NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

TADS Section 1600 Request: Comments and Responses

Proposed Element Inventory and Quarterly Data Collection

December 2012

RELIABILITY | ACCOUNTABILITY

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Executive Summary

The Transmission Availability Data System (TADS) data collection began with the establishment of the Transmission Availability Data System Task Force (TADSTF) under the NERC Planning Committee (PC) in October 2006. On October 27, 2007, the NERC Board of Trustees (BOT) approved the collection of TADS Phase I data beginning in calendar year 2008. On October 29, 2008, the NERC BOT approved the collection of Non-Automatic Outage data beginning in calendar year 2010 (Phase II).[1] To date, this data has been collected on an annual basis.

At its September 18-19, 2012 meeting, the PC approved the request for public comment on the proposed TADS element inventory and quarterly data collection.[2] The revised TADS data request would require data to be submitted on a quarterly basis rather than an annual basis. The data request also requires reporting of key element inventory data for individual circuits rather than only total applicable element counts and total element circuit miles. NERC requested public comment of this revised data request for a forty-five day comment period beginning on October 5, 2012.[3]

Reliability Benefits from the Change

NERC is proposing a modification to the TADs data request under Section 1600 of the NERC Rules of Procedure to collect outage and key element inventory data on a quarterly reporting period. Collecting TADs data each quarter rather than annually enables consistent reporting and metric display across all NERC data (such as Generating Availability Data System (GADS), and protection system misoperations which are provided on a quarterly basis). Collecting this data on a quarterly basis will also assist an entity's ability to provide the data in a timely manner through a less labor intensive review of the data. The current annual submission of TADs data does not align with other NERC metric reporting periods, and reporting transmission outage data annually causes delays in reliability risk assessment due to the large volume in a limited amount of time.

NERC uses the severity risk index (SRI) to measure risks to reliability from major events.[4] Transmission outages contribute to 30 percent weighted severity assessments. With the current practice of annual outage reporting, the calculation of this index is delayed until after March 21st of the following year. Without the quarterly data submittal, NERC will not be able to reconcile event reports of transmission outages with collected transmission outage data in a timely fashion to support event analysis until well after the events occur. A learning organization such as NERC needs to be able to develop lessons for the industry more quickly.

[1] Two reports, available at http://www.nerc.com/filez/tadstf.html, describe the TADS Phase I and Phase II data collection efforts.
[2] http://www.nerc.com/docs/pc/DRAFT_PC_Meeting_Minutes_September_2012mm.docx.pdf
[3] http://www.nerc.com/docs/pc/tadswg/Draft_1600_Data_Request_Letter_TADS_Quart_Inv.pdf
[4] http://www.nerc.com/docs/pc/rmwg/pas/index_team/SRI_Equation_Refinement_May6_2011.pdf

Additionally, only total applicable element counts and total element circuit-miles are provided to NERC by Transmission Owners (TOs) through this data collection effort. Key inventory data for individual circuits and circuit miles along with outages associated with those circuits are currently not collected. Without this information, analysis of important explanatory variables affecting transmission performance determined by transmission line exposure (*e.g.,* circuit-miles, number of terminals, *etc.*) cannot be conducted, which is vital to determine indicative trends requiring industry attention. Further, the data and output analysis cannot be used to support probabilistic planning studies and root cause analysis.

Inventory data would also help support planning studies such as determination of credible contingencies and bridging gaps between operating and planning assumptions, as outlined in section 2.6 (Intended Uses and Limitations of Data and Metrics) of the 2007 TADS report.[5] Evaluating single (category B) and multiple (category C) outages will result in improved transmission system performance.

For these reasons, NERC is requesting Board approval of a revised data request to be issued under Section 1600 of the NERC Rules of Procedure that will request quarterly collection of transmission outage data and key inventory attributes beginning in the data reporting period 6 months after NERC Board of Trustee approval of the data request.

Industry Comments

At the close of the 45-day public comment period, NERC received 27 comments: 24 responses from Transmission Owners (TOs) already responsible for TADS reporting and 3 responses from other organizations. One common concern by respondents is the additional resources and time needed to gather terminal type (ring bus, break-and-half, straight bus, etc.), which can have significant bearing on performance. Public comments to incremental costs were wide ranging and inconsistent; results were inconclusive. The Transmission Availability Data System Working Group (TADSWG) evaluated and responded to each comment submittal.[6]

Recommendation

After reviewing these comments and considering the goals of data collection to be used to prioritize reliability issues, TADSWG recommended the following modifications and extensions of inventory reporting timeline:

1. Reduce reporting of the initial inventory data fields (element identifier and circuit mileage) to two beginning six (6) months after the NERC Board of Trustee approval, rather than the total six (6) fields.
2. Other inventory data, including terminal type, will be delayed to twelve (12) months after the NERC Board of Trustee approval.

[5] http://www.nerc.com/docs/pc/tadstf/TADS_PC_Revised_Final_Report_09_26_07.pdf
[6] http://www.nerc.com/docs/pc/tadswg/Section_1600_Quarterly_Inventory_Data_Request_Comment_Responses.pdf

3. Historical precursor elements and reconfiguration dates, prior to the start of reporting key inventory fields, will not be requested. This eliminates the labor intensive historical research effort originally proposed. The initial reconfiguration date for Elements would be the implementation date of the key inventory fields instead of using the initial in-service date prior to the implementation date of the key inventory fields.
4. Responding to industry input, quarterly collection and inventory updates will be extended based on the modified, staggered schedule in Table 1.

Table 1: TADS Transition Schedule

Due Date	TADS Outage Data	Key Inventory Data
March 01, 2013	2012 Annual (200 kV+ Elements Only)	
May 15, 2013		Element Identifier and Circuit Mileage Fields Only (200 kV+ Elements Only)
September 29, 2013	2013Q1 and 2013Q2 (200 kV+ Elements Only)	
November 15, 2013	2013Q3 (200 kV+ Elements Only)	
February 15, 2014	2013Q4 (200 kV+ Elements Only)	Update All Key Inventory Fields (200 kV+ Elements Only)
May 15, 2014	2014Q1 (All TADS Elements)	If Applicable, Element Identifier and Circuit Mileage Fields Only (Less than 200 kV BES Elements Only)
August 15, 2014	2014Q2 (All TADS Elements)	
November 15, 2014	2014Q3 (All TADS Elements)	
February 15, 2015	2014Q4 (All TADS Elements)	Update All Key Inventory Fields (All TADS Elements)

Introduction

On October 5, 2012, NERC posted a request for public response regarding Element key inventory data collection and quarterly Transmission Availability Data System (TADS) reporting. The completion date for public response was November 19, 2012. At the close of the 45-day public comment period, NERC received 27 sets of comments:

- 24 responses from TO's already responsible for TADS Reporting.
- 3 responses from non-utility organizations.

The following NERC regions were represented in the comments[7]:

- 4 responses from TO's in Midwest Reliability Organization (MRO)
- 3 responses from TO's in Northeast Power Coordinating Council (NPCC)
- 1 response from TO's in Reliability*First* Corporation (RFC)
- 9 responses from TO's in SERC Reliability Corporation (SERC)
- 1 responses from TO's in Southwest Power Pool, Inc. (SPP)
- 3 responses from TO's in Texas Regional Entity (TRE)
- 3 responses from TO's in Western Electrify Coordinating Council (WECC)
- 3 responses from companies not associated with a NERC Regional Entity

There were several key comments received from the comment sets submitted. Firstly, there were multiple entities who indicated that it would take significant effort to collect terminal type and number of terminals. Secondly, entities indicated concern with the short timeline to implement the quarterly reporting and key inventory data collection. Finally, a number of entities expressed concern with collecting historical precursor Elements and reconfiguration dates.

Firstly To begin, multiple entities indicated significant effort required to collect terminal type and number of terminals. Any new data collection does require effort. However, terminal type and number of terminals are necessary to help refine the statistical analysis of TADS data. The type of the terminal is related to the probability of dependent outages, and number of terminals gives an indication of the sophistication of the protection system needed for an Element. Both attributes are useful in statistical analysis of TADS data.

[7] Some TO's are registered in more than one Regional Entity

The terminal type is bucketed into one of the following 8 types:

a. Single Bus
b. Sectionalized Bus
c. Main and Transfer Bus
d. Ring Bus
e. Breaker-and-a-Half
f. Double Breaker-Double Bus
g. Directly connected to another Element (not necessarily a reportable Element)
h. Other

It is reasonable to assume that a TO would have an one-line diagram or transmission map of their system, and an experienced transmission engineer should not take more than 30 minutes to find the number of terminals and the configuration of each terminal for each Element in a substation. This process would only have to be performed once per year.

Having listed the terminals found on one or more AC Circuits, the terminal type found would be reported for each AC Circuit connected to that particular terminal. If difficulties are determined in the process for an entity, NERC is willing to provide technical assistance to help expedite the process.

Secondly, entities expressed concern with the timeline for the data request. Entities requested additional time to implement the changes and to align changes to the beginning of the year. TADSWG agrees with the recommendations from the comments and recommends a staggered data collection approach to both outage and key inventory data collection.

Outage data would commence quarterly reporting in 2013Q2 for 200 kV+ Elements only, to avoid interfering with the 2012 annual data reporting deadline. The data submitted would include both 2013Q1 and 2013Q2 outage data. TOs would have 90 days after the end of 2013Q2 to submit the data due to the inclusion of 2013Q1 and 2013Q2 data. Quarterly TADS data submittal would proceed 45 days after each quarter for 200 kV+ Elements only until 2014Q1. In 2014Q1, outage data for all TADS Elements would be reported.

Key inventory data will also follow a staggered approach. Forty-five days after the end of 2013Q2, the Element Identifier and Circuit Mileage fields will be required for 200 kV+ Elements only, as shown in Table 2 below. This is to initially populate the inventory. In 2013Q4, the key inventory fields would be updated for 200 kV+ Elements only. In the 2014Q1 submittal, entities would submit the Element Identifier and Circuit Mileage fields only for Elements less than 200 kV to initially populate the inventory. This would follow with a final key inventory data field submittal in 2014Q4 for all TADS Elements.

Table 2: TADS Transition Schedule		
Due Date	**TADS Outage Data**	**Key Inventory Data**
March 01, 2013	TADS 2012 Annual Data Reporting Submittal (200 kV+ Elements Only)	
May 15, 2013		Element Identifier and Circuit Mileage Fields Only (200 kV+ Elements Only)
September 29, 2013	TADS 2013Q1 and 2013Q2 Data Submittal (200 kV+ Elements Only)	
November 15, 2013	TADS 2013Q3 Data Submittal (200 kV+ Elements Only)	
February 15, 2014	TADS 2013Q4 Data Submittal (200 kV+ Elements Only)	Update All Key Inventory Fields (200 kV+ Elements Only)
May 15, 2014	TADS 2014Q1 Data Submittal (All TADS Elements)	If Applicable, Element Identifier and Circuit Mileage Fields Only (Less than 200 kV Elements Only)
August 15, 2014	TADS 2014 Q2 Data Submittal (All TADS Elements)	
November 15, 2014	TADS 2014 Q3 Data Submittal (All TADS Elements)	
February 15, 2015	TADS 2014 Q4 Data Submittal (All TADS Elements)	Update All Key Inventory Fields (All TADS Elements)

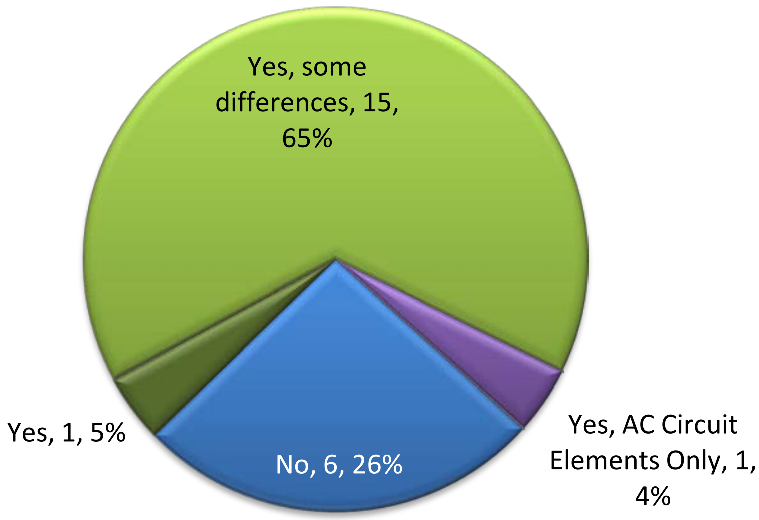
Finally, entities commented that providing historical precursor Element and reconfiguration date information was an onerous and burdensome task with little benefit. It was never the intent of either field to record historical information prior to the key inventory field implementation. These fields will only be used to record information subsequent to the implementation of the detailed inventory fields. The initial reconfiguration/change date should be entered as the initial implementation date for key inventory data.

The reconfiguration/change date should be changed only when the change to the Element would affect the Element's circuit miles. For example, if an AC Circuit has a new terminal placed into service on July 1, which increases circuit miles, the reconfiguration date should be updated to July 1 to allow the circuit mileage to be correctly calculated.

The following is a summary set of public comments:

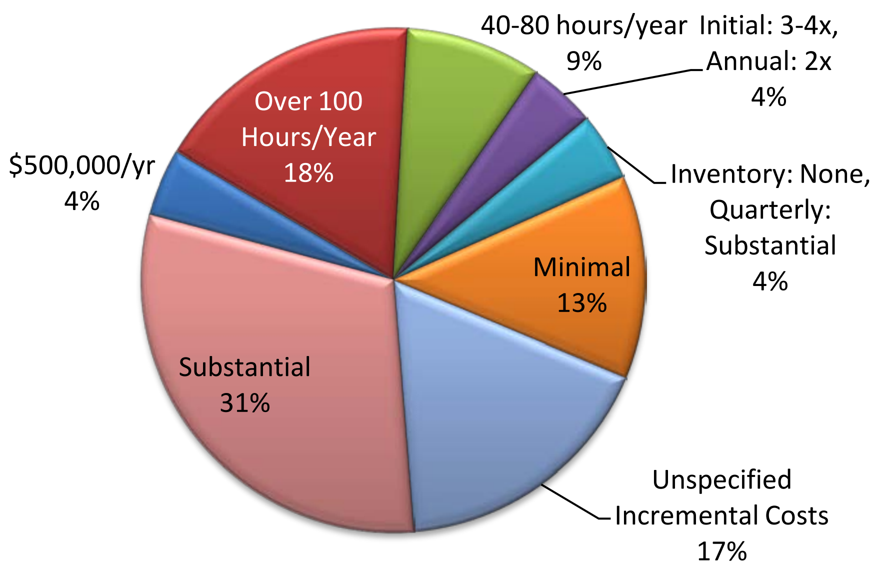
Question 1: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.

Figure 1: Key Inventory TADS Outage Data Collection (23 Responses)

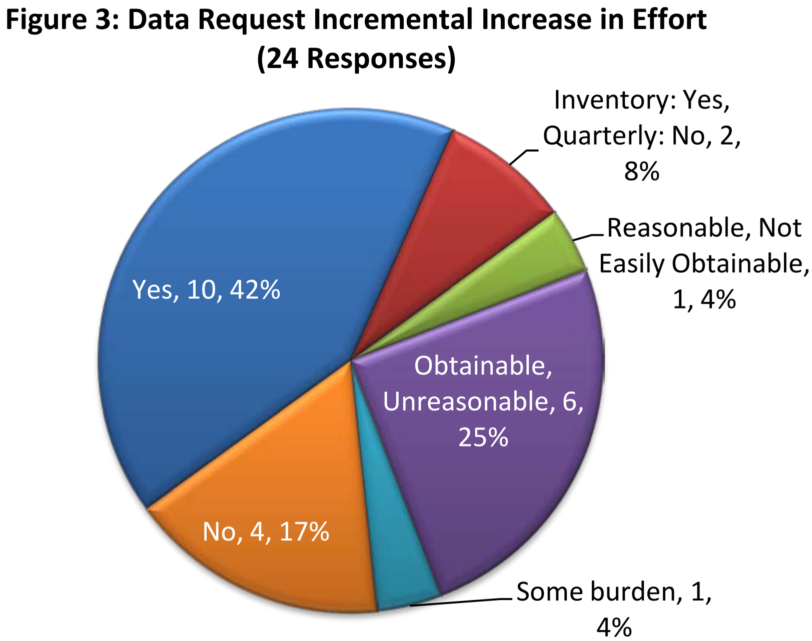


Question 2: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?

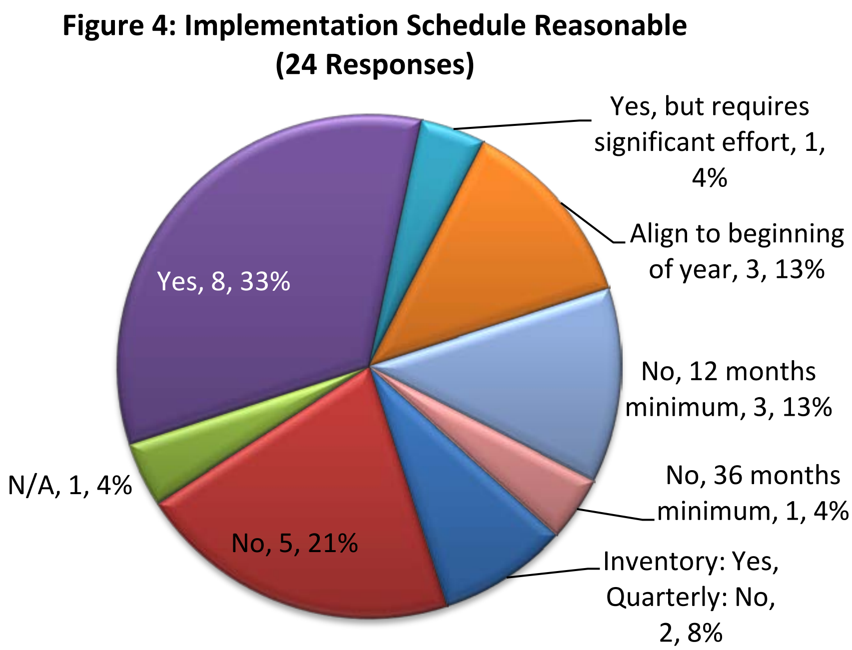
Figure 2A: Incremental Increase in Effort (23 Responses)



Question 3: Is the data being requested reasonable and obtainable? If "no," please explain.



Question 4: Is the implementation schedule for the request reasonable? If "no," please explain.



Question 5: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?

Table 3: Overall Costs, One Time System Modification, Annual Costs, and Annual Man-Hours				
TO Name	**Qualitative Costs**	**One Time Cost**	**Annual Costs**	**Annual Man-Hours**
Associated Electric Cooperative, Inc.			$500,000	
Ameren Services Company		$10,000s		
American Transmission Co. LLC			$8,000	
Austin Energy				80 (200 kV+) 320 (100 kV+)
Consolidated Edison	Minimal			
CenterPoint Energy		$26,000	$4,000	
Dominion Virginia Power		$30,000		
Duke Energy Corporation		4 to 6 Full Time Employees		2 Full Time Employees
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO	Unknown			
Great River Energy	Minimal (200 kV+) Incremental (100 kV+)			
Hydro One Networks	Unknown			
LCRA Transmission Services Corporation		50-60 Man-Hours		36
Manitoba Hydro	Unknown			
New York Power Authority	Minimal			
Oklahoma Gas and Electric Company	Manually Entered			

Table 3: Overall Costs, One Time System Modification, Annual Costs, and Annual Man-Hours				
TO Name	**Qualitative Costs**	**One Time Cost**	**Annual Costs**	**Annual Man-Hours**
Southern Company				140
Salt River Project Agricultural Improvement and Power District	Minimal			
Tennessee Valley Authority		$40,000	$10,000	
Xcel Energy	Minimal			
South Mississippi Electric Power Association	Initial: Substantial Annual: Minimal			
South Carolina Electric & Gas Company	3x to 4x Current Costs			
Bonneville Power Administration		$15,000		
Southern California Edison	Severe			

Question 6: Assuming you will have to develop a system to report outage data quarterly, what is the incremental cost comparing with reporting outage data annually?

Table A: Incremental Cost of TADS Proposal (23 Responses)

Table 4: Overall Costs, One Time System Modification, Annual Costs, and Annual Man-Hours				
TO Name	**Qualitative Costs**	**One Time Cost**	**Annual Costs**	**Annual Man-Hours**
Associated Electric Cooperative, Inc.	Minimal			
Ameren Services Company	Minimal			
American Transmission Co. LLC			$4,000	
Austin Energy				80
Consolidated Edison	Minimal			
CenterPoint Energy			$12,000	
Dominion Virginia Power			$10,000	
Duke Energy Corporation		$100,000s		
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO	Unknown			
Great River Energy	Minimal			
Hydro One Networks	Unknown			
LCRA Transmission Services Corporation	Minimal			
Manitoba Hydro	Significant			
New York Power Authority				144
Oklahoma Gas and Electric Company	Minimal			
Southern Company			$24,000	

Table 4: Overall Costs, One Time System Modification, Annual Costs, and Annual Man-Hours				
TO Name	**Qualitative Costs**	**One Time Cost**	**Annual Costs**	**Annual Man-Hours**
Salt River Project Agricultural Improvement and Power District			$50,000	
Tennessee Valley Authority			$40,000	
Xcel Energy	Minimal			
South Mississippi Electric Power Association	Minimal			
South Carolina Electric & Gas Company	Minimal			
Bonneville Power Administration			$4,000	
Southern California Edison	Severe			

Comments and Responses

Several entities included general comments to supplement the 6 specific questions in the Data Request. These comments have been considered and responses are provided below.

Table 5: General Comments	
TO and Comment	**Comment Response**
Edison Electric Institute On behalf of our member companies, the Edison Electric Institute appreciates the opportunity to provide the following brief comments on proposed expansion of the TADS database initiative. We agree that the reliability assessment program is an important feature of the Electric Reliability Organization (ERO) under Section 215 and support the efforts to strengthen the program. Data collection is an important basic ingredient for conducting various assessments. However, as set forth in these comments, we ask that NERC suspend the TADS expansion and instead seek to coordinate with the North American Transmission Forum (NATF) to ensure a reasonable data collection effort that balances costs and benefits, and the priorities of these efforts within NERC. In considering changes, we believe that it is important to recognize that companies also continuously conduct assessments and analyses of their own performance, including analyses of routine events, equipment, and personnel, as part of their regular management activities. Some of this activity takes place as part of compliance under mandatory standards; some also takes place as a matter of proactive asset management discipline. In addition, we understand that NATF has an initiative to collect data and develop various metrics involving system protection and relay equipment. The TADS proposal also comes at a time when companies expect to remain under strong pressures to manage costs and find efficiencies. Within NERC, there are multiple sets of initiatives aimed at improving the efficiency of core program areas --- standards development, and compliance and enforcement ---	We appreciate EEI's comments and suggestions of coordination with the North American Transmission Forum (NATF) and resource prioritization. Since 2009, NERC Transmission Availability Data System (TADS) Working Group (formerly TADS Task Force) and NERC staff have been communicating with the NATF and other organizations (e. g., the Canadian Electricity Association, and U.S. Energy Information Administration) on TADS data collection. Assume each NATF member provides data security permission to NERC, NERC would be pleased to have NATF sponsor a project to synchronize basic data between NATF's webTracker tool and NERC's webTADS database. This would save an extra step of each member exporting basic data from webTracker and importing it into webTADS. Another cost effective alternative is to use the existing TADS design and security management. Each NATF transmission owner may specify NATF to be their 'Delegated Reporting Entity'. That would consolidate webTADS data entry labor under NATF coordination among its members. We agree with the EEI's suggestion that coordinating data collections with NATF and other industry reliability organizations balances costs and benefits, improving efficiency and consistency. We commit to apply the same principles and work with NATF on system protection and relay

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and to sharpen the focus of the core on those issues that most affect bulk power system reliability. For almost two years, significant discussion has taken place around the 'everything is a priority' problem, and NERC has rightly responded with strong initiatives to attend to this. EEI has been on record to challenge NERC to find ways and means to identify those activities having a lower priority in attracting budget resources. In light of the present situation, EEI recommends that NERC identify TADS expansion as a lower priority and to not expand the database at this time. Moreover, we are not convinced that the additional burden associated with TADS expansion will offer a proportionate benefit to the reliability assessment program. We agree that TADS is a very small component of the NERC budget, however, this can be an example that NERC really can set priorities, discipline its budget, and recognize the real limits of stakeholders' resources to support each and every activity that NERC seeks to advance. Instead, EEI urges NERC to coordinate with NATF and its members, and to seek a way forward that will balance the legitimate objectives of the reliability assessment program with the need to accept limits. Efforts to coordinate will help ensure that efforts are not duplicated or wasted. The relevant part of Section 215 is that the ERO will conduct periodic assessments of the bulk power system. Suspending TADS expansion for now does not impair NERC from fulfilling this responsibility in a complete and cost effective manner.	equipment data collection. EEI also properly pointed out that data collection is an important basic ingredient for conducting various assessments, and the ERO needs to sharpen the focus on core programs areas – standards development, compliance and enforcement. The TADS quarterly reporting and collection of four key inventory attributes will provide the necessary information in a timely manner to enable NERC to offer high value information for risk analysis. This data will also aid in identifying new or revised standards projects that have the most potential for improving the reliability of the bulk power system. As outlined in the NERC's *2012 State of Reliability* report,[8] analysis results based on TADS and other reliability data reporting serve as technical input to standards development and project prioritization, compliance process improvement. This analysis of bulk power system performance not only provides an industry reference for historical bulk power system reliability, it also offers analytical insights towards industry action, and enables the discovery and prioritization of specific actionable risk control steps.
<u>SGS Statistical Services</u> Since 1995 SGS Statistical Services has provided the annual SGS Transmission Reliability Benchmarking Study. 2012 was the eighteenth year for the SGS Study. A total of 25 systems participated, comprising 48.1% of the US-only and 44.6% of the US/Canada bulk power circuit miles or 51.7% of US/Canada circuits (based on NERC TADS 2010). The combined peak system MW load for the US systems in the Study was 472,559 or 59.8% of highest annual non-coincident	We appreciate SGS's comments and thank you for the support of quarterly reporting. We also agreed that "More" is not necessarily "better" and circuit length is not the sole or primary driver of outages. As stated in the inventory data request letter, to minimize reporting costs while obtaining high value reliability information, NERC only requests four new key inventory

[8] http://www.nerc.com/files/2012_SOR.pdf

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total US peak MW load (year 2006, EIA). Over 3/4 the circuits and 87% of the outages in the SGS Study are in the 100-199kV voltage class or subtransmission (mostly 69 kV), compared to 22% of circuits and 12.6% of outages for > 200 kV. We process more circuits and outage data than the current TADS implementation. ***Summary of SGS Comments on Transmission Availability Data System Proposed Element Inventory and Quarterly Data Collection*** 1. NERC should require TADS reporting on a quarterly basis. 2. NERC should not require Element Inventory data submission at this time. A detailed discussion of these points follows. ***NERC should require TADS reporting on a quarterly basis.*** The SGS Study, like the current TADS reporting requires data submission during the first quarter of the calendar year. We estimate that we receive two times the number of circuits and perhaps four time the number of outages as NERC currently receives for TADS. Since TADS implementation, a common refrain from the people submitting data to SGS has been the NERC submission is tedious and time consuming in the level of detail and rigid data formats. It is not uncommon for those individuals submitting TADS data for a large system to spend two or more weeks preparing the TADS submission. The complexity is often in defining the initiating and sustained outage cause codes, fault type and event type long after the incident. Actual recording of outages usually takes place in a fast-	attributes: unique element identifier, circuit mileage, terminal type and change date. Reporting the key inventory data of circuits and transformers would enable NERC to track outage rates on specific lines and transformers and target areas of concern. The Western Electric Coordinating Council (WECC) has collected transmission line inventory data sets since 2007, including conductors per phase, insulation type, structure type, etc.[9] to examine influencing factors, such as line mile, age, and common corridor. Besides single (category B) and multiple (category C) outages, WECC also evaluates the performance of category C5 outages (two lines constructed on the same tower), and two/more line outage in the same right-of-way, and developed its regional system performance criterion[10] (TPL-001-WECC-CRT-2) based on the collected inventory and outage information. Also, the former ECAR and MAIN regional councils collected some form of inventory data for their transmission line outage efforts. The four new key inventory data would support the following important ERO risk analysis: • Unique Element Identifier Having the unique element identifier would eliminate errors of multi-identifiers for a single transmission element. In current TADS reporting, an outage is coded using an identifier that is free-form text. Analysis on a particular element cannot be made as the reporting entity can change the identifier

[9] http://www.wecc.biz/committees/StandingCommittees/PCC/RS/RPEWG/Shared%20Documents/2012%20WECC%20TRDTD%20Users%20Guide.doc

[10] http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Criteria/TPL-001-WECC-CRT-2%20System%20Performance%20Criterion%20-%20Effective%20April%201%202012.pdf

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paced control center environment and the detail required by TADS is seldom a priority for control center operators logging outage data. Quarterly submissions of TADS data would eliminate the year-end crunch of preparing an entire year's data. Outage cause codes, fault and event types would be easier to research because 3 months data would be fewer in number and in the recent past. Data quality might improve. ***NERC should not require Element Inventory data submission at this time.*** In the Request for Public Comment letter NERC states: "Key inventory data for individual circuits and circuit miles along with outages associated with those circuits are not collected. Without this information, analysis of important explanatory variables affecting transmission performance determined by transmission line exposures (*e.g.,* circuit-miles, number of terminals, *etc.*) cannot be conducted. Further, the data and output analysis cannot be used to support probabilistic planning studies and root cause analysis." The SGS Study has always required a *circuit definition table* as part of its annual submission. The table is used primarily for the purpose of validating outage data records and for calculation of circuit-years and mileage based outage statistics. While there is some merit in collecting element inventory data for each TADS-reportable element, I believe this request is **premature** based on NERC's stated intentions (i.e., statistical or probabilistic modeling) for use this information. Recently, NERC's Senior Statistician utilized the WECC Transmission Reliability Database to perform an exploratory analysis using the circuit inventory data and the outages associated with each specific circuit.	from year the year. Reporting all lines would reduce the error of double counting inventory. A future enhancement could be made to the TADS system so that there is no need to enter TADS event IDs in the protection system misoperation template. Reporting entities could use a list of the unique element identifiers to select the transmission equipment that are out of service due to the misoperations. This would greatly improve accuracy and efficiency of misoperation risk and impact analysis by reducing reconciliation efforts between two data sets. With known outage statistics on major transmission elements, probabilistic methods can be also applied in planning and operations studies, such as determination of credible contingencies and bridging gaps between operating studies and planning assumptions, as outlined in section 2.6 (Intended Uses and Limitations of Data and Metrics) of the 2007 TADS report.[11] • Circuit Mileage and Terminal Type The circuit mileage and terminal type are key performance attributes. Based on WECC's circuit inventory data, statistical analysis has revealed the circuit mileage is a significant contributor to transmission outage rates. There is a strong positive correlation of 0.44 ($-1 \leq$ corr elation ≤ 1) between the circuit outage rate and its mileage. Without the individual circuit mileage and terminal type information, the individual circuit performance cannot be correctly assigned into similar clusters, as the circuits grouped and studied within

11 http://www.nerc.com/docs/pc/tadstf/TADS_PC_Revised_Final_Report_09_26_07.pdf

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The analysis was very similar to those performed by SGS over the past 19 years within the context of the SGS Study and for client-specific consulting engagements. My understanding is the findings of the NERC statistician were consistent with those of SGS regarding outages as a function of transmission circuit (line) parameters such as circuit length, age or other attributes such as shielding, construction, type, etc. Each year the SGS Study provides a regression of 5 outage parameters versus circuit length (4 total models with and without logarithmic transformation for each response variable: all outages, momentary outages, sustained outages, line failures only, lightning-only outages), performed on a transmission owner/control area basis (i.e., data is not pooled across multiple systems). For voltages < 200 kV, particularly subtransmission, it is *occasionally* possible to find regression models with a coefficient of determination (R-square) in excess of 0.50, most often R-square is 0.30 or less. Especially for voltages > 200 kV, the coefficient of determination is *seldom* above 0.30 or 0.20. Paradoxically, it is also possible to find the regression coefficient for circuit length to the ***negative*** (i.e., as circuit length increases, outage frequency drops!). It is an erroneous paradigm that circuit length is the sole or primary driver of outages. What is the practical implication of such low coefficient of determination (R-square) values? **It means that exposure explains a relatively small proportion of outage behavior.** Seventy or eighty percent of outages are explained by inherent randomness or unknown (and perhaps unknowable) factors other than length. Explanatory variables such as those in the data request **seldom** provide meaningful predictive or explanatory ability. Modeling outages as a function of the number or complexity of terminals on a circuit sometimes provide a "whiff" of correlation, but it is seldom compelling or worth pursuit. The proposed data request will require	same voltage classes. • Change/Reconfiguration Date The NERC TADSWG has discussed the need for the change/reconfiguration date in depth. The intent of the change/reconfiguration date was not to obtain equipment age information. As SGS properly pointed out, many possible changes could impact the equipment age. TADSWG realized this, and in order to maintain an accurate count of total circuits and circuit-miles used for metric normalization, TADSWG defined the change/reconfiguration date along with a retirement date field. These dates will only be used for properly calculating total adjusted circuits and circuit-miles automatically in the summary data when elements are changed to become a separate TADS element. For example, if an AC circuit is split by a new substation, the change/reconfiguration date would be used to mark when the AC circuit element was split into two elements for adjusted inventory summary calculations. This clarification and example will be provided in the TADS reporting instruction manual.

Table 5: General Comments	
TO and Comment	**Comment Response**
extensive description of circuit terminations and it will almost certainly prove to have little value in modeling or analysis. If circuits with two or three different termination types have a lot of outages, how does NERC propose to determine whether a complex or simple termination is the cause of a high failure rate on an individual circuit or to generalize across the industry? The data request contains a requirement for Change/Reconfiguration and Retirement Dates. The definition of these dates is ambiguous. Consider these examples: (1) a circuit terminates with 30 year old breakers and they are replaced with new breakers, (2) a circuit termination remains at the same station but is changed to a different bus, (3) a wood H-frame 115 kV circuit is replaced with steel pole construction, with subtransmission underbuild (4) a circuit with steel tower construction is re-conductored, new shield wires and grounding installed and insulators replaced. Are any of these considered “reconfigurations” and if so why or why not? There are many possible changes that may require a Change/Reconfiguration and Retirement Date, but enumerating the criteria of when such changes are warranted needs to be very specific. Until NERC can specify all criteria it is premature to request this information. The data request contains a requirement for identifying a circuit as either overhead or underground (based on the majority of its length, as is used in the SGS Study). This information will not be useful unless the TADS outage cause codes are modified to distinctly separate cable versus overhead failures. While not part of the data request, simple explanatory variables contained in the WECC TRD such as shielding vs. no shielding provide compelling risk quantification, *but only in the case of long-length, subtransmission or 100-199kV circuits in locations that experience relatively high isokeraunic activity.* But do we need a statistical model to tell is this fact? Other explanatory variables such as structure type, construction type, age, etc. all present interesting questions and	

Table 5: General Comments	
TO and Comment	**Comment Response**
opportunities for modeling, but the task is far more complex than the information being requested. It is not uncommon to have mixed structure and construction types on the same circuit. How does one characterize such attributes? How does one isolate where a fault occurred to a specific structure type or segment age? Age of the circuit cannot be determined using a Change/Reconfiguration Date because it does not accurately reflect age; for instance, steel towers, if properly maintained, will last for hundreds of years. Conductors and insulators do not. How does one characterize "age" if such a line is rehabilitated? Lastly, a justification for submission of inventory data is that it will somehow be used for probabilistic planning purposes. Element inventory data does virtually nothing to attain this lofty and most likely unattainable goal. Unlike transformers or other station equipment, it is my belief that the commonly held industry assumption of lines being characterized by a Poisson failure rate, with an Exponential distribution of time between failures simply is not supportable. Each line has its own unique and complicated failure distribution and it is *seldom* described by the exponential distribution. Further, multiple contingencies or blackouts are probably impossible to model using empirical data because of compound probabilities with unknown and probably unknowable failure distributions. Probabilistic modeling of the BES in an environment of sparse data is essentially a fool's errand. We suggest that prior to mandating element inventory reporting for all 336 Transmission Owners listed in the NERC compliance registry, NERC instead perform a pilot study of a small subset of element inventory data. The TADSWG has a number of large systems represented that apparently support expansion of TADS reporting. The TADSWG systems probably represent 10% of the North American grid. Why not have the TADSWG systems **voluntarily** submit multiple years of element inventory (plus additional explanatory variables) with corresponding	

Table 5: General Comments	
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outage data and have the NERC statistician perform a detailed and exhaustive analysis of the data. If, and only if, there is demonstrable value in collecting a variable would it be added to the mandatory element inventory reporting. Consider waiting a year before mandating element inventory reporting, after the NERC statistician has validated the usefulness of required element inventory data items. "More" is not necessarily "better". 30 years ago my professors emphasized parsimonious data and models. That was an important lesson.	
<u>Ameren Services Company</u> Overall, Ameren supports the proposed element inventory and quarterly data collection described in this data request. We did, however, find a few areas of concern. First, we would like to have more than 45 days from the end of a quarter to report that quarter's TADS data. It often takes longer than 45 days to perform a full investigation and finish an analysis of a TADS event. Increasing this deadline from 45 days to 90 days would give reporting entities more time to finish their analyses and reduce the need to modify data once it is uploaded to WebTADS. Second, the current WebTADS software does not appear to have the ability to track detailed circuit inventory data. The WebTADS software would need to be modified to support the ability to bulk upload (via XML) the circuit inventory for a year. The current method used to enter the circuit inventory summary in WebTADS is already cumbersome. It would be unmanageable to use a similar system to enter detailed circuit inventory data without the ability to perform bulk uploads. Finally, it is unclear how much history is being requested in item 1.a.6 through 1.a.8 (Change/Reconfiguration date, Retirement Date, and Precursor Element(s)). It would be appropriate to collect this information about all reconfigurations that	Thank you for your excellent comments. First, TADSWG is considering your comment to increase the deadline for quarterly reporting. Also, year-to-date updating may be used instead of the current freezing of data at the end of the annual reporting period. Both of these changes should help to reduce the burden of the quarterly reporting. Secondly, webTADS Change Order #6 included functionality to track detailed circuit inventory data on a voluntary basis. It is possible to bulk upload detailed inventory current, and as part of the implementation of the data request, this ability would be refined, and a sample workbook would be distributed with the changes. Finally, you are correct that is unclear how much history is being requested in items 1.a.6 through 1.a.8. The intent of the change/reconfiguration date, retirement date, and precursor element fields is to record information after the implementation of quarterly reporting. Upon implementation, the only initial data required for the change/reconfiguration date would be the initial implementation date of key inventory data collection.

Table 5: General Comments	
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occur after the collection of detailed inventory data begins. This information should not be requested for historical changes and reconfigurations that occurred prior to the beginning of the collection of detailed circuit inventory data.	Reconfiguration dates would be needed when an Element is split into multiple Elements in order to properly calculated adjusted circuits and circuit-miles. TADSWG agrees that gathering reconfiguration dates from prior to implementation of detailed inventory is excessively burdensome and unnecessary.
<u>ACES Power Marketing, Brazos Electric Power Cooperative, North Carolina Electric Membership Corporation, Great River Energy, Arizona Electric Power Cooperative, Southwest Transmission Cooperative, and Sunflower Electric Power Corporation</u> We agree requesting this inventory data by element is a reasonable request especially since the impact of the data request will largely occur one time. We further believe that the data, in general, is readily available and that the six-month schedule for submission is reasonable. However, we do not support the quarterly reporting. While we understand that it will provide NERC more timely information and better align with other metrics reporting, we believe the quarterly reporting will have a detrimental reliability impact on small entities. Small entities have limited staff and may have the same staff submitting TADS data as the staff performing other tasks such as scheduling transmission outages. The quarterly reporting will distract the staff from their core reliability function of scheduling outages during seasons with a large number of outages. With the inclusion of sub-100 kV TADS data, this distraction will be exacerbated.	Thank you for your comments. TADSWG notes the difficulties that a smaller entity may have with additional data collection. For this reason, an extension of the deadline for the proposed quarterly reporting is being considered. In regards to reporting sub-100 kV TADS data, this would only include Elements in the newly proposed Bulk Electric System (BES). In the proposed BES definition, no sub-100 kV Elements are included except by a special inclusion process. It is not expected that there will be many sub-100 kV Elements to report in TADS.
<u>CenterPoint Energy</u> CenterPoint Energy recommends that the Transmission Availability Data System ("TADS") data collection remain unchanged and that the NERC Planning Committee reconsider a revised data request after making its determination in 2015 on the demonstration of the benefits of TADS. At that time, NERC trend analysis on five years of TADS data should be complete, and the impacts of the NERC BES definition to data collection (i.e., additions and deletions of Elements) should also be known.	

Table 5: General Comments	
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There is little evidence to support the collection of additional inventory details for the significant effort and cost to produce the inventory data in the proposed format. The use of TADS data in other NERC metrics has not been proven to provide sufficient value to necessitate the need to produce the data more frequently. *Key Inventory Data* CenterPoint Energy does not collect the additional details proposed in the request beyond what is already currently required in TADS for reporting total Element inventory. Additional research would be required and processes would need to be developed to supply and maintain the Number of Terminals, the Precursor Elements, and the Terminal Type. There is little evidence to support the collection of additional inventory details for the significant effort and cost to produce the inventory data in this format. TADS outage analysis to date is not complete, and providing additional detail is premature. Analysis by total population and cause codes should be completed before any value can be assumed from collecting additional inventory detail. *Quarterly Outage Reporting* Reporting outages quarterly, rather than annually will require additional man-hour resources to perform regulatory reporting data validation four times per year, rather than once per year. Additionally, the accelerated schedule for data validation by the Regional Entities ("RE") and NERC may not prove effective in ensuring TADS data quality. TADS data provides a historical perspective of grid availability, and it cannot be used to project future performance. Quarterly data is typically variable based on seasonal weather patterns and therefore comparison on an overall annual basis is more appropriate and substantially sufficient. The use of TADS data in other NERC metrics has not been proven to provide sufficient value to necessitate the need to produce the data more frequently.	

Table 5: General Comments	
TO and Comment	**Comment Response**
There is also a conflict in the reporting of inventory data annually and outage data quarterly if the intent is to provide quarterly metrics. TADS was originally designed by the TADSTF to be an annual reporting system based on cumulative outage reporting over a one year period.	
Dominion Virginia Power Presently inventory data is not importable (bulk upload) or exportable to webTADS. We recommend that NERC modify webTADS to allow import (upload) and export of AC Circuit Inventory data with one file that includes all voltage classes. Similarly modify webTADS to allow the import and export of Transformer Inventory data with one file that includes all voltage classes. We also recommend that updates to inventory data be possible with a full upload of data or by manual editing of existing data in webTADS. This will simplify the process and allow greater efficiency.	As part of webTADS Change Order #6, a method of providing detailed inventory was added to webTADS on a voluntary basis. The method currently allows import/export of detailed inventory. As part of this data request, webTADS would be changed to refine the existing detailed inventory entry, import, and export to allow similar functionality as other areas of webTADS. Summary inventory information would be automatically calculated from detailed inventory and available for export.
Tennessee Valley Authority Could NERC please further explain the following statements from the “Request for Public Comment ....”: • “Further, the data and output analysis [without this inventory data] cannot be used to support probabilistic planning studies and root cause analysis.” (page 2, paragraph #2) This statement is reiterated later in the document as “Also, the data WILL be used to support probabilistic planning studies and root cause analysis”. o Does NERC intend to do ‘probabilistic planning studies’? Explain. o A root cause analysis would require significantly more detail than could be provided in any ‘inventory’ data database. Wouldn’t NERC need to contact a utility for additional information anyway, and will still need to do so with this very limited amount of inventory data. • Explain how quarterly reporting and collection of detailed inventory will “enable NERC to provide high value information for risk analysis.” (page 2, paragraph 5)	The response is separated by bullet point. • The statement should be changed to read, "Also, the data can be used to support probabilistic planning studies and will be used to support root cause analysis." o No, currently there are no known plans at NERC to perform 'probabilistic planning studies'. The data is helpful as a benchmark for probabilistic planning assumptions. For example, if one wants to know the outage probability of 200 kV lines in a given Region, the data would provide a benchmark. If there is no fixed inventory data, a same-Element outage rate cannot be determined accurately. One could have a single circuit with 20 outages in one year, and that would skew the outage rate for the whole voltage class for that year in a yearly comparison. With a same-circuit outage rate, one could see that as an anomaly instead of being a misleading data point. o It is correct that a root cause analysis does require significant detail. As part of

Table 5: General Comments	
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• Explain how this data will "enable NERC to determine where improvements can be when appropriate". (page 2, paragraph 5) • Explain why "Transmission Planners will be able to compare historical Element outage rates of their own system performance expectations and assumptions to provide a baseline or to improve their own assumptions in planning and reliability studies." (page 6, paragraph 1) o Will utility Transmission Planners use the U.S. Average interruption rate rather than the specific calculated outage rate for that element? How would this be an improvement?	performing a root cause analysis, it is important to determine "what" has happened before being able to determine "why" the event happens. Having a consistent way of identifying transmission Elements helps to move away from the "free-form" text method currently used in Events reporting. • In terms of quarterly reporting, TADS data is needed to calculate the Severity Risk Index on a timelier basis. Outage counts from TADS form 30% of the index, and are crucial to more rapid reporting. TADS also contributes a significant portion of the NERC State of Reliability Report. This report gives insight into historical performance of the Bulk Electric System, and the current annual timeline for TADS reporting is a bottleneck in timely release of the report. TADS data is also used in risk analysis, and the lag in receiving data hinders timely risk analysis. TADS data is important, and its importance will increase as more years of data are collected. In terms of inventory, the detailed inventory provides a method to perform same-Element analysis. Currently, NERC is unable to perform same-Element analysis on TADS data. Same-Element analysis allows the analysis of outage rates to transform from a scalar value into a distribution of outage rates that can be compared accurately year over year. Currently, this is not possible because NERC cannot be sure that an Element in one year is the same Element in the next year even if they have the same Element Identifier. • By using TADS in risk analysis, TADS data is helpful to determining where improvements to the reliability of the Bulk Electric System can be made. For example, transmission outage rates on a same-Element basis can

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	be used to help quantitatively determine if standards are effective in reducing Bulk Electric System risk or if the standard should be modified/retired. • By using TADS same-Element outage rates, Transmission Planners can see the singleton-eliminated distribution of Element outages across North American TOs as well as their own Region. These baseline numbers would be valuable for assumptions in planning and reliability studies where there is no prior data for a TO's system. Utility Transmission Planners (TPs) would not be limited to the U.S. Average interruption rate. The TP could also use a Regional rate. This would be an improvement in cases where there isn't a specific calculated outage rate for the Element. One could have a case where the Element has just been commissioned, and has never been in an outage. Also, a utility may not have data, or enough data, on a particular type of Element (e.g. a utility starting to implement a new voltage class).

Also, the Section 1600 request includes the 6 specific questions in the Data Request. All comments have been considered and responses are provided below.

Question 1: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
Associated Electric Cooperative, Inc. Associated Electric Cooperative Inc (AECI) is a Transmission Owner and does not actively collect less than 200 kV data in a similar manner to the proposed TADS outage data collection. These details of these outages are gathered and outage reports are constructed, but not the extent to report in TADS.	Thank you for your comments.
Ameren Services Company Ameren is a Transmission Owner. While we do maintain the element inventory data described in this data request, it is not currently stored in the format requested.	Thank you for your comments.
American Transmission Co. LLC ATC collects all inventory listed with the exception of “Terminal Type”.	Thank you for your comments. A staggered schedule for key inventory data will be used to give more time to determine the terminal type.
Austin Energy No, Austin Energy (AE) has the data but does not collect it in a centralized location.	Thank you for your comments.
Consolidated Edison Consolidated Edison maintains a database containing an inventory of all individual transmission Elements. Of the eleven proposed key inventory data category listed, our current database does not have four of the categories. For each of our Elements, our database does not have: o Numbers of terminals o Retirement Date o Precursor Element(s) o Terminal Type	Thank you for your comments. A staggered schedule for key inventory data will be used to give more time to determine the key inventory fields.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
CenterPoint Energy No. CenterPoint Energy does not collect the additional details proposed in the request beyond what is already currently required in TADS for reporting total Element inventory. Additional research would be required and processes would need to be developed to supply and maintain the Number of Terminals, the Precursor Elements, and the Terminal Type.	Thank you for your comments. A staggered schedule for key inventory data will be used to give more time to determine the key inventory fields.
Dominion Virginia Power No. Although we have a listing of assets, we do not have the level of detail being requested in the inventory data	Thank you for your comments.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
Duke Energy Corporation Capturing reconfiguration data would be a change from our current practices. We don't capture Terminal Type, and would have to implement process and software changes to accomplish this. We have point-to-point information on circuits but not in a database. Data items "Change/Reconfiguration Date", "Retirement Date", and Precursor Elements" are problematic. Also, item 11 "AC Multi-Owner Common Structure Flag" is confusing.	The reconfiguration date field would mainly be used to determine when the circuit mileage changed to assist with automatically calculating circuit mileage. The retirement date and precursor element fields would only be applied to Elements retired or added after the implementation of the key inventory data fields. No historical precursor element data prior to the key inventory data implementation will be required. Item 11, "AC Multi-Owner Common Structure Flag", is already collected on a per-outage basis. Per the TADS Data Reporting Instruction Manual, Appendix 7[12], the definition of AC Multi-Owner Common Structure is: *This flag identifies whether the outaged AC Circuit is on common structures with another circuit that is owned by a different Transmission Owner. This flag does not apply to DC Circuits which by default are all assumed to be on common structures with the circuits owned by the same Transmission Owner.* This flag would be collected on a per-Element basis instead of a per-outage basis to reduce duplicative reporting for outages.

[12] http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf , p. 5.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO Yes but it is not available in the form being requested. We do not collect data at the element level as the TADS format requires. There are concerns with historical data requirements; there would be a significant resource commitment to try to collect the data in the form requested. Additional pieces of information at the element level are not something that can be provided at a reasonable cost and we question the benefit of the data. Knowing the asset class of elements is irrelevant without having the related maintenance history for the elements. The requirements to continue to update TADS are burdensome with no benefit. Exelon Transmission Owners strongly oppose this recommendation. It is an activity that could be done by independent stakeholder groups such as the Transmission Forum.	The intent of the change/reconfiguration date was not to require TOs to have to research all of the reconfiguration dates ex post facto for their inventory. The original intent of the change/reconfiguration date and retirement date fields was to be able to properly calculate adjusted circuits and circuit-miles automatically in the summary data when Elements are changed sufficiently to become a separate TADS Element. For example, if an AC Circuit is split by a new substation, the change/reconfiguration date would be used to mark when the AC Circuit Element was split into two Elements for adjusted inventory summary calculations. Having to continually update reconfiguration dates in TADS detailed inventory for every change in an Element is overly burdensome and unnecessary. The goal of the detailed inventory is to have an initial push to populate the inventory and then only require an annual update of Elements which are retired or become split into multiple Elements.
Great River Energy GRE does have individual Element Inventory data available to submit as part of this request. It would be a manual process since the data is available within various applications. Circuit miles, terminal information, voltage class, and In-Service dates are readily available and could be manually populated for submittal.	Thank you for your comments.
Hydro One Networks Yes. Hydro One captures most of its inventory data in a similar manner as proposed. However, some of the new proposed inventory data (e.g. Terminal Type) are not systematically captured in the same manner directly within our transmission outage data system.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to find the key Element inventory fields.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
LCRA Transmission Services Corporation LCRA TSC does not currently collect and maintain this kind of information.	Thank you for your comments.
Manitoba Hydro We do not have a central repository where this information is found. Various components of this data are found in numerous locations.	Thank you for your comments.
New York Power Authority We collect the data that overlaps with the current TADS data request for the following items; 1. Transmission Owner Unique Element Identifier 2. Circuit Mileage 3. Number of Terminals 4. Substation, Terminal, or Converter Name(s) 5. Element Voltage Class.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to determine the key Element inventory fields.
Oklahoma Gas and Electric Company We do not collect all the requested data in the proposed outage data request information. We do not collect the number of terminals and terminal type. We can obtain the following information: TO unique element identifier, circuit mileage, substation names, element voltage class, change/reconfiguration date, retirement date, precursor element, overhead vs. underground, and AC multi-owner common structure. The number of terminals and terminal type can be determined by manually studying the substation configuration.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to determine the key Element inventory fields.
Southern Company Southern Companies collects individual element inventory data, but in a different format and not to the extent required for current TADS requirements. It will need to be reformatted and additional information added for the proposed TADS outage reporting.	Thank you for your comments.
Salt River Project Agricultural Improvement and Power District As a WECC member, we already have this information on hand.	Thank you for your comments.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
Tennessee Valley Authority TVA collects inventory data similar to the proposed request. However, TVA does not collect all the data being requested. TVA does not currently collect the Precursor Element(s) or Terminal Type.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to determine the key Element inventory fields.
Xcel Energy Xcel Energy has inventory data readily available for transmission lines but would need to update our system to handle transformers.	Thank you for your comments.
South Mississippi Electric Power Association We currently do not have a system in place to easily report the individual Elements inventory data similar to the proposed TADS outage data. Currently, we use an outage request database for collecting non-automatic transmission outages and our operators log automatic outages in our operator's log. Both of these processes collect some data similar to the proposed TADS outage data. A modification of our current outage request database or creation of a different database will be necessary to collect and report the proposed TADS outage data.	Thank you for your comments.
South Carolina Electric & Gas Company We do currently collect 100-199 kV outage data similar to the proposed TADS outage data through an Interruption data program (IDP). The additional "individual Element" inventory will now include many more elements and requires more time and resources considering it will draw information from multiple databases (IDP, Transmission outage application, GIS, etc.) Formatting this data to fit TADS submittals will take time and resources. We suggest providing a proposed template for the new TADS submittals so that the formatting can been seen visually.	A proposed template will be provided for the detailed inventory data fields after approval of the data request with a goal of getting the template out as early as possible for TO review.

Table 6: If you are a Transmission Owner, do you currently collect individual Element inventory data similar to the proposed TADS outage data? Please describe the extent to which you collect inventory data similar to the proposed TADS outage data.	
TO and Comment	**Comment Response**
Bonneville Power Administration BPA does NOT collect TADS data on the type of circuit connection to a bus. We would have to review every circuit and categorize it. We also disagree with the value of linking lines and terminating transformers into the same outage, it's an unnecessary complication. The line terminated transformer is really AC Substation Equipment (within the substation not on the line) and the same should apply to DC converter transformers no matter the voltage level of the windows, i.e. the converter transformer is not part of the line circuit).	Thank you for your comments. During review of the TADS Data Reporting Instruction Manual, TADSWG will consider the comments related to the value of linking lines and terminating transformers into the same outage.
Southern California Edison Southern California Edison (SCE) collects information similar to proposed TADS outage data. The similarities with respect to the proposed new fields are as follows: transmission owner unique identifier, circuit mileage, substation names, element voltage class, change/reconfiguration dates, retirement dates, precursor elements, overhead/underground circuit type, and AC multi-owner common structure flag. The dissimilarities with respect to the proposed new fields are as follows: number of terminals and terminal type.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to determine the key Element inventory fields.

Question 2: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?

Table 7: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?	
TO and Comment	**Comment Response**
Associated Electric Cooperative, Inc. AECI is registered with NERC as a JRO on behalf of AECI and 6 other child companies. As an approximation this additional data reporting would require much additional coordination and employee resources. Each member of the AECI JRO would need to dedicate the time of one electrical engineer to spearhead this additional data reporting request. It is approximated that after including wages/benefits for additional personnel required, the cost would be at least $500,000 annually.	Thank you for your comment.
Ameren Services Company There will be a significant increase in effort beyond the BES standards to fulfill the proposed TADS data collection. We anticipate hundreds of hours required to fulfill the request	Thank you for your comment.
American Transmission Co. LLC Time required to identify and document “Terminal Type” for each Terminal. The time estimated to complete this activity is approximately 80 hours	Thank you for your comment.
Austin Energy To fulfill the proposed TADS data collection, AE would have to establish a collection procedure for gathering outage data in a central location in a format that is readily available for TADS reporting. AE has eleven times as many 100-199kV TADS Elements as it has >= 200 kV Elements. The amount of data AE would have to collect for TADS reporting would increase substantially if this lower voltage class is included.	Thank you for your comments. A staggered reporting schedule is being used to have TOs report 200 kV+ outage and inventory data before less than 200 kV outage and inventory data.
Consolidated Edison None	Thank you for your comment.

Table 7: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?	
TO and Comment	**Comment Response**
<u>CenterPoint Energy</u> *Key Inventory Data* For ≥200 kV, CenterPoint Energy would have to research the Number of Terminals, the Precursor Elements, and the Terminal Type for fifty-four 345 kV AC Circuits. CenterPoint Energy has no Transformers at this voltage. For <200 kV reporting if adopted by NERC, CenterPoint Energy would have to research the Number of Terminals, the Precursor Elements, and the Terminal Type for two hundred thirty-one 138 kV AC Circuits and thirty-six Transformers. Additional AC Circuits and Transformers <100 kV may also have to be researched and determined based on the final BES definition approved by FERC. This would require a detailed one-time analysis of two hundred eighty-five AC Circuit and thirty-six Transformer one-lines to determine the Terminal Type. New procedures and processes to keep the new data fields up-to-date would also need to be created which would require one-time system changes and additional man-hours annually to complete. Current systems would also need to be modified to upload inventory data into webTADS. If an inventory system in TADS is approved, CenterPoint Energy recommends keeping the same inventory fields as TADS currently requires, eliminating the need to research additional data that may or may not prove to add value. *Quarterly Outage Reporting* Reporting outages quarterly, rather than annually will require additional man-hour resources to perform regulatory reporting data validation four times per year, rather than once per year. Additionally, the accelerated schedule for data validation by the REs and NERC may not prove effective in ensuring TADS data quality.	Thank you for your excellent comments! The number of terminals and terminal type would have to be researched. However, no historical Precursor Elements will be needed for the initial detailed inventory upload. Also, there should not be any Elements <100 kV included initially included in the base definition of the Bulk Electric System approved by FERC. Elements <100 kV must be included in a special Element-by-Element inclusion process, and there are anticipated to be few of these Elements. Finally, TADSWG is considering the fields in the inventory and their value. In regards to quarterly reporting, entities are currently given 60 days after the end of the year for the annual reporting period. With the proposed quarterly reporting, entities would have 45 days to analyze approximately one-fourth to one-third (depending on season) of the outages. In total, entities would have 180 days/year (45 daysx4 quarters) to review TADS data instead of the current 60 days/year. Regional Entity review would increase from the current 30 days/year to 45 days/quarter. This additional time should assist in improving TADS data collection quality.

Table 7: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?	
TO and Comment	**Comment Response**
Dominion Virginia Power Gathering new data on COOP owned taps attached to our lines will require some effort. Adding seemingly worthless data such as "Terminal Type", "Precursor Elements" and "AC Multi-Owner Common Structure Flag" will require initial research and on-going updates on a quarterly basis. Finding historical "Precursor Element" data will require an unknown amount of effort and will have severe limitations as to its accuracy for previous years' data.	Thank you for your well-written comment. Yes, determining number of terminals and terminal types will require some effort. However, no historical Precursor Elements will be needed for the initial inventory upload because, to TADS, the first detailed inventory Elements do not have precursor TADS Elements. The change/reconfiguration date should be set to implementation date of key inventory data field reporting. Also, you are correct that historical precursor Elements would not provide benefits in comparison with the vast amount of effort required. For the AC Multi-Owner Common Structure Flag, this field is already being collected by TADS on a per-outage basis. The intent is to collect this field on a per-AC Circuit basis and remove the field from the automatic outage form. The data request will be updated to include more clarification that historical Precursor Elements will not be needed.
Duke Energy Corporation It would require a significant increase in effort to develop the inventory in the format for the report.	Thank you for your comment.
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO There is a significant scope of work involved to meet the initial data collection requirement and there is less burdensome but continuing resource commitments required maintaining the data on a going forward basis. Asset management organizations within the company will need to be engaged, process for collecting and reporting data will need to be modified.	Thank you for your comment.
Great River Energy GRE expects a very minimal increase in effort with the current reporting requirement of 200 kV and greater elements. The effort would be considerably greater with the proposed TADS reporting expansion that would include 100-199 kV elements.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting.

Table 7: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?	
TO and Comment	**Comment Response**
Hydro One Networks There will need to be an initial effort to populate the inventory data in the manner proposed. The ongoing incremental effort would be relatively small and part of our change control processes.	Thank you for your comment.
LCRA Transmission Services Corporation The proposed TADS data collection would require the manual review of 197 138kV lines and 23 345kV lines, which would require significant initial and repeated update efforts.	Thank you for your comment.
Manitoba Hydro The effort to provide detailed inventory data will be significant until we are able to develop and implement an automated database.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting.
New York Power Authority Several days of work will be needed each quarter to track down the fault type along with initiating and sustaining cause codes.	Thank you for your comment.
Oklahoma Gas and Electric Company Putting aside the question of the additional data collection and submittal related to the 100kV-199kV elements, this incremental increase should be negligible after the initial data collection and submittal of the modified inventory. Quarterly reporting vs. annual reporting is not a significant issue.	Thank you for your comment.
Southern Company The incremental increase in effort for individual element inventory data reporting is significant. It will require a large up-front cost to upgrade existing computer systems, significant costs and labor to review our existing facilities and codify their configuration in our systems, and recurring costs and labor to update our information as our facilities are modified. We estimate the incremental increase in effort for quarterly data collection to be 22 weeks of effort across 6.5 FTE's annually, or approximately 3.5 weeks of effort per FTE annually.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting.

Table 7: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?	
TO and Comment	**Comment Response**
Salt River Project Agricultural Improvement and Power District a. Assuming you are asking about the inventory data, there is no additional effort. b. For the quarterly data reporting, it is a substantial effort to add this additional burden of data submittal. NERC is requesting that the TADS data submittal burden multiply by 3 times.	Thank you for your comment.
Tennessee Valley Authority TVA will have to do a one-time effort to obtain the Terminal Type for all the existing inventory data in our outage database. TVA will also have to create a query to be able to calculate the number of terminals. There will also be additional on-going 'maintenance' to the inventory to ensure it is accurate. This is probably the largest percentage of the increased effort as keeping an inventory for internal use does not require the same level of scrutiny as reporting a detailed inventory to a regulatory authority. This will require several man-hours (days) a year to verify the accuracy of the inventory being reported.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to determine the key Element inventory fields.
Xcel Energy Xcel Energy estimates ~3-4x for first year to reformat system, then 2x in years after.	Thank you for your comment.
South Mississippi Electric Power Association There will be some incremental man-hour costs associated with creating and maintaining a process to collect and maintain the proposed TADS data collection.	Thank you for your comment.
South Carolina Electric & Gas Company Formatting the data from IDP/TOA to fit TADS submittals will take extra time and resources. We suggest devising a method to correlate the submittals for BES standards and TADS information so that they use the same format to make for easier transitions.	This is an excellent comment! TADSWG will work with NERC Staff to help correlate the BES standards and TADS information to avoid redundant reporting.
Bonneville Power Administration Without a definition/explanation for each of the inventory changes requested it is difficult to accurately estimate the incremental effort required, however, BPA estimates 240-500 hrs (coding changes and classification), plus 24 hrs/month TADS reporting.	Thank you for your comment.

Table 7: What incremental increase in effort beyond the BES Standards will be required to fulfill the proposed TADS data collection?	
TO and Comment	**Comment Response**
Southern California Edison A majority of the proposed TADS data collection is already collected through WECC current data collection/ reporting process. However, adding "terminal type" to the reporting requirement would require SCE to develop a process to collect this data. The addition of this new data field would create a fair amount of upfront work in order to integrate it into SCE's TADS data collection effort. However, SCE's biggest concern is not with the inclusion of proposed new data elements to the TADS reporting requirement, but rather with the quarterly reporting schedule. A quarterly reporting requirement for this information would tie up resources that could focus on reliability-related projects, for the sole purpose of data compilation, validation, and submittal.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to determine the key Element inventory fields.

Question 3: Is the data being requested reasonable and obtainable? If "no," please explain.

Table 8: Is the data being requested reasonable and obtainable? If "no," please explain.	
TO and Comment	**Comment Response**
Associated Electric Cooperative, Inc. No. The data being requested is obtainable yet not reasonable. Operations of these 100-199 kV elements happen across the AECI system in a daily manner. The TPL-001, TPL-002, TPL-003, & TPL-004 studies are completed annually for every AECI element. These studies have not identified any scenarios that cause a cascading event. The burden of dedicating additional personnel & resources to reporting outages on transmission elements that have been identified to not have an adverse impact on reliability the eastern interconnection displays minimal benefit.	Thank you for your comment.
Ameren Services Company Yes, the data being requested is reasonable and obtainable, subject to our comments above. It would not be reasonable to collect historical data that pre-dates the TADS detailed inventory, nor would it be reasonable to use the WebTADS web site to enter detailed circuit inventory data without having a method to perform a bulk upload.	Thank you for your comment. No historical precursor Elements are requested and initial reconfiguration dates should be entered as implementation date of key inventory data collection. You are correct that it is unreasonable to not have a method to bulk upload detailed circuit inventory data. As part of webTADS change order #6, a mechanism for entering and bulk uploading detailed inventory data was implemented. This mechanism will be refined with quarterly reporting and key inventory Element collection.
ACES Power Marketing, Brazos Electric Power Cooperative, North Carolina Electric Membership Corporation, Great River Energy, Arizona Electric Power Cooperative, Southwest Transmission Cooperative, and Sunflower Electric Power Corporation We agree requesting this inventory data by element is a reasonable request especially since the impact of the data request will largely occur one time. We further believe that the data, in general, is readily available and that the six-month schedule for submission is reasonable. However, we do not support the quarterly reporting. While we understand that it will provide NERC more timely information and better align with other metrics reporting, we believe the quarterly reporting will have a detrimental reliability impact on	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting. Upon FERC approval of the new BES definition, there will be no sub-100 kV BES Elements initially. Sub-100 kV BES Elements must be included in a special Element-by-Element inclusion process. It is not anticipated that there will be many of these Elements.

Table 8: Is the data being requested reasonable and obtainable? If "no," please explain.	
TO and Comment	**Comment Response**
small entities. Small entities have limited staff and may have the same staff submitting TADS data as the staff performing other tasks such as scheduling transmission outages. The quarterly reporting will distract the staff from their core reliability function of scheduling outages during seasons with a large number of outages. With the inclusion of sub-100 kV TADS data, this distraction will be exacerbated.	
American Transmission Co. LLC yes	Thank you for your comment.
Austin Energy No. NERC has stated that: We believe that the greatest use of TADS data will be for outage cause analysis and outage Event analysis. Event analysis will aid in the determination of credible contingencies and will result in better understanding, and this understanding should be used to improve planning and operations. Ultimately, these improvements should result in improved transmission system performance. In addition, trending each Regional Entity's performance against its own history will show how that region's performance is changing over time. However, utilities already analyze outages and determine credible contingencies. There is no incremental reliability benefit gained by NERC performing the same analyses. The additional burdens created by this reporting requirement will lead to higher costs for utilities which must be passed on to rate payers (with virtually no associated reliability benefit).	You are correct that utilities already analyze outages and determine credible contingencies. However, by pooling the outage data NERC-wide, a much larger dataset is gathered that can provide more value in terms of reliability benefit. Fortunately, most individual utilities do not have many Common/Dependent mode Events in their territory. However, across NERC, the numbers of these Events add up, and they have proven to be a valuable dataset to study. In terms of costs to the consumer, TADS data is used to help utilities avoid duplicative reporting already. For U.S. TOs, the transmission outage portion of EIA's 411 is reported on behalf of the U.S. TOs by NERC using U.S. TADS data. In the future, the proposed key inventory data will help to ease reconciliation of misoperation, PRC-004, data with transmission outage data as well as help entities report Event Analysis events by using TADS Element Identifiers to identify Bulk Electric System Elements taken out of service. TADS data is important, and it is being used to help reduce duplicative data reporting burden of TOs wherever possible.
Consolidated Edison Yes	Thank you for your comment.
CenterPoint Energy *Key Inventory Data* No, it is not reasonable, but it is obtainable. There is little evidence to support the	The proposed key inventory data will help to ease reconciliation of misoperation, PRC-004, data with transmission outage data as

Table 8: Is the data being requested reasonable and obtainable? If "no," please explain.	
TO and Comment	**Comment Response**
collection of additional inventory details for the significant effort to produce the inventory data in this format. TADS outage analysis to date is not complete, and providing additional detail is premature. Analysis by total population and cause codes should be completed before any value can be assumed from collecting additional inventory detail. As stated in item #2 above, the additional inventory fields would have to be researched and processes created to maintain them. *Quarterly Outage Reporting* No, it is not reasonable, but it is obtainable. Quarterly reporting of outages will in increase the amount of effort to report outages without providing any tangible benefit other than the ability to produce quarterly graphs sooner. Since the inventory is not collected quarterly, the metrics cannot be calculated accurately on a quarterly basis. TADS data provides a historical perspective of grid availability, and it cannot be used to project future performance. Quarterly data is typically variable based on seasonal weather patterns and therefore comparison on an overall annual basis is more appropriate and substantially sufficient. The use of TADS data in other NERC metrics has not been proven to provide sufficient value to necessitate the need to produce the data more frequently.	well as help entities report Event Analysis events by using TADS Element Identifiers to identify Bulk Electric System Elements taken out of service. TADS data is important, and it is being used to help reduce duplicative data reporting burden of TOs wherever possible. With TADS annual reporting, the data is submitted so long after the event that the data itself loses value. For example, quarterly TADS could help support Event Analysis. Also, metrics could be more quickly developed by comparing same-quarters. With the upcoming 5^{th} year of TADS reporting, it is now possible to do a same-quarter year over year comparison to avoid seasonality issues. TADS metric data has proven itself to be of value. The metrics derived from TADS data by NERC stakeholder groups are being used by the North American Transmission Forum as relevant, informative metrics for transmission performance.
Dominion Virginia Power No. Some inventory data being requested is unreasonable such "Terminal Type", "Precursor Elements" and "AC Multi-Owner Common Structure Flag". It is not at all clear what value this additional information will have. Listing "Terminal Type" for all circuits has no stated benefit and no known benefit to us, therefore exclude Terminal Type information from the TADS inventory data. Finding historical "Precursor Element" data and maintaining this data history going forward provides little if any value. NERC should be clear as to the purpose of this information and only request it if there	Thank you for your well-written comment. Yes, determining number of terminals and terminal types will require some effort. However, no historical Precursor Elements will be needed for the initial inventory upload because, to TADS, the first detailed inventory Elements do not have precursor TADS Elements. The change/reconfiguration date should be set to the implementation date of key inventory data field collection. Also, you are correct that historical precursor Elements would not provide benefits in comparison with the vast amount of effort required. These were not intended

Table 8: Is the data being requested reasonable and obtainable? If "no," please explain.	
TO and Comment	**Comment Response**
is a substantial benefit to reliability assessment. The purpose of collecting "Change/Reconfiguration Date", "Retirement Date" and "Precursor Element" is to "gather data to provide evidence that NERCs hypothesis of an aging system is affecting reliability." The date the line was configured or reconfigured has little correlation to the date of the failed equipment. The evolution of the system and documentation of every configuration change from the time the element was built is not practical or in many cases not possible. Some equipment was installed in the 1900s, others have been bought, sold, torn down and rebuilt. Sections may have been rebuilt for storm damage or rerouted. To make any conclusions based on the in service date (Change/Reconfiguration Date) of the element would result in misleading conclusions being drawn from the wrong data. As an alternative to using the in service date an additional field could be added to Outage Reporting forms called "age of failed equipment." This would get the actual data needed to draw correct conclusions regarding the age of the component or system element. The rules for determining whether a circuit is Underground/Overhead will need clarity but we assume that it will be coded as to what constitutes the majority of the line. The value of "AC Multi-Owner Common Structure Flag" is not justified. It should not matter to reliability that two owners have lines on the same structure. Having two owners for different lines on the same structure is no different from having one owner with two lines on the same structure. We suggest this data be removed. Since transformers are excluded from the "Number of Terminals" field, we also conclude transformers are excluded from the "Substation, Terminal, or Converter Names(s)" field and excluded from the "Terminal Type" field. Please add clarity to wording. Additionally we assume that the current Circuit and Transformer inventory summary data by voltage class	to be requested, and the wording will be clarified to make this the case. For the AC Multi-Owner Common Structure Flag, this field is already being collected by TADS on a per-outage basis. The intent is to collect this field on a per-AC Circuit basis and remove the field from the outage forms. The data request will be updated to include more clarification that historical Precursor Elements will not be needed. Transformers would need a single substation entered in the "Substation, Terminal, or Converter Name(s)" field, but there would not be a "Terminal Type" entered. This will be clarified in the wording. The Underground/Overhead field is already reported on a per-outage basis. This would be reported on a per-Element basis with the same definition. The majority of the circuit miles of an Element determine whether the Element is Underground/Overhead. You are correct in assuming that the inventory summary data will no longer be required. It will be automatically calculated from the key inventory data fields. This will be clarified in the data request.

Table 8: Is the data being requested reasonable and obtainable? If "no," please explain.	
TO and Comment	**Comment Response**
will no longer be required. We also assume that the old inventory data from previous years will go away and not be maintained. Please update the wording to assure this is communicated.	
Duke Energy Corporation No. This is a significant amount of work in terms of both effort and cost, which we don't believe provides a commensurate benefit in event analysis.	Thank you for your comment.
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO No. It is not reasonable because we don't think it will provide value and it is not obtainable in the form proposed without significant effort to retool asset management, maintenance and reporting processes.	Thank you for your comment.
Great River Energy Yes, the data being requested is reasonable and obtainable.	Thank you for your comment.
Hydro One Networks The data being requested is obtainable. It is reasonable as long as the data are reviewed and analysed by NERC with results and findings shared with the contributing entities. The resulting benefits from these data collections should be shared periodically with the contributing entities.	Thank you for your comment.
LCRA Transmission Services Corporation The data being collected is obtainable through significant manual review; however, LCRA TSC does not feel that request is reasonable as the benefits outlined in the Request for Public Comment Letter do not appear to outweigh the required initial and repeat efforts to obtain the information. Further explanation of the benefits might provide better justification.	Thank you for your comment.
Manitoba Hydro Yes, the data requested is reasonable but not easily obtainable for the reasons outlined in Question 1	Thank you for your comment.
New York Power Authority Yes	Thank you for your comment.
Oklahoma Gas and Electric Company Yes	Thank you for your comment.
Southern Company The data being requested is obtainable at a cost to the customers of Southern Companies. It will require significant manual data entry until an automated	Thank you for your comment.

Table 8: Is the data being requested reasonable and obtainable? If "no," please explain.	
TO and Comment	**Comment Response**
method of formatting in a TADS reportable format can be implemented. As it relates to the reasonableness of the data being requested, Southern Companies do not believe this data will improve the reliability of the BES. While Southern Companies support providing a unique line identifier, we believe the detailed inventory data should be held by the North American Transmission Forum and NERC staff should collaborate with the Forum for more in depth analysis of the data.	
Salt River Project Agricultural Improvement and Power District a. Inventory collection – is reasonable and obtainable. b. Quarterly reporting – Is unreasonable request, there has not been proven the benefit of currently collected TADS to this point and adding 3 more times data collection is over burdensome and the story for why is needed not convincing.	Thank you for your comment.
Tennessee Valley Authority No, the data being requested is unreasonable. Several of the inventory requests will not provide meaningful, actionable results	Thank you for your comment.
Xcel Energy Yes	Thank you for your comment.
South Mississippi Electric Power Association Yes.	Thank you for your comment.
South Carolina Electric & Gas Company We believe that the tracking of reconfiguration/change dates could cause an administrative burden. More clarification on the definition of "reconfiguration/change date" is needed in order to determine the level of burden.	Thank you for your comment. More clarification of the "reconfiguration/change date" as well as the "precursor element" fields will be provided in the data request.
Bonneville Power Administration No. BPA does not believe the data requested is reasonable in that it's too detailed. It is, however, eventually attainable.	Thank you for your comment.
Southern California Edison No. The data being requested by NERC can be obtained; however, SCE feels that the quarterly submittal of such data is not reasonable. Quarterly reporting will force SCE to develop new computer programs and add additional resources to collect and	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for quarterly data reporting.

Table 8: Is the data being requested reasonable and obtainable? If “no,” please explain.	
TO and Comment	**Comment Response**
process the many data streams into a TADS-compatible data template. The new TADS requirements will force SCE to perform more frequent reviews and analyses of outages taking manpower away from time-critical reliability related projects.	

Question 4: Is the implementation schedule for the request reasonable? If "no," please explain.

Table 9: Is the implementation schedule for the request reasonable? If "no," please explain.	
TO and Comment	**Comment Response**
Associated Electric Cooperative, Inc. No. The implementation schedule of six months is not reasonable. If this reporting is to become approved by FERC, the entities registered under the AECI JRO will have to hire and train at least 7 new personnel. AECI recently had an employment opportunity available to be dedicated to performing compliance duties, this required 18 months to fill that role.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting.
Ameren Services Company Yes, the implementation schedule is reasonable	Thank you for your comment.
ACES Power Marketing, Brazos Electric Power Cooperative, North Carolina Electric Membership Corporation, Great River Energy, Arizona Electric Power Cooperative, Southwest Transmission Cooperative, and Sunflower Electric Power Corporation We agree requesting this inventory data by element is a reasonable request especially since the impact of the data request will largely occur one time. We further believe that the data, in general, is readily available and that the six-month schedule for submission is reasonable. However, we do not support the quarterly reporting. While we understand that it will provide NERC more timely information and better align with other metrics reporting, we believe the quarterly reporting will have a detrimental reliability impact on small entities. Small entities have limited staff and may have the same staff submitting TADS data as the staff performing other tasks such as scheduling transmission outages. The quarterly reporting will distract the staff from their core reliability function of scheduling outages during seasons with a large number of outages. With the inclusion of sub-100 kV TADS data, this distraction will be exacerbated.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting. There will be several quarters of 200 kV+ data submitted before a transition to reporting less than 200 kV BES Element data. Based on the BOT approved BES definition, the sub-100 kV BES Elements are expected to be minimal and included in an Element-by-Element inclusion process.
American Transmission Co. LLC yes	Thank you for your comment.

Table 9: Is the implementation schedule for the request reasonable? If "no," please explain.	
TO and Comment	**Comment Response**
Austin Energy No. AE suggests the initial inventory and quarterly data submittal begin in the reporting period one year after NERC BOT approval, assuming there is a need to compile/report the requested data (please refer to our answer to question 3). This additional time would allow AE to properly allocate budget and schedule resources.	Thank you for your comments. A staggered reporting schedule is being used to allow TOs more time to prepare for less than 200 kV outage and inventory data reporting.
Consolidated Edison Yes	Thank you for your comment.
CenterPoint Energy No. CenterPoint Energy recommends that the TADS data collection remain unchanged and that the NERC Planning Committee reconsider a revised data request after making its determination in 2015 on the demonstration of the benefits of TADS. At that time, NERC trend analysis on five years of TADS data should be complete, and the impacts of the NERC BES definition to data collection (i.e., additions and deletions of Elements) should also be known. Also, the request indicates the data initial inventory and first TADS quarterly reporting "starting first quarter beginning six months after board approval" which can place the implementation date off of an annual reporting schedule. Implementation of changes to TADS, if approved by the NERC board, should be effective January 1st of the reporting year after board approval given that approval is received by June 30th of the prior year. There is also a conflict in the reporting of inventory data annually and outage data quarterly if the intent is to provide quarterly metrics. TADS was originally designed by the TADSTF to be an annual reporting system based on cumulative outage reporting over a one year period.	Thank you for your comment.
Dominion Virginia Power No. Having a start date that is based on the date of BOT approval does not provide entity's with a definitive long term date to begin implementation. Suggest that a date of 1/1/2014 or 1/1/2015 be stated and used so that entities can plan accordingly. Starting data reporting on the 1st day of a new	A staggered schedule with defined dates has been created to help TOs determine when to report the proposed data.

Table 9: Is the implementation schedule for the request reasonable? If "no," please explain.	
TO and Comment	**Comment Response**
calendar year makes more sense for comparing yearly stats than starting during the year. NERC is not clear as to whether it wants inventory data reported quarterly or annually. The information in Table 1: "Data Request Schedule" indicates inventory data submitted annually. Providing inventory data on an annual basis and outage data on a quarterly basis will create errors when outage data is entered before changes to inventory have been submitted. Inventory and outage data must be submitted on the same schedule. Table 1: "Data Request Schedule" indicates the Functional Entity reporting deadline of 45 days after end of quarter. Since NERC is citing consistency between other PRC standards (such as PRC-004) as basis for quarterly reporting, we request the submittal dates for TADS also be consistent and be changed to 60 days (or 2 calendar months) after end of quarter. This is especially important since NERC is now asking for extra data submittals on the same quarterly schedule.	
Duke Energy Corporation The schedule is not reasonable, due to the significant effort required to change processes and software. Six months is inadequate time to both develop the inventory and submit the first quarterly report. Twelve months is possible, but it will be difficult.	Thank you for your comment.
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO No. It is not reasonable because we don't think it will provide value and it is not obtainable in the form proposed without significant effort to retool asset management, maintenance and reporting processes.	Thank you for your comment.
Great River Energy Yes, the implementation schedule for the request is reasonable.	Thank you for your comment.

Table 9: Is the implementation schedule for the request reasonable? If "no," please explain.	
TO and Comment	**Comment Response**
Hydro One Networks The implementation schedule is not reasonable primarily due to the combination of coincident changes in scope, detail and frequency of reporting. The proposed implementation time extends beyond the implementation period previously provided for changes to TADS reporting. Providing inventory by first quarter in 2014 along with quarterly reporting starting in 2014 would be reasonable. Also, due to the timelines in the implementation plan of the BES definition and the exception process, final identification of BES Elements will not be available until such time.	Thank you for your comment.
LCRA Transmission Services Corporation LCRA TSC would be able to meet the schedule; however, it would require significant effort.	Thank you for your comment.
Manitoba Hydro The implementation schedule is not reasonable. In order to meet this request with the resources we have available, we are planning to implement additional automation of data collection. Such IT projects tend to take a significant amount of time to implement. We would suggest an implementation period of at least three years.	Thank you for your comment.
New York Power Authority Yes	Thank you for your comment.
Oklahoma Gas and Electric Company Yes	Thank you for your comment.
Southern Company Yes, it is reasonable; however, it will require significant manual data entry until an automated method of formatting in a TADS reportable format can be implemented. Southern Company would prefer that implementation start at the beginning of the next calendar year at least 6 months after FERC approval of the Bulk Electric System definition.	Thank you for your comment.
Salt River Project Agricultural Improvement and Power District No comment other than inventory is reasonable to gather the data.	Thank you for your comment.

Table 9: Is the implementation schedule for the request reasonable? If "no," please explain.	
TO and Comment	**Comment Response**
Tennessee Valley Authority No. The implementation schedule is not reasonable.	Thank you for your comment.
Xcel Energy n/a	Thank you for your comment.
South Mississippi Electric Power Association Yes.	Thank you for your comment.
South Carolina Electric & Gas Company Yes, we believe the schedule is reasonable considering the resources we currently have in place.	Thank you for your comment. More clarification of the "reconfiguration/change date" as well as the "precursor element" fields will be provided in the data request.
Bonneville Power Administration No. Six months is not reasonable given the uncertainties involved with establishing definitions and the efforts needed to modify cross agency business processes and applications. One year is a more reasonable timeframe.	Thank you for your comment.
Southern California Edison No. The implementation schedule is not reasonable as SCE and others will have problems collecting and processing the additional outage data required by the new TADS requirements on a quarterly basis. Currently, SCE works in conjunction with its regional entity, WECC, to compile outage data on outages at 200 kV and above and is overwhelmed by performing this task on an annual basis. As WECC and other regional entities are moving toward providing less assistance on compiling outage data, SCE will need to develop a whole new outage reporting tool. This new tool will need to function as a single internal source for compiling and processing such data to integrate both transmission and sub-transmission information for the sole purpose of TADS reporting. We do not believe that such a tool can be developed, tested, and implemented within the timeframe proposed by NERC.	Thank you for your comment.

Question 5: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?

Table 10: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Associated Electric Cooperative, Inc. It is approximated that after including wages/benefits for additional personnel required, the cost would be at least $500,000 annually.	Thank you for your comment.
Ameren Services Company Incremental cost of developing a system to export the key inventory data is estimated to be in the range of tens of thousands of dollars.	Thank you for your comment.
American Transmission Co. LLC 80 hours x $100/hr = $8,000.00	Thank you for your comment.
Austin Energy The additional cost for reporting key inventory data for TADS Elements >= 200 kV would be approximately 80 man-hours per year. If, however, this inventory data request includes TADS Elements 100-199 kV, AE estimates the cost would be an additional 320 man-hours per year.	Thank you for your comment.
Consolidated Edison N/A	Thank you for your comment.
CenterPoint Energy CenterPoint Energy estimates a one-time cost to implement a key inventory reporting system for both 100-199 kV and >200 kV Elements containing the entire set of proposed TADS inventory fields to be $10,000. Additionally, there will be a one-time cost of $16,000 to determine the newly proposed TADS Terminal Type for two hundred eighty-five AC Circuits and thirty-six Transformers. The incremental annual cost to review terminal equipment changes and to maintain the inventory reporting system data is estimated to be $4,000. There will be additional costs for the including the <100 kV BES Elements, when identified, which may increase these estimates by as much as 50%.	Thank you for your comment.
Dominion Virginia Power Estimated costs to create a system, update existing programs and populate inventory data will be $30,000. This cost may be more or less depending on need for “Precursor Element” data.	Thank you for your comment.

Table 10: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Duke Energy Corporation Development and modifications to the system are where the majority of the work lies. This is an additional workload of approximately 4-to-6 Full-Time Equivalent (FTEs) just to implement changes. Another 2 FTEs will be required to update and maintain the inventory. We don't believe the event analysis benefits justify these ongoing increases in O&M costs.	Thank you for your comment.
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO Not known at this time, need to engage IT and other subject area experts to evaluate	Thank you for your comment.
Great River Energy With the current TADS reporting requirements, the incremental cost is negligible. If the reporting requirements are expanded to include 100-199 kV, the incremental one-time costs would increase by the number of circuits that would need to be reported.	Thank you for your comment.
Hydro One Networks The incremental cost is unknown at this time.	Thank you for your comment.
LCRA Transmission Services Corporation LCRA TSC is unsure what the cost would be to develop a system to automate the inventory data collection; however, a significant initial manual review would be necessary – totaling 50-60 hours of analysis of all 220 applicable BES lines. This would also lead to a monthly, incremental increase of 2-3 hours for review.	Thank you for your comment.
Manitoba Hydro Unable to determine without further investigation.	Thank you for your comment.
New York Power Authority Assuming historical data is not required for configurations prior to the BOT approval of this proposal, very little incremental work will be needed to complete this request initially and annual. If 60 plus years of records need to reviewed, this will be an exceedingly onerous and time consuming effort.	Thank you for your comment.
Oklahoma Gas and Electric Company We do not have a system or tool to export key inventory data into webTADS. These are all manually examined and entered into webTADS.	Thank you for your comment.
Southern Company Please see the response to Question #2.	Thank you for your comment.

Table 10: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Salt River Project Agricultural Improvement and Power District No issue	Thank you for your comment.
Tennessee Valley Authority Our current database will have to be changed to be able to record some of the information that is being requested (Precursor Element(s), Terminal Type, and calculation of the number of terminals). Also, every terminal will have to be evaluated and verified before entry into the system. Also, there will be some annual costs to maintenance of the data and verification of the data. Estimate about 200-400 hours for development of the new system and entry of the data. Estimate about 50 hours annual for additional inventory data and about 50 annual hours for verification of data prior to submittal. Cost estimate for the currently proposed level of inventory reporting = $40,000 for initial setup and $10,000 per year	Thank you for your comment.
Xcel Energy n/a	Thank you for your comment.
South Mississippi Electric Power Association There will be a fair amount of man-hour costs associated to developing the initial inventory data. However once the inventory is created, the costs to maintain the inventory should reduce dramatically. Also, some training costs will be necessary to train our operators to use the system developed if they are responsible for reporting automatic outages.	Thank you for your comment.
South Carolina Electric & Gas Company The cost is dependent upon estimated additional man-hours to report the additional information. Additional man-hours and cost to develop and implement a new system to export the key inventory data is approximated at 3 to 4 times the previous cost of obtaining TADS information.	Thank you for your comment.
Bonneville Power Administration Approximately $15K.	Thank you for your comment.

Table 10: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Southern California Edison The incremental costs are severe, as this TADS proposal will require the development of an entire data processing program under SCE's SAP computer system. Our IT Department will need to perform research to design and create appropriate software and to implement the software in the three impacted business lines. The comprehensive outage database will require significant capital funding and approval from our regulators. As SCE is currently required to report only a fraction of the proposed information on an annual basis, the speed with which SCE would be required to process and report under the new guidelines would be unprecedented and difficult to achieve.	Thank you for your comment.

Question 6: Assuming you will have to develop a system to report outage data quarterly, what is the incremental cost comparing with reporting outage data annually?

Table 11: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Associated Electric Cooperative, Inc. Quarterly reporting as opposed to annual reporting is anticipated to have negligible cost impact. The primary cost impact is referenced in question #2 of this document.	Thank you for your comments.
Ameren Services Company There will be a minimal cost to modify our system to be able to report TADS data on a quarterly basis.	Thank you for your comments.
American Transmission Co. LLC 40 hours per year x $100 = $4,000.00 per year	Thank you for your comments.
Austin Energy The incremental cost for reporting outage data quarterly would be approximately 80 man-hours per year. This is primarily due to dividing the work instead of taking care of all of it at one time. Some repetition will result.	Thank you for your comments.
Consolidated Edison N/A	Thank you for your comments.
CenterPoint Energy The incremental annual cost to report outage data quarterly for both 100-199 kV and ^{3}200 kV Elements is estimated to be $12,000. The cost is driven by the need to perform regulatory reporting data validation three additional times per year. There will be additional costs for the including the <100 kV BES Elements, when identified, which may increase this estimate by as much as 50%.	Thank you for your comments.
Dominion Virginia Power The additional cost for reporting quarterly is estimated to be $5,000 - $10,000.	Thank you for your comments.
Duke Energy Corporation While some of our regions could use existing systems to report, other regions would have to spend hundreds of thousands of dollars due to the inventory changes. Again, we don't see the value of this increased data collection commensurate with the cost	Thank you for your comments.

Table 11: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO Not known at this time, need to engage IT and other subject area experts to evaluate	Thank you for your comments.
Great River Energy With the current TADS reporting requirements, the incremental cost for reporting quarterly is negligible.	Thank you for your comments.
Hydro One Networks The incremental cost is unknown at this time.	Thank you for your comments.
LCRA Transmission Services Corporation A quarterly outage data submittal period would not lead to a significant incremental cost increase, as it will require smaller amounts of data will be reviewed more frequently.	Thank you for your comments.
Manitoba Hydro The effort required to report data quarterly versus annual will be significant. We would suggest that the quarterly reporting requirement be optional and that entities have the option to report annually. Since we report annually to the Canadian Electricity Association (CEA), it makes sense to report to NERC on the same interval basis.	Thank you for your comments.
New York Power Authority 144 Man hours = (36 man hours per quarter X 4) This estimate assumes it'll take less time to track down automatic outage details than once per year but requires multiple requests.	Thank you for your comments.
Oklahoma Gas and Electric Company We see no difference in cost between annual and quarterly data submittal.	Thank you for your comments.
Southern Company We estimate the incremental cost for reporting outage data quarterly is $24,000 annually.	Thank you for your comments.
Salt River Project Agricultural Improvement and Power District a. The same data gathering structure or process we have in place would be used for quarterly reporting, the additional cost is the labor used in gathering the data at the end of the time period, reviewing it and submitting through the NERC data submittal process, expected cost increase to be near $50k per year	Thank you for your comments.

Table 11: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Tennessee Valley Authority The biggest cost to quarterly reporting is coordination with neighboring utilities. Rather than an annual coordination it will have to be done quarterly and will require about the same amount of time each quarter so it will be 4 times the annual rate. Another increase is that there will be more interruptions that have a 'continuation' flag as they carry from one quarter to the next (rather than one year to the next). This will require additional outages that have to be analyzed and verified during multiple 'cycles'. This results in multiple reviews of the same outage. Estimate would be about 100 hours per quarter which equates to an additional cost of $10,000 per quarter or $40,000 per year for quarterly reporting. With this increase in data, "The State of Reliability Report" should likewise be issued quarterly with an increase in metrics and data reported to the utilities.	Thank you for your comments.
Xcel Energy n/a	Thank you for your comments.
South Mississippi Electric Power Association There will be some incremental man-hour costs associated with the quarterly outage data report. The combined quarterly cost should be equivalent to the current annual cost.	Thank you for your comments.
South Carolina Electric & Gas Company The cost of reporting quarterly is not estimated to be any more than the cost to report annually	Thank you for your comments.
Bonneville Power Administration Approximately $4K.	Thank you for your comments.

Table 11: Assuming you will have to develop a system to export the key inventory data, what is the incremental cost of this reporting?	
TO and Comment	**Comment Response**
Southern California Edison The incremental costs are severe, as this TADS proposal will require the development of an entire data processing program under SCE's SAP computer system. Our IT Department will need to perform research to design and create appropriate software and to implement the software in the three impacted business lines. The comprehensive outage database will require significant capital funding and approval from our regulators. As SCE is currently required to report only a fraction of the proposed information on an annual basis, the speed with which SCE would be required to process and report under the new guidelines would be unprecedented and difficult to achieve.	Thank you for your comments. A staggered schedule has been developed to allow TOs more time to prepare for collection.

Survey Participants

Table 12: Survey Participants
Organization
ACES Power Marketing, Brazos Electric Power Cooperative, North Carolina Electric Membership Corporation, Great River Energy, Arizona Electric Power Cooperative, Southwest Transmission Cooperative, and Sunflower Electric Power Corporation Multiple Regional Entities
Associated Electric Cooperative, Inc. SERC
Ameren Services Company SERC
American Transmission Co. LLC MRO, RFC
Austin Energy TRE
Consolidated Edison NPCC
CenterPoint Energy TRE
Dominion Virginia Power SERC

Table 12: Survey Participants
Organization
Duke Energy Corporation SERC
Edison Electric Institute
Exelon on behalf of Baltimore Gas & Electric, ComEd, and PECO RFC
Great River Energy MRO
Hydro One Networks NPCC
LCRA Transmission Services Corporation TRE
Manitoba Hydro MRO
New York Power Authority NPCC
Oklahoma Gas and Electric Company SPP RE
Southern Company SERC
Salt River Project Agricultural Improvement and Power District WECC
Tennessee Valley Authority SERC
Utility Services
Xcel Energy MRO
SGS Statistical Services
South Mississippi Electric Power Association SERC
South Carolina Electric & Gas Company SERC
Bonneville Power Administration WECC
Southern California Edison WECC