

Appendix F



Part 1. Identification and Certification

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Certification and signature by an authorized official of the Transmitting Utility regarding the accuracy of the information submitted:

A handwritten signature in black ink, appearing to read "Chirag Patel", written over a horizontal line.

Chirag Patel
Manager Electric System Planning



Part 2. Power Flow Base Cases

Northern Indiana Public Service Company LLC submits the following base cases as part of the 2018 FERC FORM 715. These cases were developed under the 2017 Series of the Eastern Interconnection Reliability Assessment Group (“ERAG”) Multiregional Modeling Working Group (“MMWG”) process and are used as a starting point for transmission planning studies.

<u>Case</u>	<u>Abbreviation</u>
2018 Spring Light Load	2018SLL
2018 Summer	2018SUM
2018/19 Winter	2018WIN
2019 Spring Light Load	2019SLL
2019 Summer	2019SUM
2019/20 Winter	2019WIN
2022 Spring Light Load	2022SLL
2022 Summer Shoulder	2022SSH
2022/23 Winter	2022WIN
2027 Summer	2027SUM
2027/28 Winter	2027WIN



**NIPSCO's Transmission System 2018 Diagram and
Drawings
5 Pages**

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TRANSMISSION PLANNING ASSESSMENT METHODOLOGY AND CRITERIA

For Compliance with NERC Reliability Standard: TPL-001-4

3/9/2018
Version: 4.4

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1 REVISION AND APPROVAL HISTORY

This document shall be revised and updated as needed to incorporate changes in methodology and criteria and to reflect changes to the approved NERC Standard requirements.

1.1 REVISION HISTORY

Version	Date	Author	Supervisor	Comments
1.0	10/14/2011	Dawn Quick	Robert Fox	Initial document load into the DMS.
2.0	12/31/2012	Dawn Quick	Robert Fox	Annual Review. Seasonal Ratings defined. Internal Communication additions.
3.0	07/18/2013	Dawn Quick	Robert Fox	Add Generator Interconnection Section.
3.1	10/15/2013	Dawn Quick	Robert Fox	Add language for Single Breaker Ratings.
3.2	12/26/2013	Dawn Quick	Robert Fox	Annual Review. No Changes
3.3	03/10/2014	Dawn Quick	Ganesh Velumylyum	Annual Review. Section 4.5. Added footnote pertaining to Distribution Factor. Added Specification of NERC categories and Cases to study.
4.0	10/07/2015	Dawn Quick	Lynn Schmidt	Annual Review. Format and Content Changes to align with new TPL Standard
4.1	01/10/2016	Dawn Quick	Lynn Schmidt	Annual Review.
4.2	01/10/2017	Dawn Quick	Lynn Schmidt	Annual Review.
4.3	01/10/2018	Dawn Quick	Lynn Schmidt	Annual Review. Change in document review/revision requirements.
4.4	03/09/2018	Dawn Quick	Lynn Schmidt	Addition of 765kV Voltage Criteria

1.2 APPROVAL

Version	Supervisor	Title	Electronic Signature Date
1.0	Robert Fox	Leader Transmission Planning	9/28/2011
2.0	Robert Fox	Leader Transmission Planning	12/31/2012
3.0	Robert Fox	Leader Transmission Planning	7/18/2013
3.1	Robert Fox	Leader Transmission Planning	10/15/2013
3.2	Robert Fox	Leader Transmission Planning	12/26/2013
3.3	Ganesh Velumylyum	Manager Electric System Planning	3/10/2014
4.0	Lynn Schmidt	Leader Transmission Planning	10/07/2015
4.1	Lynn Schmidt	Leader Transmission Planning	1/10/2016
4.2	Lynn Schmidt	Leader Transmission Planning	01/10/2017
4.3	Lynn Schmidt	Leader Transmission Planning	01/10/2018
4.4	Lynn Schmidt	Leader Transmission Planning	03/09/2018

2 ANNUAL PLANNING ASSESSMENT

Transmission Planning shall prepare an annual Planning Assessment of the performance of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated below), shall document assumptions, and shall document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. This assessment shall be performed for both the Near-Term and the Long-Term Transmission Planning Horizons. [R2]

Past studies may be used to support the Planning Assessment if they meet the following requirements:

- For steady state, short circuit, or stability analysis: the study shall be five calendar years old or less, unless a technical rationale is provided to demonstrate that the results of an older study are still valid. [R2.6.1]
- For steady state, short circuit, or stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included in the written assessment. [R2.6.2]

For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the required performance criteria, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the required performance criteria. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. [R2.7] [R2.8]

The Corrective Action Plan(s) shall:

- List System deficiencies and the associated actions needed to achieve required System performance. [R2.7.1] [R2.8.1]
- For Steady state and Stability Studies, include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. [R2.7.2]
- Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. [R2.7.4] [R2.8.2]

When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment. NIPSCO Transmission Planning shall evaluate its current stock and procurement strategy annually. Conclusions of this evaluation shall be stated in the assessment report. [R2.1.5]

In accordance with TPL-001-4 R7, NIPSCO has executed a Coordination Agreement with MISO identifying individual and joint responsibilities for performing the required studies. NIPSCO has not delegated any of their TPL responsibilities to MISO. In addition to any data requests made by MISO required to fulfill their TPL requirements, NIPSCO will also provide results from its Short Circuit studies to MISO. [R7]

Transmission Planning shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Recipients of the Planning Assessment include: MISO, PJM, METC, Duke, and Ameren. [R8] [R8.1]

2.1 MODEL DATA

NIPSCO Transmission Planning shall maintain System models within the NIPSCO area for performing the studies needed to complete its Planning Assessment. The models are consistent with provisions of the most recent Multiregional Modeling Working Group Procedure Manual and the most recent MOD-32 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [R1].

System Models Represent:

- Existing Facilities
- Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.[R2.1.3]
- New planned Facilities and changes to existing Facilities
- Real and reactive Load forecasts
- Known commitments for Firm Transmission Service and Interchange
- Resources (supply or demand side) required for Load

A project is considered “planned” and is modeled in the base cases when a continuing need has been identified by recent and past study results. The planned project, in general, is needed in the near term and typically has budget approval for engineering or material costs.

A “proposed” project is typically not modeled in base cases. The “proposed” project is being studied for continuing need and timing when project lead time is sufficient. A “proposed” project may also be conceptual in nature. It has been identified as a possible solution in long term studies where violations may be marginal. It may also be identified as a possible solution to stressed or alternative dispatch cases. Alternative projects may be studied for best solution. Proposed projects are given a “planned” status after need has been proven, taking into consideration sufficient lead time.

2.2 *STEADY STATE*

In accordance with NERC Standard TPL-001-4, the following system conditions are required for study annually:

- System peak Load for either Year One or year two, and for year five. [R2.1.1]
- System Off-Peak Load for one of the five years [R2.1.2.]
- A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. [R2.2.1]

For each of the Near-Term studies described above, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment will vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: [R2.1.4]

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.2.1 Contingency Analysis

For the steady state portion of the Planning Assessment, Transmission Planning shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons mentioned above. The studies shall be based on computer simulation models using data provided in accordance with TPL-001-4 Requirement R1. [R3]

A list of those Contingencies to be evaluated for System Performance for Planning Events shall be created corresponding to the Planning Events P0-P7 listed in Table 1. For steady state, all planning events are simulated unless contingency outages duplicate the same elements as those of another contingency. Results of these simulations should be assessed to determine whether the BES meets the performance requirements in section 2.2.2. [R3.1][R3.4]

A list of Contingencies for those extreme events listed in Table 1 that are expected to produce more severe System impacts shall be identified and created. For Steady-State, all extreme events listed in Table 1, extreme events #1 and #2 shall be simulated. Wide-area events affecting the Transmission System, such as those described in Table 1, extreme events #3, may be evaluated. A description and rationale of these wide-area events, if included, will be documented in the assessment. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. [R3.2][R3.5]

Transmission Planning shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. [R3.4.1]

Contingency analysis shall simulate the removal of all elements that the Protection System and other automatic controls that are expected to normally clear or disconnect for each Contingency without operator intervention. [R3.3.1]

The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Synchronous generator terminal voltages will be monitored at 85% for potential tripping. Wind plants will be monitored at 90% for potential tripping. [R3.3.1.1]
- Tripping of Transmission elements where relay loadability limits are exceeded. A tripping proxy of 125% of Emergency Rating will be used for all lines and transformers. When exceeded, Transmission Planning will consult Protection Engineering to obtain actual trip values and determine if a corrective action plan is necessary. [R3.3.1.2]

Contingency analysis shall simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. [R3.3.2]

2.2.2 Steady-State Performance Requirements and Criteria [R5]

- Voltages, post-contingency voltages, and post-contingency voltage deviations shall be within acceptable limits. See Steady-State Voltage Tables below.
- Applicable Facility Ratings shall not be exceeded. Transmission Planning establishes Normal and Emergency Facility Ratings for summer and winter seasonal periods based on its documented Facility Rating Methodology. Single Breaker Ratings are also established for use in studies where the contingency may cause a facility to have a more limited rating.
- The transmission system shall not experience uncontrolled cascading or islanding. Load loss shall not exceed 300 MWs, excluding consequential load. See section 2.5, Supplemental Performance Analysis. [R6]
- Synchronous generators are projected to trip when the terminal voltage is below 85%. Wind generating plants are projected to trip when the plant voltage is below 90%. [R3.3.1.1]
- Consequential Load Loss as well as generation loss is acceptable as a result of any event excluding category P0 No Contingency.
- The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady-state performance requirements.

Steady-State Voltage Tables

Location	Normal Condition		Post-Contingency Steady-State		
	Minimum	Maximum	Minimum	Maximum	Deviation
765 kV buses	92%	105%	90%	105%	+/- 10%
345 kV buses	92%	105%	90%	105%	+/- 10%
138 kV buses	92%	105%	90%	105%	+/- 10%
69 kV buses	94%	105%	92%	105%	+/- 10%
On-Line Synchronous Generator Terminals [3.3.1.1]	95%	105%	85%	107%	+/- 10%
On-Line Wind Plant [3.3.1.1]	95%	105%	90%	105%	+/- 10%

Location	Normal Condition		Post-Contingency Steady-State		
	Minimum	Maximum	Minimum	Maximum	Deviation
Customer Substation 138kV Buses	95%	105%	90%	110%	+/- 10%

2.3 STABILITY

In accordance with NERC Standard TPL-001-4, the following system conditions are required for study annually:

- System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. [R2.4.1]
- System Off-Peak Load for one of the five years. [R2.4.2]

For each of the studies described above, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: [R2.4.3.]

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Generation additions, retirements, or other dispatch scenarios.

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies and shall include documentation to support the technical rationale for determining material changes. [R2.5]

Loads shall be modeled by P (constant current) and Q (constant impedance) which represents the aggregate overall dynamic load behavior. For sensitivity analysis, loads may be modeled by a composite load model considering more detailed behavior of induction motor loads. [R2.4.1]

2.3.1 Contingency Events

For the Stability portion of the Planning Assessment, Transmission Planning shall perform the Contingency analyses for the Near-Term and Long-Term Planning Horizons mentioned above. The studies shall be based on computer simulation models using data provided in accordance with TPL-001-4 R1. [R4]

A list of those Contingencies to be evaluated for System Performance for Planning Events shall be created corresponding to the Planning Events P0-P7 listed in Table 1. For transient stability, Planning Events for transmission facilities directly associated to an individual power plant as well as Planning Events for other selected transmission facilities are simulated. [R4.4]

Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated for impact to the BES. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. [R4.2][R4.5]

Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. [R4.4.1]

Contingency analyses shall simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. [R4.3] [R4.3.1]

The contingency analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. [R4.3.1.1]
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. [R4.3.1.2]
- Tripping of Transmission lines and transformers where transient swings will cause a Protection System operation based on generic or actual relay models. [R4.3.1.3]

Contingency analyses shall simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. [R4.3.2]

Studies shall be performed for planning events to determine whether the BES meets the following stability performance requirements and criteria: [R4.1] [R4.2]

2.3.2 Stability Performance Requirements and Criteria [R5]

The transmission system shall not experience uncontrolled cascading or islanding.

For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. [R4.1.1]

For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. [R4.1.2]

For planning events P1 through P7: Power oscillations shall exhibit acceptable damping. Observed damping ratio (ζ) shall be greater than 0.020. [R4.1.3]

Synchronous Generator Voltage: Voltages at the terminal bus of on-line synchronous generators shall return to the allowable steady-state contingency voltage within five seconds after fault clearing. [R4.3.1.2]

Wind Generating Plant Voltage: Wind plants shall have low voltage ride-through capability down to 15% of the rated voltage for 0.625 seconds (37.5 cycles). Per FERC Order 2003A and FERC Order 661. [R4.3.1.2]

Load Bus Voltages: Voltages at load buses should return to the allowable steady-state contingency voltage within five seconds after fault clearing.

2.4 SHORT CIRCUIT

The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and shall be supported by current or qualified past studies. The analysis shall be used to determine whether circuit breakers have the capability to interrupt the maximum short-circuit current the circuit breaker is expected to experience. [R2.3]

The System short-circuit model for the analysis shall be updated annually including planned generation and transmission facilities within NIPSCO, and including planned generation and transmission facilities in adjoining areas within two busses of NIPSCO.

The maximum expected short-circuit current that a circuit breaker is expected to interrupt shall be determined by performing both three-phase (3 ϕ) and single line-to-ground (SLG) fault simulations in accordance with the IEEE standard C37-010-1999 and utilizing the calculation methodology of the ASPEN Oneliner™ Breaker Rating Module. The circuit breaker interrupting rating shall be based on its nameplate value and not derated based on circuit breaker reclosing operations.

Circuit breakers with interrupting duty of 100% or greater of the interrupting rating shall be considered an identified deficiency.

2.5 SUPPLEMENTAL PERFORMANCE ANALYSIS

2.5.1 Cascading

Cascading potential shall be evaluated by sequentially removing those facilities with steady-state loading in excess of 125% of their emergency rating and those generating units with steady-state terminal voltage below their specified voltage criteria. [R6]

2.5.2 Uncontrolled Islanding

Uncontrolled islanding potential shall be evaluated by review of identified cascading outages that result in load being isolated with generation from the interconnected system. [R6]

2.5.3 Voltage Stability

Voltage stability analysis shall be performed for the Near-Term and Long-Term Planning Horizons mentioned above. Voltage stability shall be evaluated through the application of the Fast Voltage Stability Index (FVSI) and Voltage Stability Index Le. Analysis shall be performed for N-0 and N-1 contingency conditions. A voltage stability index value of 1.0 or greater is an indication of voltage instability. [R6]

3 FACILITY CONNECTION, TRANSMISSION SERVICE REQUEST ASSESSMENTS, AND GENERATOR RETIREMENTS

Transmission Reliability Planning Tests are performed on Facility Connection projects, Transmission Service Requests (TSR's), and Generation Retirements to evaluate any Thermal or Voltage criteria violations caused by projects originated through PJM, MISO and NIPSCO processes on NIPSCO's transmission system. These tests shall include NERC Contingency Categories P0, P1, and P2 (formerly A, B, C1, C2, and C5).

The Facility Connection Projects, TSR's, and Generation Retirements impacting NIPSCO's transmission shall be subject to two tests: the Individual Contribution Test and the Cumulative Impact Test.

The Facility Connections, TSR's, and Generation Retirements screened through the following two tests are studied for their impact on NIPSCO's transmission system. The RTEP and MTEP cases used by PJM and/or MISO will be used in the study process. Peak, off-peak, and high wind cases should be evaluated to determine worst-case impact. . Mitigations will be determined for all thermal and/or voltage violations.

3.1 INDIVIDUAL CONTRIBUTION TEST

The test is performed to identify individual Facility Connections, TSRs, and Generation Retirements affecting NIPSCO's transmission system. For a Facility Connection, TSR, or Generation Retirement to be considered to be impacting the NIPSCO transmission system, it should adhere to one of the two rules:

1. The contribution of the Distribution Factor of the Facility Connection, TSR, or Generation Retirement with magnitude of 3% or greater contributing to an overload on a NIPSCO facility.
2. The Contribution of a Facility Connection, TSR, or Generation Retirement on a NIPSCO facility is equal to or greater than 3% of the facility rating.

3.2 CUMULATIVE IMPACT TEST (CIT)

NIPSCO shall also perform a test to evaluate the cumulative impact of multiple Facility Connections, TSRs, and Generation Retirements when they are grouped together in the same study during the PJM and/or MISO process. The Facility Connections, TSRs, and Generation Retirements having a cumulative impact of at least 10% of the facility rating will be considered as impacting NIPSCO's transmission system.

TABLE 1. PLANNING AND EXTREME EVENTS

Category	Initial Condition	Event	Fault Type	Notes
P0	Normal System	None	N/A	Initial System Condition
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3 \emptyset	
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	N/A	
		2. Bus Section Fault	SLG	
		3. Internal Breaker Fault (non-bus tie)	SLG	
		4. Internal Breaker Fault (Bus-tie Breaker)	SLG	
P3 Multiple Contingency	Loss of generator unit followed by System Adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3 \emptyset	
P4 Multiple Contingency (Fault plus Stuck Breaker)	Normal System	Loss of Multiple Elements Caused by a stuck Breaker (non-bus tie) attempting to clear a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section 6. Loss of Multiple elements caused by a stuck Bus-tie Breaker attempting to clear a fault on the associated bus.	SLG	
P5	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	SLG	

		5. Bus section		
P6	Loss of one of the following followed by System adjustments. Loss of one of the following: <ol style="list-style-type: none"> 1. Transmission Circuit 2. Transformer 3. Shunt Device 	Loss of one of the following: <ol style="list-style-type: none"> 1. Transmission Circuit 2. Transformer 3. Shunt Device 	3∅	Curtailement of Firm Transmission Service is allowed as a System adjustment as identified in the column entitled 'Initial Condition'.
P7	Normal System	The loss of: <ol style="list-style-type: none"> 1. Any two adjacent (vertically or horizontally) circuits on common structure. 	SLG	Excludes circuits that share a common structure for 1 mile or less.
Extreme Event – Steady State 1	Loss of one of the following: <ol style="list-style-type: none"> 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 	Loss of one of the following: <ol style="list-style-type: none"> 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 	Steady State Only	
Extreme Event – Steady State 2	Normal	Local Area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. Loss of a tower line with three or more circuits. b. Loss of all Transmission lines on a common Right-of-Way. c. Loss of a switching Station or Substation (loss of one voltage level plus transformers) d. Loss of all generating Units a generating Station e. Loss of a large Load or major Load Center 	Steady State Only	
Extreme Event - Steady State 3	Normal System	Wide area events affecting the transmission System based on System Topology such as: <ol style="list-style-type: none"> a. Loss of two generating Stations. b. Other events based upon 	Steady State Only	

		operating experience that may result in wide area disturbances.		
Extreme Event- Stability 1	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3 \emptyset fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Stability Only - 3 \emptyset	
Extreme Event - Stability 2	Normal System	Local or wide area events affecting the Transmission System such as: a. 3 \emptyset fault on generator with stuck breaker or a relay failure resulting in Delayed Fault Clearing. b. 3 \emptyset fault on Transmission Circuit with stuck breaker or a relay failure resulting in Delayed Fault Clearing. c. 3 \emptyset fault on Transformer with stuck breaker or a relay failure resulting in Delayed Fault Clearing. d. 3 \emptyset fault on bus section with stuck breaker or a relay failure resulting in Delayed Fault Clearing. e. 3 \emptyset internal breaker fault f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.		



2018 FERC FORM 715 PART VI

SYSTEM EVALUATION

MARCH 15, 2018

TRANSMISSION PLANNING

CEII –DO NOT RELEASE

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2 NIPSCO ELECTRIC SERVICE TERRITORY

Northern Indiana Public Service Company LLC (NIPSCO) serves more than 457,000 electric customers across the northern third of Indiana, spanning 30 counties. NIPSCO's Bulk Electric System includes 353 miles of 345kV and 756 miles of 138kV.

NIPSCO has several tie-lines to neighboring utilities including Ameren Illinois, American Electric Power (AEP), Commonwealth Edison (ComEd), Duke Energy, and Michigan Electric Transmission Company (METC). NIPSCO is a member of the regional transmission organization Midcontinent Independent System Operator (MISO), while our interconnected neighbors immediately to the west and east are members of PJM. This unique location proves to be a challenge, particularly when PJM's market dispatch results in large flows across the NIPSCO system.

3 ASSESSMENT OVERVIEW

NIPSCO Transmission Planning analyzes its transmission system performance as part of its annual system assessment. This assessment covers the near term (1-5 year out) and long term (6-10 years out) planning horizons. Planning models are maintained and provided in accordance with the most recent Multiregional Modeling Working Group (MMWG) Procedure Manual and MOD-32 standard representing projected system conditions including; existing transmission and generation facilities, known outages of generation or transmission lasting six months or longer, new planned facilities and changes to existing facilities, forecasted peak demands, commitments for firm transmission service and interchange, and resources required for load.

Models may be supplemented by other sources as needed including items represented in Corrective Action Plans which will be described in the following sections where applicable. The system is evaluated against published criteria for all planning events in Table 1 of the NERC Standard TPL-001-4. If the analysis indicates an inability of the system to meet these performance requirements, a corrective action plan shall be established. These corrective action plans will be studied for continued need in subsequent assessments if lead time allows.

NIPSCO, in coordination with its Planning Coordinator (MISO), has full responsibility for performing the required studies for the Planning Assessment. NIPSCO shares no joint responsibilities with MISO or any other party for performing the required studies for the Planning Assessment.

Three types of studies are conducted as part of the Planning Assessment; Steady State, Transient, and Short Circuit. Qualified past studies may be used to supplement annual current study if results are still valid and no material changes have occurred to the system represented in the study. Each of the following sections provide a summary of each of the study types, cases studied, study results, and any future Corrective Action Plans modeled or proposed based on study results.

4 STEADY STATE ANALYSIS

For the Steady State portion of the 2017 Planning Assessment, a total of 7 Cases were Studied. In accordance with NERC Standard TPL001-4 R4., near term studies should include a system peak load for

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either year one or year two and for year five. In addition, a system off peak load for one of the five near term years should be included. For each of the three near term studies, a sensitivity case shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. A current study assessing expected System Peak load conditions in the long-term Transmission Planning Horizon shall also be conducted annually. As in prior year's assessment, a 10 year out case was chosen for the long term to capture a more extreme summer peak demand forecast as well as long-term transmission and generation developments.

The following cases were used for the 2017 Annual Transmission Planning Assessment:

- 2018 Summer
- Sensitivity: 2018 Summer with an East to West Market Transfer
- 2022 Summer
- Sensitivity: 2022 Summer with Whiting Clean Energy at Max MW dispatch
- 2022 Summer Shoulder
- Sensitivity: 2022 Summer Shoulder with Retirement of Schahfer Generating Units 17 & 18
- 2027 Summer

The near-term and long-term cases for steady-state analysis were developed from the most recent MMWG model library. The sensitivity cases were developed by generation redispatch to create the market transfer and retirement scenarios as noted above.

Known planned outages of generation or Transmission Facilities with a duration of at least six months are represented in study models. No outages with a duration of 6 months or longer are planned for the 2017 Assessment study horizon.

Transmission Projects included in the modeling of these cases are as follows. The Reynolds to Topeka 345kV line (MVP12 Reynolds – Burr Oak – Hiple) was modeled with an in service date of December 1st, 2019. Since the conclusion of studies, the expected in service date has changed to September 1st, 2018. Study models are not affected by this change. The Greentown to Reynolds 765kV (MISO MVP14) line is modeled and planned in service by June 1st, 2018. These are Multi-Value Projects based on MISO's Transmission Expansion Plan studies. As identified in the 2015 and 2016 Assessment, the corrective action plan to change a CT setting at Thayer substation was completed in April 2017 and included in the 2017 Assessment studies.

Studies were performed for all Planning Events P0-P7 in Table 1 of NERC Standard TPL-001-4. Studies were also performed for Extreme Events in Table 1 of NERC Standard TPL-001-4. Results of these Planning Event and Extreme Event analysis were used to determine whether the NIPSCO BES meets the performance requirements put forth by the standard and by the published NIPSCO transmission planning criteria. Events simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without operator intervention. Automatic operations of existing and planned devices which provide steady-state control of electrical system quantities were also simulated. The analysis includes post-processing tripping of generators where simulations show generator terminal steady-state bus voltage less than 0.85 per-unit. Relay loadability limits were investigated if any Thermal overloads exceeded 125%. Post-processing tripping of Transmission elements was simulated if relay loadability limits were exceeded. For all events, in all

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study cases, the system remained stable. No instances of either Cascading or uncontrolled islanding were identified.

When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment. At the time of study, based on historical failure rates, NIPSCO's spare equipment inventory and participation in the Spare Transformer Equipment Program (STEP) does not result in the unavailability of any major Transmission equipment for one year or more.

Voltage Stability was assessed by using industry accepted voltage stability indices to identify any weak buses or areas. They are known as Voltage Stability Index, Le, and Fast Voltage Stability Index, FVSI. More information can be found in the NIPSCO Transmission Planning Methodology and Criteria document. Both Indices use receiving end Power value(s) and sending and receiving end voltages, with line impedance, to calculate an index value. Values less than 1 indicate system is stable. When the value of the index approaches 1, it indicates that the system is becoming unstable. Indices were calculated for all study cases and found to be well within stable limits.

Based on 2017 study results on the performance analysis of the NIPSCO BES, several Corrective Action Plans have been developed. The Aetna to Lake George 138 kV circuit shows thermal exceedances for both P1 and P2 Contingencies. Substation conductor at Aetna, which is limiting the line, is planned for replacement in April of 2018. Babcock to Tower Road 138 kV Circuit showed thermal exceedances for P5 and P7 contingencies in the near term. An engineering review indicated the line conductor can be operated at a higher operating temperature, increasing the rating of this facility. This was completed in September 2017. Long term planning studies show several AEP contingencies, including the loss of a single 345/138 kV transformer, that cause a thermal violation on the Maple to LNG 138 kV circuit. A project to reconductor or rebuild, if necessary, a portion of the line is proposed. Need and timing will be monitored in future studies.

The partially owned 138kV NIPSCO lines from Bosserman to Olive and Bosserman to New Carlisle show overloading in both the near term and long term cases. Olive to Bosserman 138kV line shows thermal exceedances in both P1 and P4 AEP supplied contingencies. New Carlisle to Bosserman 138 kV shows overloads for a NIPSCO P7, common tower contingency. All violations are mitigated with an AEP planned project of converting their Bosserman area 34kV line(s) to 138 KV, creating a third 138 kV line from Bosserman to New Carlisle/Olive.

Performance on the non-BES 69kV System in NIPSCO's Eastern portion of its control area has identified needed upgrades. The failure of a non-redundant relay at Hiple, resulting in the loss of the 138kV station, shows heavy loading of the Northport Transformer as well as low voltage on the area 69kV buses. A plan to add redundant relaying at Hiple is proposed for 2018. For the category P6 (n-1-1) outage of the Hiple Transformers, opening the 69kV line (6990) between Hiple and Lagrange post first contingency will eliminate overloading of the Northport Transformer. Circuit 6990 shows overload for the loss of 2 138kV Circuits, a P6 (n-1-1) violation. Manual switching is available in between contingencies to mitigate violations. A project to mitigate clearance issues and increase ratings on the

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line is proposed for 2018. In 2014, a project to upgrade the Lagrange 138kV bus to a ring-bus type was identified based on study results of the failure of the 138kV bus tie breaker at Lagrange. The contingency caused overloads on several 69kV lines in the area as well as the DeKalb Transformer. The 2017 assessment still shows violations for multiple 69kV lines. The Lagrange 138kV ring-bus project is scheduled to be in service by the end of 2018.

Due to our location between ComEd and the rest of PJM, the import or export of generation by ComEd continues to be a challenge to NIPSCO. As part of the 2017 Transmission Planning Assessment, a sensitivity case was built with extreme east to west flow across NIPSCO to identify any potential risks to our system resulting from these imports/exports. The 138kV Northwest section of NIPSCO's territory is the most affected by these transfers with thermal violations identified in some studies. All violations can be mitigated with redispatch. Voltages did not exhibit any violations and remained within criteria. Facilities affected by Market Transfer with potential for thermal violations depending on severity of flows are as follows:

- Olive to Bosserman 138kV Circuit (AEP)
- New Carlisle to Bosserman 138kV Circuit (AEP)
- Aetna to Praxair #3 138kV Circuit
- Aetna to Lake George 138kV Circuit
- Aetna to USS W. Mill 138kV Circuit
- Chicago Ave to Praxair #3 138kV Circuit
- Miller to USS Coke 138kV Circuit
- Trail Creek to Bosserman 138kV Circuit
- Michigan City to Bosserman 138kV Circuit
- Maple to New Carlisle 138kV Circuit
- Hendricks to USS W Mill 138kV Circuit
- Hendricks to USS Stockton 138kV Circuit
- Chicago Ave. to MITTAL 8 138kV Circuit
- Chicago Ave to USS Stockton 138kV Circuit
- St. John to Crete 345 kV CircuitDumont to Stillwell 345kV Circuit
- Miller to USS Tin 138 kV Circuit
- Maple to LNG 138kV Circuit
- Michigan City to Trail Creek 138kV Circuit
- Leesburg to Northeast 138kV Circuit
- Roxana to Stateline 138kV Circuit
- Dune Acres to Michigan City 1 & 2
- Gary Ave. 345/138 kV Transformer

Many of these NIPSCO lines or tie-lines are identified in MISO and PJM Market efficiency studies. NIPSCO continues to participate or follow these external studies.

Existing and interconnecting wind farms continue to be the main driver for upgrades for the southern area of the NIPSCO system. The 100 mile 345kV line from Reynolds to Hipple (Topeka, IN) and the 69 mile

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765kV line from Reynolds to Greentown, as mentioned above, will alleviate some of the congestion typically seen.

5 TRANSIENT STABILITY ANALYSIS

For the Stability analysis of the 2017 Planning Assessment, a total of five system conditions were studied. In accordance with NERC Standard TPL-001-4 R2., Near-Term studies require a System peak load for one of the five years and a System Off-Peak load for one of the five years including a Load model which represents the expected dynamic behavior of the load. For each of the near-term studies, a sensitivity case shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. The Long-Term Transmission Planning Horizon portion of the Stability analysis has been assessed to address the impact of proposed material generation additions or changes in that timeframe. NIPSCO Transmission Planning participates in both MISO and PJM generation interconnection processes and remains informed of potential new generation in the area.

The following cases were used for transient Stability analysis in the 2016 Annual Transmission Planning Assessment:

- Near-term system peak load: 2021 Summer Peak
- Near-term system peak load(sensitivity): constant impedance P/Q load models
- Near-term system off-peak load: 2021 Light Load
- Near-term system off-peak load(sensitivity): constant impedance P/Q load models
- Long-term: 2026 Summer Peak

The near-term and long-term cases for transient stability analysis were obtained from the most recent MMWG model library. The sensitivity cases were developed by adjustment of the load model types.

Studies were performed for Planning Events in Table 1 of NERC Standard TPL-001-4 associated with each NIPSCO area power plant to determine whether the NIPSCO BES meets the performance requirements put forth by the standard and by the published NIPSCO transmission planning criteria.

Events simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses includes the impact of

- Successful/unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized. (*High-speed reclosing is not utilized at any NIPSCO area power plant.*)
- Tripping of generators where simulations show generator bus voltage are less than assumed generator low voltage ride through capability. (*Low-voltage ride through capability was assumed at 10% for five seconds for synchronous generators and at 15% for 37.5 cycles for windfarms.*)
- Tripping of Transmission line and transformers where transient swings cause Protection System operations based on generic or actual relay models. (*Generic mho distance relays models were utilized.*)

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Events simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area including devices such as: generation exciter control, power system stabilizers (PSS), static var compensators (SVC), power flow controllers, and DC Transmission controllers.

Results of transient stability event simulations were analyzed by review of machine rotor angle plots for indication of any loss of synchronism, by review of generator terminal voltage plots and generator over/under voltage relay model output for indication of any tripping action, by review of transmission line and transformer relay model output for indication of any tripping action, and by review of resulting generator damping coefficients for indication of an undamped or poorly damped condition.

From the transient stability event simulation results:

- For P1 planning events, no generating units pulling out of synchronism were identified. Generating units were only disconnected from the System as a result of fault clearing action.
- For P2 through P7 planning events, no tripping of any Transmission system elements resulting from apparent impedance swings other than the generating unit(s) and its directly connected facilities were identified.
- For P2 through P7 planning events, power oscillations generally exhibited damping which met or exceeded the established damping coefficient of 0.020. A very small number of events did not meet the established damping coefficient, primarily the response of Schahfer Unit #15 following a stuck-breaker condition for faults at the Schahfer 345kV yard. Visual inspection of the resulting rotor angle plots show the unit stable with good rotor angle damping. Refinement of the calculation of the damping coefficient will be pursued in response.
- Select total station outages with remote clearing were studied as extreme events. These stations were identified for study based on FERC 754, single point of failure, and CIP-014-2, physical security, assessment criteria. No instances of either Cascading or uncontrolled islanding were identified.

From the results of the transient stability analysis, no Corrective Action Plan(s) are required.

6 SHORT CIRCUIT ANALYSIS

Short circuit analysis was performed on a 2017 Summer Case with no line or transformer outages. New planned generators that are up to two buses away from NIPSCO system are included in the model. The short circuit model was compared with models used for steady-state analysis to ensure consistency of transmission system topology. Two types of faults, 3 Phase and Single Line to Ground, are performed at 345kV and 138kV busses as part of short circuit interrupting analysis on circuit breakers. Normally open circuit breakers are not included in this study. Circuit breakers that have interrupting duty of 100% or higher are considered an identified deficiency.

No circuit breakers were identified for upgrades.

From the results of the short circuit analysis, no Corrective Action Plan(s) are required.

7 METHODOLOGIES

- Cascading: Cascading potential shall be evaluated by sequentially removing those facilities with steady-state loading in excess of 125% of their emergency rating and those generating units with steady-state terminal voltage below their specified voltage criteria. Load loss shall not exceed 300 MWs, excluding consequential load
- Voltage Instability: Voltage stability analysis shall be performed for the Near-Term and Long-Term Planning Horizons. Voltage stability shall be evaluated through the application of the Fast Voltage Stability Index (FVSI) and Voltage Stability Index Le. Analysis shall be performed for N-0 and N-1 contingency conditions. A voltage stability index value of 1.0 or greater is an indication of voltage instability.
- Uncontrolled Islanding: Uncontrolled islanding potential shall be evaluated by review of identified cascading outages that result in load being isolated with generation from the interconnected system.

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8 SUMMARY OF RESULTS

Summary of Results by NERC Category:

Category P0 – System Normal

Studies did not indicate an inability of the systems to respond as prescribed by the standard. No Corrective actions are necessary.

Category P1- Single Contingency: Generator, Circuit, Transformer, Shunt

Studies indicate an inability of the systems to respond as prescribed by the standard.

Event	Study Case	Monitored Element	System Deficiency	Corrective Action	Implementation Date
Fault on a Transformer	2027 Summer	Maple to LNG 138kV Line	Thermal	Reconductor/Rebuild Portion of Line. Will monitor in Future studies	TBD
Fault on a Transmission Circuit	All	Aetna to Lake George 138 kV Circuit	Thermal	Replacement of Substation Conductor at Aetna	04/01/2018
Fault on a Transmission Circuit	2018 Summer 2022 Summer 2027 Summer	Olive(AEP) to Bosserman(AEP) 138 kV line	Thermal	AEP Supplemental Project “Bosserman Area Conversion Project”	2019

Category P2- Single Contingency – Line Section (no fault), Bus Section, Breaker

Studies indicate an inability of the systems to respond as prescribed by the standard.

Event	Study Case	Monitored Element	System Deficiency	Corrective Action	Implementation Date
Internal Breaker Fault	2018 Summer 2022 Summer 2022 Shoulder 2027 Summer	Aetna to Lake George 138 kV Circuit	Thermal Violation	Replacement of Substation Conductor at Aetna	04/01/2018

Category P3- Multiple Contingency – Loss of a Generator followed by System Adjustments plus P1

Studies did not indicate an inability of the systems to respond as prescribed by the standard. No Corrective actions are necessary.

Category P4- Multiple Contingency – Fault plus Stuck Breaker

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Studies indicate an inability of the systems to respond as prescribed by the standard.

Event	Study Case	Monitored Element	System Deficiency	Corrective Action	Implementation Date
Fault with Stuck Breaker	2018 Summer 2022 Summer 2027 Summer	Olive(AEP) to Bosserman(AEP) 138 kV line	Thermal	AEP Supplemental Project "Bosserman Area Conversion Project"	2019

Category P5- Multiple Contingency – Fault plus Relay Failure to Operate

Studies did not indicate an inability of the systems to respond as prescribed by the standard. No Corrective actions are necessary.

Category P6- Multiple Contingency- Two Overlapping Singles

Studies did not indicate an inability of the systems to respond as prescribed by the standard. No Corrective actions are necessary.

Category P7-Multiple Contingency- Two Adjacent Circuits on Common Tower

Studies indicate an inability of the systems to respond as prescribed by the standard.

Event	Study Case	Monitored Element	System Deficiency	Corrective Action	Implementation Date
Two Adjacent Circuits on a common Tower	2018 Summer 2022 Summer 2027 Summer	Babcock to Tower Road 138 kV Circuit	Thermal Violation	Review of Conductor Operating Temperature	Complete
Two Adjacent Circuits on Common Structure	2018 Summer 2022 Summer 2027 Summer	Aetna to Lake George 138kV Circuit	Thermal Violation	Replacement of Substation Conductor at Aetna	04/01/2018
Two Adjacent Circuits on Common Structure	2018 Summer 2022 Summer 2027 Summer	New Carlisle(AEP) to Bosserman(AEP) 138kV line	Thermal Violation	AEP Supplemental Project "Bosserman Area Conversion Project"	2019

Extreme Events- N-2, Tower Line, Right of Way, Substation, Generating Station, other Wide Area Event

Studies did not indicate an inability of the systems to respond as prescribed by the standard. No Corrective actions are necessary.