U.S. Department of Energy
Office of Inspector General
Office of Audit Services

Audit Report

Electricity Transmission Scheduling at the Bonneville Power Administration

DOE/IG-0637

February 2004

U. S. DEPARTMENT OF ENERGY
Washington, DC 20585

February 4, 2004

MEMORANDUM FOR THE SECRETARY

FROM: Gregory H. Friedman
Inspector General

SUBJECT: INFORMATION: Audit Report on "Electricity Transmission Scheduling at the Bonneville Power Administration"

BACKGROUND

The Department of Energy's four power marketing administrations are responsible for marketing, selling, and transmitting power produced largely at various Federal dams. Bonneville Power Administration (Bonneville), the largest of the power marketing administrations, is responsible for a territory of 300,000 square miles including Oregon, Washington, Idaho, western Montana, and small portions of several adjoining states. Bonneville's transmission system–which includes over 15,000 miles of transmission lines–accounts for about three-quarters of the high-voltage grid in the Pacific Northwest. Bonneville's system also includes major links with other regions, and other utility customers transmit power across Bonneville's transmission lines.

In April 1999, the North American Electric Reliability Council published functional specifications for electronic tags, in order to standardize the processing of transmission transactions. Currently, Bonneville relies primarily on its real-time operations dispatch and scheduling system (RODS), which was developed in the 1970s, to schedule transmission transactions across its grid. To meet new requirements, Bonneville initiated development of the Electricity Transaction Management System (ETMS) project in July 1999.

The objective of this audit was to determine whether Bonneville has a scheduling system in place to meet current and future transmission needs in an automated, deregulated environment.

RESULTS OF AUDIT

Bonneville is currently operating a hybrid system of both RODS and ETMS in order to schedule transmission transactions. This ad hoc arrangement does not fully meet its needs in the current operating environment. Bonneville originally expected to have ETMS fully operational by June 2000, but has yet to accomplish this. Specifically, ETMS cannot yet meet the need for rapid, reliable, and accurate electronic tagging and scheduling of a large volume of complex transmission transactions. Bonneville's management of the ETMS, a $25 million effort, lacked a comprehensive project plan, and system development and implementation procedures. Additionally, the effectiveness of the project management effort was hampered by the lack of standardized transmission contracts, which made it difficult to develop software codes to handle the nuances of each unique contract.

Correcting these deficiencies will benefit Bonneville and its transmission partners by minimizing future risk and expenditures. For example, automated scheduling would enhance Bonneville's electrical transmission grid by allowing Bonneville to react more quickly to disruptive events, such as a May 2003 incident in which Bonneville exceeded the operating capacity of one of its transmission lines. Moreover, Bonneville will have to spend substantial funds beyond its investment to date to complete ETMS if it is to provide a fully functioning automated scheduling capability, as originally intended.

Other electric industry participants have had success in implementing automated scheduling systems, partly because they properly considered alternatives. For example, after a 3-month pilot project to develop an automated scheduling system, Western Area Power Administration (Western) identified cost and performance concerns for one of its regions. Based on its evaluation of the pilot and its examination of a number of alternatives, Western chose a different development strategy using a combination of contractors and in-house developers. This region now has a fully functional automated scheduling system. While we recognize that Bonneville's and Western's system requirements and operations are significantly different, Bonneville could benefit from a thorough analysis of all options to acquire an automated scheduling system.

MANAGEMENT REACTION

Bonneville management, in responding to a draft of this report, concurred with the recommendations and agreed to take corrective actions. Management expressed the view that the draft report contained some incorrect observations. We addressed these concerns in the final report. Management also stated that, since the beginning of the project, it had faced a fluid environment from changing industry technology, business practices, and regulation and customer concerns and needs, and that these challenges made managing the ETMS difficult. We recognize management's point, but believe that in such an environment it would have been especially important to establish a definitive baseline and change control process to facilitate achieving the project goals. Management's verbatim comments are included as Appendix 3.

Attachment

cc: Deputy Secretary
Under Secretary for Energy, Science and Environment
Administrator, Bonneville Power Administration

ELECTRICITY TRANSMISSION SCHEDULING AT THE BONNEVILLE POWER ADMINISTRATION

TABLE OF CONTENTS

TRANSMISSION SCHEDULING SYSTEM

Background

Changes in the electric industry's regulatory environment have created the need to standardize and automate the processing of transmission transactions. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888 requiring utilities to provide open access to their transmission systems. The intent of this order was to remove impediments to competition and move toward deregulation in the electric power industry. Over the past few years, the movement towards deregulation has resulted in an exponential increase in both the complexity and volume of transmission data. Therefore, transactions must be handled more efficiently than in the past. To meet this need, the North American Electric Reliability Council (NERC) has standardized transmission processing requirements across the United States and Canada.

NERC intended standardization to occur through the use of electronic tags (e-tags) for each transaction. E-tags are submitted by customers, and describe a transmission transaction from its point of origin to its final destination. They also contain information on the physical path of the transaction and the amount of power to be transmitted. NERC first published functional specifications for e-tags in April 1999. About this time, the Bonneville Power Administration (Bonneville) recognized the need to automate its transmission scheduling to operate in the modernized business environment and to address FERC and NERC directives.

Scheduling System

Bonneville does not have a scheduling system in place that meets its needs in an automated, deregulated environment. Bonneville's Transmission Business Line has been using the real-time operations dispatch and scheduling system (RODS) for over 30 years to schedule transmission across its lines. However, RODS is an antiquated system that cannot perform as required in an automated, deregulated environment. It requires users to manually process transmission requests. Therefore, Bonneville contracted with a company in July 1999 to develop the Electricity Transaction Management System (ETMS), which would automate the transmission scheduling process. Bonneville originally expected ETMS to be fully implemented by June 2000. As of December 2003, ETMS is not fully implemented and Bonneville is uncertain when that will occur. As such, schedulers–the users of ETMS– must operate a hybrid system of both RODS and ETMS in order to schedule and track transmission transactions.

Although ETMS has undergone development and implementation for over 4 years, it has not demonstrated satisfactory performance. For instance, according to the contract, ETMS should be capable of processing at least one e-tag every 3 seconds. However, ETMS is often slow, and it can take minutes rather than seconds to process an e-tag. Also, ETMS "crashes" frequently without notification to the schedulers that it is down. The schedulers do not receive any e-tags when ETMS is down and only become aware of the problem when they receive phone calls from frustrated customers requesting action on e-tags. Furthermore, the system does not always provide accurate information. For example, ETMS recently displayed an e-tag with an incorrect value of one billion megawatts. When the schedulers examined the e-tag further, they found that the supporting data package for the e-tag showed only 21 megawatts, which was the correct value. As these problems have persisted throughout the years, schedulers have become skeptical about ETMS's ability to perform adequately.

In response to our draft report, Bonneville stated that a significant number of ETMS functions are now operational. While we recognize that some capabilities are functional, the system is still incapable of replacing RODS and meeting the demands of the automated, deregulated business environment.

During the audit, Bonneville began performing a "gap analysis" to determine the functionality of ETMS and to identify what components are necessary to achieve full implementation. The analysis will assist Bonneville in determining the remaining scope of the project, as well as future cost and schedule requirements. While we see the analysis as positive, it would have been helpful to conduct it much earlier in the project. In addition, the completed analysis should be used as a tool to thoroughly examine all alternatives available. These alternatives include completing ETMS with the current contractor, using other contractors, in-house development, or some combination if needed.

Other electric industry participants have found such an examination to be useful. For example, in 1999, the Department of Energy's (Department) Western Area Power Administration (Western) initiated a 3-month pilot project to develop an automated scheduling system for one of its regions. However, at the end of the pilot, Western examined other alternatives, since it had encountered significant cost and performance concerns. Western then chose a different development strategy using a combination of contractors and in-house developers. This region currently has a fully functional automated scheduling system in place.

In responding to the draft report, Bonneville stated that the reference to Western's approach was inappropriate considering the differences in magnitude and complexity between the two systems. However, inclusion of the example in the report was not provided to advocate a particular solution. Rather, it was provided to underscore the need to assess alternatives throughout the whole system development process.

Project Execution

When Bonneville initiated the effort to convert transmission scheduling to an automated system, key project management controls were overlooked. Specifically, Bonneville did not develop a comprehensive project plan prior to initiating system development activities or adequately involve users in the project. Also, we found that Bonneville lacked adequate internal policies or procedures to govern system development and implementation. Finally, a lack of standardization on Bonneville's transmission contracts made it inherently difficult to develop software codes to handle the nuances of each unique contract.

Project Plan

According to the Department's "Information Systems Engineering Guidance," effective project management includes developing an overall project plan with a clearly identified work scope, and measurable cost and schedule milestones. However, Bonneville did not develop a detailed, comprehensive project plan for ETMS, even though it is a large, complex project. Without such a project plan, the scope and requirements of ETMS were not clearly defined. Therefore, frequent changes were made throughout the development of ETMS. Although some changes were driven by external regulatory requirements, a substantial amount were a result of internal requests from Bonneville.

User Input

Also, Bonneville did not consistently involve the schedulers in the development of ETMS. For example, they were not consulted about changes that impacted the functional capability of ETMS. It is important that the schedulers be involved in all aspects of system selection and development to ensure that their needs are adequately met. In turn, this would increase the likelihood that the schedulers will feel a commitment to the success of automated scheduling. In addition, many "work-around" systems were developed to help bridge the gap between RODS and ETMS. Unfortunately, these work-around systems often created more work for the schedulers. Management recently recognized these systems were detracting from the focus on full implementation of ETMS and, therefore, terminated some of them.

System Development Procedures

Bonneville lacks formal, consistent policies and procedures to govern system development and implementation projects such as ETMS. Though the Department has established software development guidance, no one we spoke with at Bonneville indicated that this or other system development or project management guidance was used in the development of ETMS.

Lack of guidance for information technology projects contributed to many of ETMS's past development problems. The Department's guidance outlines the need for knowledgeable project managers and good stakeholder communication plans. However, project management personnel did not have sufficient information technology knowledge or experience. To its credit, Bonneville had assigned a project manager with such expertise to ETMS. However, this position has recently been vacated, and it is important that Bonneville fill this vacancy with a project manager possessing similar information technology knowledge and experience.

Additionally, Bonneville's Chief Information Officer is in the process of initiating Project Management Offices (PMOs) within each business line. The PMOs are intended to disseminate policies and guidance to the business lines and standardize the project management approach across Bonneville. Given the developmental problems associated with ETMS, we fully support these efforts and encourage their timely implementation.

Transmission Contracts

A business decision by Bonneville not to standardize its transmission contracts–which provide input data to ETMS–made it inherently difficult to develop software codes to handle the nuances of each unique contract. For example, 31 percent of Bonneville's current transmission contracts require special coding and programming in order to make automation work. Therefore, most development work has been focused on customizing ETMS to accommodate these non-standardized contracts and their varied product types. Although Bonneville originally purchased ETMS with the intent of deploying a commercial "off-the-shelf" software package, it has been customized to such an extent that it can no longer be considered off-the-shelf.

Minimizing Risk and Expenditures

Fully automated scheduling tools would enhance the electrical transmission grid by allowing Bonneville to respond to and minimize potentially disruptive events. For example, on May 28, 2003, Bonneville exceeded the operating capacity on one of its transmission lines. In order to function within that capacity, the dispatchers requested the schedulers to make changes to the transmission schedules. The schedulers were not able to make the changes quickly enough, partly because the existing scheduling tools are inadequate. As a result, Bonneville exceeded the operating capacity for over 30 minutes, and received a letter of reprimand from one of NERC's regions.

We recognize that dispatchers have the authority to take any action to maintain the reliability of the transmission grid. However, having the necessary automated scheduling tools would allow Bonneville schedulers access to precise information, enabling them to react more quickly to changes and reducing the pressure on dispatchers to act. Furthermore, adequate scheduling tools would better enable Bonneville to make changes to transmission schedules in accordance with Bonneville's transmission tariff and contractual obligations, reducing the financial risk associated with those changes.

Moreover, Bonneville has spent considerable funds to develop an automated scheduling capability. The original contract amount was for approximately $2 million, but numerous contract modifications arising from changes in scope and requirements have increased the cost of ETMS. An internal management review conducted by Bonneville indicated that estimated costs for implementation of ETMS through Fiscal Year 2003 are at least $25 million. Additionally, Bonneville will have to incur further costs to fully automate its transmission scheduling function.

In responding to our draft report, Bonneville stated that the $2 million was for the purchase of 12 licensing agreements, maintenance of those agreements, and initial customization products that did not represent the fully functional system Bonneville believed it would ultimately need. Further, it was known that the scheduling system would need to accommodate changes in requirements. We have concluded that regardless of the point at which a full system was envisioned, Bonneville needs a detailed project plan to better estimate the total costs of a complete scheduling system.

Because the system was still not functional, Bonneville developed other interim systems to bridge the gap. For example, Bonneville spent at least $3.7 million on a system designed to provide transition support from RODS to ETMS for Bonneville's customers. This system no longer supports ETMS; however, Bonneville officials told us that it is being used elsewhere in Bonneville. In the future, implementing sound project management principles should help Bonneville minimize such expenditures.

RECOMMENDATIONS

We recommend that the Bonneville Administrator:

1. Direct Transmission Business Line management to:

   a. Thoroughly identify and analyze all options to acquire an automated scheduling system and solicit scheduler input to select the most efficient and cost-effective option;

   b. Develop and implement a comprehensive, detailed project plan with realistic milestones and deliverables for the chosen option; and,

   c. Consider standardizing future transmission contract provisions and product types to facilitate automation of the scheduling system to the greatest extent possible.

2. Accelerate efforts to implement Project Management Offices across Bonneville and utilize existing Federal system development guidance.

MANAGEMENT AND AUDITOR COMMENTS

Bonneville management concurred with the recommendations and agreed to take corrective actions. However, Bonneville was concerned that the report contained some incorrect observations. We have addressed most of these concerns throughout the report and included management's verbatim response as Appendix 3. Three additional matters relating to management comments are addressed below.

Bonneville alleged that the auditors did not interview the original contracting officer for ETMS. However, the audit team met with numerous employees and functional experts from the Transmission Business Line. In particular, the team interviewed the contracting officer referenced in Bonneville's comments.

In addition, management stated that the scheduling and reliability functions are largely independent of each other. Based on discussions with management officials, we have revised the report to more precisely characterize the relationship between the two functions. While we recognize that the dispatchers can intervene to help prevent capacity violations, an up-to-date scheduling function would minimize the need to exercise such a measure and protect Bonneville's financial interests as well.

Finally, while management concurred with the recommendations, its corrective action for recommendation 1(a) is not fully responsive. Specifically, in concurring with recommendation 1(a), Bonneville stated that an analysis of options took place in early Fiscal Year 2003 as part of a consultant review. However, based on our review, we concluded that the purpose of the report was to perform a risk assessment of the ETMS project and not to evaluate available options. The report provided many recommendations on how to improve the ETMS development effort, but did not consider other options outside of the existing contractor. As such, we believe that additional steps are necessary to address the intent of recommendation 1(a).

Appendix 1

PRIOR AUDIT REPORTS

- *Commercial Off-The-Shelf Software Acquisition Framework* (DOE/IG-0463, March 2000). This report concluded that the Department of Energy had not developed and implemented software standards, a key component of a commercial off-the-shelf acquisition framework. The Department's inability to establish a framework was due to its decentralized information technology strategy and a lack of organizational support. Also, Department-wide software standards, necessary to support an acquisition framework, had not been established.

- *Implementation of Integrated Business Information Systems Within the Department of Energy* (DOE/IG-0466, April 2000). This audit report found that of eight contractors selected, two contractors had not implemented integrated business information systems. One contractor terminated its project to implement an integrated information system after investing 9 months and $11.5 million, and the other contractor terminated its project after spending over 2 years in development and $3.6 million in related costs. The contractors did not follow Federal and Departmental guidelines for software projects. For example, project plans were not prepared, and the project scope was not adequately defined. As a result, the Department received no appreciable benefit from the $15.1 million invested in the new systems at these sites.

- *Information System Development Practices at the Bonneville and Western Area Power Administrations* (DOE/IG-0586, February 2003). The report concluded that Bonneville and Western information system development activities were not always consistent with Federal requirements or guidance. Significant problems were found with 9 out of the 11 major projects reviewed. For example, the absence of key system development activities such as conducting an initial cost-benefit analysis and close monitoring for a Bonneville project contributed to schedule slippages of over two years and the write-off of about $9 million for the abandoned portion of the system development. Also, development delays of more than two years, and modifications costing more than $600,000 to a commercial off-the-shelf application, occurred because Bonneville did not perform a detailed analysis to identify shortfalls or examine opportunities to improve existing business processes prior to implementation.

Appendix 2

OBJECTIVE

The objective of the audit was to determine whether the Bonneville Power Administration (Bonneville) has a scheduling system in place to meet current and future transmission needs in an automated, deregulated environment.

SCOPE

The audit was performed at Bonneville in Portland, Oregon, and Vancouver, Washington, between May and December 2003. The audit covered Bonneville's efforts to develop and implement the Electricity Transaction Management System (ETMS) between July 1999 and December 2003.

METHODOLOGY

To accomplish our objective, we:

- Held discussions with program officials and personnel from Bonneville's Transmission Business Line, as well as Bonneville contract employees;
- Reviewed the ETMS contract and documentation related to system development and ETMS implementation;
- Observed transmission scheduling operations within Bonneville; and,
- Reviewed the *Government Performance and Results Act of 1993* and determined if performance plans and measures had been established.

The audit was performed in accordance with generally accepted Government auditing standards for performance audits and included tests of internal controls and compliance with laws and regulations to the extent necessary to satisfy the audit objective. Because our review was limited, it would not necessarily have disclosed all internal control deficiencies that may have existed at the time of our audit. We generally did not rely on computer-processed data to accomplish our audit objective.

We discussed the audit results with Bonneville management on January 15, 2004.

Appendix 3

United States Government **Department of Energy**

Bonneville Power Administration

DATE: November 17, 2003

REPLY TO ATTN OF: TM/Ditt2

SUBJECT: Response to Draft Audit

Office of the Inspector General (OIG)

This responds to your draft audit that examined a BPA information technology development project, known as the Electricity Transaction Management System (ETMS). ETMS supports transmission scheduling and is replacing BPA's Real-Time Operations Dispatch and Scheduling System (RODS). BPA concurs in your recommendations, specifically:

1a. We have extended our efforts to identify and analyze options. In October 2002 we hired the Tellefson Consulting Group to analyze our efforts and evaluate options available to us. We accepted their recommendation to "stay the course" by having SoftSmith continue to adapt its application software to meet BPA's unique needs. We agreed with Tellefson's finding that this is the most efficient and cost-effective option available for achieving the full functionality that we need. We have instituted new, formal communication processes to improve involvement of scheduling staff, end users and customers in the further development of the ETMS project plan and rollout.

1b. We are in the process of developing and implementing an updated project plan that is more comprehensive and detailed. It will include realistic milestones for the deliverables. We have reassigned organizational responsibility for ETMS and brought in a new management team, with greater IT experience, to oversee the project. We are aggressively tracking and managing expenditures.

1c. We are reviewing current transmission product offerings for potential reductions in complexity and increased ease in implementation of scheduling automation. About 7,500 megawatts of BPA's 30,000 megawatts of long-term transmission demand is under long-term contracts that pre-date our 1996 Open Access Transmission Tariff (OATT) and guarantee a complex array of product features. The cost to renegotiate these legacy contacts could be prohibitive. We note, too, that Federal Energy Regulatory Commission (FERC) changed the product features they required under OATT during our development of the ETMS project, and recent FERC decisions have greatly expanded requirements of utilities to offer partial interim service and modifications of service on a firm basis.

2. We will accelerate our Project Management Officer initiatives across BPA. These are in alignment with Department of Energy guidelines. A PMO has been set up for the ETMS project.

While we believe that your recommendations are sound, we are disturbed that the draft report contained many factually incorrect observations. We note that the OIG audit team did not interview the contracting officer who handled the contract from the beginning of the project through 2002. Due to the limitations that you place on the length of this response, we will address only the most seriously misleading of your findings:

First, your draft report painted a bleak picture of unreliability on the BPA transmission system should ETMS not be implemented fully and quickly. After further work, the OIG audit team found that this was incorrect, assured us that this characterization would not appear in your final report, and provided revised language regarding how ETMS would "enhance" reliability. This revision does not adequately convey the fact that the scheduling and reliability functions are largely independent of each other. Schedulers focus on the marketing function. BPA's dispatchers have ultimate responsibility for assuring that the transmission system stays operational in the face of unplanned, unintended or unpredictable events. Dispatchers will do whatever is necessary, including override schedules and re-dispatch generation, to ensure physical reliability of the system. Dispatchers possess a number of tools to manage system reliability, including instability detection systems, automated switching, remedial action schemes and standing orders for manual intervention. ETMS may reduce "economic damage" but it will not substitute for the reliability assurance of dispatch.

Second, your draft report would have the reader believe that costs for a scheduling system to replace RODS had ballooned from $2 million to $25 million. The $2-million figure actually refers to a $1.78 million purchase of 12 licensing agreements with SoftSmith, maintenance of those agreements and some initial customization products that did not comprise, in our view at the time, the full functionality we believed we would need. The ETMS statement of work at the time also made clear our expectation that the scheduling system development effort would need to accommodate changes in requirements that could be many and complex – a continuing challenge to the contractor.

Invoices for project work through the end of fiscal year 2003 now total about $25 million, but our estimate for the remaining work to bring us into full compliance with FERC, NERC and WECC standards and to set the stage for ongoing support of the still-evolving scheduling function is about $9 million. The total is in alignment with the costs other schedulers are incurring to upgrade the more complex systems, which we have found to range up to $40 million. BPA's scheduling operation is the second largest in North America. Consequently, your audit's reference point to work done on the Western Area Power Administration's very small system does not reflect a true comparison to BPA's scope, number of transactions or system complexity.

Finally, your draft report suggests that moving our system from RODS to ETMS is largely unfinished, with no timetable for completion. In fact, a significant number of functions are now operational on ETMS, including:

The database to track operating transfer capability; automated search functions to track electronic tags for customers; electronic web interfaces to allow customers to view their scheduling requests in real time; automated functions to calculate available transmission capacity (ATC); automated check-out functions to allow BPA to compare and confirm schedules with utilities in adjacent control areas; automatic upload of power schedules from BPA's Power Business Line; automatic information access to verify reservation requests from the transmission contracts database; automated screen view of 24-hour checkout process; upgraded OASIS interface to verify reservations and ATC; upgraded screens to assist in troubleshooting scheduling discrepancies; screens to track reservations, contract data and capacity; automated access for customer inputs of schedules; search mechanism to access all ETMS data; automated tagging system to process electronic tags; and the association of schedules with tags.

Work remains to be completed on the following:

Several product/service categories; automated tag verification procedures; completing automated checkout tools; ATC functionality for several transmission paths; completing curtailment functionality; completing interface to automatic generation control: completing interfaces with Dispatch and Operations; developing transmission loss calculation functionality; improved and enhanced performance; and implementing ancillary services functionality.

Since the beginning of the project, we have faced a fluid environment from changing industry technology, business practices, regulation and customer concerns and needs. Since 2002, we have engaged more aggressive project direction and new management oversight. Our objective is to complete all portions of the project that are necessary to meet WECC requirements by 2005.

If you have any questions, please contact Charles E. Meyer, Vice President for Transmission Marketing and Sales at (360) 418-8244.

Sincerely,

Jeffrey K. Stier, Vice President
National Relations

IG Report No.: DOE/IG-0637

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