NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Order 754 – Request for Data or Information

The Order 754 Drafting Team thanks all commenters who submitted comments on the Request for Data or Information. These comment questions were posted for a 45-day public comment period from May 11, 2012 through June 25, 2012. Stakeholders were asked to provide feedback through a special electronic comment form. There were 24 sets of comments, including comments from approximately 65 different people from approximately 47 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/order_754.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council	X	X	X		X	X		X	X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	Nerw York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael Lombardi	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Brian Robinson	Utility Services	NPCC	8
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NC Electric Membership Corporation	SERC	1
3.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
4.	Philip Kleckley	SC Electric & Gas Company	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10
6.	Bob Jones	Southern Company Services	SERC	1
7.	James Roberts (Guest)	TVA	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck	Matthews	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	David Thorne	Pepco Holdings Inc and Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Pepco	RFC	1
2.	Alvin Depew	Pepco	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Les Aleva	FE	RFC	
2.	Brian Orians	FE	RFC	
3.	Tom Pezze	FE	RFC	
4.	Doug Hohlbaugh	FE	RFC	

6.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators	X		X	X		X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
2.	Chris Bradley	Big Rivers Electric Corporation	SERC	1
3.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1

7.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
8.	Individual	Shirin Friedlander	Los Angeles Department of Power and Power	X		X		X	X				
9.	Individual	Thad Ness	American Electric Power	X		X		X	X				
10.	Individual	Michael Jones	National Grid	X		X							
11.	Individual	Michelle R D'Antuono	Occidental Energy Ventures Corp.			X		X					
12.	Individual	Don Schmit	NPPD	X		X		X					
13.	Individual	Patti Metro	NRECA			X	X						
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Mary Ann Zehr	Tri-State Generation and Transmission Association, Inc.	X									
16.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
17.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
18.	Individual	Milorad Papic	Idaho Power Company	X		X							
19.	Individual	Stephen J. Berger	PPL Generation, LLC on behalf of its Supply NERC Registered Entities					X					
20.	Individual	John Pearson	ISO New England		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
21.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
22.	Individual	Nathan Smith	Southern California Edison	X		X		X					
23.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X		X	X				
24.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X		X	X				

1. Please enter specific comments about the method of the data request in the provided text box.

Summary Consideration:

Seven commenters recommended additional clarity is necessary in describing the cases the Transmission Planner will use. One commenter also recommended clarifying that some entities may require several stressed cases in order to properly evaluate single point of failure across various parts of the system. Additional information has been added to the data request describing the cases the Transmission Planner will use in its assessment.

Two commenters recommended adding a statement that the Transmission Planner may simulate an uncleared fault or a fault cleared in five seconds in step 3 of the method in place of the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. The data request allows Transmission Planners to use an alternate method so long as the data provided is consistent with the data (in form and substance) that would be developed by using the method in the data request (i.e., the alternate method must yield all of the data requested on the reporting template). The data request does not preclude using five-second fault clearing or uncleared faults in step 3; however, it is not practical to list every possible alternate method in the data request and so the proposed text has not been included.

Three commenters recommended that step 10 of the method should refer to "each bus on the final list developed in step 9" rather than "each bus evaluated in step 9." The proposed text is more accurate and the recommended change has been made.

Three commenters noted the reference to Table A on page 14 is confusing because this description refers to excluding Elements, but the purpose of Table A is to exclude buses from assessment and reporting. The description has been modified to avoid the phrase "Elements excluded from the criteria in Table A." The description now states: "Note that criteria in Table A are applied only for the purpose of identifying buses to be tested; these criteria are not related to the assessment and reporting of protection system attributes."

Three commenters noted the rationale for Protection System Component Attributes undermines the validity of TPL-001-2 and they proposed alternate text. The rationale has been revised as proposed to avoid the appearance that this data request prejudges the validity of the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13). The revised rationale more clearly states the intent that a more complete list of relay types and protection system components is appropriate for this data request.

One commenter recommended revising the text in the second bulleted item in step 2 of the method to avoid the appearance that a Transmission Planner may exclude a bus from the "List of Buses to be Evaluated" solely on the criterion that through-fault protection exists on the connected transformers. The text has been revised as proposed to make it clear that the reference to removing buses applies only to the second bulleted item.

One commenter recommended revising footnote 13 (now footnote 15) to allow the Transmission Planner to simulate operation of load shedding or Special Protection System (SPS) provided "it is normally in-service, capable of responding to the simulated contingency, and does not share a single point of failure with any of the protection schemes being evaluated." Modeling all load shedding and SPS in this assessment could result in understating the reliability risk associated with protection system single point of failure. This could occur if load shedding or an SPS operated, thereby preventing the adverse impacts in Table C. This is particularly true for underfrequency load shedding (UFLS) and other safety nets installed for last resort measures which should not be relied on to mitigate the effects of protection system failures. Increased reliance on load shedding and SPS affects overall system reliability and increases the potential for undesirable interaction. The criteria for modeling load shedding and SPS have been modified to refer to "conditions associated with the simulated fault" rather than "the simulated contingency" because the original wording would unintentionally indicate the load shedding or SPS can be modeled only if it is installed to protect against the consequences of a protection system single point of failure. The criteria also have been modified to not specifically mention load shedding since many load shedding schemes (e.g., UFLS) are installed as safety nets and should not be modeled, while other load shedding schemes installed for specific purposes are included as SPS and may be modeled if they meet the stated criteria.

One commenter noted that step 8 of the method should refer to the "method described in step 3" rather than the "method described in step 4." The text for step 8 has been corrected as proposed.

Three commenters noted that the main DC panel should be considered part of the station DC supply and not the DC control circuitry. One commenter noted that including the main DC panel as part of the DC control circuitry will skew the results and should not be included in Table B for the same reason the station DC supply is reported separately. One commenter noted that including the main DC panel in the DC control circuitry conflicts with branch circuit definitions in the National Electric Code (NEC). The information in Table B has been revised to exclude the main DC panel from the DC control circuitry. Similar to the station DC supply, including the main DC panel in Table B could skew the results because stations with one station DC supply typically have only one main DC panel. Table D also has been revised to include the main DC panel.

One commenter noted the example associated with Figure 1-8 needs clarification because the scheme does not meet the criteria for independent protection schemes, but the discussion indicates "so a single trip coil should not be an issue." This example was included to demonstrate that even though the protection system in Figure 1-8 provides an incremental gain compared to the protection system in Figure 1-7, it still does not meet all protection system attributes in Table B. The examples associated with Figure 1-6 and Figure 1-7 adequately describe issues associated with bus protection and so the example associated with Figure 1-8 has been removed to avoid confusion.

One commenter recommended additional detail should be provided on the fault scenarios that must be simulated including information pertaining to bus configuration, fault location, and clearing time. For the purpose of this data request, all bus configurations are treated as a single straight bus (single-breaker) configuration. Faults on any main bus section, or immediately beyond the breakers connecting any Element are essentially identical; however, the clearing times when a single point failure prevents operation of the local protection system will depend on the specific location of the fault and also on the nature of the single points of failure present. The examples in Appendix 1, Transmission Line Single Points of Failure and Resultant Clearing Times, illustrate how a transmission line protection system may have many single points of failure, and they result in several different sets of expected clearing times. The examples identify the clearing times for a single point of failure in each component category for which a single point of failure exists; however, the Transmission Planner is required to simulate only one three-phase fault on the bus. Typically the fault clearing for this simulation is based on the expected fault clearing for a failure of the protection system to initiate tripping and breaker failure protection. However, some exceptions exist. If the only single point of failure is in the communication system the fault clearing would involve time delayed backup protection. If the only single point of failure is the circuit breaker trip coils and breaker failure protection is provided, the fault clearing would be based on operation of the breaker failure protection.

One commenter noted that for the example associated with Figure 1-12 (now Figure 1-11) the discussion seems to indicate breaker failure times should only be used if either breaker had only one trip coil. The commenter requested guidance on the fault clearing time for a fully redundant protection system with one or dual trip coils, and on the clearing times to be reported for Bus 1 and Bus 2. It is generally true that breaker failure clearing should be simulated only when the only single point of failure is the breaker trip coil, although analysis of the specific protection system design in this example identifies that failure of the tripping relay (94) also results in operation of the breaker failure protection. In the commenter's example, the local clearing time would be 4 cycles as stated in the appendix and the remote end would also trip high speed via the Directional Comparison Blocking (DCB) scheme, unless the specific mode of failure of the primary scheme is improperly transmitting a blocking signal. Additionally, if the protection systems on the bus and all connected Elements meet the attributes of Table B, this bus would not need to be analyzed. Analysis is required only for faults where a single point of failure will result in prolonged clearing times. The clearing time for the buses would depend on the specifics of the associated protection systems.

One commenter indicated it would be beneficial to have an example for a straight bus and requested confirmation that for a straight bus with redundant bus protection, an entity would only report bus protection clearing times; whereas, if a single bus protection was installed the longest remote backup clearing time would be reported. The clearing time for the buses would depend on the specifics of the associated protection systems for the bus and all connected Elements. If redundant protection, meeting all of the Table B attributes is used on the bus and all connected Elements, then the Transmission Planner is not required to simulate a fault on this bus. If only a single protection scheme is installed on the bus or on any of the connected Elements, then the clearing time is dependent on the failure mode and the associated back up protection systems. For instance, for the failure of a tripping relay on a scheme using separate tripping and breaker failure initiating auxiliary relays, the clearing time may be determined by breaker failure time plus transfer trip times. If a single lockout relay failed that is used to initiate tripping and breaker failure protection, then the fault clearing time would be determined by the remote clearing times. If the remote clearing times were not equal, then the fault magnitude would be reduced as faster terminals cleared, until the fault is finally cleared by the slowest.

One commenter noted that footnote 13 (now footnote 15) on page 9 is confusing and seems to penalize entities that have dual trip coils and breaker failure relaying because it indicates local relay protection operation times (specifically breaker failure) can be used in Step 7, only in the case of one breaker trip coil. The commenter also noted that redundant primary and backup relaying should be required as well as independent DC circuits to insure breaker failure is initiated. This note is not intended to penalize entities using redundant protection schemes including dual trip coils which also independently initiate breaker failure relaying. The note only applies when a single point of failure exists. If the protection systems meet the attributes defined in Table B, they have no single point of failure modes and the bus would be removed from the “List of Buses to be Evaluated” in step 6.

One commenter noted that although the examples on pages 37-39 are beneficial, the clearing times supplied to the Transmission Planner in Step 7 should be identified in the examples. The commenter also noted another example would be helpful and requested an example similar to the example associated with Figure 1-13 (now Figure 1-12), but with independent primary and backup line relaying. For the non-redundant directional comparison blocking scheme used in the example, several single points of failure are analyzed. In each case the resultant clearing times for all fault sources are determined. These are the clearing times to be supplied to the Transmission Planner. In Case 2, an independent “back up” scheme is added to the primary scheme. The composite scheme is shown in Figure 1-14 (now Figure 1-13).

Three commenters noted that existing and proposed Transmission Planning (TPL) standards address single points of failure in protection systems. One commenter recommended that the data request is therefore unnecessary and the standards development process should be used if there is a need to expand the studies being conducted in the TPL standards, and two commenters recommended the data request should be limited to determining current practices in conducting TPL standards assessments and any possible reliability gaps. The data request has not been revised based on these comments. The extent to which TPL-003 and TPL-004 require evaluation of single points of failure in protection systems is the subject of a request for interpretation (Project 2012-INT-02) that was identified during the FERC technical conference. The data request, also identified at the FERC technical conference, will provide statistical information on the number of buses at which a protection system single point of failure could result in an adverse impact to reliability of the bulk power system as well as the extent to which exposure to single points of failure exists at these buses, broken down by specific categories of protection system components. This data will allow NERC to assess whether a reliability gap exists that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate measures tailored to address the concern. If the request for interpretation or data request identifies a need to expand the studies being conducted in the TPL standards, the standards development process will be used accordingly.

Three commenters noted the data request is not clear regarding how each assessment by the Generator Owner, Transmission Owner, and Distribution Provider in steps 2, 5 and 10 of the method are different from each other. The protection system reviews in steps 2, 5, and 10 serve different purposes and therefore involve an increasing level of detail. The differences between steps 2, 5, and 10 have been a point of confusion and a description of each step has been added to the data request to highlight the differences.

Two commenters noted that use of actual clearing times in step 3 would eliminate the need for steps 7 and 8. Some Transmission Planners may find it useful to perform an initial screening based on conservative clearing times to minimize the overall effort; however, this is not required. Text has been added to clarify that the method in the data request uses an iterative approach between the Transmission Planner and the asset owners to narrow the list of buses to be evaluated by initially screening the buses based on conservative assumptions before moving on to detailed analysis. As noted in the data request, entities may use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, so long as the data provided is consistent with the data (in form and substance) that would be developed by using the method in the data request (i.e., the alternate method must yield all of the data requested on the reporting template).

One commenter indicated concern that step 3 of the method may require simulations to be inconsistent with actual protection system operation. Text has been added to clarify that the method in the data request uses an iterative approach between the Transmission Planner and the asset owners to narrow the list of buses to be evaluated by initially screening the buses based on conservative assumptions before moving on to detailed analysis. It is recognized that the conservative assumptions may not reflect actual protection system operation during initial screening in step 3. If the system response based on conservative assumptions is acceptable the bus can be removed from the “List of Buses to be Evaluated.” If simulations based on the conservative assumptions identify the potential for adverse system performance, the simulation will be repeated in step 8 based on expected protection system operation.

One commenter recommended that Table A be modified to exclude buses that are a breaker-and-a-half, ring bus, or double-breaker-double-bus configuration. The method in the data request uses a bus fault to assess system performance resulting from failure of a protection system to initiate clearing of a bus fault because it is representative of the system performance for a close-in fault on any Element connected to the bus. While some bus configurations may lead to different fault clearing time or sequence of Elements tripping, this does not eliminate the need to study all buses regardless of the bus configuration. This point has been clarified with additional text.

One commenter recommended using a statistically significant sample to evaluate the Performance Measures in Table C. Statistical sampling would require a method to assure random selection of buses and may not provide sufficient data. The data request includes Table A to reduce the number of buses to be tested to a representative sample. Further reductions in the number of buses tested may not provide sufficient data for NERC to assess whether a reliability gap exists that needs to be addressed and, if so, may not provide information with sufficient detail to develop appropriate measures tailored to address the concern.

One commenter requested the second bulleted item in Step 10 of the method be modified to reflect its understanding of the reporting requirement for station DC supply attributes, by limiting reporting to buses on the “Final List of Buses to be Evaluated” as identified in step 9. The data request correctly indicates that station DC supply attributes will be reported for all buses that meet the criteria in Table A, “Criteria for Buses to be Evaluated.”

One commenter requested clarification whether a three-phase fault in step 3 of the method should be left uncleared for the entire simulation, and whether low voltages in the area that do not meet the criteria in Table C should be reported. The fault should be simulated as uncleared for the entire simulation only if the transformers connected to the bus do not have through-fault protection. It is only necessary to report system performance that exhibits one of the adverse impacts identified in Table C, "Performance Measures."

One commenter recommended identifying steps 2 through 6 inclusive as optional. As noted in the data request, entities may use an alternate method so long as the data provided is consistent with the data (in form and substance) that would be developed by using the method in the data request (i.e., the alternate method must yield all of the data requested on the reporting template). The data request does not preclude skipping steps 2 through 6; however, it is not practical to list every possible alternate method in the data request and so the proposed text has not been included.

One commenter requested confirmation that the data required is: (a) the total number of buses which meet Table A; (b) the total number of those buses from (a) which do not meet Table B AND violate the parameters in Table C; and (c) the station DC supply attributes per Table D for those buses from (b). The three items identified capture the categories of required data; however, these items only represent a subset of the required data. All data identified in the reporting template is required.

One commenter recommended moving the first bulleted item in step 2 of the method to step 3, or preferably deleting this item. It is implicit in step 3 that the Planning Coordinator must obtain information regarding transformer through-fault protection to perform its assessment. The first bulleted item in step 2 has therefore been removed and the footnote describing through-fault protection has been relocated to step 3.

One commenter requested clarification of "most conservative results" in the first bulleted item in step 3 of the method. The most conservative results in this context would be the cases that produce the most severe system response. The text in step 3 has been revised from "most conservative results" to "most severe system response."

One commenter questioned how one would know the maximum expected clearing time without knowing the actual expected clearing time, and recommended use of "expected clearing time" in place of "actual clearing time" in steps 7 and 8. The phrase "expected clearing time" is more appropriate for a planning horizon assessment as the phrase "actual clearing time" can only be assessed for past events. Steps 7 and 8 of the method have been revised as proposed, as well as related discussion in the Burden to Entities section, the Example Illustrating Application of the Method in Appendix 1, and the reporting template. Text also has been added in step 3 to differentiate between the phrases "expected clearing time" and "maximum expected clearing time."

One commenter suggested adding the phrase "and expected to trip" to the 2nd bullet in step 3 of the method, to read "Trip the remote terminal(s) of all transmission lines connected to the faulted bus and expected to trip based on the maximum expected remote clearing time . . ." Cases in which operation of backup protection would not be expected at remote terminals of transmission lines connected to the faulted bus would be limited to unique cases. Given the unique nature of this scenario, adding the proposed text may add complexity and potential for confusion with minimal benefit. An asset owner may address this scenario when providing maximum expected clearing times to the Transmission Planner. However, this scenario is expected to be rare enough to not influence any decisions made as to whether a reliability gap exists that needs to be addressed.

One commenter noted that wind and solar units may trip due to low voltage rather than losing synchronism and questioned whether the first criterion in Table C should be modified to include tripping of units based on low voltage ride-through (LVRT). The first criterion was modified based on comments from the first posting to exclude units that trip as a result of the fault. Units that trip due to insufficient LVRT typically trip as a result of locally depressed voltage during the fault, which is unaffected by the single point of failure. The data collected based on limiting the first criterion to unit instability will provide sufficient information to assess whether a reliability gap exists that needs to be addressed.

One commenter questioned whether a generator step-up transformer connecting aggregate generating resources, each with gross nameplate rating less than 20 MVA, but with total gross nameplate rating exceeding 20 MVA, should be included for purposes of applying Table A. Entities should apply the 20 MVA threshold based on the aggregate generation connected. This is consistent with the intent that the number of circuits connected to a bus is representative of system strength. The word “aggregate” has been inserted to make this clarification.

One commenter indicated the estimated burden on entities is very low, perhaps by a factor of 2 or more. The estimates of burden on entities were developed with stakeholder input based on estimates from several entities, including entities in one Region that have performed this type of assessment previously. The majority of commenters did not raise concerns with the accuracy of the estimates. As noted in the data request, the burden on individual entities will vary depending on a number factors; however, NERC believes the estimates in the data request are representative of the average burden across the industry.

One entity recommended that a better metric, such as power entering the bus or per unit fault current may be a better criteria in Table A than the number of circuits and also noted that at 500 kV and greater it would be appropriate to test all buses regardless of the number of circuits. The number of circuits connected to a bus as defined in Table A is indicative of system strength and has been selected in place of alternate criteria such as per unit fault current or power flow thresholds. The criteria in Table A are easily applied to identify a representative sample of buses. Using a criterion such as per unit fault current would add precision, but the objective still would be to select a representative sample of buses for analysis. The criteria are expected to identify a representative sample of buses even at 500 kV and higher since the criteria would only exclude switching stations with three lines and substations with two transmission lines and one transformer. The Transmission Planner may include any other buses necessary for the reliable operation of the bulk power system not identified by applying these criteria.

One commenter recommended additional clarity in the 3rd row of Table D would be beneficial, but did not identify what is unclear. A note has been added in response to another comment on Question 4 that the phrase “battery open condition” refers to not having a continuous current path from the positive terminal of the station battery set to the negative terminal.

One commenter noted the data request scope is overly broad and should not apply to Generator Owners since a single outage on a plant is not likely to cause the transmission system to collapse. It is necessary to collect information for all Elements connected to buses that meet the criteria in Table A because a fault adjacent to the bus on any of the connected Elements accompanied by a protection system failure would have the same potential impact on system reliability. The burden for Generator Owners is limited because the only data the Generator Owner must provide to their Transmission Planner(s) is protection system attributes for their generator step-up (GSU) transformer and auxiliary transformers and their connections to the high-side switchyard bus.

Organization	Question 1 Comment
Northeast Power Coordinating Council	Revise the language in Section 3 under Survey-Method page 8 to read: • Simulations will be based on a case representing the expected 2015 system with stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment. • Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. As an alternative, the Transmission Planner may assume uncleared faults or assume fault clearing at 5 seconds after fault initiation. The language changes in the first bullet are to provide a uniform year as the basis for all assessments. As presently written, the cases could be for the year 2022, where corrective action plans have been developed, but there is not enough detail known about their future installation yet to be able to complete the survey. Using the year 2015, or something akin to it, would allow for projects which are in process and are well known to be evaluated. The changes to the second item are to eliminate the need for contacting entities for estimated clearing times, since an uncleared or 5 second fault is sufficient since this is only a screening evaluation. Step 7 of the process will allow further refining based on actual anticipated clearing times. Revising the bulleted step eliminates a data request and it has no consequence on the usefulness of the final data to be provided.

Organization	Question 1 Comment
	It would be beneficial if the final ‘Request for Data or Information’ provided additional guidance regarding which case(s) to use for testing, in order to achieve more consistent results without tying the hands of the entities performing the tests. Consider augmenting the text regarding case(s) to use in Step 3 with that the case(s) should represent system conditions for a study year within five (5) years, in an effort to simplify how to consider projects in progress or planned. By restricting the time horizon to five years, we believe that there is more certainty and information available regarding in progress or planned (not-yet-in-service) projects to perform the evaluation in a consistent manner.
SERC Planning Standards Subcommittee	The first bullet item in step 10 of the method says "For each bus evaluated in step 9"... It should instead say "For each bus on the final list developed in step 9..." In the first paragraph of the Rationale section at the top of page 14, there is the following statement: "Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes." This is confusing because buses which don't meet Table A are excluded from assessment and reporting. If this statement is referring to lines, transformers, etc. excluded by the notes on Table A, it should clearly indicate this. As currently worded the second paragraph in the Protection System Components and Attributes section undermines the validity of TPL-001-2 concerning the relay failures that are required to be studied. One NERC document should not undermine another Board approved NERC document. The following wording is suggested: "An alternative approach to limit the scope to the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13) was considered. For the purposes of this data request, however, it is not considered reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern." Page 8, Step 3, 1st bullet: Cases used in the most recent annual assessment are not necessarily the most recent cases available. Flexibility should be given on which series of cases may be used. Also, to ensure consistency NERC should specify the case year to be used for the assessment.

Organization	Question 1 Comment
Pepco Holdings Inc and Affiliates	Step 2: The last sentence in the second bulleted item in Step 2 should be re-worded to read as follows: "Each Transmission Planner will create an initial "List of Buses to be Evaluated" by removing these "excluded" busses from the "List of Buses to be Tested." The existing language which uses the phrase "any buses identified in this step (step 2)" should be removed, since it could be construed as allowing removal of buses solely on the criteria that transformer through fault protection exists, as that identification is also part of step 2. Alternatively, the bullets could be broken into steps 2A and 2B, or the identification of transformers with through fault protection be made into a separate step altogether. Step 7: The last sentence of footnote 13 should be re-worded as follows: "The operation of load shedding or Special Protection Systems may be modeled if the scheme is normally in service, capable of responding to the simulated contingency, and does not share a single point of failure with any of the protection schemes being evaluated." Even if these schemes were not installed specifically to address the contingency being evaluated, ignoring the operation of these types of schemes during the simulation may provide an unrealistic representation of true system performance during the event. Step 8: The phrase "in accordance with the method described in step 4" should be re-worded to read "in accordance with the method described in step 3".
FirstEnergy	1. In Table B on Page 12, on the line item for DC Control Circuitry, DC control circuit requires two independent circuits where each DC circuit includes DC control circuitry, auxiliary relays, circuit breaker trip coils, DC distribution Panels, fuses and DC distribution Panel breakers. The description under this line item indicates that independent DC distribution panels are required for primary and backup relays - one DC panel for primary relaying a separate DC panel for backup. According to Table B, DC panels are considered an integral part of the DC control circuit to the relaying. This requirement seems to define a circuit to include the main DC panel and seems to conflict with branch circuit definitions in the NEC. We suggest the definition for DC Control Circuitry exclude the Main DC Panelboard. Instead, the Main DC Panelboard should be included in the DC station supply. This would require a modification of Note 1 under Table D on page 13. We suggest single point of failure redundancy would be met with a Main DC Panel with independent distribution panel breakers to feed primary, backup, and breaker failure relaying.

Organization	Question 1 Comment
	2. The last paragraph on page 32 regarding evaluating the Bus Protection scheme in Figure 1-8 for single point of failure indicates the protection scheme that has a single point of failure as the lockout relay used to trip the Bus Bkrs and the auxiliary relay used to initiate breaker failure are supplied from the same DC. This discussion is confusing and needs clarification for this example. The scheme does not meet requirements for independent primary and backup relaying schemes and would appear to not meet single point of failure redundancy requirements for that reason. However, the discussion indicates “so a single trip coil should not be an issue” but yet Table B requires two independent DC control circuits with no common circuit breaker trip coils. Table B indicates separate trip coils are required. Another point of discussion in this example is breaker failure relaying. It is not clear in this data request to what extent breaker failure to trip relaying needs to be included in the data request review for single point of failure. This should be clarified in Table B. If breaker failure relaying needs to be included in the request to evaluate single point of failure (as discussed in this example) it should be included in the Protection System Attributes to be Evaluated as a separate line item in Table B. Also, it is not apparent that Breaker Failure to trip relaying needs to be on an independent DC circuit from primary and backup relaying and the breaker failure initiate contacts should be independent of the breaker tripping contacts. If a single relay contact is used to trip a breaker such as in an electromechanical relays, there appears to be no way to meet single point of failure redundancy requirements as an auxiliary relay used to initiate Breaker Failure to trip must be supplied from the same DC circuit as the tripping relay. 3. We believe that more detail is needed on the clearing times that need to be supplied in Step 7 shown on page 9 and the method to evaluate these times for various three phase bus faults. For example, Figure 1-12 on page 37 shows 2-115 kV busses with 15 breakers in a breaker and a half configuration. The discussion in the document is specifically for a fault between breakers 52-2 and 52-3 and identifying clearing times for this specific fault resulting from failure of one protection system. The document identifies breaker failure operating output in 10 cycles (with breaker times of 3 cycles) for a total of 13 cycles. The discussion seems to indicate breaker failure times should only be used if either breaker had only one trip coil. However, if there is fully redundant primary and backup relaying, for failure of primary relay, the backup relay would operate in 1 cycle (assuming Zone 1 relay operation) + breaker time = 4 cycles for local relay operation. The remote backup clearing from line A is identified as 20 cycles. Is the clearing time for this fault and Bus Section then 20 cycles for both the case of one or dual trip

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	coils? The discussion should also indicate that all bus sections should be evaluated (all buses between all breakers as well as the main 115kV Bus 1 and Bus 2). More guidance is requested as far as what clearing times need to be reported for Bus 1 and Bus 2 in this example. It would also be beneficial to have an example for a straight bus. We assume in the straight bus case, if redundant dual bus protection was used, only bus protection clearing times would be reported. If only a single bus protection scheme was installed, the longest remote backup clearing time would be reported. Is that correct? 4. Footnote 13 on page 9 - The footnote indicates local relay protection operation times (specifically breaker failure relaying clear times) can be used in Step 7 only in the case of one breaker trip coil. This statement is confusing and seems to penalize entities that use dual trip coils and also have breaker failure relaying into supplying longer remote backup clearing times. Also, both redundant primary and backup relaying should be required as well as independent DC circuits to insure breaker failure is initiated. 5. Although the examples on pages 37 - 39 are beneficial, final clearing times that should be supplied to the Transmission Planner in Step 7 are not specified. Another example similar to Figure 1-13 but with independent primary and backup line relaying would be helpful. Clearing times supplied to the Transmission Planner in Step 7 should be identified in the example.
ACES Power Marketing Standards Collaborators	(1) We thank the drafting team for the additional clarity and clarification that other methods can be used to satisfy the data request. However, we continue to believe that the data request is broader than necessary. We believe that the data request should be limited to determining if Transmission Planners and Planning Coordinators have applied category C and D contingencies from TPL-003 and TPL-004 such that single points of failure in the Protection Systems are already evaluated extensively. This data request would be limited and could be completed in a relatively short period. Once such a limited data request is completed, then NERC can assess if additional studies are warranted. As the proposed data request stands now, Transmission Planners may be compelled to complete a burdensome and cumbersome request that could have been addressed more easily. (2) Despite the additional clarity provided in this second draft, the data request is still confusing and ambiguous and potentially contains duplicative steps. The second and fifth steps require the Generator Owner (GO), Transmission Owner (TO), and Distribution Provider (DP) to

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	determine if any of the buses can be excluded because “the protection system(s) for all Elements connected to the bus and for the physical bus(es)” satisfy the attributes in Table B. The only difference appears to be that step 5 specifically states that GO, TO, and DP will review documentation while step 2 references the TO’s, GO’s, or DP’s knowledge of protection systems. We assume that step 2 is intended for the TO’s, GO’s, and DP’s personnel knowledgeable about their protection systems to perform a quick review without the aid of documentation to identify the buses with protection systems that meet Table B attributes. However, the step does not say this and only mentions the knowledge of the TO, GO and DP. One could argue documentation owned by the TO, GO and DP is part of their institutional knowledge and, thus, step 2 requires a documentation review. The bottom line is that further clarity is needed on what is specifically intended in step 2 and what is intended in step 5. Additionally, step 10 requires the GO, TO, and DP to conduct what appears to the same documentation review for protection systems against the attributes in Table B. It is only after reviewing the explanation of step 10 in the example on page 20 that it becomes clear that the review is only to be completed if the documentation review in step 5 was terminated after finding the first single point of failure. However, step 5 never states the documentation review of protection systems for each element should be terminated after finding the first single point of failure. Rather, it states the review should be completed for all Elements connected to the bus. (3) Is the only difference in between the simulations in step 3 and 8, the clearing times? If so, why not utilize actual clearing times in step 3? Yes, this is the only difference. (4) Step 3 could be interpreted as requiring simulations to be inconsistent with actual equipment that is isolated from clearing of a fault. For instance, the second bullet states that the remote terminal of all transmission lines connected to the faulted bus should be tripped. Given that the footnotes for step 1 state that all bus configurations will be treated as straight buses, step 3 could be interpreted as requiring all lines to be tripped for both physical busses of a breaker and half configuration. Rather, the more likely contingency for failure of a protection system on a breaker and half configuration is to isolate one physical bus which open ends lines connected to the cleared bus but leaves the lines on the other bus tied together. If the intent is to truly trip all lines connected to both physical buses as a screening study, then the step needs to state this more directly. Either way the step needs more clarity.

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Southern Company	The first bullet item in step 10 of the method says "For each bus evaluated in step 9"... It should instead say "For each bus on the final list developed in step 9..." In the first paragraph of the Rationale section at the top of page 14, there is the following statement: "Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes." This is confusing because buses which don't meet Table A are excluded from assessment and reporting. If this statement is referring to lines, transformers, etc. excluded by the notes on Table A, it should clearly indicate this. As currently worded the second paragraph in the Protection System Components and Attributes section undermines the validity of TPL-001-2 concerning the relay failures that are required to be studied. One NERC document should not undermine another Board approved NERC document. The following wording is suggested: "An alternative approach to limit the scope to the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13) was considered. For the purposes of this data request, however, it is not considered reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern." Page 8, Step 3, 1st bullet: Cases used in the most recent annual assessment are not necessarily the most recent cases available. Flexibility should be given on which series of cases may be used. Also, to ensure consistency NERC should specify the case year to be used for the assessment.
American Electric Power	Table A: We suggest changing the criteria in row 3 from “Buses operated at 100 kV to 200 kV with 6 or more circuits” to “Buses operated at 100 kV to 200 kV with 6 or more circuits, except buses that are a breaker and half, ring bus, or double breaker double bus configuration, and buses with generation resources with gross nameplate rating less than 20 MVA.” Compound bus station configurations are inherently more reliable than a single bus station configuration. The proposed three-phase fault test on these compound bus stations provides

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	much less value to the process, because of the lower probability of a total protection failure relative to single bus configurations. AEP urges NERC to consider these revised screening criteria given that the volume of effort to reply to this data request is already quite heavy. Table C: We suggest testing a statistically significant sample to evaluate the Performance Measures in this table rather than using the entire list generated in Steps 1 through 3.
National Grid	We believe that it would be beneficial if the final 'Request for Data or Information' provided additional guidance regarding which case(s) to use for testing, in order to achieve more consistent result without tying the hands of the entities performing the tests. We propose to consider augmenting the text regarding case(s) to use in Step 3 with that the case(s) should represent system conditions for a study year within five (5) years, in an effort to simplify how to consider projects in progress or planned. By restricting the time horizon to five years, we believe that there is more certainty and information available regarding in progress or planned (not-yet-in-service) projects to perform the evaluation in a consistent manner.
Occidental Energy Ventures Corp.	The process developed by the project team appears satisfactory to Occidental Energy Ventures Corp (OEVC). It steps through at least three analytical iterations - refining the list of affected busses and the associated Protection System components each time. That should ensure that only the most suspect relay systems are considered in a future mitigation process.
NRECA	NRECA believes that the revised draft of the data request addresses many of the concerns presented by the industry to Draft 1 of the data request. The changes provide much needed clarity by providing examples and illustrations to help applicable entities complete the necessary steps outlined in the data request. Although there is a need to collect additional information from Transmission Planners as required in Order 754, NRECA believes the intent of the order was not to conduct new studies but to ask questions to determine current practices in conducting TPL standards assessments and any possible reliability gaps and the data request should be revised to reflect this intent.
Ameren	(1) Method Step 10 says to use the 'final List of Buses to be Evaluated' and Step 11, 3rd bullet then requests statistics concerning DC Supply attributes 'at selected buses.' Our understanding is that the Project Team is only interested in DC Supply attributes to be evaluated and reported for the final list of buses resulting from step 9. Please revise Step 10, 2nd bullet by replacing

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	the following '...that meets the criteria in Table A ...Evaluated' with 'resulting from step 9'. Step 10, 2nd bullet should then read 'The attributes of the station DC Supply listed in Table D, "Station DC Supply Attributes to be Reported," for each bus resulting from step 9.' (2) Method Step 3, 4th bullet: We request the Project Team to clarify: (a) Are we to leave a three-phase fault un-cleared for the entire simulation? (b) If this results in low-voltages in the area but not a Table C criteria violation, should it be reported? (3) We request the Project Team to identify steps 2 through 6 inclusive as optional, and at the end of step 7 append 'or from step 1 if steps 2-6 are skipped.' Then for clarification: (a) in step 8, replace 'as revised in step 6 in accordance with the method described in step 4, except that' with 'used in step 7 in accordance with the method described in step 3 using...' (b) and in step 9 replace 'was revised in step 6' with 'used in step 7'. (4) For those who will be following steps 2 through 6, the method is still confusing, because there is apparent redundancy between steps 2 and 6. It seems to us that the goal of steps 2 and 6 is the same (to pare down the list of buses that satisfy all the criteria of Table B, which is protection system redundancy). However, it is not clear to us how step 6 would reduce the list of buses at all because the buses still on the list at step 6 which have already been evaluated against Table B and should have been removed from the list during step 2. (5) From our perspective, what is needed appears to be the following (please confirm): (a) The total number of buses which meet Table A. (b) The total number of those buses from 1- which do not meet Table B AND violate the parameters in Table C. (c) The DC Supply attributes per Table D for those buses from 2.
Tri-State Generation and Transmission Association, Inc.	1. The first bullet in step 2 should either be moved to step 3 or removed entirely (our preference) since it is already a necessary part of the fourth bullet in step 3.

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	2. Clarify what "most conservative results" means in the first bullet of step 3. 3. Using "actual clearing time" from step 7 in step 3 instead of "maximum expected remote clearing time" would eliminate the need for steps 7 and 8. Without knowing the "actual clearing time," how does one know the maximum expected remote clearing time? However, rather than "actual clearing time," "expected clearing time" would be a better term to use. 4. What is the purpose of step 5, since this review should have already taken place in the second bullet of step 2? 5. Moving step 6 to after step 2 could greatly reduce the number of simulations required.6.Eliminate steps 7 and 8.
LCRA Transmission Services Corporation	-The second bullet of step 3 states, "Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time..." It is unclear how this would be applied to breaker-and-a-half or ring bus schemes and would appear to have the effect of tripping the entire station. We recommend the procedure state, "Trip the remote terminal(s) of all transmission lines connected to the faulted bus and expected to trip based on the maximum expected remote clearing time..." -Wind and solar units may be allowed to trip due to low voltages under the ERCOT Voltage Ride Through (VRT) requirements (these units do not lose synchronism) because of the severity of a protection system failure contingency. Should VRT be monitored for Wind units in addition monitoring units that may trip due to loss of synchronism?
Tacoma Power	In Note 1 for Table A, should a generator step-up transformer connecting aggregate generating resources, each with gross nameplate rating less than 20 MVA, but with total gross nameplate rating exceeding 20 MVA, be included for purposes of applying Table A? In Table B, for DC Control Circuitry, it is noted that DC control circuitry "does include...any DC distribution panels..." It is common that the station DC supply feeds one DC panel. Does this mean that DC control circuitry is automatically not independent, even if dual trip coils are used, different breakers within the DC panel are used, and there is no main breaker in the DC panel? If this is the case, there may be very few instances in which DC control circuitry can be considered independent.

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	The burden estimates (engineer-hours) for Transmission Owners, Generator Owners, and Distribution Providers seems very low, perhaps off by a factor of 2 or 3, at least.
Idaho Power Company	The main objective of the 754 data request, as we understood, is to assess the impact of non-redundant protection systems on system reliability. Also, there is an expectation that collected data will help to identify if a gap exists regarding the study and resolution of a single point of failure on protection systems. The requested data will identify where delayed clearing due to protection failures could lead to a potential significant disturbance. Request for Data or Information (DRAFT 2) has incorporated a number of issues pointed out in comments December 22, 2011 to February 6, 2012 and addressed more clearly all steps for performing studies related to the Order No. 754 SPOF on protection systems. However, there are still some items in the Draft 2 that need clarification. We would like to point the following: Table A classifies buses into five different groups 100-200 kV, 200-300 kV, 300-400 kV, 400-600 kV and 600 + kV with applying two basic criteria for their classification based on the number of connected circuits. It would seem to IPC that might be a better metric to determine which buses to be tested (e.g. power entering and leaving the bus, fault current in p.u., etc.). It seems appropriate to test any 500+ kV bus regardless of the number of circuits. This present approved planning standards and proposed new planning standards deal with performance criteria of the BES under various n-0, n-1, n-1-1, n-2 and n-k category of outages which should also cover the conditions caused by protection systems failure events. IPC believes that studies conducted for compliance with TPL standards should identify any reliability issues that would result from protection system failures, therefore the data request is not needed. To pick number of busses for inclusion is likely to miss stations and buses that could have high impacts or include buses with little impact. Better to have a method evaluating all buses and excluding less critical buses, along the lines of PRC-023. If there is a need to expand the studies being conducted in TPL standards the new standard development process should be used for this purpose instead of a data request. It would be beneficial if you provide more clarity in wording of a statement in the row 3 of Table D - Station DC Attributes to be reported? Also, more clarity is needed on what case scenario will be used to perform testing (load level, transfer level, generation pattern, etc.). Some entities might be required to use several

Organization	Question 1 Comment
	stressing cases in order to evaluate properly SPOF across various parts of the system.
PPL Generation, LLC on behalf of its Supply NERC Registered Entities	It appears the information request is overly broad since the problem (2011 SW Outage) was a single point open on a TRANSMISSION LINE not a single failure on a generator. That failure should have been studied by the TO/TP/PC. PPL does not feel that it is necessary to require generation data since a single outage on a plant is not likely to cause the transmission system to collapse. The work needed by GOs would typically require consultant work since normally the GO does not have on staff full time dedicated relay engineers. This would result in undue expense and would not have a significant reliability impact. PPL requests that GOs not become subject to TPL studies or the TPL standards.
ISO New England	Change language in Section 3 which is presently: • Simulations will be based on case(s) used to perform the most recent annual transmission assessment representing stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment. • Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. Modify Language above to read: • Simulations will be based on a case representing the expected 2015 system with stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment. • Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. As an alternative, the Transmission Planner may assume uncleared faults or assume fault clearing at 5 seconds after fault initiation. The language changes in the first bullet are to provide a uniform year as the basis for all assessments. As presently written, the cases could be for the year 2022, where corrective action plans have been developed, but there is not enough detail known about their future installation yet to be able to complete the survey. Using the year 2015, or something similar to

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	it, would allow for projects which are in process and are well known to be evaluated. The changes to the second item are to eliminate the need for contacting entities for estimated clearing times, since an uncleared or 5 second fault is sufficient since this is only a screening evaluation. Step 7 of the process will allow further refining based on actual anticipated clearing times. Revising the bulleted step eliminates a data request and it has no consequence on the usefulness of the final data to be provided.
South Carolina Electric and Gas	The first bullet item in step 10 of the method says "For each bus evaluated in step 9"... I believe it should instead say "For each bus on the final list developed in step 9..." In the first paragraph of the Rationale section at the top of page 14, there is the following statement: "Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes." This is confusing because buses which don't meet Table A are excluded from assessment and reporting. If this statement is referring to lines, transformers, etc. excluded by the notes on Table A, it should clearly indicate this. As currently worded the second paragraph in the Protection System Components and Attributes section undermines the validity of TPL-001-2 concerning the relay failures that are required to be studied. One NERC document should not undermine another Board approved NERC document. The following wording is suggested: "An alternative approach to limit the scope to the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13) was considered. For the purposes of this data request, however, it is not considered reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern." Page 8, Step 3, 1st bullet: Cases used in the most recent annual assessment are not necessarily the most recent cases available. Flexibility should be given on which series of cases may be used. Also, to ensure consistency NERC should specify the case year to be used for the assessment.
Exelon Corporation and its affiliates	The data request needs more detail concerning separately fused dc control circuits from a single battery and what constitutes independence of these circuits. The document should very

Organization	Question 1 Comment
	clearly state that separately fused dc control circuits from a single battery are considered independent for the purposed of this survey.

2. **Please enter specific comments about the data reporting template of the data request in the provided text box. Note: The posted template is the structure of reporting data and actual reporting may use a different mechanism, such as, this electronic comment form.**

Summary Consideration:

Five commenters identified a discrepancy between Row 2 and Note 2 on each of the equipment protection tabs (i.e., Transmission Line, Transmission Xfmr, GSU Xfmr, Step-down Xfmr, Shunt Device, and Bus). Note 2 has been revised on each equipment protection tab to correct this discrepancy.

Four commenters identified that Note 3 on the "Buses Evaluated by the Transmission Planner" tab should reference step 8 of the method rather than step 7, and that Note 4 should reference step 9 rather than step 8. Notes 3 and 4 have been revised to correct these errors.

One commenter recommended adding a note to the "Station DC Supply Attributes" tab indicating "The total number of busses reported on this form should equal the total number of busses that meet the criteria in Table A, 'Criteria for Buses to be Evaluated.'" The proposed note has been added to the Station DC Supply Attributes tab.

One commenter recommended modifying Note 1 on the "Station DC Supply Attributes" tab to not include the main DC distribution panel in the DC control circuitry. Note 1 has been revised to reflect the changes made to Tables B and D in the data request.

One commenter recommended adding a note on the equipment protection tabs that asset owners are required to evaluate Elements directly connected to the final list of buses resulting from step 9. Note 1 on each protection equipment tab has been modified to provide this clarification.

One commenter requested inclusion of clarification noted during a webinar that that once any protection system component is found to be non-redundant on an Element, the entity can stop the evaluation for that Element. Text has been added to the data request to clarify the differences between the Generator Owner, Transmission Owner, and Distribution Provider protection system reviews in steps 2, 5, and 10. The description for steps 5 and 10 address this issue of when an asset owner may stop its review.

One commenter noted there is a tremendous amount of data requested and recommended an entity should not have to enter the data through a portal. NERC plans to utilize a portal for collecting the data as proposed in the first posting of the data request. Methods will be investigated to import the data from the spreadsheet to minimize clerical errors entering the data.

One commenter noted that additional direction, clarity, or examples for Table B would be helpful without noting any particular areas of confusion. Examples have not been added as the commenter did not provide adequate specificity to address the concern and the majority of commenters did not raise concerns with clarity of Table B.

One commenter questioned whether the single points of failure determine the fault scenarios that must be simulated for delayed clearing or whether there is a different set of fault locations and scenarios that should be studied. The Transmission Planner is only required to simulate one fault on each bus on the final "List of Buses to be Evaluated." Faults on any main bus section, or immediately beyond the breakers connecting any Element are essentially identical; however, the clearing times when a single point failure prevents operation of the local protection system will depend on the nature of the single point(s) of failure present.

Organization	Question 2 Comment
Northeast Power Coordinating Council	There may be an error in the text associated with Note #2 in the Excel spreadsheets for 'Attributes of Evaluated Transmission Line/ Transmission Transformer / Generator Step-Up Transformer / Step-Down Transformer / Shunt Device / Bus Protection Systems'. The present version of the text states: "The number of Shunt Devices to be entered in Row 2 is the subset of [Device Type] entered in Row 1 for which the protection system meets all of the specified protection system attributes in Table B, "Protection System Attributes to be Evaluated.", while the text in row 2 of the Table states: "Number of [Device Type] for which protection systems does not meet all of the specified protection system attributes for redundancy in Table B:". The text "meets all" in the notes should be replaced by "does not meet all" to be consistent with the text in the Tables.
Pepco Holdings Inc and Affiliates	1) In the "Busses Evaluated by the Transmission Planner" tab, we believe that Note 3 should reference Step 8 rather than Step 7. Also, Note 4 should reference Step 9 rather than Step 8. 2) In all the protection system evaluation tabs (Transmission Line, Transmission Transformer, Generator Step-up Transformer, Step-Down Transformer, Shunt Device, and Bus) the wording of Note 2 conflicts with the wording in row 2. Note 2 should use the phrase "does not meet all the specified protection system attributes", in place of the current wording that reads "meets all the specified protection system attributes". 3) In the Station DC Supply Attributes tab an additional note should be added for clarity that states: "The total number of busses reported on this form should equal the total number of busses that meet the criteria in Table A "Criteria for Busses to be Evaluated". 4) Also see comments from question 4 below concerning posing additional questions regarding the use of independent DC distribution panels with single DC supply systems.

Organization	Question 2 Comment
Southern Company	Note 4 on the Buses Evaluated by the Transmission Planner table should refer to step 9 rather than step 8. For each of the tables regarding protection systems, row 2 conflicts with note 2. Row 2 says "does not meet" while note 2 says "meets all". Note 2 should say "does not meet"
National Grid	We believe that there may be an error in the text associated with Note #2 in the Excel spreadsheets for 'Attributes of Evaluated Transmission Line/ Transmission Transformer / Generator Step-Up Transformer / Step-Down Transformer / Shunt Device / Bus Protection Systems'. The present version of the text states: "The number of Shunt Devices to be entered in Row 2 is the subset of [Device Type] entered in Row 1 for which the protection system meets all of the specified protection system attributes in Table B, "Protection System Attributes to be Evaluated.", while the text in row 2 of the Table states: "Number of [Device Type] for which protection systems does not meet all of the specified protection system attributes for redundancy in Table B:". We think that the text "meets all" in the notes should be replaced by "does not meet all" to be consistent with the text in the Tables.
Occidental Energy Ventures Corp.	OEVC believes that the format and technical basis of the data reporting template are solid. We would prefer that a single template be used wherever possible - perhaps allowing the Transmission Planner to add unique fields only if absolutely necessary. This will make the process more uniform across all of our generator Facilities.
Ameren	(1) We believe that the Note 4 in the Buses Evaluated by the Transmission Planner is incorrect. It should refer to step 9 result, not step 8, and should read '[This entry is equal to the number of buses on the final List of Buses to be Evaluated resulting from Step 9.] (2) We suggest the Project Team, in each of the Attributes template tables, clarify that the Elements (e.g. Lines, Transformers, etc.) directly connected to buses resulting from step 9 are the only Elements for which Protection System is to be evaluated in detail. We suggest appending this to Note 1: 'The TO / GO / DP is only required to evaluate Elements directly connected to the final list of buses resulting from step 9.' (3) We suggest the Project Team to include an explanation that once any Protection System component (i.e., Protective Relay, or Communication System, or AC Current Input, etc.) is found non-redundant on an Element, the entity can record that and stop that Element's evaluation. We believe that this was covered in the webinar, but has been omitted from the RFI (or we could not find it.)
Tri-State Generation and Transmission Association, Inc.	There is a tremendous amount of data requested and it should not have to be entered through a portal,

Organization	Question 2 Comment
	such as, this electronic comment form.
Idaho Power Company	The template seems clear in what is being requested. Further comments will be unknown until the work is done completing the request. Additional direction, clarity, or examples for Table B would be helpful in the identification process for protection system single points of failure. Additionally, do the single points of failure determine the fault scenarios that must be simulated for delayed clearing or is there a different set of fault locations and scenarios that should be studied? This is not clear in the data request. The data request implies that bus faults should be run if a single point of failure is discovered and does not account for the actual bus topology (double breaker, ring bus, etc) that is used to limit the scope of protection system failures under fault scenarios.
ISO New England	It appears that there may be an error in the text associated with Note #2 in the Excel spreadsheets for 'Attributes of Evaluated Transmission Line/ Transmission Transformer / Generator Step-Up Transformer / Step-Down Transformer / Shunt Device / Bus Protection Systems'. The present version of the text states: "The number of Shunt Devices to be entered in Row 2 is the subset of [Device Type] entered in Row 1 for which the protection system meets all of the specified protection system attributes in Table B, "Protection System Attributes to be Evaluated.", while the text in row 2 of the Table states: "Number of [Device Type] for which protection systems does not meet all of the specified protection system attributes for redundancy in Table B:". It seems that the text "meets all" in the notes should be replaced by "does not meet all" to be consistent with the text in the Tables.
South Carolina Electric and Gas	Note 4 on the Buses Evaluated by the Transmission Planner table should refer to step 9 rather than step 8. For each of the tables regarding protection systems, row 2 conflicts with note 2. Row 2 says "does not meet" while note 2 says "meets all". Note 2 should say "does not meet"

3. Please enter specific comments about the reporting schedule of the data request in the provided text box.

Summary Consideration:

One commenter noted the discrepancy between Row 2 and Note 2 on each of the Equipment protection tabs (i.e., Transmission Line, Transmission Xfmr, GSU Xfmr, Step-down Xfmr, Shunt Device, and Bus) and that Note 4 on the "Buses Evaluated by the Transmission Planner" tab should reference step 9 of the method rather than step 8. Note 2 has been revised on each equipment protection tab to correct this discrepancy. Note 4 on the "Buses Evaluated by the Transmission Planner" tab has been revised to correct this error.

Two commenters noted the estimated burden on Generator Owners, Transmission Owners, and Distribution Providers is low; one stated by a factor of 2. The estimates of burden on entities were developed with stakeholder input based on estimates from several entities, including entities in one Region that have performed this type of assessment previously. The majority of commenters did not raise concerns with the accuracy of the estimates. As noted in the data request, the burden on individual entities will vary depending on a number factors; however, NERC believes the estimates in the data request are representative of the average burden across the industry.

Three commenters stated they do not believe it is necessary to report data for any buses prior to the end of the 24 month period and noted earlier reporting removes the flexibility for the Transmission Planner to complete these studies along with their normal TPL study cycle. It is necessary to include some reporting within 12 months to be responsive to FERC Order No. 754. Reporting first on buses operated above 300 kV addresses the portion of the system where a protection single point of failure is likely to have the greatest impact on reliability. This approach also should limit the effort required in the first 12 months by focusing first on the portion of the system where application of redundant protection systems is more common. During the first posting some entities requested an 18 month reporting schedule to allow coordination with the TPL study cycle and the longer reporting schedule for buses operated at 300 kV and below provides time for coordination for entities that believe this will be beneficial.

One commenter stated that the staged reporting schedule will create confusion regarding which case to use for the analysis and potentially creates the need to use inconsistent separate cases for the various buses. The results of the data request will be used identify whether a reliability gap exists that needs to be addressed and use of base cases differing by one year will not prevent obtaining information that is indicative of potential risk to overall system reliability. A note has been added to step 3 in the method to clarify "It is recognized that due to the staged reporting approach the assessments for all voltage levels may not occur in the same year and may be based on different Near-Term Transmission Planning Horizon representations."

One commenter requested that the schedule be extended to 48 months. A 48 month schedule would not be responsive to FERC Order No. 754. The schedule was extended from 12 months to 24 months in response to comments during the first posting. This longer time for completion considered the burden associated with this data request while the staged approach, with reporting for buses operated at

300 kV or higher due in 12 months, recognized the need for timely reporting of data. During the second posting many entities expressed satisfaction with this change and only one requested an additional extension.

One commenter requested clarification on the reporting schedule for buses operated below 100 kV. This data request does not require assessing buses operated below 100 kV; however, the third and fourth criteria in Table A could have the unintended result of including buses operated below 100 kV on the “List of Buses to be Evaluated.” Table A has been modified to include a 100 kV threshold for the third and fourth criteria.

One commenter requested a more granular schedule addressing participation of the Generator Owners, Transmission Owners, and Distribution Providers. Numerous comments during the first posting requested maximum flexibility for Transmission Planners to use other methods that are consistent with acquiring and reporting the necessary data. Providing specific milestones would be inconsistent with providing this flexibility as the schedule that is most efficient may vary among Regions or among entities within a Region.

One commenter recommended that a task be added to the Reporting Schedule for the Transmission Planner to provide the associated Generator Owners, Transmission Owners, and Distribution Providers a plan of work with proposed milestone dates. Development of a schedule will benefit all responsible entities and Transmission Planners are encouraged to coordinate with asset owners in their transmission planning areas to establish a schedule. However, a reporting requirement for the Transmission Planner to report on this task has not been added to the data request to avoid unnecessary burden.

One commenter recommended that upon approval by the NERC Board of Trustees the relative dates in the Reporting Schedule should be replaced with specific due dates. The final data request will include specific dates for each reporting milestone as requested.

One commenter recommended replacing the staged reporting by voltage class with a requirement that data for 25 percent of buses be reported within 12 months, 50 percent within 18 months, and 100 percent within 24 months. The decision following the first posting to extend the schedule from 12 months to 24 months was based on reporting first on the portion of the system where a protection system single point of failure is likely to have the greatest impact on reliability to be responsive to FERC Order No. 754. Reporting on a simple percentage basis would not achieve this objective.

Organization	Question 3 Comment
SERC Planning Standards Subcommittee	Note 4 on the Buses Evaluated by the Transmission Planner table should refer to step 9 rather than step 8.For each of the tables regarding protection systems, row 2 conflicts with note 2. Row 2 says "does not meet" while note 2 says "meets all". Note 2 should say "does not meet"
Pepco Holdings Inc and Affiliates	Although we believe the Drafting Team’s time estimate for GO’s, TO’s, and DP’s to complete Steps 5,

Organization	Question 3 Comment
	7, and 10 is about half of what would actually be required, we nevertheless believe that the 24 month schedule to complete this data request is adequate.
ACES Power Marketing Standards Collaborators	We thank the drafting team for extending the reporting schedule for the data request to 24 months. However, we do not believe it is necessary to report data for any buses prior to the end of the 24 month period. Submission of any data prior to the end of the 24 month period removes the flexibility for the Transmission Planner to complete these studies along with their normal TPL study cycle. Furthermore, it creates confusion regarding which case to use for the analysis and potentially creates the need to use inconsistent separate cases for the various buses. The first bullet under step 3 of the method states that simulations will be based on the case(s) from the most recent annual transmission assessment. Since the reporting period covers 24 months, there will actually be two annual assessments used. Thus, if a Transmission Planner has buses from 115 kV to 345 kV, they might start the data request using the cases from their 2012 annual transmission assessment for the 345 kV. By the time they start the analysis for the 115 kV buses, the 2013 annual transmission assessment will likely be completed. Should they then use the case(s) for the 2013 assessment which will provide the most up to date results or do they stick with the cases for the 2012 assessment for consistency.
Los Angeles Department of Power and Power	We would like the schedule to be extended to 48 months because the estimate of engineer hours is too low, and engineering resources are already committed to meet other planning and regulatory burdens. LADWP's initial assessment indicates that a significant number of busses may remain on the "List of Busses to be Evaluated", so the burden on engineer hours may be substantially underestimated in the Draft Request for Data or Information. While LADWP does study Category D contingencies, such contingencies are selected by engineering judgment rather than by an evaluation of all possible Category D contingencies. (The number of permutations for Category D is very large.) Because of this, LADWP does not have a significant set of pre-existing Category D studies that can be used for this data request.
American Electric Power	The scheduled reporting timelines are broken out by bus voltages ranges; however, it is not apparent where sub - 100 kV buses fit in the reporting timeline. The same applies to the data reporting spreadsheet. Based on the criteria set forth in the last two rows of Table A, some sub-100 kV buses could be in scope.
Occidental Energy Ventures Corp.	We fully agree with the extension in time for lower voltage Facilities to 18 and 24 months. The initial focus should be on higher voltage BES components which have the most impact to reliability. Once

Organization	Question 3 Comment
	those are addressed, the process should be more refined - which helps when dealing with a far larger number of impacted entities.
NRECA	NRECA thanks the team for extending the reporting schedule for the data request to 24 months. NRECA does question the need to staged reporting. The submission of data prior to the end of the 24 month period removes the flexibility for the Transmission Planner to complete these studies along with their normal TPL study cycle which will impose a substantial burden on the submitting entities by creating the need for additional studies.
Ameren	We appreciate the schedule revision, which will allow 24 months to complete the tasks, as compared to the previous 12 month schedule. However, it is questionable whether the intermediate status reports are really necessary. Can the intermediate reporting be eliminated or minimized?
Tri-State Generation and Transmission Association, Inc.	The reporting schedule is acceptable.
LCRA Transmission Services Corporation	The time frame for completing this data request is appropriate.
Idaho Power Company	As the reporting work includes groups other than just the Planners, a more granular schedule would assist in scheduling of the work for the non-Planning groups. For example, “Planners provide list of buses for Protection evaluation at the end of the 6th month for all 300kV and higher...”
Exelon Corporation and its affiliates	The completion of data survey and submission to NERC is due within 24 months beginning the first day of the first month following NERC Board of Trustees approval. Exelon suggests that following NERC BOT approval the periodic reporting template be updated to specify reporting due dates to reduce confusion. In addition, although this data reporting schedule directly applies to Transmission Planners (TPs) and not to the Distribution Providers (DPs), Generator Owners (GOs) and Transmission Owners (TOs), there is a requirement for the DPs, GOs and TOs to provide certain data to the TPs. To ensure that the DPs, GOs and TOs are provided reasonable notice from the associated TPs on their expectations for data submissions, Exelon suggests that an enhancement be added to the End of the 1st month Activity section of the Schedule Reporting Table to include a requirement that the TP provide the associated DPs, GOs and TOs a plan of work with proposed milestone dates.
Public Service Company of New Mexico	The current reporting schedule requires entities to report progress based on voltage class levels, that is, end of 12th month TPs are required to report data for buses operated at 300 kV, end of 18th month

Organization	Question 3 Comment
	TPs are required to report data for buses operated at 200 kV or higher or below 300 kV, and end of 24th month TPs are required to report data for buses operated at 100 kV or higher or below 200 kV. PNMR recommends that reporting schedule be based on % of total number of buses to be evaluated by an entity. Thus, if an entity identifies 100 buses to be evaluated as part of the data request, reporting schedule may require entities to complete 25% of total numbers of buses by end of 12th month, 50% by end of 18th month, and 100% by end of 24th month.

4. Please enter any other comments about the data request in the provided text box.

Summary Consideration:

Two commenters recommended defining “bus” in the context of this data request. Additional clarification has been added regarding how different bus configurations are evaluated. A definition of “bus” has not been added because most commenters have not indicated this is necessary and adding a detailed definition may introduce new points of confusion.

One commenter requested that the main DC panel be considered part of the station DC supply and not the DC control circuitry, noting that including the main DC panel as part of the DC control circuitry will skew the results and should not be included in Table B for the same reason the station DC supply is reported separately. Another commenter questioned whether a primary and secondary DC breaker is considered redundant from a single battery bank/charger. The information in Table B has been revised to exclude the main DC panel from the DC control circuitry. Similar to the station DC supply, including the main DC panel in Table B could skew the results because stations with one station DC supply typically have only one main DC panel. Table D also has been revised to include the main DC panel. Independent DC control circuits each with its own breaker meet the DC control circuit attributes in Table B provided that if the two independent DC control circuits are supplied through a single main DC breaker or fuse, the DC control circuit breakers or fuses must be coordinated such that a DC short on one control circuit cannot prevent operation of the protection system. This clarification has been added as a note under Table B.

One commenter recommended adding a clarifying note that the first criterion in Table C “does not include the total loss of generation tripped as a direct result of remote fault clearing.” This criterion is clear that it applies only to units that lose synchronism. The proposed note was not added to avoid introducing confusion regarding generation that may trip for any other reason.

One commenter reiterated a comment from Question 3 that the estimated burden for Generator Owners, Transmission Owners, and Distribution Providers is understated by a factor of 2. Another commenter noted it appears the estimated burden fails to consider that a qualifying 230kV bus will have no less than 4 protection systems to be evaluated. The estimates of burden on entities were developed with stakeholder input based on estimates from several entities, including entities in one Region that have performed this type of assessment previously. The majority of commenters did not raise concerns with the accuracy of the estimates. As noted in the data request, the burden on individual entities will vary depending on a number of factors; however, NERC believes the estimates in the data request are representative of the average burden across the industry. All buses that meet criterion 1 or 2 in Table A will have at least four connected circuits with protection systems to be evaluated. The estimated burden is based on a sampling of several entities and the actual number of circuits has been factored into the estimates.

One commenter suggested it would be equally instructive, if not more so, to show how the reporting template is to be filled out for the GSU and Transmission Line examples, as those schemes are more complicated. Additional examples are deemed unnecessary because the required data is the same for each equipment type and the explanation in the bus example is translatable to filling out the template for other equipment types. Also, the template includes notes that clarify the required data.

One commenter recommended it would be helpful to identify how the reporting responsibility should be delegated for arrangements when multiple parties own parts of the protection system for the same zone. A new Note 6 has been added to the reporting template instruction tab to clarify that “For protection systems with multiple owners, The Transmission Owner, Generator Owner, or Distribution Provider that operates the protected Element will report the data to its Transmission Planner.”

One commenter reiterated a comment from the first posting that the Planning Coordinator should be the entity to which the data request is targeted, noting that for areas that operate in organized markets, Planning Coordinators are in a better position (number of staff, availability of data, already have stakeholder process for gathering data and information from TOs, GO, and DPs etc.) to handle this voluminous data request, and further noting that for areas that are not in an organized market, the Planning Coordinator and Transmission Planner are likely the same entity. The overall comments support retaining the Transmission Planner as the responsible entity and only one commenter has raised this concern. The Transmission Planner and Planning Coordinator responsibilities are the same regardless of whether an organized market structure exists and NERC believes it is most appropriate to balance work load by making the Transmission Planner the responsible entity. Naming the Transmission Planner as the responsible entity does not preclude the Transmission Planners from working with their Planning Coordinator and does not preclude a Planning Coordinator from coordinating the work among Transmission Planners within its area.

One commenter noted the reference to Table A on page 14 is confusing because this description refers to excluding Elements, but the purpose of Table A is to exclude buses from assessment and reporting. The description has been modified to avoid the phrase “Elements excluded from the criteria in Table A.” The description now states: “Note that criteria in Table A are applied only for the purpose of identifying buses to be tested; these criteria are not related to the assessment and reporting of protection system attributes.”

Two commenters noted that the significant burden of the data request and the potential diversion of resources from responsibilities which have a much greater impact on the reliability of the BES, noting in particular the number of handoffs between the Transmission Planner and the other supporting entities. One of the commenters expressed concern that this data request may set a precedent that the industry will be chasing every worrisome scenario without regard to frequency of occurrence and relative risk to the BES. The potential for this data request to divert resources from other responsibilities has been accounted for in extending the schedule to 24 months. This schedule also accounts for the number of hand-offs; however, a Transmission Planner may use an alternate method to reduce handoffs. It important to note this data request responds to a specific concern identified in Order No. 754, and while single point of failure events occur infrequently, they have the potential for significant reliability impacts as observed in the Westwing outage.

One commenter noted that impending EPA regulations have driven potential retirement of units system-wide and that system changes in the next five years could be significant. Thus, results from this assessment could be quite different from those that may be obtained if the generating units retire. The results of the data request will be used to identify whether a reliability gap exists that needs to be addressed and will be indicative of potential risk to overall system reliability even though the results for any particular facility may vary with time.

One commenter requested additional clarification on when to include and not include breaker failure clearing times versus remote clearing times and on the “open battery condition.” Typically the fault clearing would involve remote clearing based on the expected fault clearing for a failure of the protection system to initiate tripping and breaker failure protection. However, some exceptions exist. If the only single point of failure is in the communication system the fault clearing would involve time delayed backup protection. If the only single point of failure is the circuit breaker trips coils and breaker failure protection is provided, the fault clearing would be based on operation of the breaker failure protection. Notes have been added to Table D and the reporting template to clarify that the open battery condition refers to not having a continuous current path from the positive terminal of the station battery set to the negative terminal.

One commenter questioned whether a capacitor bank protection system would meet the attributes in Table B if it included a relay that detects single line to ground and phase faults, another relay that detects unbalance within the capacitor bank, and each individual can is also fused for overcurrent. As noted in Appendix 1 under “Shunt Devices, “one scheme that detects single-line-to-ground and three-phase faults at the capacitor and one scheme that detects unbalance within the bank would not meet the attributes in Table B.” The individual capacitor fuses do not provide protection for faults which would be of concern relative to this data request.

One commenter reiterated concern that transmission planning assessments conducted for compliance with the TPL standards identify reliability concerns associated with single points of failure in protection systems and corrections are implemented as needed. The commenter recommended the data request is therefore unnecessary and the standards development process should be used if there is a need to expand the studies being conducted in the TPL standards. The extent to which TPL-003 and TPL-004 require evaluation of single points of failure in protection systems is the subject of a request for interpretation that was identified during the FERC technical conference. The data request, also identified at the FERC technical conference, will provide statistical information on the number of buses at which a protection system single point of failure could result in an adverse impact to reliability of the bulk power system as well as the extent to which exposure to single points of failure exists at these buses, broken down by specific categories of protection system components. This data will allow NERC to assess whether a reliability gap exists that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate measures tailored to address the concern. If the request for interpretation or data request identifies a need to expand the studies being conducted in the TPL standards, the standards development process will be used accordingly.

One commenter indicated the data request encourages use of a 50H relay wired as a partial differential, but noted this scheme is discouraged in relay literature because of a possibility of misoperation due to poor current transformer performance. As noted in the data request, the examples are selected to illustrate concepts discussed in the paper and are not intended to be prescriptive or to suggest preferred methods of protection, nor are they inclusive of all possible methods for providing protection. This note has been moved to a more prominent location in Appendix 1.

One commenter requested confirmation that protection for distribution transformer low-side faults is outside this data request. This is correct.

One commenter requested that the final attestation letter include checklists so a responding entity can indicate the reliability functions for which they are registered (i.e., Transmission Planner, Generator Owner, Transmission Owner, or Distribution Provider) and indicate their role in completing the survey. The only entity required to report data in this request is the Transmission Planner. The proposed checklists would not be used unless reporting obligations were added for the other entities. Requiring other entities to fill out the checklists to indicate their role would add unnecessary burden.

One entity questioned whether communication systems powered by a common station DC supply can be considered to meet the attributes in Table B. Yes; communications systems, in the context of Table B, do not include the station DC supply or DC control circuitry. If single points of failure exist in the station DC supply or the DC control circuits supplying the communication system these single points of failure will be reported under the station DC supply or the DC control circuit component category.

One entity indicated the data request will require Transmission Planners to perform simulations on all 100 kV and 200 kV substations even if they are part of radial systems not considered part of the BES. Buses operated below 200 kV are to be tested only if they have six or more circuits terminated and buses operated at 200 kV or higher only if they have four or more circuits terminated. As described in Table A, the term “circuits” includes transmission lines, transmission transformers, and generator step-up transformers connecting aggregated generation greater than 20 MVA, and excludes radial line and step-down transformers. Buses in radial systems typically do not have four or more source circuits supplying power to the bus. These criteria should exclude most buses that are part of radial systems.

One commenter noted that the data request will require Transmission Providers to gather loading information from Generator Owners and Load Serving Entities, and will require Generator Owners and Transmission Providers to perform tests on a broad range of facilities. The commenter notes that hours involved to scope the test, evaluate the test results, and report back to NERC will be enormous and indicates concern that the grounding test for these facilities must be done while the equipment is energized, which is somewhat dangerous. Gathering loading information and testing of energized equipment is not required to respond to this data request. The only information that Transmission Owners and Generator Owners are required to provide are expected fault clearing times based on protection system design and protection system attributes based on knowledge of the protections systems and review of documentation.

One commenter requested that throughout the data request process, care and consideration be given to requesting data with a justified value and to allowing for reasonable data collection management including realistic turnaround times to avoid overburdening data providers. These considerations have been factored into identifying the required data and buses to be evaluated and, in part, resulted in extending the schedule from 12 months to 24 months. Transmission Planners are encouraged to coordinate with asset owners in their transmission planning areas to establish schedules which should result in advance notice and realistic turnaround times for data providers.

One commenter requested further guidance on what constitutes actual clearing times. The phrase “actual clearing time” has been revised to “expected clearing time.” The expected clearing time should be determined on the same basis used for other planning assessments. In this context, expected clearing times typically are determined based on operating times for relay assertion and breaker interrupting time and relay time delay settings.

One commenter requested clarification on use of the phrase “no common circuit breaker trip coils” relating to DC control circuitry, noting they have cases where Protective Relay System # 1 trips both trip coils and likewise Protective Relay System #2 trips both trip coils. To meet the attributes of Table B in this example, it would be necessary to use separate contacts or separate solid-state outputs from the system 1 relay to trip the system1 and system 2 trip coils.

Organization	Question 4 Comment
Northeast Power Coordinating Council	Bus needs to be defined in order to develop uniform assessments. Suggest a definition be developed similar to the following definition taken from NPCC’s Criteria A-10, Classification of Bulk Power System Elements: “Bus ...the term bus refers to a junction with sensing or protection equipment within a substation or switching station at which the terminals of two or more elements are connected, regardless of whether circuit breakers are provided. In this context, bus may not have a direct correlation to the use of this term in substation design or a power flow data set...”Specifics regarding bus configurations and other information can be found in the NPCC A-10 Classification of Bulk Power System Elements document.
SERC Planning Standards Subcommittee	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Bonneville Power Administration	BPA appreciates the opportunity to comment on Order 754 Request for Data or Information and has no

Organization	Question 4 Comment
	comments or concerns at this time.
Pepco Holdings Inc and Affiliates	1) Table B: Having a single battery system is not one of the single point of failure attributes in Table B. However, suppose you have a single battery system that is connected to a single DC distribution panel with short un-fused leads and there is no incoming main breaker, or fuse, in the DC panel (Ref. IEEE 1375, Section 8.4, Fig 19). Per IEEE 1375 this arrangement is used “when interruption of the battery supply cannot be tolerated for any reason.” Therefore one might choose this arrangement to enhance the reliability of a single battery system. There are, however, independent fuses in the DC panel feeding separate protection systems. Is having a single DC panel a violation of Table B? Or, by having independent fuses in the panel are the attributes of Table B satisfied? We believe the arrangement described above should satisfy the attributes of Table B. Therefore we believe Table B needs to be re-worded to address these types of DC designs and disagree with including the DC distribution panel itself under the DC Control Circuitry section of Table B. Obviously for two battery systems, independent DC distribution panels are common. However, for single battery systems they are not. The Drafting Team indicated that a failure of the DC supply in a single battery station would be excluded from the simulation testing protocol and instead elected to just gather statistics on monitoring of single DC supply stations. If you exclude the need to examine the failure of a single battery system from the testing protocol, yet the probability and consequence of failure of the battery is identical to the failure of the leads from the battery up to and including the main bus work in the DC distribution panel, then why shouldn’t these facilities also be excluded from the testing protocol. If an entity employs a single battery directly connected to a single DC distribution panel (with no main breaker or other fuses in between), but utilizes independent fuses or breakers in the panel to supply independent protection schemes, then the single point of failure for the panel itself (i.e. main bus work within the panel) is no different from the failure of the single battery system, or the leads from the battery to the distribution panel. Also, since the battery charger (which by definition is part of the DC supply) is usually connected to the DC distribution panel, then the interconnecting wiring between the battery and the charger should be considered part of the DC system. In addition, the battery charger (which provides the DC supply monitoring) also monitors the health of the DC system up to and including the main bus in the DC panel. We do agree that on single DC supply stations that primary and backup protection should be supplied from separate fuses or breakers within the DC distribution panel. This would be similar in concept to having a single VT but requiring separately fused secondary windings. As such, the last sentence of Table B should be re-worded to eliminate the DC panel itself and read as follows: “For the purpose of this data request the DC control circuitry does not include the station DC supply, but does include all DC circuits used by the protection system to trip a breaker,

Organization	Question 4 Comment
	including any fuses and breakers located in any DC distribution panels." If the Drafting Team is interested in knowing whether independent DC panels (with, or without, main breakers) are used for single battery systems then perhaps additional questions could be posed in the Station DC Supply Attributes data form. 2) Table C: The Order 754 Drafting Team in their response to Draft #1 comments agreed to relax the loss of generation criteria by "not including generators tripped as a direct result of remote fault clearing". As such, a note should be added to Item 1 in Table C that reads: "(does not include the total loss of generation tripped as a direct result of result of remote fault clearing)". 3) We believe the Drafting Team's time estimate for GO's, TO's, and DP's to complete Steps 5, 7, and 10 is about half of what would actually be required. 4) The examples in the Appendix are quite helpful. The Bus and Distribution Transformer examples illustrate how to fill out the reporting template for the various single points of failure. It would have been equally instructive, if not more so, to show how the reporting template is to be filled out for the GSU and Transmission Line examples, as those schemes are more complicated. 5) Also, on the GSU example the switchyard (breakers and relays located within) are often owned by the TO. An overall unit differential relay (owned by the GO) often protects the GSU leads up to the switchyard breakers, whereas the TO may install distance or overcurrent protection as backup protection for this zone. The TO may own the breakers (including the CT's) but the GO may own the unit differential relay. These types of intertwined protection practices are common when the once vertically integrated utility companies (who owned both sets of protection) divested itself of generation assets. It would be helpful to identify how the reporting responsibility should be delegated for these types of arrangements when multiple parties own parts of the protection system for the same zone.
ACES Power Marketing Standards Collaborators	(1) We continue to believe that this data request should be targeted at Planning Coordinators. For areas that operate in organized markets, Planning Coordinators are in a better position (number of staff, availability of data, already have stakeholder process for gathering data and information from TOs, GO, and DPs etc.) to handle this voluminous data request. For those areas that are not in an organized market, the Planning Coordinator and Transmission Planner are likely the same entity. (2) There is a statement on page 14 at the end of the first paragraph that needs further clarification. The statement reads: "that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes". First, Elements are not excluded using Table A. Only buses are excluded. Second, the whole purpose of Table A

Organization	Question 4 Comment
	is to limit the size and scope of the data request. If this statement is intended to remove some of the buses that are excluded, it needs to be stated more clearly. Furthermore, if this is the intent, we disagree with it.
American Electric Power	Though this most recent draft RFI apparently aims to lessen or limit the burden on registered entities, AEP still expects the request to be, as previously stated by NERC, “extremely burdensome”. The burden that this data request places upon Planner and Owner resources is very substantial, and the manpower required to fulfill this request, just for AEP alone, is estimated to be approximately 7,000 hours. The burden of this data request will divert resources from performing their core responsibilities which have a much greater impact on the reliability of the BES. The execution of the survey process will require time consuming communications between business units (beyond what already takes place) within single companies and in many cases between multiple business units in multiple companies. In its current form, the method requires six handoffs between the TP and the TO or GO to complete the survey and a seventh handoff when the TP provides the results to NERC. It should also be noted that impending EPA regulations have driven potential retirement of units system-wide, and the changes coming in the next five years could be the largest that the system has seen. The results obtained by the proposed RFI could be quite different from those results obtained after those units would be retired.
Occidental Energy Ventures Corp.	OEVC understands the background behind the data request, which is intended to address rare events which may lead to a wide-area impact. However, we are troubled that any number of worrisome scenarios can be envisioned - requiring the industry’s immediate attention. Although OEVC saw data that showed that some outages were a result of lack of relay redundancy, we never saw data which showed that it was more critical than many other potential BES weaknesses. Should this set a precedent, the industry will be chasing every potential risk imaginable. These investigations have material impact on all of our resources, which then are not available for other more viable concerns. Furthermore, NERC is developing a data-driven method to determine the largest threats to BES reliability - which this exercise has bypassed. In our view, this is a far more scientific means to improve reliability; with years of proven results across a wide number of industries.
NPPD	NPPD would like to see more clarification on when to include and not include breaker failure clearing times versus remote clearing times. There is discussion of how to calculate clearing times in the examples. One suggestion is to add a single Table or section in the document with how to assess clearing times. This might help guarantee that all entities evaluate local versus remote clearing time in the same manner.

Organization	Question 4 Comment
	Could there be more clarification of the "battery open condition". Is it correct that a primary and secondary DC breaker is considered redundant from a single battery bank/charger? Cap banks are referenced in page 36 under shunt devices. If a cap bank scheme has a relay that detects single line to ground and phase faults, another relay that detects unbalance within the cap bank, and each individual can is also fused for over currents would this meet the attributes in Table B?
NRECA	NRECA still believes that the assessments conducted for compliance with TPL standards identifies any reliability issues that would result from protection system failures and as such are corrected as needed, therefore the data request as written is not necessary. If there is a need to expand the studies being conducted in the TPL standards, the vetting for such studies should be conducted through standards development not a data request.
Ameren	(1) In the 'Distribution Transformer' example the use of the 50H wired as a partial differential is encouraged for redundancy; but, in general, we have seen this scheme being discouraged in relay literature because of a possibility of miss-operation due to poor CT performance. (2) We understand that the lack of redundancy for a distribution transformer low-side fault is outside this RFI scope. We request the Project Team to confirm this.
LCRA Transmission Services Corporation	The Transmission Planner is the only entity required to file results associated with this data request and other impacted entities are only required to provide information to the Transmission Planner. To ensure efficient and effective coordination of information between these entities, additional language needs to be included in the final attestation letter encouraging each entity required to participate as required. LCRA TSC suggests the following: Responding Entity is a NERC Registered: ___Transmission Owner ___Transmission Planner ___Generation Owner ___Distribution Provider Please mark all the following that are applicable:

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	___ Entity is a Transmission Planner and completed the data request as required by NERC. ___ Entity provided information to the Transmission Planner to complete the data request as required by NERC. ___ Entity provided information to another Transmission Planner and its response is being reported by this other Transmission Planner (List other Transmission Planner here:____)
Idaho Power Company	The time estimates for collecting and evaluating protection systems are listed per bus, but using the criterion, a qualifying 230kV bus will have no less than 4 protection systems to be evaluated. It does not appear that this additional time requirement has been accounted for in the estimates, and represents a significant burden to system protection entities with a high number of qualifying busses.
ISO New England	One of the attributes in Table B states "Communications Systems: The protection system for the element includes two independent communication channels and associated communication equipment......" Does this mean that for the communications system to be considered redundant, dual batteries are not required but instead only the DC circuitry needs to be separated such that no single DC fuse or circuit breaker would result in a failure of both communication systems? Bus needs to be defined in order to develop uniform assessments. Suggest the following for bus definition: Bus Within this document the term bus refers to a junction with sensing or protection equipment within a substation or switching station at which the terminals of two or more elements are connected, regardless of whether circuit breakers are provided. In this context, bus may not have a direct correlation to the use of this term in substation design or a power flow data set. In some configurations a bus may include more than one physical bus, such as in a breaker-and-a-half arrangement or a single-line-single-breaker arrangement in which two physical buses are connected through a bus-tie breaker. The examples in Figure 1 depict two of many possible configurations where two physical buses are tested as a single bus. Buses that are separated by normally open bus-tie breakers are considered as separate buses. The termination of line sections through switches should not be considered as a bus requiring testing unless the switches are activated as part of a protection system for the line which they sectionalize as part of normal protection system actions. Figure 1 - Configurations where Bus A and Bus B are tested as one bus. Please refer to NPCC A-10 Classification of Bulk Power System Elements. In some configurations elements may not be terminated to the bus through circuit breakers, such as the generator bus for a unit connected generator or a bus between a transmission line and transformer that

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	are switched as a single circuit. The examples in Figure 2 depict two of many configurations where two physical buses are tested as separate buses. Figure 2 - Configurations where Bus A and Bus B are tested as two separate buses. Please refer to NPCC A-10 Classification of Bulk Power System Elements.
Southern California Edison	Southern California Edison has reviewed order 754 - Request for Data or Information ("The Order"). The Order appears to burden Transmission Providers with performing simulations on all the 100 and 200 KV substations, even if they are part of radial systems that are not today considered Bulk Electric System assets. This is a major impact to distribution system engineers. In addition The Order will require that the Transmission Provider gather loading information from Generator Owners and Load Serving Entities; their cooperation is not fully within the Transmission Provider's control. Generator Owners and Transmission providers will be required to perform test on a broad range of facilities; 1. Buses Evaluated. 2. Attributes of Protection Systems on Evaluated Transmission Lines. 3. Attributes of Protection Systems on Evaluated Transmission Transformers. 4. Attributes of Protection Systems on Evaluated Generator Step-up Transformers. 5. Attributes of Protection Systems on Evaluated Step-down transformers. 6. Attributes of Protection Systems on Evaluated Shunt Devices. 7. Attributes of Protection Systems on Evaluated Buses. 8. Station DC Supply Attributes. The hours involved to scope the test, evaluate the test results, and report back to NERC will be enormous. Furthermore the grounding test for these facilities have to be done while the equipment is energized, which is somewhat dangerous.
Exelon Corporation and its affiliates	As a general comment, Exelon recognizes that this data will be requested of the Transmission Planners who in turn will gather the data from GOs, TOs and DPs. Because of this relationship, it is not easy to judge the scope of the data requested and the impact/burden of the task. The burden of the data requested will vary by entity (GO/TO/DP) based on a number of factors (e.g., the number of connected "elements" owned by a GO) and the extent to which entities are able to use existing studies and assessments. Exelon requests that

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	throughout the data request process, care and consideration be given to requesting data with a justified value and to allowing for reasonable data collection management including realistic turnaround times to avoid overburdening data providers. Thank you for the opportunity to comment.
Public Service Company of New Mexico	1. PNMR requests further clarification on Actual Clearing Times. In absence of any definition of Actual Clearing Times, further guidance on what constitutes actual clearing times will be appreciated. 2. The DC control circuitry description below is too restrictive a description in some cases. Specifically, the words "no common circuit breaker trip coils" needs substantiation as to how that lessens reliability. We have cases where Protective Relay System # 1 trips both trip coils and likewise Protective Relay System #2 trips both trip coils. We also have lines with three protective relay systems with each system tripping both trip coils. We feel this is robust and reliable but the wording for DC Control Circuitry says otherwise. Please clarify.

END OF REPORT