shown in the simplified diagram above. Each operations center is autonomous and is directed by a Regional Manager who reports to the Administrator in the CSO. The primary driver for this difference is the fact that Western’s system is comprised of various transmission projects that were developed under different legislative acts.

Western is still in the process of OCI. The purpose of OCI is to improve efficiency by consolidating the BA, TOP, TSP, and TP functions for its DSW and RMR operations centers. Prior to OCI, the DSW functions for BA, TOP, TSP, and TP, shown in Chart C4a, all reported to the

DSW Regional Manager. Reporting for these functions was recently moved from DSW to RMR, although no employees were relocated. The other two operations centers, SNR and UGP, remain relatively autonomous. Transmission settlements activities still remain at each regional operations center and report to their regional manager.

6.3.4 Real-time BA, TOP, and TSP Functions

Real-time BA, TOP, and TSP functions are performed at the operations center by specific operations desks. These desks are generally staffed on a seven-day, twenty-four hour basis.

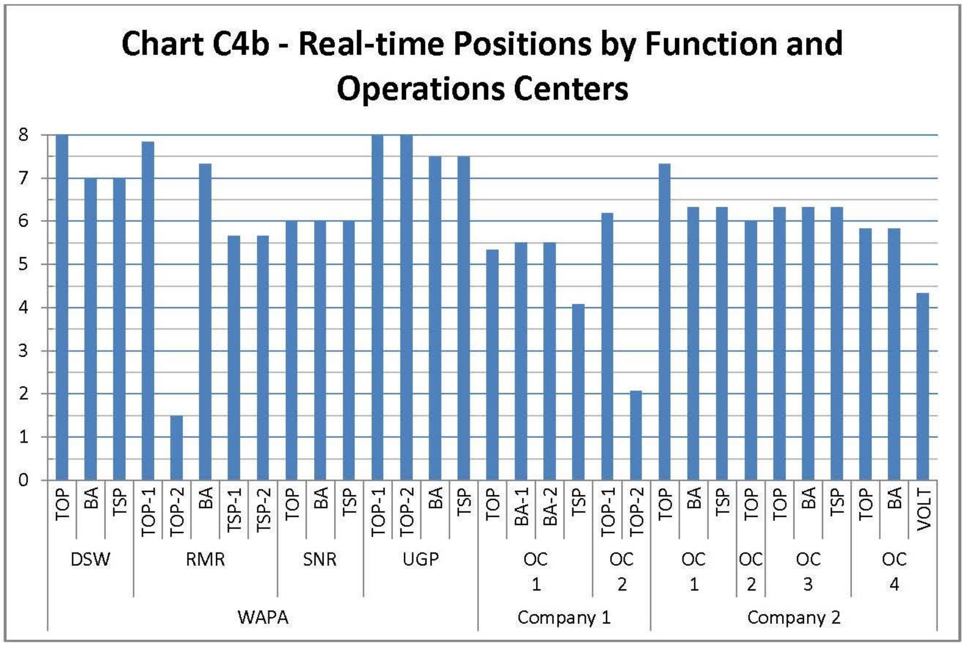
Table C4a summarizes the activities that were generally performed by each of the desks. It should be noted that only one operations center at one company (Company 2 – OC4) had a separate voltage control desk.

Table C4a – Operator Desk Activities

Type of Desk	Activities
Switching Desks (TOP)	Transmission Switching & Voltage Control
AGC Desks (BA)	Automatic Generation Control & generation/load balancing
Transmission Service Desks (TSP)	E-tags
Voltage Control Desk	Voltage Monitoring and Control

Staffing levels of the operations desks were somewhat consistent, in that a certain number of positions are required to staff a desk on a 24-hour/7-day basis. At Western, some the desks had vacant positions, which made staffing more challenging.

In the charts and tables in this report, DSW references the Phoenix Operations Center, RMR references the Loveland Operations Center, SNR references the Folsom Operations Center, and UGP references the Watertown Operations Center.



The following observations were made regarding the data in Chart C4b:

- The staffing for a desk, including the shift supervisor (the level just above the operators), the operators, and any operator trainees, was usually in the range of five to eight positions, as shown in Chart C4b.
- WAPA-RMR's Operations Center is staffed with more than eight positions, including shift supervisors, for its two TOP desks. RMR has extensive switching activities from Monday through Thursday during the daytime hours, so it has found it cost-effective to staff two switching desks for ten hours during these days. All other times, including weekends, only one switching desk is staffed.
- Company 1 – OC1 has some of the lowest staffing levels on its desks, particularly the TSP desk.
- Company 1's second TOP desk at OC2 was only allocated two positions. The second desk is a daytime only, sub-transmission switching desk. At night, the main desk handles switching for the entire system.
- Company 2's OC4 Voltage Desk is staffed with four to five positions, but this desk is only staffed during the morning and afternoon shifts.
- At Company 2's OC4, there is minimal e-tagging work, since this is mainly handled by their RTO. Whatever work does exist can be handled by the BA desk.

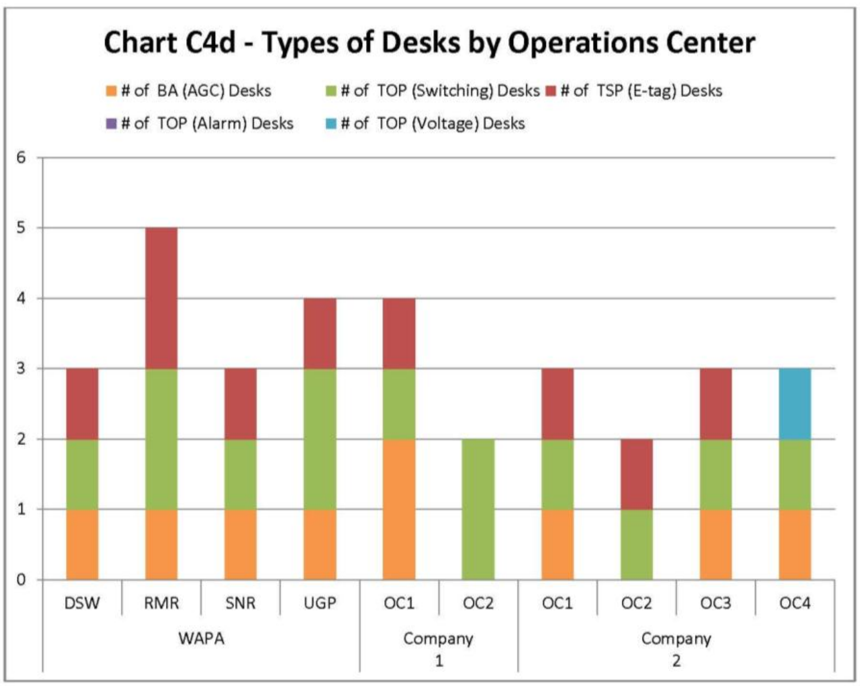
Table C4c summarizes the number of operations centers and number of desks for each partner.

Table C4c – Summary of Operations Center and Operations Desks				
Attribute	**WAPA**	**Company 1**	**Company 2**	**AEP**
Operations Centers	4	2	4	5
Switching Desks (TOP)	6	3[4]	4	Not available
AGC Desks (BA)	4	2	3[1]	Not available
Trans. Service Desks (TSP)	5	1	3	Not available
Transmission Alarm Desk	0	0	0	Not available
Voltage Desk	0	0	1[2]	Not available

Notes:

1) Company 2 has one Local BA desk, where an RTO performs the main BA functions. Another BA desk will similarly turn over functions to another RTO in the near future. After that, it will have one full BA desk and two local BA desks with limited duties. OC1 and OC2 are operated as a single BA from OC1. The TSP desk for OC1 also covers OC2.
2) This voltage desk is only staffed during the mornings and afternoons (peak conditions).
3) This includes a switching desk that RMR staffs for Monday through Thursday during the day due to increased switching during that period.

The information in Table C4c is presented graphically in Chart C4d below.



The following observations were noted based on Table C4b and Chart C4d:

- Four of the ten operations centers have maintained the typical “three desk” arrangement. These are WAPA’s Phoenix and SNR operations centers, as well as Company 2’s OC1 and OC3. Two potential explanations for this are the geographic disbursement and the historical operation of these operations centers.

- WAPA-RMR, WAPA-UGP, and Company 1’s OC2 operation centers all had two TOP desks.

- At Company 1's OC2, the second transmission desk is a daytime-only desk that handles the sub-transmission switching during those hours. During non-daytime hours, the entire system is operated from the main desk.

- WAPA's RMR operations center has two separate TSP desks. RMR has extensive switching activities from Monday through Thursday during the daytime hours, when maintenance crews need switching activities. RMR found it cost-effective to staff two switching desks for ten hours during these days. All other times, including weekends, only one switching desk is staffed.

- Company 1 has geographically consolidated its BA and TSP functions into one of its two operations centers.

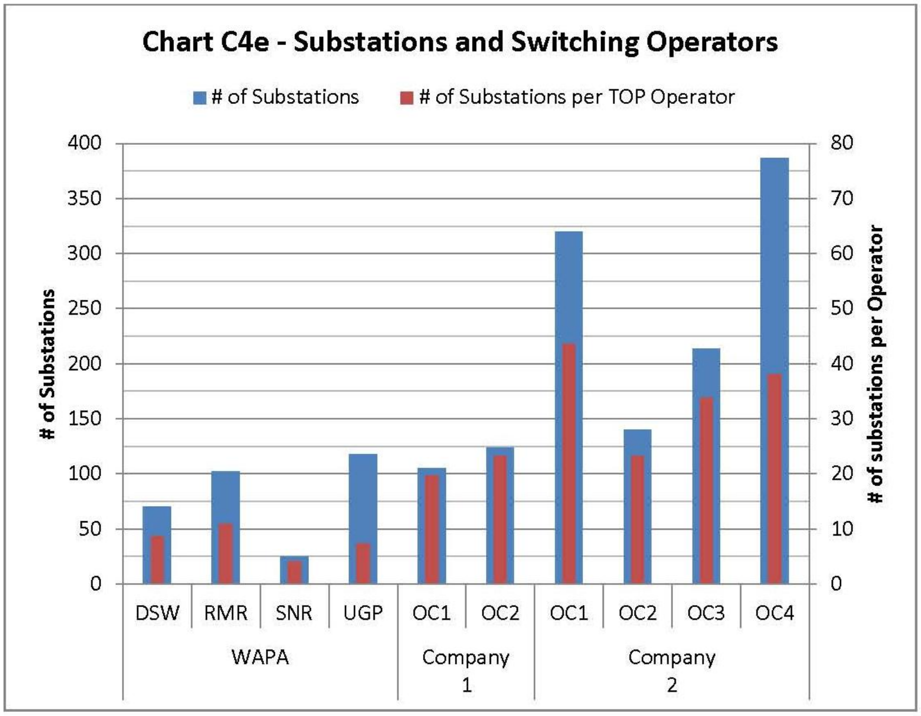
- Company 1 has consolidated the transmission service desk into one desk at its main operations center, which handles transmission service for its entire system.

- Company 1 has moved the BA/AGC desk from OC2 to OC1. Both BAs are still separately registered and are handled by separate desks at OC1. It is possible that these desks may be reorganized if the BAs are combined in the future.

- Company 1 has also cross-trained its operators, such that they can work both the transmission and distribution switching desks.

- Company 2 has one voltage desk at its OC4. None of the other operations centers have a separate voltage desk.

The number of transmission substations controlled by the operations centers varied from 105 for Company 1-OC1 to 387 for Company 2-OC4. Four of the ten operations centers control approximately 300 or more substations, as shown in Chart C4e. Chart C4e also shows that the number of substations per switching desk operator varied significantly by operations center, with an average of about 20 substations per switching desk operator.



While the structure and staffing of the desks is fairly consistent, there were some notable variations between the organizations:

- In Chart C4e, the total number of substations and the number of substations per operator is proportional, especially for operations centers where there is only one TOP desk to be staffed. This generally requires somewhere in the range of five to eight positions, as shown in Chart C4a. For operations centers where the number of substations per operator is low and the number of substations is high, this indicates that there may be too many operators based on the given number of substations.

- The average number of substations per operator was 20. Operations centers with less than the average of 20 may be candidates for consolidation. Other factors may prohibit consolidation, such as the number of System Operating Limits, the number of neighboring Transmission Operators, loop flow impacts of neighboring systems, Special Protection Systems, and legislative requirements.

- UGP had an innovative approach, in that its AGC and TSP desks were staffed from a group of operators who were trained to operate both desks.

- Company 1 also had operators who were cross-trained to staff the transmission switching desk as well as the distribution switching desks (below 25kV).

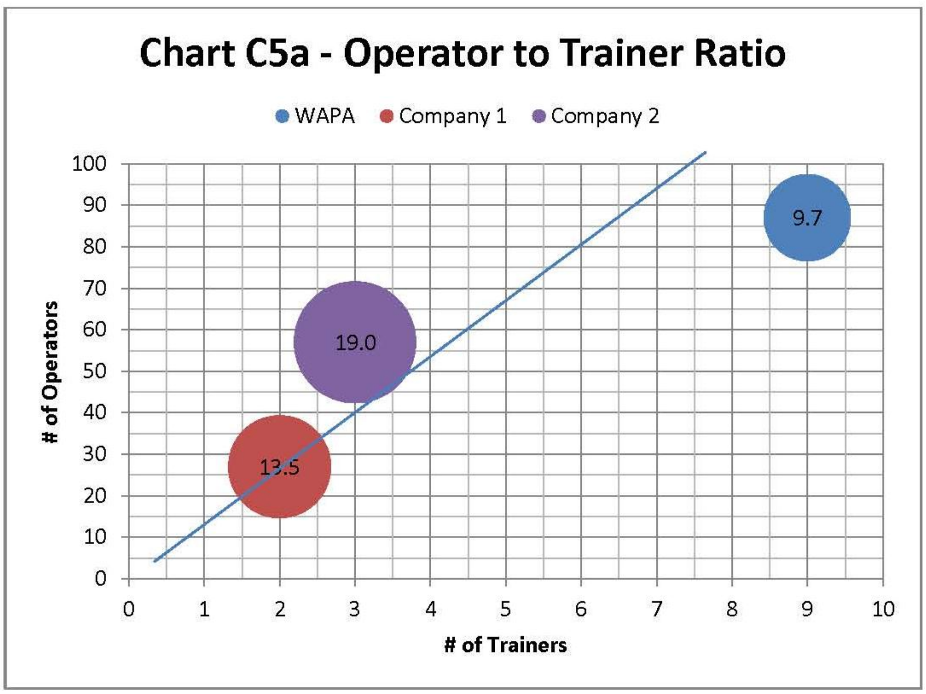
➢ For Company 2's OC4, the voltage support desk operators were counted as TOP operators since they perform TOP functions that would be executed by the switching desks at the other operations centers.

6.3.5 Transmission Operations (TOP) Training Support

Several support categories were common among all of the organizations that were benchmarked.

The first support category, Training Support, is necessary to ensure that operators become and remain knowledgeable. It is also required to remain compliant with NERC standards, namely PER-002-0.

Since the number of operators in each organization varied, this was considered to be a reasonable normalizing factor for the number of trainers. As shown in Chart C5a, the ratio of operators to trainers ranged from 9.7 for Western to 19 for Company 2.



In Chart C5a, a larger bubble indicates that the company was able to cover more operators per trainer. If the center of the bubble is above the blue line, this indicates that the company exceeded the average number of operators per trainer.

The following observations were noted from the data provided:

- The ratio of Operators to Trainers is similar to class size, since it measures the number of students per instructor.

- Company 1 had almost exactly the average number of operators per trainer.

- Western was below the average number of operators per trainer, while Company 2 was significantly above the average. Western's trainers do not solely train operators, which may partly explain its larger training staff.

- All of the trainers in all of the benchmarked training centers were geographically spread and were not centrally supervised.

- The organization report varied by operations center. The most common reporting structure was for the trainers to report to the operations center manager or be located within an operations support group. UGP's structure was the most unusual, with the trainers reporting to the Compliance Manager.

6.3.6 Transmission Operations (TOP) Outage Coordination Support

Table C6a summarizes the number of outage coordinators for each operations center.

Table C6a – Outage Coordinators per Operation Center

Company Name	Op Center	# of Outage Coordinators
WAPA	DSW	2
	RMR	2
	SNR	1
	UGP	0
Company 1	OC1	1
	OC2	1
Company 2	OC1	2
	OC2	1
	OC3	1
	OC4	1

Each company averaged about one to two outage coordinators per operations center. UGP was the only operations center that did not identify a specific position for outage coordination.

6.3.7 Transmission Operations (TOP) Energy Management System Support

The Energy Management System (EMS) is the most important tool for operators. It is a system of computer-aided tools used by operators to monitor, control, and optimize the performance of the generation and transmission systems. The actual tools used to implement the EMS for each partner will be discussed under the tools section later in this report.

While there has been a trend in the industry for the EMS to be managed by a centralized information technology group, many companies still have some support positions organizationally located under the operations group.

The study partners had a variety of arrangements for EMS support, so no clear standard arrangement exists.

In Western, three different Energy Management Systems exist for four operations centers. DSW and RMR are presently in the process of migrating to a single EMS as part of the OCI.

DSW, RMR, and SNR have separate information technology groups that handle the bulk of the EMS support. UGP, which uses an EMS that was developed in-house, had the largest EMS support group located under Operations. Because it was outside the scope of this study, no data was gathered to determine how many employees under the information technology groups are required for EMS support.

UGP felt that its arrangement was economically beneficial, since it has avoided the significant cost of acquiring a commercially-produced EMS. One concern, however, is that it is difficult to sustain the necessary level of expertise in-house to maintain and update the EMS.

Company 1 recently migrated to a single EMS for both of its operations centers. Each operations center had a separate internal EMS support group. Because the EMS has been moved to OC1, the role of the support group at its OC2 is now focused on distribution and other computer support activities.

At Company 2, all of the EMS support is handled by a separate information technology group. This is similar to the arrangement at DSW, RMR, and SNR.

Table C7a - Summary of EMS Support Positions Under Operations

Company	Location	Total Positions	Included Under Ops?	Comments
WAPA	DSW	0	No	Information Technology group handles all EMS Support
	RMR	0	No	
	SNR	0	No	
	UGP	13	Yes	All EMS under Ops
Company 1	OC1	12	Yes	Most EMS Support under Ops
	OC2	0	No	
	OC2	0	No	
Company 2	OC1	0	No	Information Technology group handles all EMS Support
	OC2	0	No	
	OC3	0	No	
	OC4	0	No	

As summarized in Table C7a, two out of the three companies had at least one operations center with some EMS support under its operations group. This was only true for 25% of the operations centers, however. Eight of the ten operations centers had their EMS supported by a separate information technology group.

6.4 Transmission Operations (TOP) Planning and Long-Term Transmission Planning (TP) Functions

Transmission Planning is performed both on the short-term operations horizon – up to one year into the future – and on the planning horizon – one year into the future and beyond. Short-term planners are sometimes called Operations Engineers, while long-term planners are sometimes called Planning Engineers. Operations engineering includes planning in the real-time, hour-ahead, day-ahead, and seasonal time spans, which are covered by the TOP NERC Standards. Planning engineers are focused on the TPL NERC Standards, which cover annual assessment of future conditions, up to ten years into the future.

Table D1 summarizes the organization of these two groups in the partners' organizations.

Table D1 – Long-Term Planning and Operations Engineering Metrics

Partner	Under different groups?	Centrally supervised?		Geographically centralized?	
		Long Term	Operations	Long Term	Operations
WAPA	DSW/RMR- Yes SNR/UGP-No	DSW/RMR- Yes [1] SNR/UGP-No	DSW/RMR- Yes [1] SNR/UGP-No	No	No
Company 1	Yes	Yes	Yes	Yes	No
Company 2	Yes	Yes	Yes	No	No

Note:

1) As part of the OCI, DSW and RMR's Long-Term Planning activities were put in separate groups. The supervision is centralized, but the employees are geographically dispersed. This is similar to Companies 1 and 2.

While both groups use some of the same power flow and dynamic simulation software, they also require different skill sets and knowledge bases. Long-term planners need some background in operations planning, however, and vice versa.

Chart D1 shows the number of substations per planning and operations engineering positions, by operations center.

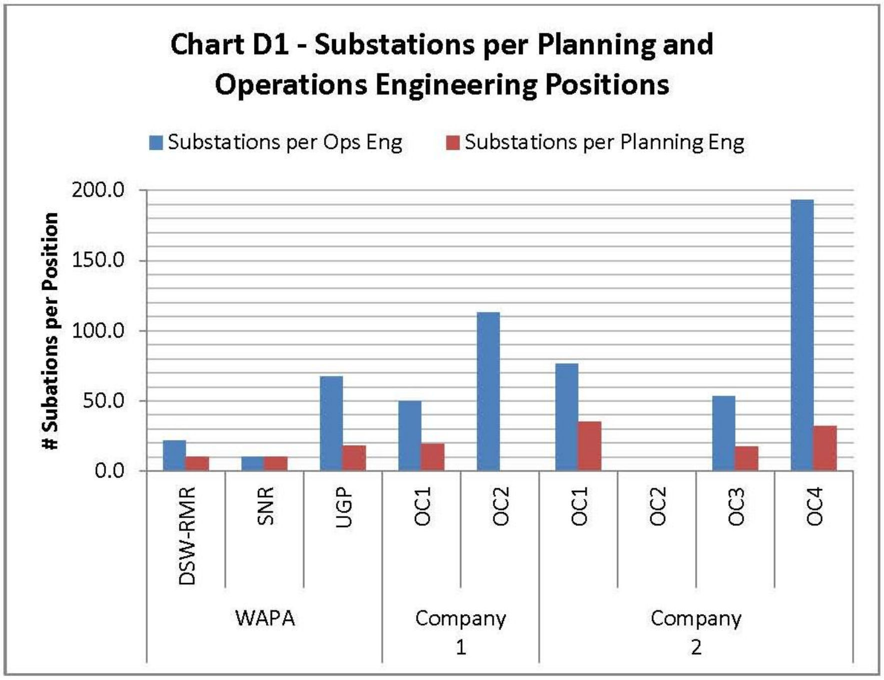
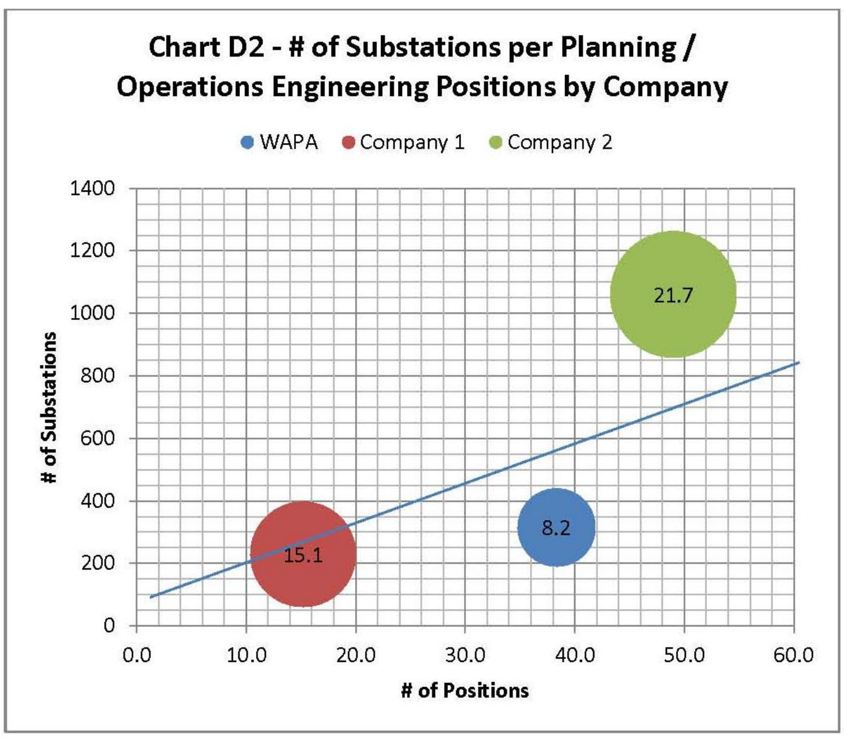


Chart D2 shows the total planning and operations engineering positions, by company, when it is normalized using the number of substations. A larger bubble indicates that the company was able to cover more substations per planner. If the center of the bubble is above the blue line, this indicates that the company exceeded the average number of substations per planner.



The following observations were noted, based on the information that was provided and summarized on Table D1 and Charts D1 and D2:

- The most common configuration was for the Long-Term Planning Engineers and Short-Term Operations Engineers to be organizationally separated.
- SNR and UGP were the only entities that had a single group performing both Planning and Operations Engineering activities, as shown in Table D1.
- Both SNR and UGP had the two lowest numbers of total positions for Planning and Operations Engineers. Due to the limited number of employees, these groups may need to be able to perform both types of activities. These groups also indicated that they saw benefits for having closer ties between the Planning and Operations Engineers. Planning Engineers at DSW and RMR indicated that having separate groups was beneficial, however, since it permitted more focus and less distraction.
- Companies 1 and 2 structured their organizations to include centralized supervision for the Planning Engineering Group and the Operations Engineering Group.
- The changes implemented in the DSW and RMR operations centers as part of the OCI have brought DSW and RMR more in line with the other partners in this study by having centrally supervised separate groups for Planning Engineering and Operations Engineering.
- Company 1 has geographically centralized its Long-Term Planning Engineering at its OC1, as shown in Table D1. All of the other Planning and Operations Engineering groups were centrally supervised with employees who were remotely located at each operations center.
- The total number of Planning and Operations Engineering positions was normalized using the number of substations per engineer as a metric.
- Not including Western, the average number of substations per engineer was approximately 19. This is close to Companies 1 and 2 (15.1 and 21.7).
- Western's ratio of substations per engineer was 8.2, which reduced the overall average to about 16.

6.5 Transmission Service Provider (TSP) Tariff and Contract Administration Functions

In addition to real-time transmission scheduling, the TSP function also included Tariff and Contract Administration. This includes interconnection queue management, interconnection processing, and interconnection agreement negotiation and execution. Table E1 summarizes the metrics for Tariff and Contract Administration.

Table E1 - Summary of Tariff Administration Positions Under Operations

Company Name	Location	Total Positions	Centrally Supervised?	Geographically Centralized?	Single Tariff?	Single OASIS and Queue?
WAPA	DSW	2.5	Between DSW / RMR	No	Yes	4 separate sites and queues
	RMR	2.5				
	SNR	1	No			
	UGP	3	No			
Company 1	OC1	6	Yes	Yes	Yes	Yes
	OC2	0				
Company 2	OC1	10	Yes	No	Yes	3 separate sites and queues
	OC2	0				
	OC3	2				
	OC4	2				

Chart E1 summarizes the total positions from Table E1 by company.

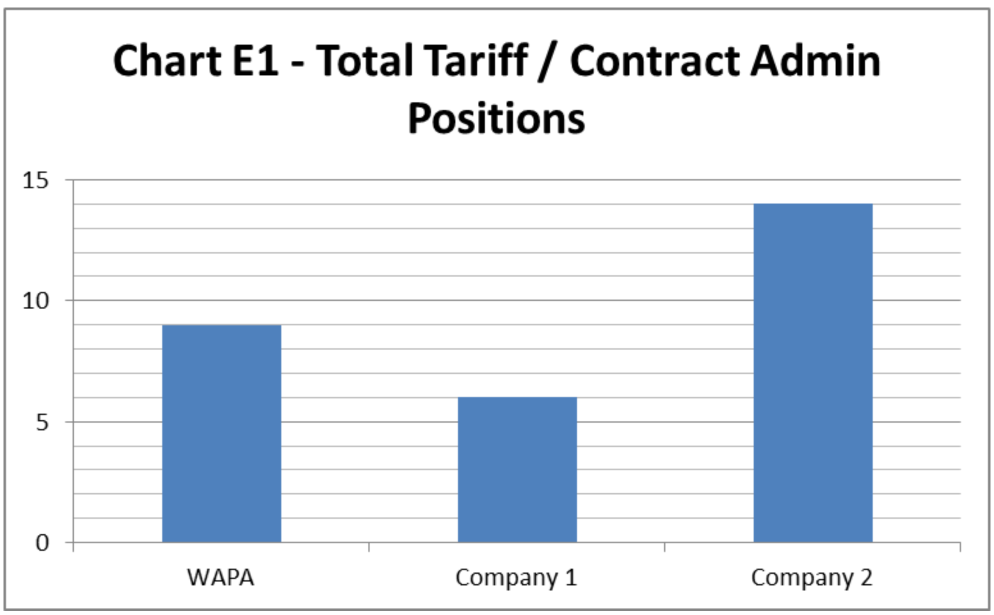


Chart E2 summarizes the queued generation projects for each partner. The data for completed projects and withdrawn projects was not available for DSW, RMR, UGP, or Company 1, so only the active data is completed in Chart E2. The data was based on the publicly available queues for these entities as of May 15, 2012.

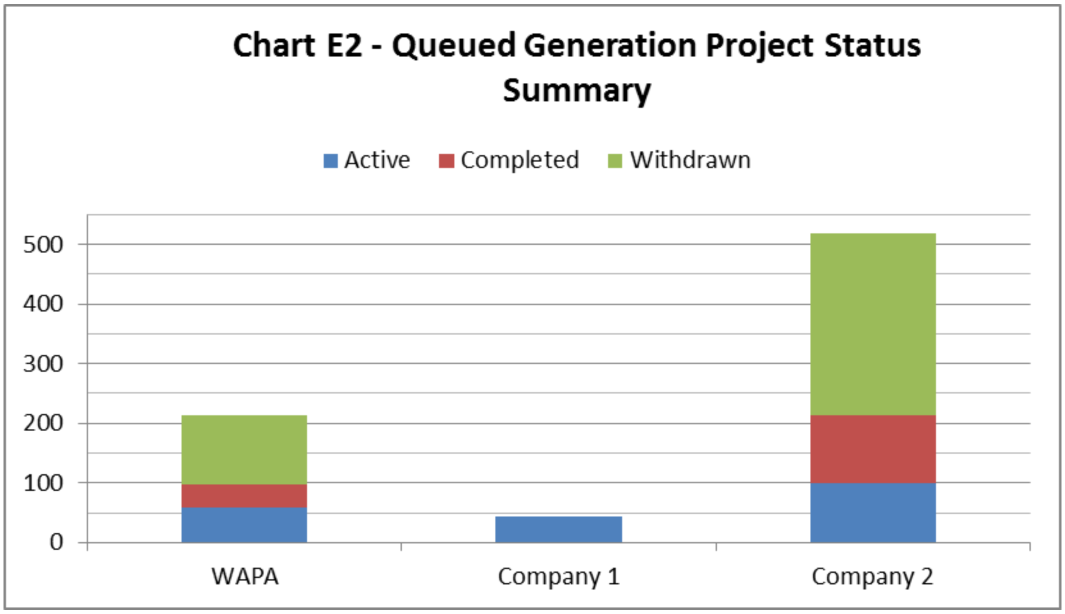
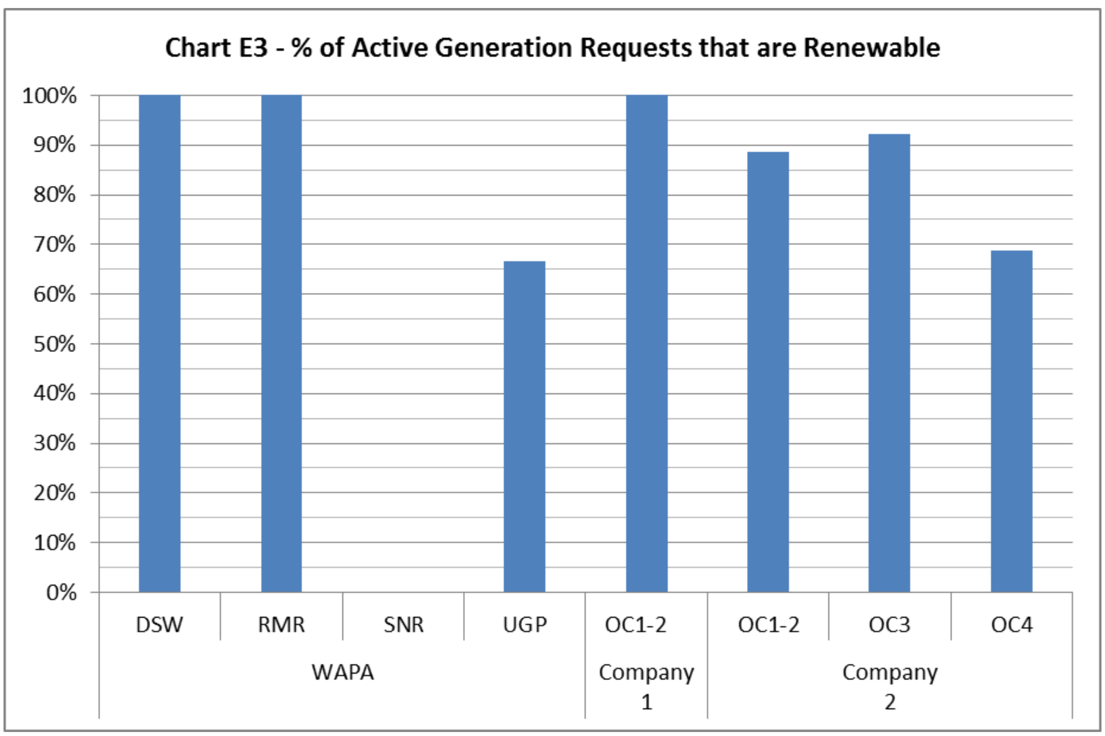


Chart E3 summarizes the impact on renewable resources for each of the operations centers.



The following observations were noted based on the information summarized in Table E1 and Charts E1 and E2:

- No single normalizing factor was identified for the information presented, but some contributing factors may include the number of operations centers, number of RTOs involved, and legislative requirements.

- All of the partner companies were governed by a single Tariff. Company 2, however, was also governed by the two additional Tariffs of its ISO and RTO, as well.

- All of the partners, except for Western, have a centrally supervised Tariff Administration Group. RMR and DSW have moved in that direction as a result of the Operations Consolidation Implementation. The Tariff and Contract Administrators for those two regions are now centrally supervised.

- Company 1 has either completely or mostly geographically centralized its Tariff and Contract Administrators. Western and Company 2 still have positions in each region.

- The number of active generation requests could indicate that projects are being processed quickly, or that the area served by the partner is not conducive to renewable generation, which is a significant contributor to queue congestion in many parts of the country.

- SNR had only one active generation request, which was submitted in 2005. It only has one position that handles tariff administration. This position handles other issues as well, due to the lack of generation interconnection requests.

- As a whole, Western has nine positions dedicated to Tariff and Contract Administration. It was third with regard to the number of generation requests, but second with regard to the number of positions dedicated to Tariff and Contract Administration. There may be some duplication of effort due to lack of centralization and maintenance of multiple queues and OASIS sites.

6.6 Compliance and Procedure Writing

The scope of this benchmarking analysis was primarily focused on the organizations that perform the following NERC functions: BA, TOP, TSP, and TP. For all of the benchmarking partners (except Western), the primary compliance organization structure was not located within the organizations that performed the subject NERC functions.

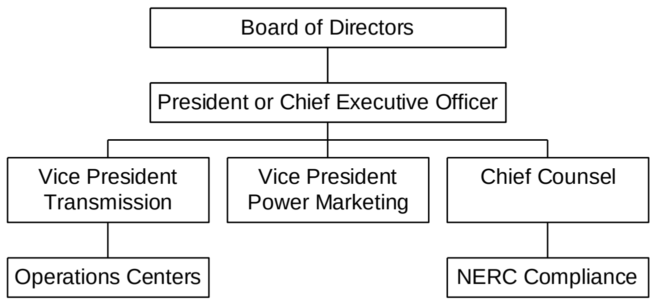
In the NERC Policy Statement on Enforcement, in Item 22 on page 10 (Docket #PL06-1-000), FERC states that "the following are factors that will be taken into account in determining credit given for a company's commitment to compliance:

> *"... Is the program supervised by an officer or other high-ranking official? Does the compliance official report to or have independent access to the chief executive officer*

and/or the board of directors? Is the program operated and managed so as to be independent?"

Based on the FERC policy statement above, it is advisable that the main compliance structure be independent and completely separate from NERC functions that are the subject of this report. Chart F1 represents a typical organizational structure.

Chart F1 – Sample Organizational Chart with Independent Compliance Group



With that said, one common complaint is that NERC Compliance is an additional item on everyone's plate. To address this issue, some companies are using "embedded" compliance positions located within the subject functions to assist with procedure writing, to develop Reliability Standard Audit Worksheets, and to act as subject matter experts. These positions are not part of the independent compliance structure with regard to reporting.

Some of the provided organizational charts included some positions and groups that performed procedure writing and embedded compliance support. These positions are not necessarily required since this is sometimes performed by operators, shift supervisors, or other subject matter experts, in addition to their regular duties.

Procedures are not generally required by the NERC Standards, but are helpful in maintaining compliance with the NERC Standards. Procedures may also be helpful in reducing penalties from NERC Standards violations since they indicate a lapse in individual – not corporate – performance. They also demonstrate a "culture of compliance."

Table F1 summarizes findings regarding the compliance and procedure writing activities within the subject functions in the partners' organizations.

Table F1 - Comparison of Compliance and Procedure Writing Positions			
Company	**# of Embedded Compliance Positions**	**# of Tech. Writers**	**Does independent compliance group exist?**
Western	6.5	6	Matrixed
Company 1	0.5	0.5	Yes
Company 2	10	0	Yes

The following observations were noted from the provided information:

- In Western's organization, the compliance positions are distributed throughout the operations centers. These positions are coordinated through a committee that includes the Compliance Managers from each of the regional offices, a Compliance Manager from the Chief Operating Officer's office and a consultant from the General Counsel's office, but the reporting is not direct or independent, as suggested by the FERC Policy Statement on Enforcement.

- Company 1 had one embedded position to assist with compliance support and procedure writing. Internal compliance work (such as procedure writing and RSAW drafting) is handled by subject matter experts in addition to their existing responsibilities. Company 1 also has an independent compliance group that performs an independent audit function.

- Company 1 will be combining its two current entities into a single entity NERC registration in 2013. Western and Company 2 do not have any concrete plans to modify their current multiple NERC registrations.

- Company 2 had the most embedded compliance positions, which were included in a separate group under the Vice President of Transmission. This group is centrally supervised with representatives in each operations center, which should provide standardization between the operations centers. Company 2 also had an independent compliance organization.

- No assessment of recent audit results or external compliance staffing was performed, so it could not be determined if the internal staffing levels were reasonable or effective. Based on the study team's previous experience and input from the partners that had implemented embedded compliance positions and procedure writers, these positions were very helpful in allowing the team members who perform the other functions to focus on their primary responsibilities.

6.7 Transmission Settlements

Transmission Settlements was difficult to benchmark since the processes and software used for this activity varied from partner to partner. The partners were asked to estimate the number of positions that were required to perform transmission (not energy) settlement. They were also asked to only include positions that perform settlements (after-the-fact verification of metered data) and not billing or bill preparation.

Chart G1 summarizes the settlements positions for each partner by operations center.

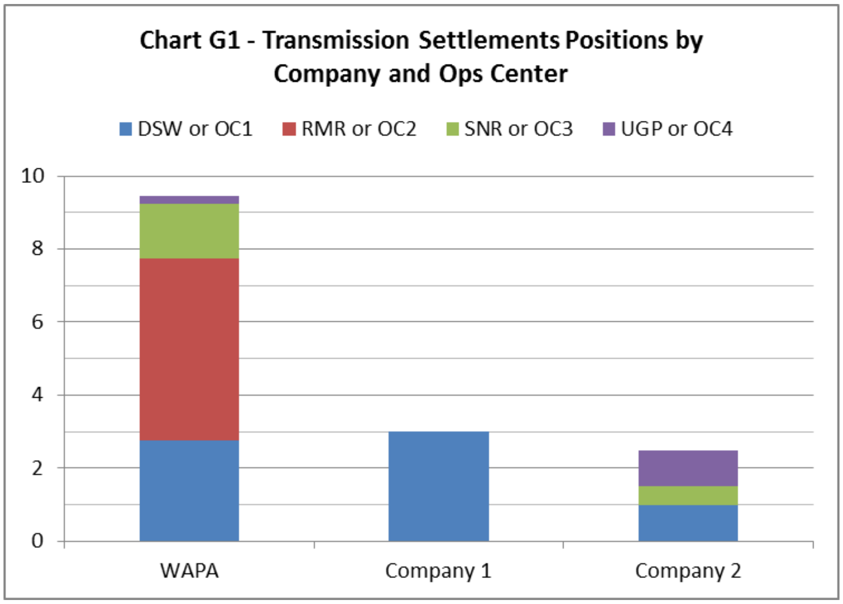


Table G1 summarizes the settlements positions for each partner by operations center, as well as the organizational structure and reporting. In some operations centers, settlements personnel were organized in a separate group with their own supervisor. In other operations centers, settlements personnel report to a supervisor who is not exclusively responsible for settlements (such as the director of the operations center).

Table G1 – Summary of Settlements Positions and Structural Organization

Company Name	Location	# of Trans. Settlement Positions	Separate Settlements Supervisor?	Centrally Supervised?	Geographically Centralized?	Reports to…
WAPA	DSW	2.75	Y	N	N	Power Marketing
	RMR	5	Y	N	N	Power Marketing
	SNR	1.5	Y	N	N	Power Marketing
	UGP	0.2	Y	N	N	Ops
Company 1	OC1	3	N	Y	Y	Contracts
	OC2	0				

Table G1 – Summary of Settlements Positions and Structural Organization						
Company Name	**Location**	**# of Trans. Settlement Positions**	**Separate Settlements Supervisor?**	**Centrally Supervised?**	**Geographically Centralized?**	**Reports to…**
Company 2	OC1	1	N	Partially	Partially	Ops
	OC2	0				
	OC3	0.5	N	N	N	Ops
	OC4	1	N	N	N	Ops

The following observations about Transmission Settlements are based on Chart G1 and Table G1:

- Company 1 has organizationally and geographically centralized its settlements functions, while Western and Company 2 have not.
- In Company 2, the settlements positions report to the Operations Center Managers, who then report to a centralized director of operations, so there is some high-level central management.
- The organizational location of the settlements positions varied significantly. At DSW, RMR, and SNR, these positions reported to Power Marketing. At UGP and Company 2, they reported to Operations. Company 1 had them report to Contracts and Accounting.
- The need for a separate group for settlements positions varied also.
- Company 1 and Company 2 had relatively low and consistent settlements staffing levels, while Western had higher staffing levels.
- Settlement staffing levels are dependent on complexity of the settlement process and automation of tools. Complex settlements, such as greater-than-hourly settlements or financial settlement of energy imbalance, could require high staffing levels. RTO and ISO typically handle ancillary service settlements, so fewer staff would be required at the company level if they are an RTO or ISO member.

6.8 Span of Control

Span of control was determined for each partner, based on the number of non-supervisory positions per supervisory position for all of the groups that performed the benchmarked activities. Table H1 summarizes the span of control calculation.

Table H1 –Position Counts and Span of Control			
	Supervisory	Non-Supervisory	Non-Supervisory Positions per Supervisory Position
Western	31	197.1	6.4
Company 1	11	79	7.2
Company 2	22	133	6.0

The span of control ranged between 6 and 7.2 non-supervisory positions per supervisory position.

6.9 Drivers for Mergers and Reorganizations

The remaining sections of the benchmarking analysis are based on the questionnaires that were submitted by the partners and follow-up interviews that were conducted. This first section deals with drivers for mergers and reorganizations, both past and present.

6.9.1 Western Area Power Administration

The Western Area Power Administration was formed in 1977, when the Department of Energy was formed. Since its inception, Western has merged operations and combined functions in order to increase the efficiency of its operations, as described in section 6.3.3.

Western is in the process of OCI, which combines the functional organizations for Operations (J4000), Transmission Services (J7000), SCADA support (J2600), and Reliability Compliance (G2000) between DSW and RMR. This is the largest reorganization effort Western has engaged in since the elimination of the Operations Center related to CRSP, which occurred about 15 years ago. The reorganization was executed for these main strategic reasons:

- To increase the organization's ability to eliminate the need for Alternate Control Centers (ACC) that supported the CRSP, DSW, and RMR power systems. OCI will result in the Loveland and Phoenix control centers backing each other up, which will reduce costs associated with maintaining the ACC facilities, and will result in more robust backup centers, which enhances power system reliability.

- To increase the organization's ability to adapt common business processes and IT tools, including SCADA and Operations tools, between these organizations. This will reduce costs and enhance efficiencies.

- To minimize inefficiencies associated with conducting regulated activities in various fashions by consolidating these functions under a common organization for these regions. Examples of these areas include the OATT functions under the Transmission Services Organization, and the NERC Compliance functions under the Internal Compliance Program.

Various options were considered, including combining the Balancing Authority boundaries as part of this functionality, and including the WAUW facilities under this option. However, based on customer feedback and other factors, Western decided upon the path outlined above.

This is a major effort which is not yet complete. The actions are beginning to have their desired effect, but have resulted in some major challenges. The lessons learned from the process include the following:

- ***Leadership*** – *If management is not on board, it is less likely that employees will buy into the change.*
- ***Justification*** – *Drivers for change must be clearly identified, as well as projected savings.*
- ***Communications*** – *Communication must be consistent, honest, and frequent.*
- ***External Impact*** – *Impacts outside of the reorganized groups must be considered and addressed early in the process. Human resource consultants and change management consultants would be helpful.*
- ***Roles and Responsibilities*** – *Roles and responsibilities must be clearly defined before and after.*
- ***Tools Selection*** – *Process and justification for standardizing tools should be addressed early, with an emphasis on cost impacts and life cycle costs. Choices should not be based on politics, but on facts.*
- ***Budget and Cost Allocation*** – *Costs of the reorganization should be budgeted. Short-term resources should be utilized since employees cannot be expected to have time to implement change while performing their existing responsibilities.*
- ***Culture*** – *Cultural differences between regions must be taken into account.*

6.9.2 Company 1

Company 1 was formed by a corporate merger of two companies about 13 years ago. For the past 12 years, the companies underwent merger transition activity, but this resulted in only minor consolidation of the transmission functions. For instance, upper level management at the Director level was merged into a single leadership position, but the organization remained largely unchanged below that level. Front line leadership was maintained at pre-merger staffing levels, as was operator staffing. One notable exception was the consolidation of the two companies' transmission planning functions under a single manager, eliminating the continuance of two separate and distinct transmission planning groups.

After the initial merger transaction, no further re-structuring or reorganization occurred over the next four years. However, the two operations departments collaborated on the selection of an Energy Management System vendor and suite of applications. Several attempts were made to combine efforts on streamlining control center activities, such as training methods, scheduling protocols and procedures, outage management processes, transmission billing, and energy accounting. For lack of compelling drivers to achieve consolidation, none of these efforts bore fruit and may have actually built barriers to future cooperation.

In 2005, Company 1 embarked on a consolidation initiative that would further reorganize the two operating companies, with the goal of producing operating savings for the organization. The Transmission division named a new Director of Electric System Control Operations, and the management (non-bargaining) positions were re-staffed under a new organizational structure. That structure followed a model of separate T&D operations groups, while consolidating the Balancing and Interchange Scheduling operations. Thus, the corporation maintained a separate and distinct group of transmission and distribution operators at each of its two operations centers. Each operations center had its own supervisors and Energy Management System support group. The consolidation occurred within the Balancing and Interchange groups, which were put together under individual leadership positions and physically relocated to the northern operations centers. This action eliminated the balancing and interchange functions that had been performed at the southern operations center. For the first time since the corporate merger of 1999, there was a physical and organizational driver of consolidation within the control center operation. This very quickly produced unification of processes and procedures within these balancing and interchange functions.

In the reorganization discussed above, the new Director of Control Center Operations was given charge of consolidating as much as possible. In this same reorganization, the marketing affiliate organization was combined between the two original entities and centered in the southern office. Therefore, to maintain both functional and geographic separation of Transmission from Energy Marketing, the Transmission Organization was encouraged to locate as many functions as possible in the northern office. Consideration was therefore given to relocating the entirety of TOP to the northern location. While this would likely have led to more attainable efficiencies, the barriers proved too great for this to be achieved. Barriers included the technology, e.g., Map-board and console real-estate, as well as the ability to retain transferred operator personnel. It was decided that the most efficiency could be gained at the least cost and disruption by focusing on consolidating the BA/TSP functions. These required fewer employees and relied mostly on PC-type applications, which would be relatively easy to duplicate in a consolidated fashion in the Northern control center.

Their experience demonstrated that the effect of the changes was close to what was planned. The consolidation of the Balancing and Interchange function produced an efficiency savings of five full-time-equivalent employees. Five balancing operators were given the opportunity to transfer from the southern office to the newly-consolidated BA office in the northern facility, but only two accepted that option. The Company was able to attract two experienced BA operators from external sources, and filled the remaining position with a promotional opportunity within the group.

The most striking and positive change attributed to this reorganization of the Balancing and Interchange group was the commonality that was achieved in processes, work flows, and communications. It immediately became unacceptable to have disparate approaches to job tasks and procedures. Staff members were in a position that demanded a unified approach to the work. Best practices were leveraged, and employees had both stake and participation in the outcome.

The lessons learned from this reorganization include the following:

- Physical relocations of employees are extremely difficult to plan and carry out; however, the co-location of a particular function, when compared to allowing that function to operate separately, does lead to efficiencies and the effective discovery of best practices, as well as fostering high levels of cooperation in the group. Leadership becomes simpler, conflict is reduced, and efficiencies are gained. The downside is, of course, the impact on employees involved in the change. Also impacted are those fellow-employees who may perceive management as being non-supportive; there becomes an environment of uncertainty in job and location stability even among those who are not directly affected by the changes.

- Another key lesson is to ensure that management is crystal clear about the rationale for any proposed change. Mixed messages, hidden agendas, etc., have no part in the communication of pending changes. Employees are better equipped to handle the change if they feel that the decisions are sound, reasonable, and consistent with the mission or strategy of the organization. In short, there must be an environment where leaders who will implement the change: (1) buy in to the new direction; (2) agree to disagree and are nevertheless willing to lead in a direction that may be contrary to their own preference; or (3) if the above two cannot be achieved, separate that leader from the change altogether.

6.9.3 Company 2

Company 2 was formed between 1997 and 2000 by two mergers involving three companies. There was very little reorganization of the BA functions, transmission operations, and transmission service provider functions. The company kept three managers over the three previously existing operations, and had them report to a director responsible for all three operating companies. The biggest changes were with the formation of an RTO, which would eventually include one of the operation centers, and an ISO, which included another.

The ISO took immediate responsibility for the tariff administration, and eventually developed a full market that collapsed all twenty-seven balancing authorities into a single BA. The twenty-seven BAs became LBAs within the ISO. The LBA operators are responsible for ensuring proper load and tie-line accounting.

The RTO immediately took on the role of the tariff administrator and has created a balancing market that will move toward a full market like the ISO. The operations center under the RTO is still is a BA Area until the full market is implemented.

6.10 Impact of Mergers and Reorganizations

Each of the organizations provided the following input regarding the impacts of restructuring and reorganization on its employees.

6.10.1 Western Area Power Administration

These benchmarked functions, as well as the various functions they interact with, are in various states of adapting to the cultural changes imposed by the ongoing OCI. Input has been solicited from employees as part of this analysis.

The employees that were interviewed all recognized that the changes in the electric utility industry would require organizational changes as well to stay competitive. Many felt that the most recent change could have been better managed, as discussed in the lessons learned in Section 5. With that said, some employees embraced change, while others did not. This is one of the cultural differences that need to be considered and addressed in future reorganizations.

Many employees felt overworked during the change process because it only added to their existing responsibilities.

6.10.2 Company 1

The initial response of the employees on both sides of the BA function consolidation and relocation was negative. Obviously, those employees who were directly impacted by the relocation of their positions were upset and distraught. But even those employees who performed TOP functions, and were "unaffected" by the change were troubled. They felt that this was an unnecessary organizational change and likely feared that more was to come. The proposal was viewed as an indication that something was wrong with how they had been performing their jobs, and a natural instinct of defensiveness arose. Also, at the outset of the implementation of the change, there was considerable friction between front line leaders of the two organizations – a power struggle of sorts.

As new leadership was introduced into key positions within this reorganization, employees initially had a mistrust of the unknown, but quickly came to develop a trust that was ultimately necessary to be successful in the organizational change. A few employees remained whose negativity toward the change proved to be cancerous to the environment. Very quickly, however, employees moved from a position of certainty that the changes would fail to becoming participative in the new direction, even leading some of the change management. Front line leadership had to be very active in daily operations to ensure consistency of operations and to help the team make decisions about how best to proceed on a variety of issues and tasks.

Today, many of the affected operators are of the opinion that the changes initiated in the 2005 reorganization of Balancing and Interchange were not only good decisions, but that further consolidation might be in order.

6.10.3 Company 2

The initial merger had very little impact on operations, but there was some uncertainty among the staff as to whether the control centers were going to be combined into a single control center or left as they were. Lessons learned include being clearer on the long range goal of the company with regard to the operations centers.

Over the last ten years, enterprise-wide tools, policies, and practices were implemented across the four transmission control centers and three operating companies to drive towards consistency. These enterprise-wide tools, including the Daily Log and EMS, may have minor modification to accommodate regional practices.

6.11 RTOs and ISOs

6.11.1 Western Area Power Administration

Western has considered participating in RTO/ISOs. Two major efforts Western is engaged in now are:

- A study of the impact that joining the CAISO would have on SNR's customers.
- A study regarding options for Western's transmission system in the Eastern Interconnection, including a review of potential impacts from:

- joining MISO;
- leaving Western's transmission outside MISO and SPP, but placing generation assets inside the MISO and SPP market;
- joining SPP; and
- status quo (none of the above at this time).

Western's decision whether to join an RTO/ISO would be motivated by the estimated benefits and cost impacts, including both actual costs and potential forgone revenue/costs from market participation. It is also influenced by customer input on matters such as impacts joining would have on their own transmission systems or generation assets. There are also potential statutory limitations to consider, as it is a federal agency governed by Reclamation Law.

6.11.2 Company 1

Company 1 has stayed engaged in RTO development activities over the past decade. This participation has been driven by the purpose of ensuring its interests are protected and ensuring due diligence consideration of all reasonable business opportunities.

In general, the reluctance to promote membership in an RTO organization is based on conclusions that the RTO model, with its attendant costs, will not provide a sufficient financial earnings margin to justify the risks. Included in these concerns is that of the risk of market dispatch outcomes that would potentially price the company's relatively new generation fleet out of the market, thereby precluding a fair recovery of capital investment in these facilities.

Company 1 continues to keep a close watch on RTO activity, but would need to see a compelling business case that would guarantee returns in excess of the existing structure.

6.11.3 Company 2

As part of the merger settlement agreement that formed Company 2, two of its operations centers became members of one ISO and one RTO. Its experience in these organizations has generally been positive. Joining these organizations did not result in significant staffing changes at its operations centers since Company 2 still requires employees to verify the actions of the ISO/RTO.

Company 2's second operations center remains outside an RTO and ISO, but would join one if it were determined to be in the company's best interest.

6.12 Industry Changes

6.12.1 Western Area Power Administration

Renewable generation integration, energy imbalance markets (and the associated Enhanced Curtailments Calculator), and FERC-1000 are all major efforts with significant potential impact. In addition, Western has the following concerns:

- Impact of FERC’s ruling regarding Bonneville Power Administration’s variable generation curtailments in light of OATT comparability requirements.
- Impact of FERC's decision on locational exchanges in the PPL filing and what that will mean to Western's displacement and exchange arrangements with a variety of firm electric service customers.
- Ongoing and expanding NERC reliability compliance requirements and demands.
- Continued pressures to adapt to changes imposed by RTOs and ISOs, whether or not they are member participants of these organizations.
- Intra-hour scheduling in shorter time-frames.

The ongoing OCI efforts and Western Operations Review study effort are two major examples of measures underway to help them position Western effectively for these upcoming changes.

6.12.2 Company 1

As mentioned above, “RTO-esque” initiatives, such as the EIM program and others, are cautiously approached at this time. In order to protect its interests and ensure that it adequately considers all opportunities, it is closely monitoring the developments of these initiatives. Were these (EIM, for instance) proposals to come to fruition, Company 1 has the potential to drastically change the operation of the Interconnection, with or without its direct participation.

Its strategy in dealing with the proliferation of renewable generation, particularly of the intermittent nature (wind and solar), is to maintain sufficient flexibility with existing resources and planned resource alternatives to be able to react to changes on the horizon. The seemingly unabated charge toward high penetration of intermittent renewable resources causes concern, and due caution is in order to ensure that limits are imposed such that system reliability is maintained. Company 1 must allow for the possibility that the extreme cost of the resources and their subsidies may eventually bring about a change of national policy and potential shift back toward conventional resources. To hedge its bets, the industry would be best served by maintaining a high degree of diversity in energy supply technology.

If intermittent renewable generation develops to the high penetration levels that some are projecting, some degree of BA consolidation, or more likely cooperation, will become necessary. To effect these changes, communication and control technology will play a key role in preserving reliability of the grid.

FERC Order 1000 focuses on the planning of regional transmission projects and the allocation of costs across the population of entities that derive benefits from the projects. In the near term, implementation of Order 1000 is believed to have a potential impact to the operating environment through time delays in the construction of key transmission projects for reliability. These delays are inevitable when introducing the complication of complex and controversial cost-allocation regimes. It is likely that the industry can work through these complexities, however, in the short-term; some reliability may be sacrificed as needed transmission projects are held up by contractual disputes. To prepare for this effect, higher margins of reliability may be necessary in the near-term.

6.12.3 Company 2

Company 2 is positioned well to move the OC2 system into a mature market. It has learned much with the formation of its ISO and RTO that will help it with design and implementation of the market that it anticipates will develop for its remaining operations center. As far as renewable generation, Company 2 is a leader in the industry with about 700 MW of wind on its OC4 system, 1500 MW of wind on the OC1-2 system, and 1800 MW of wind on the OC3 system. Except for local transmission constraints resulting from the wind integration into the market, the formation of its ISO and RTO markets has been beneficial for OC4 and OC1-2. The higher penetration of wind in its OC3 system, without any developed market, has brought operational challenges for OC3. Company 2 feels that its participation in its RTO and ISO has been beneficial in accommodating the influx of renewable generators.

6.13 Back-up Control Centers

6.13.1 Western Area Power Administration

Each of Western's four operations centers has a primary center and an un-staffed backup control center. The BUCCs are located far enough from the primary center to avoid being uninhabitable for a likely event that would cause the primary center to be uninhabited, but close enough to meet the NERC standard requirements for continuity of operations. The BUCCs each replicate the necessary computing and control functionality in order to perform the essential duties of the respective primary control center functions. The BUCC facilities are considerably smaller in square footage and have no wall-board/map-board facilities. The BUCCs are each located at company facilities; however, the centers themselves are not manned. Each of the BUCCs is routinely used to demonstrate their ability to operate the system.

RMR and DSW are in the process of consolidating their operations facilities under the OCI program, and will eliminate their respective backup facilities when this is complete. Both the Loveland and Phoenix operations centers will be continually manned and have the ability to back up the other operations center if necessary. Elimination of two BUCCs was a primary benefit of OCI.

6.13.2 Company 1

Company 1 maintains two primary control centers and two backup control centers at this time. The primary control center in the south provides Transmission and Distribution operations functionality for the southern territory; the center in the north provides Transmission and Distribution for the northern territory and BA functions for both territories. Each primary center has a BUCC in its respective city. The BUCCs each replicate the necessary computing and control functionality in order to perform the essential duties of the respective primary control center functions. The BUCC facilities are considerably smaller in square footage and have no wall-board/map-board facilities. The BUCCs are each located at staffed company facilities; however, the centers themselves are not manned. The functionality exists to perform both TOP and BA functions from the northern BUCC for both north and south systems. Similarly, as long as either the Primary or BUCC is intact in the north, either the Primary or BUCC in the south can be used to perform BA and TOP for both entities.

6.13.3 Company 2

OC3 and OC4 have unmanned back-up centers, while OC1 has a manned back-up center that is also the primary center for the OC2's transmission operations. All back-up centers have full real-time functionality with a supporting plan for non-real-time functions like Energy Accounting.

6.14 NERC Compliance

6.14.1 Western Area Power Administration

Western has a Reliability Compliance Manager that reports to the Chief Operating Officer in the Central Service Office, who in turn reports to Western's Administrator. Each regional office has embedded compliance positions, including Reliability Compliance Managers that coordinate with the Reliability Compliance Manager at the Central Service Office, and have direct access to their Regional Manager. One exception is that the embedded compliance position at the RMR operations center reports to the Reliability Compliance Manager at DSW. Reliability compliance personnel coordinate through a reliability compliance committee.

As discussed in section 6.6, Western has approximately 6.5 positions that are embedded positions directly related to NERC Compliance. In addition, it has an additional six positions for technical writers who spend a portion of their time drafting operating procedures and RSAWs that support NERC Compliance.

Western is continuing to improve its NERC Compliance Program and has plans to reduce the number of registered entities in the future, since each region is now registered separately. There are some benefits to being registered separately, so these issues will need to be considered.

One of Western's challenges is the fact that it deals with two different RROs (MRO and WECC) in two of its regional offices.

6.14.2 Company 1

In a general sense, the activities of NERC compliance are imbedded within all of the staff of the BA/TOP/TP/TSP functions. The vast majority of NERC-related activities are described in procedural documents, which are then executed by the staff members, such as EMS staff, Operations Engineers, Trainers, Operators, Planners, Schedulers, and leadership. As such, it is nearly impossible to identify a specific number of FTEs that work on the activities.

Company 1's compliance program consists of a group of "Compliance Leads" to which a finite number of NERC requirements are directly assigned. Each NERC Requirement has an assigned Compliance Lead. The Compliance Lead's responsibility is to continuously ensure that processes and procedural mechanisms are in place and effective at both carrying out the tasks of the assigned requirements as well as the retention of adequate evidence of compliance. These Compliance Leads have primary responsibility within the organization as leaders, individual contributors, etc., and as such, the duties of Compliance Lead are imbedded in their normal job responsibilities. For instance, the Manager of T&D Operations has a primary responsibility to guide and direct the T&D Operations and lead a staff of operators, engineers, analysts, etc., but in addition to these responsibilities, this individual acts as a Compliance Lead for many of the NERC TOP, EOP, and VAR Requirements. Compliance Leads are also responsible to ensure that, as requirements change through the dynamic NERC Standards Development

Process, procedures for operations and processes for documentation of compliance evidence are continuously configured to ensure enduring compliance.

In rare instances, an individual contributor position is fully dedicated to NERC Compliance. For instance, the Senior Consultant – Procedures and Compliance position was specifically created to develop and manage compliance evidence techniques and to establish and maintain linkages between the procedural documents and the requirements of the NERC/WECC Standards. Similarly, transmission trainer positions would arguably have exclusive dedication to activities that carry out NERC requirements.

From a perspective of corporate oversight, Company 1 has a FERC Compliance department consisting of an Executive, Ethics, and Corporate Compliance person, and a Program Manager. These individuals maintain the corporate oversight to ensure consistent and effective processes are in place to promote compliance with, among other things, the NERC and RRO Standards. Responsibilities also include maintenance of the Corporation's ICP, FERC Compliance Plan, and NERC Compliance Plan. The group provides oversight and review of evidence for key or high-profile requirements – in essence, an internal audit function.

Company 1 has largely had success with this approach; however, of late, it believes that the diligence and ongoing effort required to succeed may be unsustainable. Thus, it is seeking process improvements or potentially incremental staffing to ensure continued success.

At present, Company 1's two entities are separately registered in the NERC Compliance Registry. As separate entities, they encounter a certain degree of duplication of effort, and in some areas, divergence of compliance approach. As pointed out in a combined compliance audit for the Order 693 Standards, many facets of the compliance approach and documentation are out of sync with one another. Through the 2013 consolidation of its two BA/TOP entities, Company 1 seeks to make significant gains toward commonality and consistency of compliance approach.

6.14.3 Company 2

Company 2 is very unique with regard to compliance. The OC1-2 system is under an RRO in the Eastern Interconnection, OC4 is within a different RRO in the Electric Reliability Council of Texas (ERCOT), and OC3 is within the Western Interconnection. Each operating company is subject to compliance audits from three interconnections and three regional entities. The Control Center Managers are the Standard and Requirement Compliance Owners and subject matter experts during audits.

Each operating company has two or three transmission business unit compliance individuals who report to a transmission business unit manager (ten, total) to provide coordination, review, and oversight. Company 2 also has an enterprise-wide regulatory compliance department that reports directly to the VP of Regulatory Compliance (four, total). There is close coordination between the transmission business unit compliance individuals and the regulatory compliance individuals to ensure that Company 2 meets all local, state, regional, and NERC standards.

6.15 Tools

Table O1 summarizes the standardization of tools for the main categories of activities that were benchmarked in this analysis.

Table O1 – Tools Standardization

Activities	WAPA	Company 1	Company 2
SCADA	2 of 4	Y	Y
OASIS	Y	Centralized	Y
Transmission Switching	2 of 4	Y	Y
Transmission Scheduling	Y	Centralized	Y[3]
Real-time, Next Day Analysis	N	Y	Y
E-tags	3 of 4	Centralized	Y
Settlements	Y[1]	Centralized	Y
Compliance Tracking	Y[2]	Y	Y
Training Tracking	Y	Y	Y

Notes:

1) Main tools are standardized. There is some variation by region on other tools. While some regions use the same software, most of the software is not implemented at the Western-wide level without standardization.
2) UGP does not use Team Track. RMR listed some extra tools.
3) Yes, for operations, but uses different tools for scheduling due to different Reliability Coordinators.

Based on data the companies provided, the following observations were made:

- Companies 1 and 2 have almost completely standardized the tools that are used by their various operations centers. Company 2 said that there is some variation in how these tools are implemented.

- Company 2 also had some variations in the tools that were used due to its governance by its ISO and RTO for three of its four operations centers.

- Western had the most variation of all of the partners, especially in the areas of SCADA, switching, and real-time, next-day analysis. In those areas, DSW and RMR have become more standardized due to OCI. SNR and UGP remain more autonomous.

- UGP has the only SCADA/EMS that was developed in-house.

- Western had three in-house tools, while Company 1 only had one. Company 2 had two in-house tools listed.

- Western had the largest number of vendors listed, while Company 1 had the least.

- Company 2 was the only company that was still using a spreadsheet application to track compliance status. Company 2 uses Bentley's Project Wise software for document storage and collaboration.

- Western has attempted to standardize a number of its tools, but the tools are typically not centralized and need to be supported in each office.

6.16 Other Industry Viewpoints

As part of this benchmarking study, other industry viewpoints were solicited from various utilities and agencies. Some were forthcoming and willing to talk, while others were not. Many of the concerns expressed were similar to those expressed by the partners. The following is a short list of observations and comments that were not directly addressed above.

- Susan Kelly of the American Public Power Association (APPA) had an interesting perspective and deep knowledge regarding the future of the electric utility industry and its impacts on public power agencies. Susan expressed a concern about some tension between ideals that fostered the beginnings of public power and a full competitive market.

  Susan does not think that RTOs and ISOs are necessarily a bad idea and remarked that some smaller APPA members belonged to these organizations (such as Pasadena, Riverside, and Anaheim in California). The concern with RTO's, as implemented in the U.S., is that they are not always competitive markets. As currently implemented, some markets allow the exercise of market power and, and at times, outright market manipulation. Several such cases have been brought to FERC's attention, regarding Constellation and JP Morgan.

  Susan also had a concern about Southwest Power Pool and others moving toward a full marketplace. She felt that Energy Imbalance may be only the beginning, in that day-ahead ancillary services and capacity markets will follow. She was concerned that those who are writing the rules for those markets may not be considering the viewpoints of public power companies.

- Gary Tarplee, a former director in the operations and planning groups at Southern California Edison, was also interviewed. Gary had the following insight and comments regarding the establishment of the CAISO, future industry changes and back-up centers and tools:
  - CPUC restructured the electric utility industry in California, requiring the investor-owned utilities to divest of generation and to form an RTO, which resulted in the formation of the CAISO. The purpose of restructuring in California was to increase market efficiencies with the intention of reducing electricity costs to customers.
  - An advantage of CAISO has been greater coordination of transmission planning in the state. CAISO has provided an independent reviewer of the need for transmission projects. Once a transmission project is approved by CAISO, FERC essentially rubber-stamps its approval since an independent organization has already approved the project's need.
  - It is unknown whether CAISO has delivered lower costs to the customers as originally expected.
  - Greater penetrations of intermittent renewable generation will become a driver in the formation of larger BAs to be able to have sufficient diversity among the intermittent resources and to have sufficient amounts and quality of dispatchable resources to be able to manage the intermittent generation.
  - FERC will continue to strongly encourage and incentivize utilities to establish RTOs that will result in better and less costly access to the transmission system.
  - Transmission will be exclusively planned with the approval of regional transmission planning groups.
  - NERC compliance and penalties will become more severe going forward as NERC continues to strengthen the standards and enforcement program.
  - SCE has a fully redundant backup control center that duplicates the functionality of the main control center. It does not have a dynamic map-board, and it does not have the same amount of work area, but it has office space for the real-time dispatch function, outage planning, program engineering, and operating engineering functions. It also has a conference room for control center management to use for office space. The control center staff reports to the backup center on a routine basis and will operate the SCE system from the backup center for a 12-hour shift on a once per quarter basis.

- SCE used the GE XA21 SCADA and real-time analysis tools while Gary worked there. Switching and scheduling were done with in-house Lotus Notes applications.

6.17 Conclusions

The NERC functions and supporting activities performed are very similar for each of the partners. This similarity is a result of the fact that some structural elements, such as the Transmission Switching Desk, are common to all of the partners. With regard to the structural organization, the three options shown in Table Q1 were identified.

Table Q1 - Options for Organizational Structure

Option	Organizational Culture	Management of a specific NERC Function (Centralized or Decentralized)	Location of Employees performing a specific NERC Function (Centralized or Decentralized)
Option 1	Most Autonomous	Decentralized	Decentralized
Option 2	Somewhat Autonomous	Centralized	Decentralized
Option 3	Least Autonomous	Centralized	Centralized

Table Q2 summarizes the Options that each partner applied for the various benchmarked activities.

Table Q2 - Organizational Structure Summary[2]

Function/Activity	Central Supervision		
	WAPA	Company 1	Company 2
Realtime Switching (TOP)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 2	Option 2
Realtime Balancing (BA)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 2	Option 2
Realtime Scheduling (TSP)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 2	Option 2
Operations Support[1] (TOP)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 2	Option 2
Operations Engineering (TOP)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 2	Option 2
Long Term Planning (TP)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 3	Option 2
Tariff Administration (TSP)	SNR/UGP-Option 1 RMR/DSW-Option 2	Option 3	Option 2
EMS Support (inside Ops)	UGP-Option 1 RMR/DSW/SNR-External	Option 3	External
Transmission Settlements	Option 1	Option 3	Option 2

Notes:
1) Operations Support includes technical writers, outage coordinators, and embedded compliance support.
2) Central Supervision indicates the function reports to the same Operations Director/Manager or Transmission VP.

Option 1, which was only identified at Western, is the most autonomous structure. The positions that performed specific activities, such as Transmission Switching, report to Regional Managers who are responsible for all of the functions and activities. Since this structure is the most autonomous, it allows for independent decision-making. In order to promote consistency, Western has several committees that meet regularly to promote standardization where applicable. Since these committees do not carry the same authority as a centralized manager or director, it is sometimes difficult to reach a common ground to promote standardization. Western RMR and DSW have moved to Option 2 with the consolidation of operations and transmission functions under OCI.

Option 2 is a middle ground between Options 1 and 3. In Option 2, the supervision is centralized, but the positions are not. Employees are still located on the "front lines" and have firsthand knowledge of the issues that are important to customers. There is a centralized authority, however, that can decide what standardization is the best alternative.

Option 3 is the least autonomous option. In this case, both the management and the employees are centralized. Since this allows for the least independent decision-making, it is better suited for areas that have strict procedures and criteria. Such areas would also not require much independent decision-making.

This analysis identified the following variations for improving efficiency, which should be considered by all of the partners:

- ***Organizational Structure at the Vice President / Regional Manager Level –*** *Company 1 and Company 2 had a single Vice President of Transmission, with a majority of the BA, TOP, TSP and TP functions under that position.*

Western was the most unique organization in this regard, since the BA, TOP, TSP and TP function primarily report to a Regional Manager instead of a centralized Vice President.

More autonomous structures, such as Western's, can be advantageous for taking quicker action, but may also be less advantageous for establishing common methods and procedures or gaining efficiencies with resources and tools.

- ***Centralized Management*** *– There was a definite trend towards centralized management (Options 2 and 3). If employees who are performing the same NERC functions in geographically-dispersed operations centers, improved consistency in* *procedures and methodologies can be obtained by having these employees report to the same supervisor, manager, director, or vice president.*

Companies 1 and 2 have centralized management (Option 2 or 3) for all of the benchmarked activities. Western has moved in this direction with its Operations Consolidation Implementation.

- ***Geographical Centralization** – As shown by several of the partners, geographical centralization (Option 3) is also a possibility. If the electric systems are too large to combine desks, it is possible that multiple desks for multiple areas can be located at the same operations center. Since this is a costly alternative, both from logistical and human resources perspectives, the "lessons learned" that were described in previous sections would obviously apply to geographical centralization.*

- ***Desk Staffing** – The most common operation desks in this analysis are the TOP, TSP, and BA desks. Because the responsibilities of these desks may vary by the time of day, some innovative strategies for staffing were observed.*

  - *Cross-training was employed in several of the partner companies to allow operators to work more than one desk. Two examples are cross-training in Transmission/Distribution or BA/TSP.*

  - *Staffing a desk for peak hours only and combining responsibilities into one desk for off-peak periods is another efficient strategy.*

  - *Voltage security and transmission security desks that are staffed only during peak hours allow some of the TOP activities to be handled by a separate desk.*

- ***Operations Support** – Support positions such as training, outage coordination, and EMS support were common to almost all of the organizations. Except for Western, these support activities report to an Operations group that reported to a centralized Operations director (Option 2).*

  With regard to EMS support, it was more common for this role to be performed by a group that is not under the Operations director or under the Vice President of Transmission. At Western, a similar situation existed for DSW, RMR, and SNR, where a separate group for EMS support was under the Regional Manager and not the Operations director.

- ***Long Term Planning and Operations Engineering** – There was some minor variation for these activities, but also many commonalities:*

  - *Long-Term Planning and Operations Engineering are generally performed by two separate groups. SNR and UGP were the two exceptions to this rule.*

- *The Operations Engineers report to the Operation Manager or Director.*

- *Except for Western, Long-Term Planning was centrally supervised and reported to the Vice President of Transmission.*

- *Company 1 geographically centralized Long-Term Planning. This function may be more suitable for geographic centralization, since it is focused on a common set of NERC criteria and require less independent decision-making.*

➢ ***Tariff Administration and OASIS Sites*** *– All of the companies operated from a single Open Access Transmission Tariff (OATT). The following variations were noted, however:*

- *Company 2 was also subject to two additional tariffs from its ISO and RTO.*

- *Company 1 has a single combined OASIS, while Western and Company 2 do not. Company 2 is limited by the requirements of its RTO and ISO with regard to its OASIS sites.*

- *Company 1 has geographically centralized the management and employees for its Tariff Administration activities. Since it is governed by a single tariff, this would seem to be a reasonable structure.*

➢ ***Transmission Settlements*** *– This activity had significant variation in the staffing levels and organizational structure. Companies 1 and 2 have both centralized this function from a management and geographical perspective (Option 3). Company 2 has the Settlements positions reporting to the operations center managers, who report to a centralized director of System Operations (Option 2). At Western, the Settlements positions are completely autonomous. At DSW, RMR, and SNR, Settlements reports to Power Marketing. At UGP, Settlements is located under Operations Support, which is under the Operations Manager.*

➢ ***Renewable Generation*** *– Renewable generation is having significant impact on all of the systems, except for SNR. The percentage of new requests that are renewable resources ranged from 65% up to 100%.*

➢ ***Compliance*** *– All of the partners were concerned about compliance and had a significant number of positions dedicated to that issue. Companies 1 and 2 had a separate compliance group that reports directly to the upper levels of management.*

Western's compliance team reports to each Regional Manager individually, but coordinates through a committee that includes the General Counsel and the Reliability Compliance Manager located at CSO.

Based on the partners in this analysis, centralization of the management of the BA, TOP, TSP, and TP functions appears to be the trend. Geographical centralization of the employees that perform these functions is less common and was focused on activities that had specific criteria or focus (such as long-term planning, operations engineering, or tariff administration). BA and TSP desks were more likely to be combined. TOP desks were more difficult to combine, depending on the complexity of the system, but could be moved to geographically centralized operations centers with multiple desks.

The participants in this study and the other industry participants all agreed that they have seen significant changes in the electric utility industry and will probably continue to see significant changes for the foreseeable future. The trend will be towards larger markets that include energy imbalance, hourly, day-ahead, and capacity markets. Regional planning will become the norm. Organizations need to be structured for consistency over large geographic areas, yet remain nimble on the front lines of customer service.

7 Future Industry Changes and Strategic Initiatives

7.1 Background

During the process of preparing this report, several documents from Western and the electric utility industry were collected. The basics of those documents and options to address projected industry changes and strategic initiatives being proposed are addressed in this section. The DOE assigned some goals to Western as an agency of the DOE. As the executor of marketing the generation from the Federal Hydro Projects, Western is governed by many pieces of legislation relative to marketing and delivering federal power, even as it may be specific to just one project. In addition, Western is operator of a large, loosely-connected transmission network. This transmission is, or could be, key to the development of a system that could benefit the Western United States. Western should be a leader in the effort to strengthen the transmission system in the West.

Although Western operates in both the Eastern and Western Interconnection, this report will be more focused on the facilities in the Western Interconnection or Western Electricity Coordinating Council (WECC). Each of Western's Regional offices operates in the WECC; however, the Upper Great Plains Region has only a small part of its facilities in the WECC. The bulk of its facilities are in the Eastern Interconnection; specifically, the Midwest Reliability Organization (MRO).

A practical barrier to incorporating the transmission facilities of the Eastern Interconnection with the Western Interconnection is the methodology of determining the ATC. The Eastern

Interconnection uses a Flow-Based approach that considers each party's usage of the neighboring systems. The WECC uses a Contract Path Methodology to determine the ATC. Contract Path Methodology may have a path fully subscribed; e.g., the path is being used contractually, and the owner has declared that there is no ATC long before the facilities are physically loaded to their capability. And, in certain instances, the facilities can be physically loaded, but using the Contract Path Methodology, the transmission owner declares that some ATC is yet uncommitted. Flow-Based and Contract Path ATC methodologies are generally not compatible. Several questions arise for Western including:

- Can the parties be moved to a compatible position?
- Are there ways to mitigate the differences?
- Should Western take a position on this?

7.2 Future Industry Changes

7.2.1 FERC Order 1000:http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

The Federal Energy Regulatory Commission has amended the transmission and cost allocation requirements established in Order No. 890. The amendments require that each public utility transmission provider: a) participate in a regional transmission planning process that produces a regional transmission plan; and b) amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and improve coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Order requires:

- Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.

- Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.

This Final Rule was effective October 11, 2011. Each public utility transmission provider is required to make a compliance filing with the Commission by October 11, 2012. Compliance filings for interregional transmission coordination and interregional cost allocation are required by April 11, 2013.

Western appears to have many options. Western can plan for transmission system needs regionally or Western-wide. Western's regions/BAs can plan for transmission system needs regionally with all adjacent transmission providers, or some reasonable combination of the above.

7.2.1.1 Activities for Western

Across Western, the activities required by Order 1000 appear to be in mid-process. The questions below provide a framework for the issues that Western needs to address regarding Order 1000:

- How will Western address Order 1000? Will it be Western-wide or by regional office? Will it be through regional reliability organization participation or participation in an RTO, ISO, or similar organization?
- In a grander picture, what would be the best move to meet the requirements? How many of the requirements of FERC 1000 does Western meet today? What changes could be made to satisfy the remaining requirements?
- Is there a functional structure among Western/customers/neighbors that is better situated to satisfying the requirements?
- Is there a short-term and long-term plan for inclusion of Transmission Facilities of others in the Western Tariff? And the obverse, e.g., is there a short-term or long-term plan to make a physical connection to remote facilities or to move remote Western transmission facilities into the appropriate non-Western tariff?
- Is there a regional transmission option that is agreeable to Western and its neighbors?

7.2.2 Memo from Secretary of Energy Chu – dated March 16, 2012

A memo was sent from the Secretary of the DOE to all federal Power Marketing Administrators requesting that the federal government lead the way for a modern, secure, and reliable electric transmission grid.

7.2.2.1 Implement Western's New Transmission Authorities

Congress, the Department, and Western appear to believe that Western has the authority to move forward with third parties and make necessary improvements to the transmission infrastructure to effect economic transactions and encourage the development of renewable generation. These new authorities are intended to be administered separately from the historic mission of delivering power from the Federal hydro dams. In his memo, the Secretary appears to be pressing Western for more aggressive action under these authorities.

7.2.2.2 Improve Western's Rate Designs

While the intent of this initiative in the Secretary's memo reaches beyond the functions addressed in this report, those that can be related to transmission will be discussed. One key seems to be for Western to take actions that will minimize rate pancaking in its service territories. In addition, rate structures and operating procedures for the transmission system should incentivize the following: energy efficiency programs, demand response programs, integration of variable resources, and preparation for electric-vehicle deployment.

7.2.2.3 Improve Collaboration with Other Owners and Operators of the Grid

In each of its regions, Western operates a transmission system with its neighboring transmission providers. These combined systems make up the grid. It is imperative that all of these system operators work together constructively to maintain a reliable and effective grid. These operators are representative of both public and private power, and for a reliable and effective transmission system, all parties must cooperate, coordinate operations, and participate in regional planning. This is an affirmation of FERC Order 1000.

Economic benefits are to be gained by all parties working together. It is critical that Western identify those benefits and inject that information into the discussions. Western should also facilitate the improvement of collaboration with the other owners of the grid.

7.2.2.4 More Activities for Western

- What are the barriers to implementing Western's new transmission authorities?
    - Concern for cost recovery?
    - Over-whelming task?
    - Commitment by the parties involved?
    - Resources (and funds) available that are outside of Western's operational and transmission services' existing responsibilities?
- Is there a usage or funding mechanism that would encourage/accelerate the usage of these new transmission authorities?
- How can Western remove pancaking among the federal facilities? What are the barriers? How can those barriers be removed? Do the examples used in CAISO, MISO,

the IS and other consolidated tariff/rate options provide options to remove rate pancaking between Western's transmission systems? It would seem that the place for Western to start begins with each BA. That is, to develop one transmission rate for all transmission facilities, including non-federal facilities within the BA, then move to the next question. Can a single transmission rate cross multiple BAs/Sub-BAs? This next question has already been answered in Western and by others. It appears that the East/West Electrical Separation is not a barrier to removing pancaked rates as the IS transmission rate crosses that boundary using an AC-DC-AC converter station at Miles City, MT. Therefore, if the systems are interconnected, there appear to be no physical barriers to removing pancaked rates.

- See Bonneville Power Administration Transmission Services "Available Transfer Capability Implementation Document (MOD-001-1a), Effective Date: April 11, 2012." Is Contract Path Methodology for determination of ATC a barrier to removing pancaking? Are Contract Path Methodology determination of Available Transmission Capacity and the physical capability of the system compatible?
- Does rate pancaking across the federal system send the correct pricing signal to encourage the most widespread use and/or encourage appropriate planning and system upgrades? How can the financial/philosophical differences be mitigated? Again, examples exist of this being done in CAISO, MISO, the IS, and other systems.
- Primary concern for the project appears to be cost recovery. Is there a short-term and long-term plan for inclusion of others' Transmission Facilities in the Western Tariff that ensures appropriate cost recovery for all? And the obverse, e.g., is there a short-term or long-term plan to make a physical connection to remote facilities or to move remote transmission facilities of Western into the appropriate non-Western tariff, and yet ensure cost recovery?
- Is there a regional transmission/tariff option that is agreeable to Western and its neighbors?

7.2.3 Encourage the Integration of Renewable Generation

Several options have been suggested to encourage the inclusion of renewable generation in the resource mix of the system. Are current transmission operating and support conventions the limiting factor for inclusion of these intermittent generators in the mix?

7.2.4 Intra-Hourly Schedules

By moving to intra-hourly schedules for generators and loads, would that allow providers greater options/choices for matching generation and load without leaning on ancillary services?

This could be a benefit to the Federal generation system, as it would put the burden back on the resource providers to match generation to load within a smaller time period, and lesser imbalance energy amounts could result.

7.2.5 Cost Causation Rate Designs

Are transmission and ancillary service rate designs unfairly shifting costs to the intermittent generators? Is it possible that intermittent generation and intermittent loads are related? Should the transmission cost of supporting intermittent generation be assigned to loads that do not follow generation? This may seem a silly discussion, but in cost causation rate designs, certain assumptions are made, and it is forgotten that many assignments of cause are related to "who was first." Maybe those discussions should re-examine the processes and define appropriate assignment of costs that encourage the most wide-spread use and send the correct pricing signals to encourage the development of available resources.

7.2.6 "The Future of the Electric Grid – an Interdisciplinary MIT Study - 2011" http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml

This report and its conclusions support FERC Order 1000. The discussion in that document could be of benefit to Western's planners as they work their way through the issues.

7.3 WECC Strategic Initiatives

7.3.1 Energy Imbalance Market in WECC. (Western should be a leader.)

- Western has chosen to participate. Is Western situated/staffed to be a leader? What are the barriers to Western being a leader in this effort? Western needs to determine its role and objectives in its participation.
- Are there differences in administration of the Western tariff from BA to BA? Are multiple BAs/Sub-BAs barriers to combining tariff/rates? Why do some BAs have multiple rates, and are the Tariffs treated the same across all rates in the BA?
- How does Western fit into the Market? What would be the role of Transmission, and what would be the role of Power Marketing?
- Does the Market provide opportunity? Will Western need support from the Market? Would it have surplus resources that could benefit from the Market? Could it resolve the issue of providing ancillary services with federal resources?
- Western has one OATT. If it were to move to EIM, would it be better situated if it combined appropriate facilities under one Tariff/Rate? Would combining neighbor facilities under a single tariff and rate better position Western and its neighbors? If there are differences in the rates/usage, how will the impacts among the projects/neighbors be mitigated?

- What functions or structures is Western using now that are market friendly; which functions or structures are not?
- Will the Market compensate for benefits provided, including benefits provided today that are uncompensated? Will the initiative commandeer facilities whose usage will not be compensated?
- Would some projects benefit more than others? If Western joins as a unit, how does it share benefits among the projects?
- What are the positions of Western's customers and neighbors on the initiative? Are they accurate in their interpretation?
- If this is a "First Step to a Market," is Western able or in a position to lead this to a good point? E.g., if the "First Step" is expanded beyond a transmission market, is Western able to ensure that the benefits of the Federal Generation Resource will go to the intended beneficiaries?

7.3.2 NERC/WECC Standards Compliance

- Areas of liability keep expanding.
- Compliance requirements are uncertain.
- An increasing demand is present for human resources to manage compliance and to complete requirements established by Standards. (FAC, PRC, PER, TOP)
- An increasing demand is present for participation in NERC/WECC processes, committees, sub-committees, work groups, etc.

7.4 Western Strategic Initiatives to Consider

7.4.1 Positioning Western to Face the Challenges

- Would alternatives suggested in this report aid Western in meeting its strategic initiatives?
- Western as an organization should adopt medium- and long-term strategic plans.
- Regional marketing plans should be assessed annually and updated as necessary to adapt to an evolving industry with a goal of creating a single marketing plan with attachments/sections for each region.
- Create a standing business practices review team that will assess and evaluate Western's functional areas, X0000, X1000, X2000, etc., on an annual basis.
- Utilize the results of the previous three elements to perform an annual assessment and provide recommendations to create an annual plan for accomplishing strategic goals. The annual plan would incorporate a 10-year planning horizon.

7.4.2 Common Tariff Expanded

Expand the common Tariff to include:

- Common rates under the Tariff
  - Consider the six cost allocation principles in FERC Order 1000 to bring together the rates in each BA; each planning region; and intra-regionally, or across the whole reliability organization.
- Common Administration of the Tariff

7.4.3 Common Compliance and Oversight Program to Track Regulatory Changes of NERC/WECC/MRO

- NERC PER-005 Implementation

7.4.4 Common Policy on Market Participation

- Is this a merchant function-driven issue?
- Evaluate benefits/costs relative to Operations/Transmission and similarly for merchant function.
- Another issue that UGP faces over the next few years is whether it will need to join an RTO/ISO.
  - The basic issue is that, with organized markets to the south SPP, east and north-east MISO, and limited transmission to the northwest, Sask Power (via phase shifting transformer) and west, West Interconnection (via AC-DC-AC ties) leaves it with limited marketing partners. At this time, UGP has not made a decision to join either RTO or ISO. Based on discussions with neighbors and its initial review of MISO processes, it is not clear that joining an RTO/ISO would have significant impact to the operations organization staffing levels. UGP could retain the transmission switching operation, a portion of the BA responsibilities, and a significant responsibility dealing with interconnections, facility studies, and planning within its BA. The Transmission Owner in MISO handles all transmission switching. As a consolidated BA, MISO handles most of the NERC Standard's BAL requirements; however, the Local Balancing Authority (LBA) remains responsible for establishing and maintaining all tie lines, metering, and checkout. Based on this responsibility and the Joint registration with NERC, the LBA remains responsible to comply with all other NERC Standards dealing with BA requirements. The Transmission Owners in MISO retain a very active role in the MISO interconnection process and service requests that include system improvements. Also, some of the entities in MISO have eliminated their real-time merchant functions and turned over real-time operations of the generation to the reliability function. However, those entities have not decreased their merchant FTE, but have converted the FTE used for the real-time desks to cover

settlement processes. UGP has not decided what it should do; however, this could result in the transfer of some of the work currently performed in the merchant function to the AGC/BA reliability function. Based on that statement, current thoughts are that joining may result in some impact to the staffing on the AGC/TSS desks, depending on how it deals with the real-time merchant responsibilities.

7.4.5 Transmission Settlements Function Review

- Transmission settlements is not a clearly defined function across Western.
- Transmission settlements function is currently integrated in the billing or power marketing function for some regions.
- As Western may interact more closely with a market, the work load will significantly increase. This can be seen in the regions interacting with the MISO and CAISO.
- As the regions other than RMR implement real-time energy imbalance accounting, an increased workload in the transmission settlements area will result.
- Transmission settlements costs are not, in all instances, recorded as Transmission or SOLDM costs in the Accounting System.

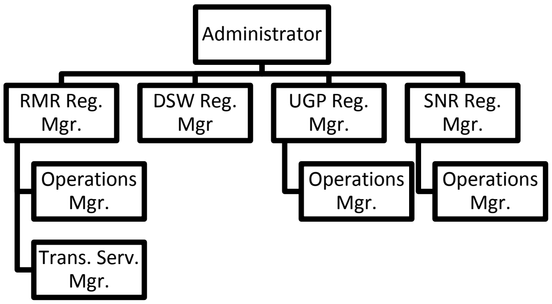
8 Assessment of Alternatives

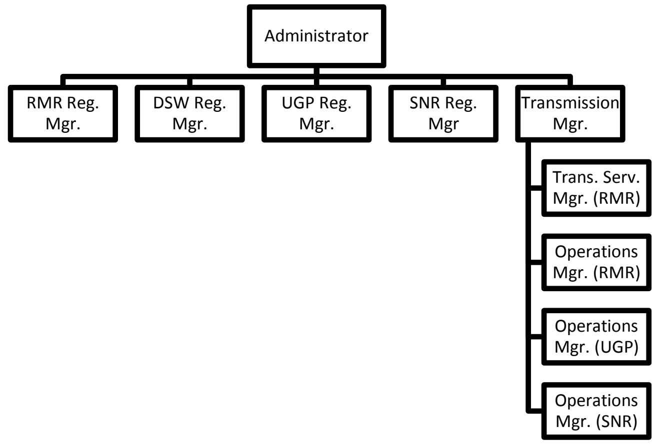
8.1 Structural Changes

8.1.1 Centralize TOP, TP and TSP Functions Under a Single Senior Manager

8.1.1.1 Organizational Structure

This alternative would place each of Western's Operations/Transmission Services Managers under the direction of a single Senior Manager who would be responsible for all transmission operations functions. This new structure should also include transmission settlement functions. Under this concept, each operations/transmission services office would have a manager who reports to the Senior Manager, and the Senior Manager would in turn report to the Administrator. The proposal also seeks to place the Electric Power Training Center within this new organization, as well as Headquarters-based Open Access Same Time Information System (OATT) and other operations support personnel.





Existing Org. Chart

Alternative Org. Chart

Note that these high-level organization charts do not reflect the inclusion of transmission settlements, transmission rate design, the EPTC training group, and other transmission support personnel within Western's Headquarters in the new transmission organization, but they are included as part of this alternative. A more comprehensive organization chart of this alternative is included in Appendix C-4.

8.1.1.2 Discussion

Western's transmission operations department is currently organized based on historical U. S. Bureau of Reclamation and Corps of Engineers-defined river basins. This was a reasonable organizational structure that also followed specific congressional approval of various river basin projects. This structure assigned the responsibility for repaying the project costs, including transmission facilities, to the regions in which they were located. Each project had unique characteristics, and Congress identified who, what, how, and when the projects would be repaid. Generally, specific direction on how the transmission investment was to be repaid was lacking, and this permitted each region to determine how it would meet the congressional mandates for repaying the transmission investment. This led to numerous regional differences on how the transmission is allocated, operated, and repaid.

In 1996, FERC issued the first of many orders that required the promotion of wholesale competition through open access, non-discriminatory transmission services by public utilities. Western's position has evolved to the point that it has agreed to follow such principles with a few exceptions that tie back to the mandates in the congressional authorization of the projects. Western, for the most part, has been meeting the FERC requirements and has filed a single

Transmission Tariff that applies to all of the projects. Each of the regions has interpreted and implemented the single Tariff in various ways, which has led to some confusion and other electric utilities questioning whether Western is meeting the FERC requirements. Management of the transmission system under a single manager would lead to a more consistent interpretation and implementation of Western's OATT.

Additionally, on August 8, 2005, the U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" that would span North America, with FERC oversight in the U.S. The legislation stated that compliance with reliability standards would be mandatory and enforceable. Western has allocated many resources and expended great effort to develop systems and processes in order to meet these reliability standards. The standards continue to evolve, and constant effort is needed to ensure that all reliability standards are met. The allocation of additional resources to meet these compliance requirements has put a strain on Western's ability to complete all of its required functions, particularly operations. The creation of a single organization responsible for all transmission functions could help alleviate some resource limitations by combining similar functions and eliminating duplicative functions in each of the regions.

Regional responsibilities for operating the transmission system have required similar operations centers to be established in Watertown, SD; Loveland, CO; Phoenix, AZ; and Folsom, CA. Each of these offices has dispatch desks for Transmission Switching and Operation, Transmission Scheduling and Security, and Load Balancing or AGC. Each office also has an operations engineering, transmission planning, transmission settlements, transmission, and ancillary service rate design, along with other support functions associated with the operations centers. The OCP combined the Phoenix and Loveland operations centers under the management of a single organization to take advantage of similar function resources. A single organization responsible for all of Western's transmission operations could lead to a more efficient utilization of dispatch, transmission planning, transmission rate design, transmission settlements, and other operating resources.

Operations' training is another area in which each office is responsible for its own training. These activities have proven not to have been coordinated as well as possible. Combining all of the training into a single organization could improve the efficiency of the training program. A single program could be developed to prepare and train for changes.

The EPTC has been a useful organization in support of operations, but it is often unable to support the individual regions as much as necessary. Having the EPTC under the direction of a new Senior Manager could help ensure that the center is more responsive to specific needs within the organization. Each office currently develops its own dispatch intern program, and the EPTC could be a useful tool to identify a single program that could work for each office.

The regional responsibilities for planning the transmission system have required similar transmission planning offices be established in each region's offices. Although there are regional coordination considerations, Western has not been able to maximize the efficient use of planning resources to plan transmission systems across all of Western's 15-state geographical territory. A single organization responsible for transmission planning could lead to more efficient utilization of planning resources. A centralized transmission planning function could also put Western in a better position to help achieve the DOE's goal of Western utilizing its new authority under the 2009 American Reinvestment and Recovery Act to facilitate capital improvements in the transmission system. It would also promote more cooperation and collaboration with other owners and operators of the transmission system.

The regional responsibilities for repaying the projects have also led to each region creating its own transmission settlements organization. Consolidating the settlements organizations could lead to more efficient utilization of resources, as well as ensure that this settlement function is uniformly implemented according to Western's OATT.

In addition to each office having a transmission settlements group, it also has a rates group that designs and calculates the transmissions rates and associated ancillary service rates. It is recommended that Western look at centralizing a transmission rates group within this new organization. This could also lead to a more efficient transmission rate group structure and a rate design that better meets the changing needs of the electric grid. This new rate group could also be more proactive in designing solutions that could minimize transmission rate pancaking. Consideration should also be given to the creation of a centralized transmission and ancillary service rate group.

The autonomous nature of Western's regions has also led to the purchase and development of numerous tools to perform the required functions in each of the groups described above. It has been demonstrated numerous times that, due to the independent nature of Western's regions, it is very difficult to achieve common tools among them. A great deal of this difficulty lies in the fact that each region has been permitted to decide what special modifications it will require. A single organization for operations and transmission services could facilitate more common practices and procedures that could lead to supplementary common tools and the associated cost savings for bulk purchases of those tools. This could also facilitate minimal tool customization for a specific region's needs.

Each of the alternatives listed below could be achieved without the consolidation of operations and transmission services into a single organization under a single Senior Manager, but will not achieve the efficiency that a single organization provides. A single organization could much more easily implement changes that Western desires in order to meet the changing nature of operations. A single organization could also lead to implementation of any or all of the recommendations listed below. Previous Western reorganizations, including Transformation and the OCP, have demonstrated that regional reorganization is beneficial. It should also allow for the most efficient use of Western's limited resources.

Each of Western's partners who participated in this study had undergone previous mergers and reorganized their structures so that the transmission functions were under one or two senior (vice-president) manager(s).

8.1.1.3 Regional and Customer Impact

The regional managers would no longer have direct control over the project’s transmission system that they are currently responsible for operating. Additional coordination and communications would also need to be established between the new organization and the regions. In addition, each of the transmission rates groups would need to be closely coordinated with so the rate processes would match any recommended changes in the implementation and settlement processes. This could also lead to more efficient transmission rate group structures, including the formulation of a single transmission rate group within the new organization.

Some of Western's transmission customers may feel that they do not have as much influence in the process as they did under a regional organization, but the new organization should still implement processes that would consider their comments and input. Western's OATT requires that all transmission customers have the same open access, and a single organization would treat them all equally.

8.1.1.4 Compliance

A single organization should be in a better position to more efficiently meet all operations and transmission NERC reliability standards, as well as OATT requirements, since the entire group would achieve compliance in a similar manner with similar processes. Compliance could also be achieved with a minimum amount of resources since duplicate functions would not need to take place. A downside for a single program could be a greater sanction for a non-compliance issue since the system size and number of violations within a given time period often determines the sanction level.

8.1.1.5 BA and Footprint

Footprints would initially remain the same, but could evolve, depending on which functions the new organization reorganizes or consolidates. Footprints for various NERC functions could be different. For example, BA functions do not have to align with TOP or PA functions. Systems that would keep projects "whole" financially, even with changes in operational characteristics, would need to be developed.

8.1.1.6 Human Resource Impacts

Initially, the only direct impact on the employees would be the reporting chain. Employees could be impacted later, depending on reorganizations and consolidation of functions. The new organization would need to review and prioritize what parts of the organization would be changed and when such changes would be initiated. Decisions would also need to be made on how support services, such as human resources, procurement, property, administrative support, and budget will fit within the new organization. Refer to the OCI Lessons Learned for further considerations.

8.1.1.7 Integration of Renewable Resources

A single organization would simplify the process for potential renewable resource transmission customers to engage in Western's processes. The existing regional systems may require them to go through multiple regions' processes, where this new single organization would involve a single process.

8.1.1.8 Industry Changes

Regions as individual organizations have generally been too busy performing their required functions to look in detail at Western-wide initiatives. A single organization would lead to thinking more functionally instead of regionally, and would enable Western to be in a better position to respond to industry changes.

The electric utility industry has rapidly-changing requirements, and a single organization would allow for a more efficient use of resources to follow and respond to those changes and proposed changes. Western could also be seen to have more influence in the direction of the changes, as representatives could better represent the entire organization instead of an individual region.

8.1.1.9 Risk Analysis

Western has a fairly high level of risk today in meeting all of its required political, regulatory, and customer demands. Sometimes these conflicts are regional. Resources are in short supply, and non-compliance is not an option.

Moving to a single operations and transmission services organization could be detrimental to Western customers' political support. Another risk is of customers and employees not "buying into the process." Western's regional independent culture could impair the success of this new organization.

8.1.1.10 Cost Analysis

Although cost reduction is not the driving factor in this reorganization, long term efficiencies could lead to significant savings down the road. It is contemplated that any efficiencies gained would be utilized to meet the ever-changing electric utility environment and minimize the continuing request for new resources.

8.1.1.11 Pros

- This alternative could help meet the Secretary of the DOE's request for Western to "transition to a more flexible and resilient electric grid and much greater coordination among system operators."
- It could also help meet Secretary Chu's request for Western "to take a leadership role in transforming our Nation's electric sector, to the extent allowable under their enabling statutes."
- This alternative would help meet the Secretary of Energy's strategic goal of moving to a more centralized dispatch.
- A single transmission and operations organization would promote greater cooperation and collaboration among the other transmission system owners and operators.
- This would provide consistent tariff management.
- It could lead to more efficient dispatch organizations.
- It would provide more efficient dispatch training.
- EPTC could be better utilized.
- This alternative would provide more efficient utilization of transmission planning resources.

- Transmission planning staff would be better positioned to look at Western's larger geographical area.
- A centralized transmission planning function could also put Western in a better position to help achieve the DOE goals of Western utilizing its new authority under the 2009 American Reinvestment and Recovery Act to facilitate capital improvements in the transmission system.
- This alternative would provide more efficient use of settlement resources.
- A single transmission rates group could more easily change the rate design to be more in line with DOE goals. It would also be a good facilitator to help eliminate transmission rate pancaking.
- This could provide better standardization and less customization of tools - common tools.
- Employees could give greater importance to Western-wide issues rather than concentrating on regional issues.
- Western could meet NERC compliance requirements more efficiently.
- This alternative would provide more flexibility to change operational boundaries such as BA or TOP as desired.
- It would provide more flexibility to shift resources to high priority needs.
- It would simplify the process for potential renewable resource transmission customers.
- It would provide more flexibility to quickly respond to industry changes.
- It would result in greater influence in the electric utility industry.
- It could help minimize risk in a very dynamic industry.

8.1.1.12 Cons

- Western has a long history of regional differences.
- Legislation led to setting up projects with different requirements.
- Some project customers would likely object to this new structure because they would lose some control of transmission issues. Often Western's preference power customers have associated project transmission with project power allocation and desire a greater involvement in transmission issues.
- Some employees have a higher regard for their region than for Western as a whole and could object and not support this new structure.

- Western could probably not point to cost-saving as a justification for this reorganization, although long-term efficiencies could lead to savings down the road.

8.1.2 Consolidate the OASIS System Activities

8.1.2.1 Organizational Structure

Western should consider merging the OASIS systems in all Western Interconnection systems and review whether the Eastern Interconnection system could also be included.

8.1.2.2 Discussion

Each region presently has its own OASIS site and three of the four operations centers uses an OATI OASIS, which would help with the transition. A single OASIS node would display Western as a single entity, rather than each region having an individual OASIS node. The multiple OASIS nodes are often confusing, making it difficult for potential transmission customers to get a "big picture" of Western's available transmission. A single OASIS node may also remove most of the technical barriers that may restrict Western from exploring other Western-wide transmission products in the future. It is understood that Western's Senior Management Team approved the review and implementation of the OASIS consolidation as part of Western's Strategic Targets for 2012, and that it supports this recommendation.

8.1.2.3 Regional and Customer Impact

This should not have a major impact on regional employees or existing customers, other than understanding the new OASIS node.

8.1.2.4 Compliance

A single OASIS should simplify the meeting of OATT compliance requirements.

8.1.2.5 BA and Footprint

This should not impact the BA or footprint configuration.

8.1.2.6 Human Resource Impacts

Extensive expert resources would be required to study and accomplish this transition. The resources would also need to continue to maintain the existing OASIS systems while designing and implementing a new one.

8.1.2.7 Integration of Renewable Resources

A single OASIS would benefit renewable resource providers in that they would be able to go to a single node to determine what transmission Western has available (ATC).

8.1.2.8 Industry Changes

This would be a step forward in preparing for additional industry changes.

8.1.2.9 Risk Analysis

This would add an extensive effort to the already heavily utilized resources.

8.1.2.10 Cost Analysis

A common OASIS system could reduce the overheads and annual charges, but the cost to implement is unknown.

8.1.2.11 Pros

- This alternative would be an initial step in promoting DOE's desire to create new transmission products and rate designs.
- It would help meet the Secretary of Energy's strategic goal of moving to a more centralized dispatch.
- This promotes additional use of available transmission across Western, including renewable resources.
- It decreases possibility of non-compliance issues, as a group of centralized experts will be responsible for meeting all regulatory requirements.
- It could reduce annual cost of maintaining multiple OASIS sites.

8.1.2.12 Cons

- This alternative would require extensive use of expert resources to implement.
- The cost to implement this alternative would also be a disadvantage.

8.1.3 Consider Consolidating TP and TSP Functions Into a Single Organization.

8.1.3.1 Organizational Structure

Western should consider consolidating the TP and TSP functions under a single manager. Any consolidation of TP personnel should include keeping planning staff in each region to ensure coordination with other local and regional utilities. A suggested organizational chart is included in Appendix C-3.

8.1.3.2 Discussion

This would help ensure that transmission planning activities across Western are well-coordinated and consideration given to multi-regional planning. A single TSP organization could lead to improved efficiencies and reduce possible non-compliance impacts. Western would be better able to utilize transmission planning staff to perform multi-regional studies. Partner utilities that had merged with other utilities indicated that these functions were merged under a single senior transmission manager.

8.1.3.3 Regional and Customer Impact

Regional Managers would no longer be responsible for the TSP and TP activities within their region. It is contemplated that they would still have local staff available for consultation. Customer impact should be minimal.

8.1.3.4 Compliance

Consolidated TSP functions could reduce the possibility of OATT non-compliance since all transmission service requests would be handled similarly. Also, a single organization would be responsible for meeting all TP standards and could set procedures in place to ensure reliability compliance.

8.1.3.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.3.6 Human Resource Impacts

Reporting structure could change, but employee re-location could have minimal change.

8.1.3.7 Integration of Renewable Resources

Could simplify the integration of renewable resources through similar OATT processes for contracting for transmission.

8.1.3.8 Industry Changes

Western would be better positioned to accommodate industry change and be more flexible to implement new authorities under the 2009 American Reinvestment and Recovery Act (ARRA).

8.1.3.9 Risk Analysis

Minimal risk.

8.1.3.10 Cost Analysis

The cost to implement is unknown.

8.1.3.11 Pros

- This alternative allows for improved coordination for TP functions.
- It provides additional flexibility to engage in multi-regional transmission planning.
- It would help meet the Secretary of Energy's strategic goal of participating more effectively in regional planning.
- Western would be better positioned to implement new authorities under ARRA.
- This alternative provides for a single TSP process with similar contracting procedures.

8.1.3.12 Cons

- Regional Managers may feel loss of control of planning transmission within their region.

8.1.4 Consider Consolidating the Transmission Security and Scheduling Dispatch Desks

8.1.4.1 Organizational Structure

Presently, five Transmission Security and Scheduling (TSS) desks are located within Western. They include one in Watertown, where dispatchers rotate with their Balancing desk (AGC); one in Folsom; one in Phoenix (recently reduced from two); and two in Loveland. As the industry has matured with the purchase and scheduling of transmission, many new tools and automation have developed. It may be possible to do real time OASIS approvals and transmission scheduling with a fewer number of desks. This function would not be dependent on location, but would need real-time SCADA information from each of the systems.

8.1.4.2 Discussion

It is recommended that Western:

- Do an in-depth analysis of the hourly workload for each of the TSS desks to identify any efficiencies that could be gained by combining the workload into a fewer number of desks.
- Consider historical overtime use in this review and analysis.
- Consider automation changes, such as the WECC Western Interchange Tool (WIT), that are continuing to evolve, and minimize the human contact.
- Consider light workload during the nights.

- Consider impacts of industry going to greater than hourly scheduling.
- Review active and passive approval of E-tags to determine the appropriate manner for approval. Western offices are not consistent on how they handle approvals. Other utilities should be reviewed as to how they are handling the approvals.
- Consider that RMR has responsibility to manage some WECC transmission paths. This function requires skills that other TSS desks presently do not have and would either need to move to another desk or additional training would need to be given to any reorganized organization. Alternative 8.2.1 recommends moving this responsibility to WECC.
- Would also need to consider east side TSS workload and whether it is feasible to include it in any consolidated function.

8.1.4.3 Regional and Customer Impact

Impacts would include: involved TSS employees, transmission settlements groups, and TSP support groups. Further, SCADA and IT would need to make sure that all required information is available to any consolidated function employees. It should not have a major impact on transmission customers, other than they would have "one-stop shopping" for this service.

8.1.4.4 Compliance

This should help to improve OATT compliance since all transmission system activities would be handled in the same manner.

8.1.4.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.4.6 Human Resource Impacts

The main impacts would be with involved TSS and transmission settlement employees.

8.1.4.7 Integration of Renewable Resources

A centralized TSS function would enable entities with renewable resources to more easily schedule the resources across Western's system, as they would have "one-stop shopping."

8.1.4.8 Industry Changes

Western would be in an improved position to manage industry changes, such as increasing transmission scheduling times to more than one per hour. Each individual office would not need to modify its tools and procedures to meet these changes, as they could be done as a single project.

8.1.4.9 Risk Analysis

If all of the considerations listed in the discussion above are accommodated, there should be minimal risk. Identifying how the RMR transmission path management is handled would be necessary. This consolidation would decrease the risk of OATT compliance violations as stated above.

8.1.4.10 Cost Analysis

An anticipated potential is that this consolidation will save one or more desks and result in tool unification. The costs and savings are unknown at this time.

8.1.4.11 Pros

- This alternative would help meet the Secretary of Energy's strategic goal of moving to a more centralized dispatch.
- It provides for more efficient TSS function.
- It could potentially reduce the number of real time TSS desks across Western.
- This alternative promotes the efficiency of single tool application.
- It would improve OATT compliance.
- It would also improve customer "one-stop shopping" for transmission service, including customers with renewable resources.

8.1.4.12 Cons

- Regional Managers may feel a loss of control of the system they are presently responsible for operating.

8.1.5 Organizational Alternatives for Transmission Planning and Operations Engineering

8.1.5.1 Organizational Structure

Currently, RMR has an operations engineering support group separate from the transmission planning group, whereas all other regions have this function included within the transmission planning function. It is recommended that Western assess how best to address operations engineering support and transmission planning.

8.1.5.2 Discussion

RMR's operations engineering support group is separate from the transmission planning group, while all other Western organizations handle the operations support, including next day studies, within their planning function. As NERC standards and associated compliance activities have evolved, requirements to support real-time operations have increased, including real-time and next-day studies. It appears that most organizations' transmission planning staffs are spending increased amounts of time supporting operations and are unable to perform the longer-term transmission planning functions that are required. Separate organizations could increase the efficiency for both organizations.

It is noted that all partners in this study have separated out their transmission planning and operations engineering functions.

8.1.5.3 Regional and Customer Impact

The regions and customers should not see much change.

8.1.5.4 Compliance

This option would reduce TOP and TP compliance risks, as responsibilities would be more clearly defined, with increased time to focus on specific requirements. This would also ensure that the TOP and TP standards are applied in a consistent manner on a system-wide basis.

8.1.5.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.5.6 Human Resource Impacts

Employees may report to a different group, but no relocation would be required.

8.1.5.7 Integration of Renewable Resources

This should not impact the integration of renewable resources.

8.1.5.8 Industry Changes

The industry and regulatory changes are moving very rapidly, and this would allow staff to focus on their aspects of planning or operating changes.

8.1.5.9 Risk Analysis

Minimal risk is seen with this change, although it could point out a deficiency in staffing in some locations.

8.1.5.10 Cost Analysis

This alternative should not create a cost impact unless additional staff or supervision is required.

8.1.5.11 Pros

- Staff should be more focused and efficient in TOP and TP functions.
- This should reduce compliance risks in TOP and TP functions.

8.1.5.12 Cons

- It may require additional staff or supervision/lead.

8.1.6 Establish a Single Operations Engineering Support Group Responsible for Running All Next-Day and Short-Term Studies

8.1.6.1 Organizational Structure

Establish a single Operations Engineering Support group within Western that would be responsible for running all next-day and short-term transmission studies.

8.1.6.2 Discussion

Presently, RMR is the only region that has a separate Operations Engineering Support group. The other regions generally utilize the transmission planning staffs for engineering and operations support, including the running of next-day and other short-term transmission studies. All regions, including RMR, have identified a shortage of staff to properly maintain the transmission model and run the NERC required studies.

RMR's Loveland Operations Center is also the only office that routinely utilizes an Advanced Applications system to run state estimation and contingency analysis. The RMR Phoenix Operations Center has an Advanced Applications system, but has not had the staff to maintain the model sufficiently to run daily studies. SNR also has an Advanced Applications system, but also has not been able to maintain the model consistently to run daily studies. UGP has expressed a need to obtain an Advanced Applications system and is looking into procuring one. Experience has shown that maintaining a transmission model and running daily studies requires a large amount of resources. This proposal would centralize this function.

Advanced Applications programs are generally associated with SCADA systems, but there is no requirement for them to be common. Western could utilize a single Advanced Applications system with back-up that would meet all of Western's needs. State estimation and contingency analysis could be run for all BAs and Sub-BAs from any secured location with a single set of staff. It should be noted that the staff does not have to be consolidated and could be spread throughout Western. Each region's SCADA system would have to provide real-time information to the common model, similar to how the WECC Reliability Coordinators get the data today. Benefits include:

- Minimizing the support needed to run and maintain the system model.
- Central repository (with back-up) for all model data.
- Regions would not have to abandon their SCADA systems and could send real-time data to a central location and alternate.
- All offices are critically short on staff to fully implement and maintain individual Advanced Applications systems.

It should be noted that the Arizona-Southern California Outages on September 8, 2011 Causes and Recommendations Report created by FERC and NERC had no less than seven Findings and Recommendations that dealt with utilities not properly modeling their systems for real-time and next-day studies. The report included the following Findings and Recommendations in this area (numbers refer to report finding numbers):

1) Failure to Conduct and Share Next-Day Studies;

2) Lack of Updated External Networks in Next-Day Study Models;

3) Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies;

11) Lack of Real-Time External Visibility;

12) Inadequate Real-Time Tools;

16) Discrepancies Between RTCA and Planning Models; and

17) Impact of Sub-100 kV Facilities on BPS Reliability.

This alternative would help Western meet these recommendations in the most efficient manner.

8.1.6.3 Regional and Customer Impact

All regions could have staff to run and maintain an Advanced Applications system and could share the benefit of a common topology and model. Each office could share in the maintenance of the model, as well as daily running of state estimation and contingency analysis studies. Staff requirements could be minimized over each office maintaining and running individual systems.

8.1.6.4 Compliance

This organization would enhance compliance by ensuring that daily studies are performed and the model is kept current.

8.1.6.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.6.6 Human Resource Impacts

No staff relocation would be required, but the staff associated with running and maintaining this system would need to develop a greater knowledge of Western's transmission system.

8.1.6.7 Integration of Renewable Resources

Could more easily run daily studies with different resource mixes across Western's entire transmission system.

8.1.6.8 Industry Changes

Enhances industry changes in that only one system model with an associated back-up needs to be maintained, and each region doesn't need to maintain individual models.

8.1.6.9 Risk Analysis

Maintaining a system model that covers all of Western's transmission system is an intensive effort, but should be less than each region maintaining its own.

8.1.6.10 Cost Analysis

Significant cost savings could result from procuring a single system with back-up over each region procuring its own. There should also be a significant staff savings over each office maintaining and utilizing individual systems.

8.1.6.11 Pros

- This alternative would help meet the Secretary of Energy's strategic goal of moving to a more centralized dispatch.
- It would also help Western meet the recommendations included in the FERC and NERC Arizona-Southern California Outages on September 8, 2011 report in an efficient manner.
- Greater efficiency would result.
- This would provide a staff savings over each office having its own system.
- Western's staff would have greater knowledge of the entire transmission system.
- Savings would result from procuring only a single Advanced Applications system for all of Western.

8.1.6.12 Cons

- SCADA data would need to be sent to a single repository and back-up.
- Additional communications systems could be required.

8.1.7 Consider Merging All of Western's Transmission Settlements Functions

8.1.7.1 Organizational Structure

Western's regions support the transmission settlements in various parts of their organizations. RMR has a transmission settlement group within its Power Marketing organization that only does transmission settlements. DSW has a similar group within its Power Marketing organization that is also responsible for some energy settlements, which is considered a merchant function. SNR has a similar structure to DSW, but most of the workload is in the merchant area. UGP does not have a separate group dedicated to transmission and uses a variety of resources all within the operations organization.

This recommendation is to make transmission settlements a function of transmission, either within each region or centralized under a single organization.

8.1.7.2 Discussion

It is believed that some risk is associated with having a transmission function within a group that is also responsible for merchant activities. The nature of transmission settlements involves some discretion and negotiation with other entities on final agreed-upon numbers. As such, it is recommended that this function be located within the transmission organization.

It is also felt that efficiencies may be gained if transmission settlements are done as a centralized function, and possibly some of the settlements and associated billing activities could be spread throughout the month. Currently, staff is very busy during the first ten or so days of the month, and if some of the workload could be shifted to other times within the month, efficiencies may be gained.

If Western chooses to pursue this, it could be initiated with the RMR and DSW regions, as they both already support one transmission organization. This, in itself, could provide a more efficient organization.

8.1.7.3 Regional and Customer Impact

No relocations would be required for this recommendation. If transmission settlements were moved under transmission, but not centralized, staff would remain at their current location, but report to transmission. Note that UGP already has these personnel within operations. If transmission settlements were centralized, Western could utilize resources from each region to perform the function, but they would report to a different structure.

Transmission customers could be impacted either by dealing with different Western staff, or by possible timing changes with some of the settlement and billing practices.

8.1.7.4 Compliance

Transmission settlements reporting under the transmission organization would reduce OATT compliance risks, in that no conflict of interest would exist between merchant and transmission activities.

8.1.7.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.7.6 Human Resource Impacts

No relocations would be required, but personnel could be required to change organizations.

8.1.7.7 Integration of Renewable Resources

This change should not impact renewable resource integration.

8.1.7.8 Industry Changes

Having a centralized function could enable Western to meet industry changes in a more efficient manner.

8.1.7.9 Risk Analysis

Minimal risk.

8.1.7.10 Cost Analysis

Further investigations would need to be done to determine what efficiencies could be gained. Consolidating this function could lead to similar processes and tools for all the regions, which could lead to financial savings.

8.1.7.11 Pros

- This alternative would help meet the Secretary of Energy's strategic goal of moving to a more centralized dispatch.
- It would provide less risk in meeting OATT compliance.
- Tool, processes, and staff efficiencies in combining the task would result.

8.1.7.12 Cons

- Some may see moving this task from Power Marketing to Operations as negative.

8.1.8 Define Transmission Settlements Function and Processes

8.1.8.1 Organizational Structure

No change.

8.1.8.2 Discussion

In our interviews, it appeared that the Transmission Settlement function was not consistently defined, and each office structured its transmission settlement effort differently. There also exists the possibility that OATT violations could occur by staff treating various transmission customers differently, and all of the offices except for UGP handle this function within the Power Marketing group, which also may have Merchant responsibilities. It also appears that expenses for this service may not be appropriately charged. See Section 4.2.4, Transmission Settlements, for more details on this recommendation.

8.1.8.3 Regional and Customer Impact

This alternative would better coordinate and make consistent between regions all transmission settlement functions. All transmission customers would be treated similarly.

8.1.8.4 Compliance

This alternative would reduce OATT compliance risks.

8.1.8.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.8.6 Human Resource Impacts

This alternative would result in better utilization of resources.

8.1.8.7 Integration of Renewable Resources

No impact.

8.1.8.8 Industry Change

Future industry changes would be handled consistently.

8.1.8.9 Risk Analysis

This alternative would reduce Western's risk for OATT non-compliance.

8.1.8.10 Cost Analysis

No cost analysis has been completed.

8.1.8.11 Pros

- This alternative would result in better utilization of resources.
- All transmission customers would be treated equally.
- Better recovery of expenses for this service would result from this alternative.

8.1.8.12 Cons

- Additional resources would be necessary to develop a program and coordinate this function.

8.1.9 Review Compliance Structure

8.1.9.1 Organizational Structure

This proposal would move Western to implementing a single compliance program. A possible organization chart is included as Appendix C-2.

8.1.9.2 Discussion

Currently, three independent compliance programs are located in DSW, SNR, and UGP, with a Chief Compliance Officer located in Western's Headquarters. SNR has the only program that is totally independent of functions under its purview, and it reports to the highest-level Senior Manager. Moving to a single program could enhance Western's compliance efforts. Successful compliance programs have demonstrated that an intensive investment in resources is required, and consolidation of the programs has the potential to more efficiently utilize the resources.

All partners in this study had compliance reporting to a high level official that was independent of the NERC functions that were the subject of this report. This is consistent with FERC's policy for determining penalties.

8.1.9.3 Regional and Customer Impact

Regional compliance programs would be merged into a single program. Although it is anticipated that local compliance personnel would be required, some compliance personnel may have to be relocated. This program should not impact the customers.

8.1.9.4 Compliance

This could enhance Western's compliance program in three ways:

1. Single compliance program;
2. Compliance would not be under the jurisdiction of the groups it is responsible for overseeing; and
3. Could report to the highest-level Senior Manager in Western.

8.1.9.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.1.9.6 Human Resource Impacts

Some compliance personnel may be required to be relocated, but that should be minimal since all regions will need to maintain compliance staff locally. The compliance personnel would need to report to a new organizational structure.

8.1.9.7 Integration of Renewable Resources

This proposal would not have an impact on renewable resources.

8.1.9.8 Industry Changes

Western would be more flexible to industry and standard changes by having a single program rather than three programs, and would be better positioned to track and comment on proposed industry compliance changes as well as implement them.

8.1.9.9 Risk Analysis

Minimal risk.

8.1.9.10 Cost Analysis

A cost analysis has not been completed, but it is anticipated that resource and program efficiencies can be gained by reducing duplication across the regions into a single program.

8.1.9.11 Pros

- A single compliance program would be in place.
- Compliance would not be under the jurisdiction of the groups it is responsible for supervising.
- Compliance staff could report to the highest-level Senior Manager in Western.
- This alternative provides for a more efficient use of resources.

8.1.9.12 Cons

- Regions would not have compliance managers under their own direction.

8.1.10 Consider Reviewing All Dispatch Desk Staffing

8.1.10.1 Organizational Structure

Western should consider doing a review of all dispatch desk staffing and do a comprehensive study of the hourly and emergency workload.

8.1.10.2 Discussion

This review would entail a thorough look at the hourly workload for each desk to determine if it is appropriately staffed. Reviewing all of Western's dispatch offices could reveal areas where efficiencies could be gained. Overtime is used extensively in running a real time dispatch desk and should be included in this review. Many of the recommendations in this report would already include dispatch staffing reviews.

8.2 Regional Changes

8.2.1 Consider Transferring RMR's Path Operator and Associated TOP-007 Responsibilities to the WECC Reliability Coordinator or other Transmission Organization

8.2.1.1 Organizational Structure

The TSS desk in WACM is a path operator with TOP-007 responsibility in WECC. It is the only Western office that has this responsibility. Currently, in the Eastern Interconnection, the RC has curtailment responsibility for the whole MRO. In WECC, several BA/Transmission Operators act as path operators with the associated responsibility.

8.2.1.2 Discussion

This responsibility hinders Western from moving forward with several initiatives that could improve Western's efficiency, including complicating the ability of the Loveland and Phoenix offices to back each other up. It also hinders Western's ability to merge AGC & TSS functions across RMR, or even all of Western. The authors of this report are not aware of any effort to move this function to the WECC Reliability Coordinator, but it is recommended that Western initiate discussions with WECC concerning its taking over this responsibility for path operations. Since the paths consist of lines with multiple owners, Western does not have a NERC obligation to operate them; and since this function hinders Western's ability to reorganize to become more efficient, it should take immediate steps to move that function to another entity. This function also adds risk to Western's non-compliance liability for meeting reliability standards.

Western should survey the other WECC transmission path operators to see if they would be interested in joining Western to approach WECC about transferring this responsibility to the Reliability Coordinator. Western should also seek the support of the other RMR transmission path owners in re-delegating this responsibility to WECC. Western should then approach WECC about transferring this function and point out that there are no NERC requirements for Western to manage multiple owner paths.

WECC has been unsuccessful in developing a WECC-wide plan to manage and curtail multiple owner paths, and it has been left to each path operator to get formal or informal agreements with the other transmission owners on criteria and priority for path management. The path operations complexity has increased in recent years with the addition of renewable and other resources that do not have transmission ownership in the path. Western does not have the authority to direct the re-dispatch of resources that are not within its BA or TOP, and this could hinder its responsibility to mitigate an overloaded transmission path. The WECC Reliability Coordinator has this authority and is the logical place for this function to be located.

8.2.1.3 Regional and Customer Impact

This alternative would remove path operations responsibility from the RMR TSS desk and would open up other reorganization possibilities. Other transmission path owners would be impacted by Western transferring this function to WECC. An alternative would be for one of these transmission operators to assume this function, but it is unlikely that they would agree to do so, with the increased liability of non-compliance.

8.2.1.4 Compliance

Western would no longer be responsible for TOP-007 compliance and would diminish its liability/risk for non-compliance.

8.2.1.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.2.1.6 Human Resource Impacts

RMR TSS desk, operations engineering, and transmission planning responsibilities would be diminished.

8.2.1.7 Integration of Renewable Resources

No impact, other than WECC has more authority to curtail generation than existing path operators have.

8.2.1.8 Industry Changes

Multiple owner transmission path operations should be directed by an unbiased operator, and WECC is the logical organization to do this.

8.2.1.9 Risk Analysis

This alternative would diminish Western's risk for path operations violations.

8.2.1.10 Cost Analysis

Western would continue to participate in developing path operations criteria, but would no longer have the responsibility to implement it. Western has been responsible for absorbing the cost to operate these paths. Path operations utilizes not only TSS dispatcher resources, but also considerable operations, engineering, and transmission planning resources to develop and update the path ratings, develop an operating plan, communicate and negotiate the plan and associated curtailment procedures with the other transmission path owners, and then operate the path under TOP-007 criteria. These expenses should be shared among the other path owners, and this alternative would help to implement these cost-sharing responsibilities.

8.2.1.11 Pros

- This alternative better positions Loveland and Phoenix TSS desks to back each other up.
- It opens up the possibility of combining the Loveland and Phoenix TSS and AGC desks, resulting in improved efficiency.
- It could possibly reduce the Phoenix and Loveland TSS and AGC desks from five to four.
- This also opens up the possibility of combining TSS desks Western-wide.
- Western's reliability compliance risk would be reduced.
- Western would no longer be required to absorb the costs associated with operating these paths.
- The paths across WECC would be operated by an independent party, reducing the risk of a conflict of interest in path operation at any single location.

8.2.1.12 Cons

- None; only the use of resources to negotiate this change.

8.2.2 UGP Takes Responsibility for Operating the RMR Facilities Within the MRO Footprint

8.2.2.1 Organizational Structure

RMR is presently responsible for operating some transmission system facilities within the MRO footprint. It is recommended that responsibility for operations and compliance of these facilities be transferred to the UGP region.

8.2.2.2 Discussion

RMR has some transmission system facilities within the MRO footprint that it is responsible for operating and for meeting all associated NERC standards. Most of the RMR system is within the WECC footprint, where it is registered. RMR has not registered with the MRO and has not developed a relationship with it. Some exposure has been identified for non-compliance since RMR is not registered in the MRO. This alternative would transfer the operating responsibility from RMR to UGP. UGP is already registered in the MRO. Transmission switching could remain with RMR if desired, but under the direction of UGP operators. A review of the reserve sharing arrangements for this sub-system should be undertaken to make sure they are the most efficient.

8.2.2.3 Regional and Customer Impact

This may increase some customer scheduling coordination. RMR maintenance coordination would increase since it would need to coordinate with UGP dispatch. RMR rates group would need to coordinate with UGP on operating expenses. This could increase the RMR transmission customer cost recovery, as this function is not currently being performed or recovered by RMR. There may be a cost shift between RMR and UGP.

8.2.2.4 Compliance

This would decrease the likelihood of a non-compliance finding. Without this change, RMR could be audited by the MRO, which has not been required in the past.

8.2.2.5 BA and Footprint

This change would not involve a BA change. The RMR footprint would exclude facilities within MRO, and the UGP footprint would expand with the east side RMR facilities.

8.2.2.6 Human Resource Impacts

No relocations would be required.

8.2.2.7 Integration of Renewable Resources

This alternative should have a minimal impact on renewable resource scheduling.

8.2.2.8 Industry Changes

This would help meet industry changes, as RMR would not have to keep up with MRO changes.

8.2.2.9 Risk Analysis

Minimal risk.

8.2.2.10 Cost Analysis

Costs would be minimal; only some additional training would be required for UGP dispatchers. See section 8.2.2.3 above.

8.2.2.11 Pros

- This alternative would decrease the likelihood of a non-compliance finding.

8.2.2.12 Cons

- Additional workload and training for UGP dispatchers would be required.

- A possible cost shift to RMR transmission customers could result.
- Additional coordination for both UGP and RMR dispatchers would result.
- Additional coordination for RMR maintenance would result.
- Additional coordination between RMR and UGP rates groups would result.
- Additional coordination between UGP and RMR finance groups would result.

8.2.3 RMR Takes Responsibility for Operating the UGP Facilities Within the WECC Footprint

8.2.3.1 Organizational Structure

UGP has transmission facilities located in both the MRO and WECC, and it is registered in both NERC regions. Most of its system is located in the Eastern Interconnection within the MRO region, but it is required to stay current with WECC changes and practices. This change would move operating and compliance responsibility to RMR. Switching is proposed to remain with the Watertown Operations office, and maintenance would remain with UGP.

8.2.3.2 Discussion

Changing the operating responsibility from UGP to RMR would free UGP from having to register in the WECC footprint and avoid being audited by WECC. It is proposed that switching would remain with Watertown, so no SCADA control would be required at RMR. A number of considerations would need to be reviewed prior to the proposed change. West side resources are utilized under the marketing plan to cover east side load obligations, and the DC ties are utilized to cover this requirement. Additional coordination would be required between UGP and RMR. Customer concerns about possible increased costs with change may also result.

UGP operates two BAs, and future consideration should be given to combine RMR's WACM and UGP’s WAUW BAs. The proposal listed above would enable this to be considered in the future.

8.2.3.3 Regional and Customer Impact

Customer concerns may result from possible increased costs with this change, as RMR operations would be doing work on these facilities.

8.2.3.4 Compliance

This alternative would enable UGP to avoid registering with WECC and undergoing a WECC audit.

8.2.3.5 BA and Footprint

This change would not initially involve a BA change, but could prepare for a WAUW and WACM merger in the future. The UGP footprint would exclude facilities within WECC, and the RMR footprint would expand with the west side UGP facilities.

8.2.3.6 Human Resource Impacts

No relocations would be required.

8.2.3.7 Integration of Renewable Resources

Minimal impact should occur on renewable resource scheduling.

8.2.3.8 Industry Changes

Would help meet industry changes, as UGP would not have to keep up with WECC changes.

8.2.3.9 Risk Analysis

The greatest risk would be with UGP customers concerned about increased costs to them.

8.2.3.10 Cost Analysis

There would probably not be any reduced costs for UGP (no staff reductions) and could expose UGP customers to additional costs from RMR.

8.2.3.11 Pros

- This could possibly enable UGP to avoid registering in the WECC and participating in a WECC audit.
- Having a position to later merge the WAUW and WACM BAs is desirable.
- This could provide resources and reserve benefits for combining WAUW and WACM BAs.

8.2.3.12 Cons

- It would not reduce dispatch staffing.
- UGP customer concerns about cost benefits could arise.
- Additional coordination for both UGP and RMR dispatchers would result.
- Additional coordination for UGP maintenance would result.
- Additional coordination between RMR and UGP rates groups would result.

- Additional coordination between RMR and UGP finance groups would result.

8.2.4 Consider Merging the WALC and WACM Balancing Authorities

8.2.4.1 Organizational Structure

Combine the WALC and WACM BAs.

8.2.4.2 Discussion

RMR operates two BAs, one out of the Phoenix control center (WALC), and another out of the Loveland control center (WACM). Efficiencies may be gained by combining the BAs into a single BA. Benefits include the possible reduction of an AGC desk, more flexibility with resource management, and better utilization of reserves. May also be able to move from being members of, and having responsibilities in, two reserve sharing groups to a single reserve sharing group. Efficiencies may be gained by reducing the need for two AGC desks, but consideration would need to be given on how BA back-up would occur, as the two desks now back up each other. Would probably need to include merging the TSS and AGC desks as outlined in Alternative 8.2.6.

8.2.4.3 Regional and Customer Impact

Transmission customers should not see a direct impact from this merger, but interconnected utilities would see a change. Transmission settlement groups should probably be combined to gain the most efficiency.

8.2.4.4 Compliance

Compliance should not be affected, and Western would continue to meet all requirements.

8.2.4.5 BA and Footprint

The BA footprints would be combined into a single BA.

8.2.4.6 Human Resource Impacts

AGC desk and transmission settlement personnel would be impacted.

8.2.4.7 Integration of Renewable Resources

This could benefit the integration of renewable resources by additional resources being available to regulate with. Industry has long promoted that larger BAs facilitate renewable resources.

8.2.4.8 Industry Changes

Industry and political entities have been proclaiming increased benefit with larger BAs. This consolidation would meet this industry expectation.

8.2.4.9 Risk Analysis

Some Western customers may see this consolidation as another step in RMR "taking over" DSW responsibilities, although it should benefit both BA customers. Any efficiencies should be shared among the regions.

Another risk to be considered would be the possibility of two reserve actions occurring at the same time, if RMR were still a participant in two reserve sharing groups. Would be a justification to strongly consider participation in a single reserve sharing group.

8.2.4.10 Cost Analysis

Tools are already being combined, so no savings would result in that area, but it could help reduce the need for one dispatch desk. There could be additional efficiencies of available resources, and the need for some external purchases for regulation may be eliminated. Some savings may also result from moving from multiple reserve sharing group participation to a single reserve sharing group.

8.2.4.11 Pros

- This would meet industry and political consideration for larger BAs.
- It could result in a possible reduction of AGC desk staff.
- Western may be able to participate in a single reserve sharing group.
- It would help meet the Secretary of Energy's strategic goal of moving to a more centralized dispatch.

8.2.4.12 Cons

- A possible customer perception that RMR is taking over DSW responsibilities.
- Western would need to determine how back-up AGC function would work.

8.2.5 RMR Merges the Automatic Generation Control and the Transmission Security and Scheduling Dispatch Desk Personnel into a Single Organization

8.2.5.1 Organizational Structure

RMR currently has two TSS desks and one AGC desk in the Loveland Control Center, and one TSS desk and one AGC desk in the Phoenix Control Center. This proposal envisions that separate TSS and AGC desks would remain, but staff would be integrated and trained to perform either function.

8.2.5.2 Discussion

The Watertown Operations office has operated the TSS and AGC desks successfully, with combined staff, for a number of years and believes it is an efficient way to staff these functions. This alternative recommends that RMR consider combining the functions into a similar structure. The possible benefits and considerations include:

- Efficiencies to be gained, including the possible reduction of a dispatch desk.
- Dispatchers would be cross-trained to perform either function, and more staff would be available to fill in for rotation vacancies or emergencies.
- Elimination of a dispatch manager position.
- Consideration of the different work and volume of work could spread dispatchers thin. It has been estimated that the two AGC dispatchers are each 50-60% busy, and the three TSS dispatchers may also have some available slack time.
- If the new tools work as anticipated, additional available dispatch time may result.
- This combination could allow BAs to be merged and have a back-up available.
- Consideration would need to be given for a multiple system event, which could be a compliance issue.
- WACM is one of the WECC path operators, but in the Eastern Interconnection, the Reliability Coordinators are the path operators. There is no NERC requirement that WACM has to be a path operator, and consideration should be given to discussions with WECC about transferring this responsibility to others, as outlined in Alternative 8.2.1.

8.2.5.3 Regional and Customer Impact

RMR already has responsibility for all of these functions, and an internal reorganization should not impact organizations outside of operations. Customers should not be impacted by this change.

8.2.5.4 Compliance

Compliance should not be impacted, but back-up and multiple system events should be considered in the analysis.

8.2.5.5 BA and Footprint

The BA and footprint would not change.

8.2.5.6 Human Resource Impacts

AGC and TSS dispatch personnel and one dispatch manager could be impacted.

8.2.5.7 Integration of Renewable Resources

No impact on renewable resources.

8.2.5.8 Industry Changes

Additional staff trained in multiple disciplines should provide additional flexibility for future industry changes.

8.2.5.9 Risk Analysis

As long as WAPA has TOP-007 (path operations) responsibility, there is a risk of combining desks with large events. There is no NERC requirement that WACM has to be a path operator, and consideration should be given to discussions with WECC about transferring this responsibility to others, as outlined in Alternative 8.2.1.

8.2.5.10 Cost Analysis

This alternative could result in a possible savings of dispatch desk personnel and a dispatch manager.

8.2.5.11 Pros

- It provides increased flexibility with dispatch staff.
- It could result in a more efficient use of resources.
- The potential savings of dispatch staff would be a plus.
- The potential savings of dispatch manager would also be a plus.
- It positions WACM and WALC to be combined into a single BA.
- It also provides cross-trained staff for control center back-up purposes.

8.2.5.12 Cons

- This alternative would require significantly increased knowledge and training for dispatchers.
- It could result in possible transmission path operation violations with large events unless path operations is delegated to WECC.

8.2.6 SNR Merges the Automatic Generation Control and the Transmission Security and Scheduling Dispatch Desks.

8.2.6.1 Organizational Structure

SNR currently has one TSS desk and one AGC desk. This proposal envisions that these two functions would be combined into a newly-formed single function. The proposal would have two desks staffed during peak hours, and one desk would be staffed during off-peak hours. Staff would be integrated and trained to perform either function.

8.2.6.2 Discussion

Workload for TSS is not consistent throughout every hour of the week, and this option provides additional FTE for other priority functions. It is envisioned that the TSS and AGC dispatch staff could be reduced from ten to eight, and two dispatch supervisors could be reduced to one, providing a savings of three FTE. The Watertown Operations office has operated the TSS and AGC desks successfully, with combined staff, for a number of years and believes it is an efficient way to staff these functions.

8.2.6.3 Regional and Customer Impact

Minimal regional or customer impact is expected, as all functions will continue to operate similarly to their present configuration.

8.2.6.4 Compliance

Compliance should not be impacted.

8.2.6.5 BA and Footprint

No proposed Sub-BA or footprint change.

8.2.6.6 Human Resource Impacts

Impacted employees will be AGC and TSS dispatchers, along with one dispatch supervisor.

8.2.6.7 Integration of Renewable Resources

This change should not impact the integration of renewable resources.

8.2.6.8 Industry Changes

Cross-trained employees are better prepared for future industry changes.

8.2.6.9 Risk Analysis

Minimal risk with this proposal.

8.2.6.10 Cost Analysis

Savings should include three FTE positions. Additional costs should only be the additional training required for staff to perform both functions.

8.2.6.11 Pros

- This alternative could result in three FTE savings.
- It would produce more efficient usage of resources.
- Dispatchers would be cross-trained.

8.2.6.12 Cons

- None noted.

8.2.7 WASN Collaborates with SMUD for WASN to Become the BA/Operator and SMUD to Become the Sub-BA

8.2.7.1 Organizational Structure

The SNR Sub-Balancing Authority, WASN, is currently within the SMUD-operated BANC BA. This proposal would shift the BA responsibilities to WASN, and SMUD would have Sub-BA responsibilities.

8.2.7.2 Discussion

The purpose of this proposal would be to combine all of the transmission facilities within the BA into a system with a single transmission rate under Western's OATT. A transmission rate would be developed that would include all of SNR's and SMUD's transmission facilities under Western's OATT. The revenue would then be shared so that each participant recovers its investment.

8.2.7.3 Regional and Customer Impact

Impacts would include SMUD and other SNR customers. The CAISO interconnection would change from SMUD to Western.

8.2.7.4 Compliance

The SNR compliance requirements would increase, as SNR would be registered as a BA and be required to meet the associated standards. Its compliance audit would also include BA standards.

8.2.7.5 BA and Footprint

The footprint would be expanded to include the entire current BANC footprint.

8.2.7.6 Human Resource Impacts

Staffing should not be expected to change significantly, although SNR would have greater responsibilities to meet the BA requirements. It is currently meeting them as a Sub-BA, so the increased workload would be minimal, but would include additional reporting to WECC and NERC.

8.2.7.7 Integration of Renewable Resources

This could help with the integration of renewable resources, as the proposal would eliminate pancaking of transmission rates.

8.2.7.8 Industry Changes

This alternative would better position Western to lead any industry changes that develop.

8.2.7.9 Risk Analysis

Risks would include greater responsibility to meet NERC BA standards.

8.2.7.10 Cost Analysis

The costs are unknown.

8.2.7.11 Pros

- Western would have a single transmission rate for the SMUD and SNR systems.
- It would eliminate pancaking of rates for the two systems, which is a strategic goal outlined by Secretary of Energy Chu.

8.2.7.12 Cons

- SNR would register as a NERC BA and would be responsible for meeting the associated standards.

8.3 Tool Changes

8.3.1 Standardize Processes and Tools Among Operations Offices

8.3.1.1 Organizational Structure

Western should aggressively establish a plan to migrate to as many common tools as possible among the operations offices.

8.3.1.2 Discussion

This has been a long-term goal of Western for many years, but a number of obstacles have prevented it from becoming reality. The chief hindrance seems to be the independent nature of each of the regions, resisting changing the way they do business, and the short-term costs associated with migrating to new tools. Few within Western would disagree that common tools would be desirable, but limited resources and the costs of shifting to new tools has minimized the transition.

It will be difficult for Western to achieve common tools without becoming a single organization. OCP demonstrated that it is very difficult to standardize processes and achieve common tools even within a single organization that has a single management chain. Western's regional independent culture leads to teams that are frequently not open to what is best overall for Western. Members of teams continue to support their own regions' best interests. The difficulty in achieving common tools and processes without physically combining staff was also expressed by one of the partners in this study. Even though they had a single manager at the Director level who was responsible for all transmission functions, they were unable to gain commonality in their two dispatch centers until they did a physical consolidation. The partner's survey states:

> "Several attempts were made to combine efforts on streamlining control center activities, such as training methods, scheduling protocols and procedures, outage management processes, transmission billing, and energy accounting. For lack of compelling drivers to achieve consolidation, none of these efforts bore fruit, and may have actually built barriers to future cooperation."

Unless Western sets a mandatory priority of becoming more common with tools and practices among the regions, it is felt that little progress will be gained. Efforts to achieve common Western-wide tools and standards have often led to different implementation practices. Western has been sensitive to customer desires and regional flexibility, but this is not necessarily consistent with "open access" transmission policy and uniform implementation of its OATT, nor the Secretary of Energy's desire to transition to a more flexible and resilient electric grid with much greater coordination among system operators.

The following are examples where Western has experienced challenges in implementing common practices and tools:

- DSW and RMR had identical SCADA systems, including the same version number, but implemented the systems differently. It has taken more than two years to reach compatibility for further consolidation into a single system.
- Another example that came up during discussions with personnel concerns the recent decision that Western would move to a single billing program. Some were disappointed that the power billing program will end up with "one program," but that program is being implemented differently in each region. For example, Network Integrated Transmission Service (NITS) is calculated differently between regions, and some are using other tools to supplement the new billing program. Some felt that more agreement could have been reached to eliminate the differences that were not required due to legislation or the regional marketing plans.
- Each of Western's operations offices are preparing to meet the new PER (personnel) reliability standards. Although all of Western's operations offices are required to implement and meet the same standard, they are independently preparing to meet that standard. However, this does not mean the offices have no desire to work together; rather, it is seen as being quicker and easier for each region to do it on its own. Although most would agree that, in the long run, it would save resources to jointly develop the implementation material, additional resources would be expended initially, and the offices do not feel they have those resources available.

Standardizing prepares Western for future changes, and it is recommended that Western establish a program to move to common operations tools. Guidelines for the teams should include:

- Utilizing an unbiased outside facilitator to lead the effort.
- Performing a thorough survey of tool requirements, including other tool dependencies.
- Default would be to standardize, unless a good business reason not to do so (legislation or Marketing Plan) is defined.
- Remove as many preferences as possible. Specific regional requirements are expensive to develop and maintain and have not been thoroughly analyzed in the past.
- Communicating and working with Western's customers.

8.3.1.3 Regional and Customer Impact

Moving to common tools could have considerable regional and some customer impact. Processes will change, and customers may experience some of these changes. Good communication with the customers could demonstrate that they will continue to get the information they need, although it may be in a different form.

8.3.1.4 Compliance

All operations tools currently meet reliability compliance standards, and any new tools would continue to meet them. Compliance could be enhanced by having all regions utilize the same tools and processes.

8.3.1.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.3.1.6 Human Resource Impacts

No relocations are expected to occur with this effort, but employee work could change. Common tools would enable IT staff in each region to avoid supporting every operations tool, as a single tool could be maintained in a centralized manner. Tool users would need to coordinate issues and changes with staff outside their region. Regional employees would need to be trained to work for the best Western solution and not necessarily the best regional solution.

8.3.1.7 Integration of Renewable Resources

This could help facilitate integration of renewable resources by the regions utilizing common practices and processes.

8.3.1.8 Industry Changes

This alternative could help Western prepare for industry changes, in that each office would not need to individually enhance its office's tools. Any changes would be made for all regions at the same time, with the same tools.

8.3.1.9 Risk Analysis

Tools frequently interact with other tools, and a thorough analysis of requirements must be addressed up front. Experienced expert resources (users and IT staff), which are in short supply, would be required to make the projects successful.

8.3.1.10 Cost Analysis

Cost issues would need to be addressed up front, in a manner that is fair to all regions and their customers. Some regions may not need to change tools, while other regions that have adequate tools may need to change. Those regions should not have to pick up the burden of paying for the new tools. It is anticipated that moving to common tools could bring about an initial upfront investment that is greater than current expectations, but longer term savings could result from common tools utilized across Western.

8.3.1.11 Pros

- Cost savings would result from eliminating maintenance fees and programming costs required to support multiple software packages that perform similar functions.
- Each region would not have its own separate set of tools.
- Each region will not have to maintain every operations tool.
- Western will have more flexibility.
- Regions would be more consistent with each other.
- Operations staff would be better able to assist other regions.
- This alternative prepares for future Western and industry changes.
- It would provide increased bargaining power with software vendors.

8.3.1.12 Cons

- Initial costs to move to new tools, when adequate tools are available, could be a problem.
- Employee buy-in.
- Customer buy-in.

8.3.2 Consider Moving Toward a Single SCADA System for All of Western

8.3.2.1 Organizational Structure

This proposal would have Western begin looking at a single SCADA system for all regions.

8.3.2.2 Discussion

Western currently has four SCADA systems, and the OCP is moving to consolidate the Phoenix and Loveland SCADA into a single system. That will leave Western with three different systems. The Phoenix and Loveland systems are GE XA/21; SNR has an Alstrom (Areva) system; and UGP has an in-house developed system that is PC-based. All systems are adequate, but efficiencies could be achieved in moving Western to a single system with a back-up. Current technology and communications networks would allow a single SCADA system (with appropriate back-up) to be able to control all of Western's transmission systems from a single location. All systems, except for the UGP system, have an Advanced Application suite of tools integrated with them. UGP is looking to purchase an Advanced Application system, and this project could save that investment. Some communications paths could also need to be enhanced for this alternative.

This alternative also has the potential for other offices to back up a control center and reduce the number of back-up control centers.

8.3.2.3 Regional and Customer Impact

This could eliminate some regions' SCADA systems and associated staff. Customers should not be impacted by this change.

8.3.2.4 Compliance

Western will need to consider all reliability impacts; the new system should not impact reliability compliance. Compliance could be enhanced by having other manned operations centers available for back up.

8.3.2.5 BA and Footprint

No BA or footprint change is anticipated due to this change.

8.3.2.6 Human Resource Impacts

Some regions' SCADA staff could be impacted. Dispatch and other operating personnel would need to be trained on the new system.

8.3.2.7 Integration of Renewable Resources

This project would not directly enhance the integration of renewable resources, but could be the foundation for other future changes that could be beneficial.

8.3.2.8 Industry Changes

This would be a benefit in that, as the industry changes, Western would only have to incorporate the changes into a single system, instead of three systems.

8.3.2.9 Risk Analysis

The greatest risk would be in losing communication to a remote dispatch office, but that could be minimized as demonstrated in the OCP project.

8.3.2.10 Cost Analysis

No cost analysis has been done, but inherent savings should be realized in a single system with a back-up over three systems and their associated back-ups.

8.3.2.11 Pros

- This alternative would help meet Secretary of Energy Chu's strategic goal of centralizing dispatch and improving Western's infrastructure for a more efficient organization.
- It would result in a single SCADA to employ and maintain.
- It would reduce the number of SCADA support staff.
- Western would become more standardized in operations.
- It could set the stage for other future changes.
- It would provide a single Advanced Applications system for all of Western.
- Other offices would potentially be available to back up a control center and reduce the number of back-up control centers.

8.3.2.12 Cons

- Western would have to expand the communications system.
- A loss of communications could impair remote operations.

8.3.3 Develop a Secure Method to Allow a Simplified Login for Dispatchers for Multiple Products so as to Reduce the Time Involved, Yet Maintain Security

8.3.3.1 Organizational Structure

No change.

8.3.3.2 Discussion

Dispatchers interact with many pieces of software as a part of their daily work, and in order to have access to each package during their shift, they must login separately to each package at the beginning of a shift. This takes considerable time and effort.

8.3.3.3 Regional and Customer Impact

This would improve dispatchers' ability to log in to systems that they need.

8.3.3.4 Compliance

This would also improve compliance, in that less time would be involved into logging in, and the dispatchers would be able to more quickly monitor the system for potential compliance issues.

8.3.3.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.3.3.6 Human Resource Impacts

It would reduce dispatchers' routine tasks and leave more time for important reliability and safety issues.

8.3.3.7 Integration of Renewable Resources

No impact.

8.3.3.8 Industry Change

No impact.

8.3.3.9 Risk Analysis

This alternative minimizes routine tasks that don't impact reliability or safety.

8.3.3.10 Cost Analysis

No cost analysis has been completed.

8.3.3.11 Pros

- It would simplify dispatcher login process.
- Dispatchers would be able to spend more time on reliability and safety issues instead of routine tasks.

8.3.3.12 Cons

- It would need to use IT resources to develop a system to simplify login processes.

8.4 Other Non-Structural Changes

8.4.1 Clarify the Understanding of "One Western"

8.4.1.1 Organizational Structure

Embark on a process that would clarify the understanding of "one Western."

8.4.1.2 Discussion

Discussions with Western managers and employees revealed that no common understanding exists as to what the Administrator means by referring to "one Western." The following definitions were often given:

- "One Western" means understanding the uniqueness and making things standard where possible. Only allow differences where they have to be different, such as items addressed in the legislation or Marketing Plans. Differences should not be allowed based on preference.
- Others see "one Western" as allowing for changes if customers or employees desire them. This is seen as being customer-oriented.

Not having a clear understanding of the boundaries that are allowed has complicated tool selections with OCP and increased the time and cost to implement a common billing program. Sometimes accommodating small changes can be very expensive and increase the cost significantly. Unique changes also complicate program maintenance. The following lessons have been learned:

- Different implementations of Western's single tariff have complicated moving the billing program to all of Western.
- The billing program has hundreds of thousands of business practices in order to accommodate regional preferences.
- Terminology between regions is often different.
- RMR chose not to implement the NITS portion of the common billing program and will utilize other support programs, based on regional preference.
- Sometimes Senior Managers have had to get involved in order to resolve implementation issues.
- Issue papers have been created to help resolve differences.

- Steering committees with cross-regional and functional representation have helped with uniformity, as long as the committee members are flexible and open to other regions' ideas.
- Senior Managers have sometimes become involved to get their regions' preferences included.
- Establishing one business practice has been challenging.
- Minute changes in business practices can have significant costs that are often not fully evaluated in the decision to adopt a unique business practice.
- Organizations that want the change should have to justify it, and a determination needs to be made concerning whether the business practice differences are worth the customization cost. All costs, including future maintenance costs, should be included in the analysis.
- Functional users have not been flexible and willing to change.

If Western could establish a clear definition on when unique business practices could be customized, tool selection would be much easier. Western has not typically considered the cost associated with customization, including future maintenance costs, as a factor in determining whether a unique practice would be implemented.

8.4.2 Consider Registering as a Single NERC Entity

8.4.2.1 Organizational Structure

Currently, each Western region is registered with NERC as a separate entity. Western has the option of registering as a single NERC entity. A second alternative would be for Western to register as a single entity within WECC and a single entity within the MRO.

8.4.2.2 Discussion

The greatest impact of this change would be that Western would experience one compliance audit (or two if registered separately within the Eastern and Western Interconnections) instead of the five audits in which they currently participate. It is felt that even with a single (or double) audit, the auditors would want to visit all operations centers.

Western would be required to standardize all operating procedures so that each region operates to the same procedures, where applicable. This would entail an extensive workload to get Western in that position, but should provide efficiencies in maintaining those procedures. A downside to single registration is that, when a non-compliance item is found, the sanctions are often associated with the size of the utility and the previous number of violations of that standard. Western, registered as a single entity, could entail a greater sanction based on Western's size compared to a regional size. Another factor in determining the sanction size is the number of violations within a specific time frame. If one region had a previous violation, and another region violated the same standard within the given time frame, a greater sanction could result.

Currently, NERC practices dictate that if an entity is registered in two NERC regions, audits will be done simultaneously in a single audit; the region with the most facilities will be the lead. UGP currently participates in a single audit by both WECC and the MRO in which the MRO leads the audit. Moving to a single or double registration could lead to a single Western audit by WECC and the MRO, but WECC could be the lead.

Additional efficiencies could be achieved by combining the compliance function in each region into a single organization.

8.4.2.3 Regional and Customer Impact

The impact of this change would require a great deal of resources to achieve standardization of practices and procedures. Maintenance efficiencies could offset this in the future. Customers should not be impacted by this change.

8.4.2.4 Compliance

Compliance could be enhanced by Western moving to a consolidated compliance program under a single registration.

8.4.2.5 BA and Footprint

No BA or footprint change would be required.

8.4.2.6 Human Resource Impacts

Western employees would not have to relocate, but additional coordination with the other regions would be required.

8.4.2.7 Integration of Renewable Resources

No impact to the integration of renewable resources should occur.

8.4.2.8 Industry Changes

Western would be in a better position to monitor and implement changing NERC standards with a single compliance program.

8.4.2.9 Risk Analysis

Sanctions could be increased under this program.

8.4.2.10 Cost Analysis

No cost analysis has been done, although there are expected short-term costs and associated long-term savings.

8.4.2.11 Pros

- Only a single audit would be performed.
- It would result in standardized processes and procedures.
- A single compliance program would result.
- It would provide greater regional coordination.

8.4.2.12 Cons

- It could result in a possible larger sanction for non-compliance.
- Having WECC and MRO perspectives on audits is advantageous to Western.
- One registration would lead to reduced influence in MRO region.

8.4.3 Set a Goal and Milestones to Achieve One Set of Transmission Rates Per BA

If possible, Western should include the transmission facilities of customers and others that support the system within the BA.

8.4.3.1 Organizational Structure

No change.

8.4.3.2 Discussion

Interpretation and application of Ancillary Services is not consistent across Western. Even though Transmission Service rates for each transmission system are in place across Western, the Ancillary Services rates are generally set per BA. For example, in WALC, there are Transmission rates for four different transmission systems, but one set of rates for Ancillary Services for the BA. If Western can reach agreement on one set of Ancillary Services for a BA, it appears that it could have one set of Transmission rates for the BA also. If possible, it would also be desirable to include transmission facilities of customers and others that support the system within the BA.

8.4.3.3 Regional and Customer Impact

This would change the transmission rates within the BAs. If customers’ facilities were included in Western's transmission rate, it could impact their costs. Western would have to determine a fair and equitable method for reimbursing each transmission project or facility.

8.4.3.4 Compliance

No change.

8.4.3.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.4.3.6 Human Resource Impacts

Considerable resources would need to be invested to pursue this alternative.

8.4.3.7 Integration of Renewable Resources

This alternative could benefit renewables by eliminating some pancaking of transmission rates.

8.4.3.8 Industry Change

It would move Western toward minimizing transmission rate pancaking.

8.4.3.9 Risk Analysis

Risks would include possible cost shifting.

8.4.3.10 Cost Analysis

No cost analysis has been completed.

8.4.3.11 Pros

- This would eliminate pancaking within a BA.
- It is in line with DOE goals for Western.
- If other transmission systems were included in Western's rate, it would further reduce pancaking.

8.4.3.12 Cons

- This alternative could result in possible cost-shifting.
- Considerable resources would be required to investigate and implement.

8.4.4 Develop a White Paper on Rates Methodology and Identify the Barriers to Combining Transmission Systems and Un-Pancaking of Rates Within Each BA

8.4.4.1 Organizational Structure

No change.

8.4.4.2 Discussion

In the WECC area, very little load is served with NITS. NITS should, by design, be the most effective and economical method of transmission service for resource to load within a system. If it is not, then the proper pricing signals for transmission rate design may not be used or current pricing methods are allowing loads and resources to game the system and avoid paying for benefits received from facilities needed to sustain the transmission system.

8.4.4.3 Regional and Customer Impact

This would change the transmission rates. Western would have to determine a fair and equitable method for reimbursing each transmission project or facility. Some transmission customers could see a cost increase and others could see a cost decrease.

8.4.4.4 Compliance

No change.

8.4.4.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.4.4.6 Human Resource Impacts

Considerable resources would need to be invested to pursue this alternative.

8.4.4.7 Integration of Renewable Resources

It could benefit renewables by eliminating some pancaking of transmission rates.

8.4.4.8 Industry Change

This would move Western toward minimizing transmission rate pancaking.

8.4.4.9 Risk Analysis

Risks would include possible cost-shifting.

8.4.4.10 Cost Analysis

No cost analysis has been completed.

8.4.4.11 Pros

- This could eliminate pancaking within a BA.
- It is in line with DOE goals for Western.
- Some transmission customers could see a cost decrease.

8.4.4.12 Cons

- It could result in possible cost-shifting.
- Some transmission customers could see a cost increase.

8.4.5 Review Possibilities of the WASN Sub-Balancing Authority Becoming a Sub-Balancing Authority of WALC or WACM

8.4.5.1 Organizational Structure

It is recognized that this has been previously considered, but has not been seen as feasible. The major obstacle to making this happen is that transmission service would be required between the intended BAs.

8.4.5.2 Discussion

This alternative is probably not a high priority, but should continue to be a part of Western's vision. WASN, being a Sub-BA under BANC (operated by SMUD), is working well. In order to accommodate this change, additional transmission would either need to be built or contracted for between WASN and WACM (possibly through Bonneville Power Administration) or between WASN and WALC from Tracy to Mead in southern Nevada, or Adelanto in southern California. Only minimal transmission service would be required, and only transmission service that is sufficient for regulation purposes would be necessary, although additional transmission service could enhance other aspects of operations.

8.4.5.3 Regional and Customer Impact

This would be a major change with Western's customers and the region.

8.4.5.4 Compliance

All compliance requirements would need to be met, and compliance should not be impacted by this proposal.

8.4.5.5 BA and Footprint

The WASN Sub-BA footprint would be within the WACM or WALC BA footprints.

8.4.5.6 Human Resource Impacts

This would have minimal impacts, other than the resources to investigate this.

8.4.5.7 Integration of Renewable Resources

This alternative could help with the integration of renewable resources, as more regulation would be available, depending on availability of transmission service.

8.4.5.8 Industry Changes

It would increase Western's BA size, which is often seen as positive.

8.4.5.9 Risk Analysis

Western needs to consider SNR customers and transmission availability.

8.4.5.10 Cost Analysis

No cost analysis has been done. SNR has a contract with SMUD (BANC) to operate the BA, and this project could have potential savings by utilizing existing Western resources to operate the BA.

8.4.5.11 Pros

- Assuming transmission service was obtained, this would tie all of Western's transmission systems together contiguously.
- This would increase Western's BA size.
- Greater resources would be available to regulate with and exchange, depending on transmission service availability.
- Efficiencies in dispatch staffing could result.

8.4.5.12 Cons

- This alternative requires transmission service between SNR and RMR or DSW.

8.4.6 Consider Looking at a Program to Document Western's Procedures

8.4.6.1 Organizational Structure

Western should consider looking at a program to document its procedures.

8.4.6.2 Discussion

During this study, it was noted that few Western offices have documented many of their operating procedures that are outside of those required to meet compliance standards. Many of these undocumented procedures are in the settlements groups. Documenting procedures could also help identify differences between regions and could lead to new efficiencies.

8.4.7 Develop a Program Using Common Tools to Track and Perform Routine Training

8.4.7.1 Organizational Structure

No change.

8.4.7.2 Discussion

Most of the NERC certification training is provided in-house, but in some offices, individuals are responsible for tracking their hours, while in other offices, it is tracked by supervisors with various pieces of software.

8.4.7.3 Regional and Customer Impact

This would result in better utilization of resources.

8.4.7.4 Compliance

It standardizes compliance tracking and reporting for dispatchers.

8.4.7.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.4.7.6 Human Resource Impacts

It would result in better utilization of resources.

8.4.7.7 Integration of Renewable Resources

No impact.

8.4.7.8 Industry Change

No impact.

8.4.7.9 Risk Analysis

This alternative reduces Western's risk for non-compliance.

8.4.7.10 Cost Analysis

No cost analysis has been completed.

8.4.7.11 Pros

- This alternative provides better utilization of resources.
- It reduces the risk of non-compliance.

8.4.7.12 Cons

- Resources would be necessary to develop and implement a program.

8.4.8 Review Operations Training Manual

Determine the most cost effective method to develop a consistent intern training program.

8.4.8.1 Organizational Structure

No change, but better coordination on intern training. Interns could be assigned to an individual office, or under the direction of a single office.

8.4.8.2 Discussion

An intern program for new dispatchers appears necessary. The team noted that RMR has a program, while others do not. This is another example of regions not well-coordinated for development of dispatcher staff. Some regions just use Chapter 7 of the Western-wide operations training manual to test skills of applicants to prepare for in-house on-the-job training. While this may be effective to develop local staff, it may not be the most cost effective method across the regions.

8.4.8.3 Regional and Customer Impact

This would result in better coordination among operations offices on intern training.

8.4.8.4 Compliance

It would improve dispatch interns' knowledge of dispatch functions and associated compliance responsibilities.

8.4.8.5 BA and Footprint

No BA or footprint changes would occur due to this recommendation.

8.4.8.6 Human Resource Impacts

It would result in better utilization of resources.

8.4.8.7 Integration of Renewable Resources

No impact.

8.4.8.8 Industry Change

No impact.

8.4.8.9 Risk Analysis

It would improve Western's intern training program and minimize risk that new dispatchers are not fully trained.

8.4.8.10 Cost Analysis

No cost analysis has been completed.

8.4.8.11 Pros

- This alternative would result in a better utilization of resources.
- It would result in better training of future dispatchers.
- It would provide better coordination of Western's training programs.

8.4.8.12 Cons

- Time and resources would be expended to coordinate such a program.

8.4.9 Improve Efficiency of Switching Program Training

8.4.9.1 Organizational Structure

No change.

8.4.9.2 Discussion

Some offices with remote switching locations use non-Western personnel to perform switching. To be prepared for this, they train many people – both Western employees and non-Western personnel – to perform switching. In addition, Western trains USBR and Corps of Engineers staff on switching, who may or may not be used by Western for switching. SNR has cut back on the training. They found that they were training many people who have never been or may never be used for switching.

8.4.9.3 Regional and Customer Impact

This would result in better utilization of resources, but some customers may feel this is a Western customer service issue that they would be losing.

8.4.9.4 Compliance

This change should not impact compliance.

8.4.9.5 BA and Footprint

No change.

8.4.9.6 Human Resource Impacts

This would result in better utilization of resources.

8.4.9.7 Integration of Renewable Resources

No impact.

8.4.9.8 Industry Change

No impact.

8.4.9.9 Risk Analysis

No change in risk. In an emergency, dispatchers can always use someone they are comfortable with to do switching.

8.4.9.10 Cost Analysis

No cost analysis has been completed.

8.4.9.11 Pros

- This would result in a better utilization of resources.

8.4.9.12 Cons

- Customers may feel this is a customer service that they would be losing.

8.4.10 Agreement to Support Transmission Service

The Operations Manager and Power Marketing Manager enter into an agreement that would allow Western's Merchant function to adequately plan for and obtain resources for the BA, if necessary, to support Transmission Service with the necessary generation-based ancillary services.

8.4.10.1 Organizational Structure

No change.

8.4.10.2 Discussion

Western has drafted a Generation Based Ancillary Services Policy (GBAS). This policy is concerned with the relationship between the Transmission-based operation of the system and the ancillary services that must be provided by the generation or merchant offices within the BA. This paper suggests that "Each BA that utilizes Project resources should have a defining document in place that identifies the terms and conditions of such use." This document should be an agreement between the Power Marketing function and the Operations Function operating the BA.

8.4.10.3 Regional and Customer Impact

This would clearly delineate Power Marketing and Transmission/Operations responsibilities.

8.4.10.4 Compliance

It would improve OATT compliance, in that this document would outline how ancillary services are obtained.

8.4.10.5 BA and Footprint

No change.

8.4.10.6 Human Resource Impacts

No impact, other than drafting and negotiating agreement, and it would clarify responsibilities.

8.4.10.7 Integration of Renewable Resources

This alternative would define how Western's BAs would obtain resources to regulate for renewable resources.

8.4.10.8 Industry Change

Western would be better prepared for integration of new resources, and it would identify details of how ancillary services would be obtained.

8.4.10.9 Risk Analysis

It reduces Western's risk for use of federal resources.

8.4.10.10 Cost Analysis

No cost analysis has been completed.

8.4.10.11 Pros

- This clearly defines Transmission/Operations and Power Marketing responsibilities.
- It would lay out Western's policy on use of federal resources for regulation purposes, including renewable resources.
- This alternative could allow the Merchant function to plan for and obtain resources beyond federal generation when needed to support the BA.

8.4.10.12 Cons

- The limitation of Federal Resources for use by non-preference customers could be challenged politically and legally.

8.4.11 Require All BAs to Settle Energy Imbalance Accounts Financially

8.4.11.1 Organizational Structure

No change.

8.4.11.2 Discussion

Energy Imbalance and Regulation Service put the federal generation resource at risk. All of the Rate Schedules for these services allow financial settlement of the energy deviations. However, only the WACM BA requires financial settlement of energy deviations. Prior to enforcing financial settlement for Energy Imbalance, some transmission customers were taking high-cost energy and returning low-cost energy. After enforcement, energy imbalance was not abused.

It is expected that this may be occurring in the other BAs, to some extent. Financially Settling Energy Imbalance accounts sends the appropriate price signal to reduce the abuse of this Ancillary Service. In addition, it is the responsible method and most fair to all parties involved.

8.4.11.3 Regional and Customer Impact

The Regions may be faced with harsh criticism from preference customers who do not want to change the way they currently do business. Energy may not be currently tracked on an hourly basis and could require system enhancements to account and bill for this service.

8.4.11.4 Compliance

Consistent with OATT compliance requirements.

8.4.11.5 BA and Footprint

No change.

8.4.11.6 Human Resource Impacts

This alternative could require extensive resources to implement, as the proposal would need to be developed and negotiated with the customers, and systems would need to be put into place to track and bill for this service.

8.4.11.7 Integration of Renewable Resources

It would standardize renewable resource regulation across Western.

8.4.11.8 Industry Change

It would standardize procedures across Western and help prepare for future changes, such as EIM.

8.4.11.9 Risk Analysis

It reduces Western's current risks of incurring additional costs associated with providing regulation, and also improves OATT compliance.

8.4.11.10 Cost Analysis

No cost analysis has been completed, but based on RMR's experience, the benefits exceed the cost of implementation.

8.4.11.11 Pros

- It is anticipated that the benefits and savings exceed the cost of implementation.

- It would standardize procedure across Western.
- It would treat all transmission customers equally.

8.4.11.12 Cons

- This alternative requires the use of extensive resources to implement.
- Preference power customers may object to enforcement of this rate schedule provision.

8.4.12 Evaluate Federal Generation Capacity

Evaluate the current commitment of federal generation capacity to Regulation Service, and assess whether moving to inter-hourly resource schedules could reduce the commitment significantly.

8.4.12.1 Organizational Structure

No change.

8.4.12.2 Discussion

Regulation Service can commit a significant amount of federal generation capacity to operation of the BA if LSE's generation resource schedules are not adjusted over the hour. This can be magnified by LSEs with both scheduled and non-scheduled generation. Intra-hourly resource scheduling can reduce the impact on federal generation capacity for providing Regulation Service.

8.4.12.3 Regional and Customer Impact

Intra-hourly scheduling would significantly change the way business is currently being done. It could require modification of tools and systems to implement. Customers may object to changing this business practice.

8.4.12.4 Compliance

Consistent with OATT compliance responsibilities.

8.4.12.5 BA and Footprint

No change.

8.4.12.6 Human Resource Impacts

This would require resources to evaluate this proposal. If this proposal moves forward, it could require extensive resources to develop tools and systems to implement.

8.4.12.7 Integration of Renewable Resources

If implemented, it could require additional scheduling of renewable resources.

8.4.12.8 Industry Change

It would be consistent with anticipated future industry changes, including EIM proposals.

8.4.12.9 Risk Analysis

This alternative reduces Western's financial risk for federal resources to be used for regulation.

8.4.12.10 Cost Analysis

No cost analysis has been completed.

8.4.12.11 Pros

- It reduces Western's financial risk for use of federal resources for regulation.
- It prepares for future industry changes, including EIM.

8.4.12.12 Cons

- Extensive use of resources would be required to develop tools and processes to implement.

8.4.13 Review and Develop an Effective and Economical Strategy for Western's Registrations and Committee Participation

8.4.13.1 Organizational Structure

No change.

8.4.13.2 Discussion

A significant amount of time is dedicated to participation in WECC, MRO, and NERC committees. Some offices have reduced their commitments to NERC and WECC to save time and money. Some committees have multiple representatives from different offices. Western needs to participate in and influence the industry by its participation, but may not currently be utilizing optimal resources to do this.

It would also benefit Western if better internal systems were developed to communicate committee hot issues and proposed changes.

8.4.13.3 Regional and Customer Impact

This could better represent Western with optimal resources.

8.4.13.4 Compliance

It could improve communication throughout Western on compliance issues.

8.4.13.5 BA and Footprint

No change.

8.4.13.6 Human Resource Impacts

It would better utilize resources within Western.

8.4.13.7 Integration of Renewable Resources

No impact.

8.4.13.8 Industry Change

This could develop better processes for communicating industry changes throughout Western and have more influence in proposed changes.

8.4.13.9 Risk Analysis

Risk would be minimized by better use of resources and improved communications.

8.4.13.10 Cost Analysis

No cost analysis has been completed, but it is anticipated that costs could be saved by reducing the number of employees attending committee meetings.

8.4.13.11 Pros

- This alternative would result in a better use of resources.
- It would also produce better communications.
- It would better represent Western and not just individual Regions.
- Cost savings would result from optimizing resources used to attend committee meetings.

8.4.13.12 Cons

- Individual offices may not be represented as well.

- Attending committee meetings is sometimes seen as an employee benefit and motivates employees.

8.4.14 Compare Differences and Standardize

Perform a comparison of the differences of East and West in developing Western standards, and work to standardize and improve the operating practices of each reliability organization in which Western operates.

8.4.14.1 Organizational Structure

No change.

8.4.14.2 Discussion

Even with the implementation of the NERC Standards, there are some differences between the operations methodologies of the Eastern and WECC Interconnections. These differences make common practices across Western difficult, in some cases. As previously stated, East and West have different NASB interests. In developing standards for the East, the MRO defines the risks and monitors; whereas, in the West, the WECC finds, fixes, and tracks. As Western operates in both the East and West Interconnections, it has experience and opportunity to argue for the best practices of each Interconnection. It is in Western's best interest to standardize its policies, practices, and procedures wherever possible. In principle, most policies and standards can be implemented in either Interconnection. However, in a few instances, Western has not yet taken a position on a specific standard because of the differences in operations methodologies of the reliability organizations. An example may be the determination of ATC. The prevalent position in WECC for determination of ATC is to use the "Contract Path" method. Yet others, such as BPA, CAISO, and the Eastern Interconnection, have chosen a "Flow-Based option" for determination of ATC. See Bonneville Power Administration Transmission Services "Available Transfer Capability Implementation Document (MOD-001-1a) Effective Date: April 11, 2012."

WECC, MISO, SPP, and MRO do not want to deal with issues that may cross the East-West separation; therefore, it seems like a natural separation for Western to use as it begins to standardize its operations. But it is also an opportunity for Western to be a leader in effecting change and bring the best practices of each method of operation into the discussions of the reliability organizations.

In addition, Western has several anomalies that must be addressed; e.g., RMR has some facilities on the East that have some exposure for compliance since they are not registered in the MRO. There is also a small BA operated in Montana by UGP. Those facilities do not have the same unregistered risks as the RMR East facilities, but they are across the separation from most of UGP's facilities and provide generation resource to the East. These issues and solutions are discussed more in length in the Alternatives section under Regional Changes suggested above.

8.4.14.3 Regional and Customer Impact

This alternative may lead to changes within an office.

8.4.14.4 Compliance

It would improve consistency in compliance processes.

8.4.14.5 BA and Footprint

No change.

8.4.14.6 Human Resource Impacts

The resources to investigate these issues and represent Western in WECC and MRO could be significant.

8.4.14.7 Integration of Renewable Resources

No impact.

8.4.14.8 Industry Change

No impact. Western could be a conduit for arguing best practices in each reliability organization.

8.4.14.9 Risk Analysis

This alternative reduces Western's risk for non-compliance.

8.4.14.10 Cost Analysis

No cost analysis has been completed.

8.4.14.11 Pros

- This alternative better coordinates Western standards and processes.
- It allows Western to argue for best practices in each reliability organization.

8.4.14.12 Cons

- The resources to investigate and represent this alternative could be extensive.

8.5 Alternatives Considered But Not Recommended

8.5.1 Consider Consolidating the Transmission Switching Desks

8.5.1.1 Organizational Structure

This alternative considers consolidating the Transmission Switching Desks.

8.5.1.2 Discussion

Consolidating the TSO desks was considered, but is not recommended for the following reasons:

- The TSO desks are efficiently organized, and little additional efficiencies could be gained;
- The TSO desks have high vulnerability for safety-related issues, and even small gains in efficiency would not compensate for these vulnerabilities;
- Local contact with maintenance personnel is highly valued; and
- Each dispatch office has adequate map-boards. Providing space and new map-boards that could accommodate all of Western's transmission systems would be expensive.

It should be noted that one of the partners in this report consolidated many of its other operations functions, but rejected consolidating the TSO function. They stated in their response to our questionnaire:

> "Consideration was therefore given to relocating the entirety of Transmission Operations (TOP) for ... to the ... location. While this would likely have led to more attainable efficiencies, the barriers proved too great for this to be achieved. Barriers included the technology, e.g., map-board and console real-estate, as well as the ability to retain transferred Operator personnel. It was decided that the most efficiency could be gained at the least cost and disruption by focusing on consolidating the BA/TSP functions."

It is therefore not recommended to pursue this alternative at this time.

8.5.2 Consider Integrating the Eastern Interconnection BA and TOP (WAUE) with Other Western Systems.

8.5.2.1 Organizational Structure

This alternative would consider integrating the Eastern Interconnection BA and TOP (WAUE) systems with other Western systems.

8.5.2.2 Discussion

Consideration of a merger of the WAUE system with other Western Interconnection (WECC) systems was considered, but is not recommended. Operating the BA and TOP functions in the Eastern Interconnection is so vastly different from the Western Interconnection that it is not recommended to consider consolidation of their functions. Even though it is not recommended that the east side BA and TOP be considered for a consolidation, Western could still consider merging the following functions:

- Consolidating the OATT functions; and
- Consolidating TP and TSP functions.

8.5.3 Split the Operations and Transmission Services Managers' Reporting from the RMR Regional Manager to the RMR and DSW Regional Managers.

8.5.3.1 Organizational Structure

This proposal would be to split the reporting of the Operations and Transmission Services managers from the RMR Regional Manager to the RMR and DSW Regional Managers.

8.5.3.2 Discussion

The OCP project merged the DSW and RMR operations functions into a single function under the direction of the RMR Regional Manager. Adjusting the structure to have the Operations Manager report to one Region and the Transmission Services Manager report to the other Region does not appear to further Western's desire to facilitate a single transmission organization in the two regions nor help meet Secretary Chu's strategic goals of a more efficient and flexible Western.

This alternative was considered, but not recommended for the following reasons:

- The OCP Final Report dated December 14, 2007 recommended "that the selected location host both the Operations Center and the Transmission Services functions. The coordination of the TSP functions is the driving force for this recommendation. Co-location maximizes the communication and coordination of the TSP functions that interact with real-time operations." Although the implementation of this recommendation was changed, the principle of coordination within a single organization was preserved.

- The RMR Operations and Transmission Services Managers already feel tension having to interface with two regional managers and the CRSP manager. This change would complicate that further.
- Questions continue to arise over such things as which manager should sign various OATT agreements. Reporting to different managers would compound this issue.
- Close coordination needs to occur, and this would be complicated with a split in functional reporting.
- It would also appear to take a step backward with moving to a single set of tools. Tool selection has been very difficult, even within a single organization, and having separate organizations select a single tool, with a single implementation, would be even more difficult.
- Splitting the organizations between regions would complicate issues and would not alleviate any staffing or budget-related issues.

A benefit that would occur with this recommendation is that it would help alleviate the overhead cost allocation disparity perception, as more employees would report to DSW and fewer to RMR. This benefit is not seen as a great enough value to offset the deficiencies, and pursuing this alternative is therefore not recommended.

APPENDIX A

OCP Timeline

2007 -	Senior managers form a team to review consolidation of operations functions across Western, resulting in a recommendation to consolidate RMR and DSW operations in either Phoenix or Loveland. The back-up control center was recommended to be located within one hour of the chosen site. The final OCP Team Report was published December 14, 2007.
Dec 2007 -	Senior manager decision to proceed with OCP, with RMR being the primary and DSW being the back-up, which is a variation of the OCP Team recommendation.
Jan 2008 through Oct 2008 -	RMR and DSW work on alternatives that meet the senior managers' December 2007 OCP decision.
Sep 2008 -	Tyler Carlson leaves the DSW Regional Manager position to join Mohave Electric Cooperative.
Oct 2008 -	Option "C" is selected by the senior managers as the alternative to pursue. This alternative showed that both Phoenix and Loveland operations staffs would be under the RMR region.
Nov 2008 through Feb 2009 -	RMR and DSW steering committee formed to lead and oversee details of implementing Option C. Craig Knoell comes on board as full time project manager.
Jan 2009 -	Darrick Moe assumes the DSW Regional Manager position and is added as a senior sponsor.
Jan 2009 -	Human Resources and Procurement are involved in creating the reorganization package and begin procuring new tools, although they are not on the steering committee.
Feb 2009 -	Letter to customers notifying them that Option C was selected and Western will move forward with consolidating RMR and DSW operations functions.

Feb 2009
through
Jan 2010 - RMR and DSW staffs work on plans, costs, organizations and other details to implement OCP. Also address customer concerns.

May 2009 - Informal customer meeting takes place to update OCP activities.

Aug 2009 - Craig Knoell leaves OCP project manager position to assume Western's TIP Manager position. Mike Montoya assumes OCP project manager position, but is not relieved of his other duties, in effect being available only on a part time basis.

Sep 2009 - Letter to customers is sent reaffirming Western's commitment to continue with OCP.

Jan 2010 - DOE approves reorganization.

Feb 2010 - OCP reorganization is implemented.

Feb 2010 - OCP is considered complete by achievement of the following: customers notified of decision, reorganization completed, implementation plan developed, project plan and schedule developed for SCADA and cost analysis completed for the scheduling system.

Mar 2010 - Initiation of OCI occurs.

APPENDIX B

The Secretary of Energy
Washington, DC 20585
March 16, 2012

MEMORANDUM FOR THE POWER MARKETING ADMINISTRATORS
KENNETH LEGG, SEPA
JAMES MCDONALD, SWPA (ACTING)
TIMOTHY MEEKS, WAPA
STEPHEN WRIGHT, BPA

FROM: STEVEN CHU Steven Chu

SUBJECT: Power Marketing Administrations' Role

BACKGROUND:

Our Nation has unprecedented opportunities to build a more secure and sustainable electric sector, one that:

- stimulates job creation along with local and regional economic development;
- accelerates introduction of new technologies ranging from cyber-security to alternative energy generation;
- takes greater advantage of our indigenous and inexhaustible resources;
- improves public health;
- reduces strategic vulnerabilities, price and supply risk, and environmental liabilities; and
- advances our competitiveness in international markets.

Taking greater advantage of energy efficiency, demand resources and clean energy – while at the same time reducing costs to consumers – requires a transition to a more flexible and resilient electric grid and much greater coordination among system operators. This can only be accomplished by upgrading our infrastructure to take advantage of modern communications and control technologies and bringing the benefits of increased connectivity to more Americans. As the Department of Energy's (DOE) own Power Marketing Administrations (PMAs) have historically played a valuable role in the electric sector, they can and should help lead this evolution.

As owners and operators of a significant portion of the infrastructure that is vital to this Nation's prosperity, the PMAs have the tools to take a leadership role in transforming our Nation's electric sector, to the extent allowable under their enabling statutes. In the weeks and months to come, I will be calling on the hard-working and dedicated employees of the PMAs. While the PMAs have been doing an admirable job in implementing the DOE's goals and are leaders in some areas, we can all do better. To that end, I will identify specific

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goals intended to strengthen each PMA's ability to modernize the grid through leadership roles in their regions. Because of their uniqueness, I will provide individualized direction to each of the PMAs. This memorandum is intended to describe my foundational goals for the PMAs, thereby establishing a framework on which subsequent memoranda will build.

THE FOUR POWER MARKETING ADMINISTRATIONS:

The DOE's four PMAs have been reliably delivering electricity from federal hydroelectric dams for over 75 years. The federal hydropower system produces prodigious amounts of carbon free, low-cost electricity. The PMAs' transmission systems overlay the transmission and distribution systems of utilities in 20 states, which represent about 42% of the continental United States.[1]

Over the years, the rights and responsibilities of three PMAs have expanded beyond simply selling energy from federal dams:

- BPA and WAPA purchase energy from non-federal generators on behalf of their customers;
- BPA has the authority to acquire the output of resources, including conservation, to meet load requirements;
- BPA, SWPA, and WAPA collectively own and operate 33,700 miles of transmission lines and 594 substations;
- BPA and WAPA have revolving loan funds for expanding this Nation's transmission grid;
- BPA is the primary transmission operator over two states; and
- SWPA and WAPA are empowered to facilitate private-sector development of transmission through use of the federal eminent domain authorities.

Each PMA has a different enabling statute. Within a PMA, each system of dams may have a different statute, and sometimes, even a single dam within the system has its own statute. All of this makes the administration of the PMAs extremely complex.

IMPROVING PMA EXISTING INFRASTRUCTURE:

The following summarizes the existing infrastructure owned and operated by the PMAs:

[1] The PMAs market power in 30 states, but only have transmission assets in 20 states.

FY 2011 PMA Statistics

	Transmission lines (miles)	Substations (all voltages)	Powerplants[1]	Installed capacity (MW)	Customers[2]	Total Power & Transmission Rev (millions of dollars)	Sales (billions of kWh)	Percent of sales in marketing area
Bonneville	15,215	263	31	22,363[3]	276	$3,285[4]	83.1[6]	30%[7]
Southeastern	N/A	N/A	22	3,392	489	$265	6.2	2%
Southwestern	1,380	25	24	2,174	103	$171[5]	4.1	9%[8]
Western	17,135	321	57[9]	10,508	687	$1,202	42.4	6%
Total	33,730	609	134	38,437	1,555	$4,923	135.8	N/A

1. Plants are primarily owned by the Federal government and operated primarily by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation. Production is marketed by the power marketing administrations.
2. Includes firm and nonfirm power customers and project use customers.
3. Nameplate rating for federally owned generation from BPA's 2010 "White Book" on loads and resources.
4. Total operation revenue, as reflected on page 1 of BPA's 2011 Annual Report.
5. Not an audited number.
6. FY 2010 number from 2012 BPA Rate Case Wholesale Power Rate Final Proposal, Statements A-F, July 2011.
7. Approximate percentage from page 22 of BPA's 2011 Annual Report.
8. Calculated from 2010 data.
9. Includes 56 hydropower plants and 1 coal-fired plant

Rev: 2/27/2012

As with much of the Nation's infrastructure, the PMAs' infrastructure is aging and some of it needs to be upgraded or replaced. The federal hydropower system needs investment just to maintain capability as well as capture additional incremental capability. As referenced above, the PMA's transmission lines overlap the transmission grid in more than 40% of the continental United States, the vast majority of which is alternating current (AC). Its AC nature means that the PMAs' equipment is integrally intertwined with the underlying system; therefore, the PMAs' equipment must be resilient.

I will be directing[2] that each of the PMA's strategic plans and capital improvement plans recognize the changing nature of the electric sector, including but not limited to complying with NERC reliability standards, integrating variable resources, scheduling on an intra-hour basis, centralizing dispatch, responding to solar flares and minimizing cyber-security vulnerabilities. As the grid becomes smarter, it is also imperative to address its vulnerabilities and to protect critical infrastructure. The PMAs are uniquely positioned to serve as test beds for innovative cyber-security technologies, and we should take advantage of that opportunity.

[2] I recognize that, in some cases, one or more of the PMAs may already be accomplishing the directive.

I recognize that the current economic environment is creating pressure on many of the PMAs' customers. Capital improvements, therefore, must be staged to ensure the costs are appropriately managed.

1. **IMPLEMENTING THE PMA's NEW TRANSMISSION AUTHORITIES:**

   In the 2005 Energy Policy Act (EPAct 05) and in the 2009 American Reinvestment and Recovery Act (ARRA), Congress gave new powers to two of the PMAs. These PMAs have been administering and must continue to administer their new authorities distinctly from their historic mission of delivering power from federal hydro dams.

   a. **Section § 1222:**
   While EPAct 05 enabled both WAPA and SWPA to partner with third parties to develop needed transmission, the §1222 Program has not yet been used. Both WAPA and SWPA are actively evaluating applications under this authority.

   DOE will continue to work with WAPA and SWPA to evaluate these applications, with a critical eye toward achieving the transmission development goals that Congress intended.

   b. **Borrowing Authority Program:**
   The Deputy Secretary has been working and will continue to work with WAPA and other Department entities to implement reforms necessary to ensure the borrowing authority programs are building the infrastructure this Nation needs while protecting and providing value to the taxpayer. Subsequent memoranda will provide specific directives on the borrowing authority program.

2. **IMPROVING THE PMAs' RATE DESIGNS:**

   With the changing needs for and uses of the electric grid, rate design will also change. While continuing to market and deliver federal hydropower at cost-based rates, to the extent allowed by their enabling statutes and existing contractual arrangements, I am directing the PMAs to create rate structures that incentivize the following:
   - energy efficiency programs,
   - demand response programs,
   - integration of variable resources, and
   - preparation for electric-vehicle deployment.

   I am also directing the PMAs, if applicable, to take actions that will minimize rate pancaking in their service territories.[3] Further instructions will be provided by subsequent memoranda to implement the partnership between DOE headquarters and the PMAs to achieve this end.

[3] Rate pancaking inhibits the transport of electricity over large distances. Advocating for the elimination of rate pancaking should not be viewed as a call for the creation of a regional transmission organization. My goal is to make the transport of electricity more economic.

3. IMPROVING COLLABORATION WITH OTHER OWNERS AND OPERATORS OF THE GRID:

The reliability of the grid depends on cooperation and collaboration among all owners and operators of the grid. I direct the PMAs to continue to look for ways to strengthen relations with other owners and operators of the grid and grid components, which should include, but not be limited to, the following:

- coordinating operations with neighboring balancing authorities;
- increasing cooperation between public and private power; and
- participating more effectively in regional planning.

I am also directing the PMAs to capture economies through partnering with others in planning, building, and operating the grid. I have been informed that WAPA is working with the WECC and other critical stakeholders, including the Public Utility Commission driven Energy Imbalance Market (PUCeim), National Renewable Energy Lab (NREL), and its customers, on the Energy Imbalance Market (EIM) proposal. WAPA has made a decision to assume that the EIM will go forward and that it will be a market participant. I applaud this decision, as it will capture many of the potential efficiencies that remain untapped in the Western Interconnection. While WAPA may incur costs during the initial transition to an EIM, ultimately the move should reduce the overall costs for WAPA's customers.

4. WORKING WITH CONGRESS TO MODERNIZE OVERSIGHT OF THE PMAS:

As discussed above, the statutes governing the PMAs are extremely complex. There are hundreds of different statutes--the earliest dating back to 1902--that affect how and to whom the PMAs market Federal power. Of course, there are also a plethora of statutes that apply to all entities in the electric sector including the PMAs, such as reliability standards and environmental laws. The maze of statutes can divert the PMAs' attention away from building and maintaining the infrastructure needed to compete in the global economy.

One of the PMAs, BPA, has a revolving fund that allows it to fund capital improvements. However, two PMAs--WAPA and SWPA[4]--must obtain Congressional approval to invest in even modest capital improvement, which could inadvertently limit the PMA's ability to maintain the reliability of the transmission grid.[5] The PMAs should be given the financial rights and responsibilities to go along with their existing responsibilities for keeping the lights on.

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[4] While SEPA must also get Congressional approval for capital improvements, it does not own or operate transmission lines. Therefore, its ability to finance capital improvements does not directly affect grid reliability.

[5] Historically, the PMA customers have recognized the difficulties created by this model and have worked with the PMAs either to fund directly capital projects or to pre-pay some of their utility bills allowing the PMA to use these customer advances towards capital improvements.

DOE will be asking Congress to provide both WAPA and SWPA with a revolving fund similar to BPA.

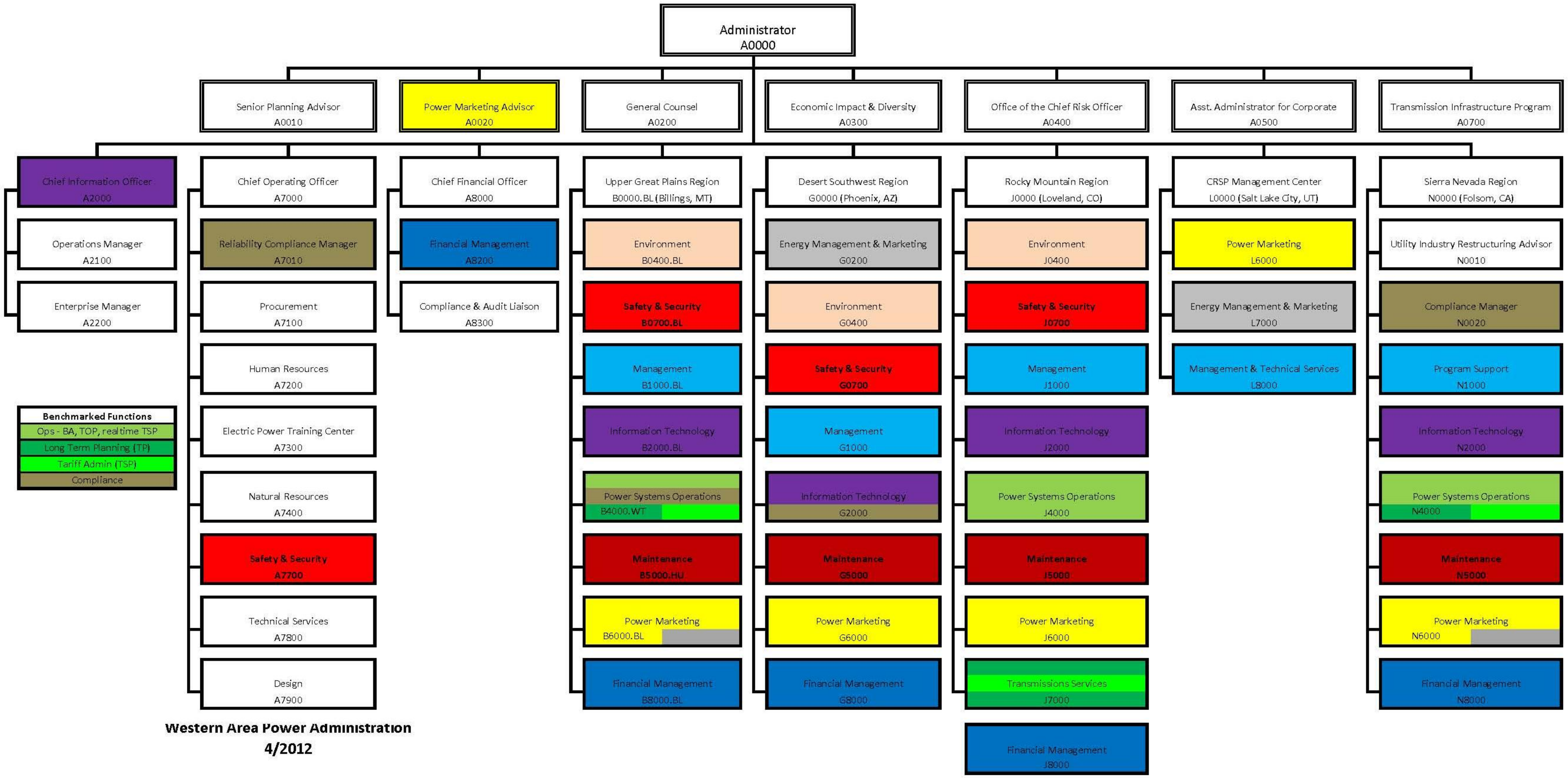
CONCLUSION:

The PMAs have done an admirable job delivering federal hydropower over the last century. However, while continuing a commitment to cost-based rates, the PMAs must now rise to the challenges of the 21st century. Just as DOE is calling on the private sector to help our Nation win the future, DOE and the PMAs must do the same. The federal government should be leading the way for a modern, secure and reliable electric transmission grid.

APPENDIX C-1

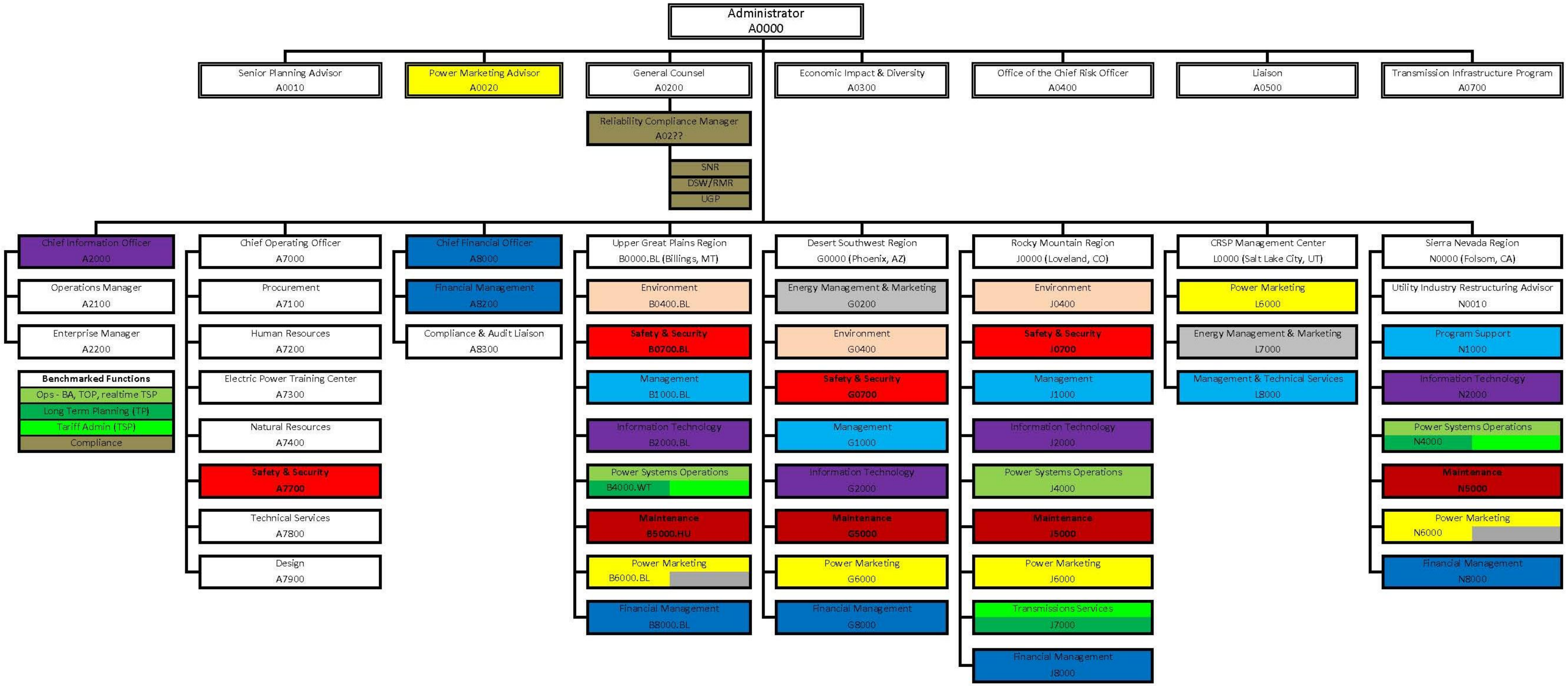
Alternative Assessment Organizational/Functional Charts

Current



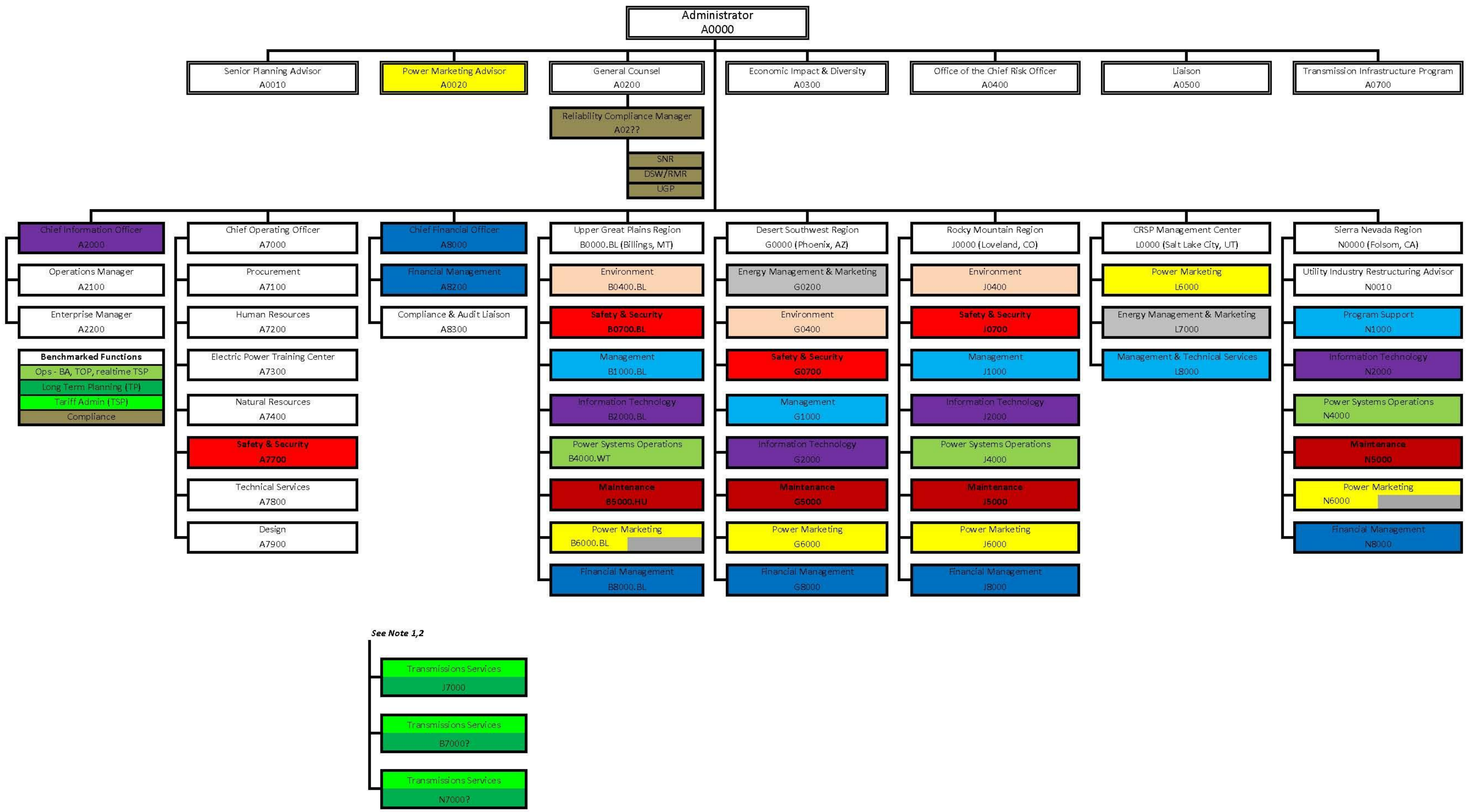
APPENDIX C-2

Move Compliance



APPENDIX C-3

Consolidate TP and TSP

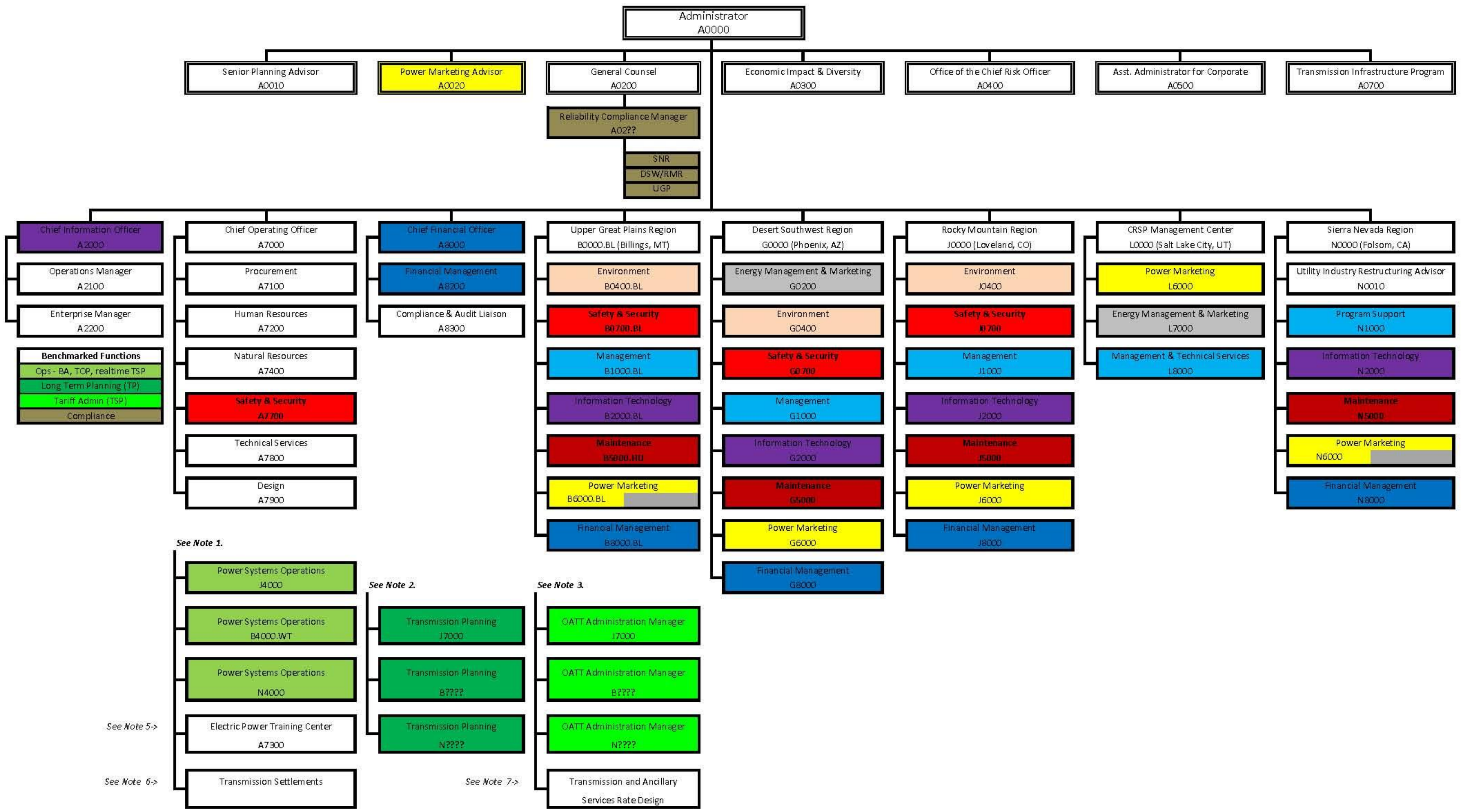


1) Consolidated Transmission Planning/Transmission Services Group could report to COO, a Regional Manager, or a new position reporting to the Administrator.

2) Transmission Planning and Transmission Services functions could be further separated and report to two different COO's, Regional Managers or a new positions reporting to the Administrator.

APPENDIX C-4

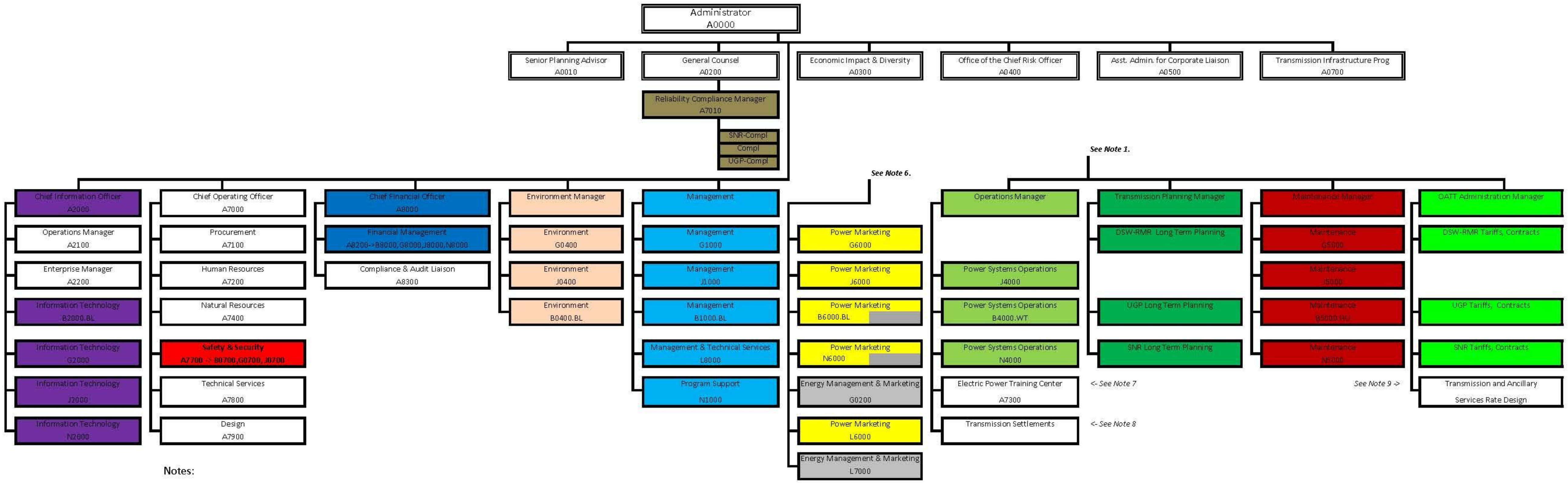
Consolidate TP, TSP, and TOP

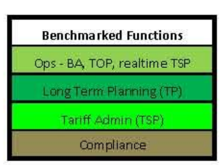


Notes:
1) Consolidated Ops group could report to COO, a Regional Manager, or a new position reporting to the Administrator.
2) Consolidated Transmission Planning Group could report to COO, a Regional Manager, or a new position reporting to the Administrator.
3) Consolidated Transmission Services/Contracts Group could report to COO, a Regional Manager, or a new position reporting to the Administrator.
4) TP-TSP functions could be under a single reporting structure as they currently are within the RMR organization.
5) The Electric Power Training Center could report to the new consolidated Operations Group as a variation on this alternative.
6) The Transmission Settlements could report to the new consolidated Operations Group as a variation on this alternative.
7) The Transmission and Ancillary Services Rate Design could report to the new consolidated Operations Group as a variation on this alternative.

APPENDIX C-5

Full Consolidation





Notes:

1) Consolidated Transmission Group would most likely report to a "Vice Administrator of Transmission."
2) Based on the benchmarking analysis, many of these functions would remain geographically dispersed, but could be centrally managed or supervised.
3) Some functions such as long term planning could be geographically centralized.
4) Separating UGP and SNR Long Term Planning from Operations Engineering may be difficult due to limited staffing.
5) SNR and UGP also have limited staffing for Tariff Administration.
6) Power Marketing Organization would most likely report to a "Vice Administrator of Power Marketing."
7) The Electric Power Training Center could report to the new consolidated Operations Group as a variation on this alternative.
8) The Transmission Settlements could report to the new consolidated Operations Group as a variation on this alternative.
9) The Transmission and Ancillary Services Rate Design could report to the new consolidated Operations Group as a variation on this alternative.