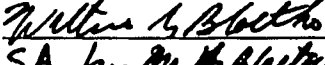## ATTACHMENT 1
Design Analysis Cover Sheet

Design Analysis	Last Page No. ° G3.-13

Analysis No.: ¹ BYR13-176	Revision: ² 000 Major ☒ Minor ☐
Title: ³	Loss of Phase Detection EMTP Analysis
EC/ECR No.: ⁴ 389896	Revision: ⁵ 004

Station(s): ⁷	Byron	Component(s): ¹⁴	
Unit No.: ⁸	1 & 2	Various	
Discipline: ⁹	ELDC		
Descrip. Code/Keyword: ¹⁰	E07		
Safety/QA Class: ¹¹	Non-Safety Related		
System Code: ¹²	AP		
Structure: ¹³	N/A		

CONTROLLED DOCUMENT REFERENCES ¹⁵

Document No.:	From/To	Document No.:	From/To
Calculation BYR13-177	To		

Is this Design Analysis Safeguards Information? ¹⁶	Yes ☐ No ☒ If yes, see SY-AA-101-106
Does this Design Analysis contain Unverified Assumptions? ¹⁷	Yes ☐ No ☒ If yes, ATI/AR#:
This Design Analysis SUPERCEDES: ¹⁸	in its entirety.

Description of Revision (list changed pages when all pages of original analysis were not changed): ¹⁹
Original Issue

Preparer: ²⁰	Benjamin Marx	*[signature]*	6/25/2014
	Print Name	Sign Name	Date

Method of Review: ²¹	Detailed Review ☒	Alternate Calculations (attached) ☐	Testing ☐
Reviewer: ²²	William G Bloethe	*[signature]*	6/25/2014
	Safa Alkhatib (Att. G)	SA by *[signature]*	6/25/2014
	Eric Hope (Att. F, G)	EH by *[signature]*	6/25/2014
	Print Name	Sign Name	Date
Review Notes: ²³	Independent review ☐	Peer review ☐	

(For External Analyses Only)			
External Approver: ²⁴	Sanjiv Shah	*[signature]*	6/25/2014
	Print Name	Sign Name	Date
Exelon Reviewer: ²⁵	M. P. Patel	*[signature]*	6-26-14
	Print Name	Sign Name	Date

Independent 3ʳᵈ Party Review Reqd? ²⁶	Yes ☒ No ☐ ITPR BY EPRI, COMMENTS INCORPORATED
Exelon Approver: ²⁷ Brion Ledger	*[signature]* Brian Ledger 6/27/14
Print Name	Sign Name Date

ATTACHMENT 2
Owner's Acceptance Review Checklist for External Design Analyses
Page 1A of 1C

Design Analysis No.: BYR13-176 _____ **Rev: 000**

No	Question	Instructions and Guidance	Yes / No / N/A
1	Do assumptions have sufficient documented rationale?	All Assumptions should be stated in clear terms with enough justification to confirm that the assumption is conservative. For example, 1) the exact value of a particular parameter may not be known or that parameter may be known to vary over the range of conditions covered by the Calculation. It is appropriate to represent or bound the parameter with an assumed value. 2) The predicted performance of a specific piece of equipment in lieu of actual test data. It is appropriate to use the documented opinion/position of a recognized expert on that equipment to represent predicted equipment performance. Consideration should also be given as to any qualification testing that may be needed to validate the Assumptions. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐
2	Are assumptions compatible with the way the plant is operated and with the licensing basis?	Ensure the documentation for source and rationale for the assumption supports the way the plant is currently or will be operated post change and they are not in conflict with any design parameters. If the Analysis purpose is to establish a new licensing basis, this question can be answered yes, if the assumption supports that new basis.	☒ ☐ ☐
3	Do all unverified assumptions have a tracking and closure mechanism in place?	If there are unverified assumptions without a tracking mechanism indicated, **then** create the tracking item either through an ATI or a work order attached to the implementing WO. Due dates for these actions need to support verification prior to the analysis becoming operational or the resultant plant change being op authorized.	☐ ☒ ☐ _As explained in Sec 3, Assumptions are not required to be verified._
4	Do the design inputs have sufficient rationale?	The origin of the input, or the source should be identified and be readily retrievable within Exelon's documentation system. If not, then the source should be attached to the analysis. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐
5	Are design inputs correct and reasonable with critical parameters identified, if appropriate?	The expectation is that an Exelon Engineer should be able to clearly understand which input parameters are critical to the outcome of the analysis. That is, what is the impact of a change in the parameter to the results of the analysis? If the impact is large, then that parameter is critical.	☒ ☐ ☐
6	Are design inputs compatible with the way the plant is operated and with the licensing basis?	Ensure the documentation for source and rationale for the inputs supports the way the plant is currently or will be operated post change and they are not in conflict with any design parameters.	☒ ☐ ☐

Design Analysis No.: BYR13-176 _____ **Rev:____000**

No	Question	Instructions and Guidance	Yes / No / N/A
7	Are Engineering Judgments clearly documented and justified?	See Section 2.13 in CC-AA-309 for the attributes that are sufficient to justify Engineering Judgment. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐ _See sec. 4 for references used_
8	Are Engineering Judgments compatible with the way the plant is operated and with the licensing basis?	Ensure the justification for the engineering judgment supports the way the plant is currently or will be operated post change and is not in conflict with any design parameters. If the Analysis purpose is to establish a new licensing basis, **then** this question can be answered yes, if the judgment supports that new basis.	☒ ☐ ☐ ✱
9	Do the results and conclusions satisfy the purpose and objective of the Design Analysis?	Why was the analysis being performed? Does the stated purpose match the expectation from Exelon on the proposed application of the results? If yes, **then** the analysis meets the needs of the contract.	☒ ☐ ☐
10	Are the results and conclusions compatible with the way the plant is operated and with the licensing basis?	Make sure that the results support the UFSAR defined system design and operating conditions, or they support a proposed change to those conditions. If the analysis supports a change, are all of the other changing documents included on the cover sheet as impacted documents?	☒ ☐ ☐
11	Have any limitations on the use of the results been identified and transmitted to the appropriate organizations?	Does the analysis support a temporary condition or procedure change? Make sure that any other documents needing to be updated are included and clearly delineated in the design analysis. Make sure that the cover sheet includes the other documents where the results of this analysis provide the input.	☒ ☐ ☐ ✱ ✱
12	Have margin impacts been identified and documented appropriately for any negative impacts (Reference ER-AA-2007)?	Make sure that the impacts to margin are clearly shown within the body of the analysis. If the analysis results in reduced margins ensure that this has been appropriately dispositioned in the EC being used to issue the analysis.	☒ ☐ ☐
13	Does the Design Analysis include the applicable design basis documentation?	Are there sufficient documents included to support the sources of input, and other reference material that is not readily retrievable in Exelon controlled Documents?	☒ ☐ ☐
14	Have all affected design analyses been documented on the Affected Documents List (ADL) for the associated Configuration Change?	Determine if sufficient searches have been performed to identify any related analyses that need to be revised along with the base analysis. It may be necessary to perform some basic searches to validate this.	☒ ☐ ☐
15	Do the sources of inputs **and** analysis methodology used meet committed technical and regulatory requirements?	Compare any referenced codes and standards to the current design basis and ensure that any differences are reconciled. If the input sources **or** analysis methodology are based on an out-of-date methodology or code, additional reconciliation may be required if the site has since committed to a more recent code	☒ ☐ ☐

✱ Item-8- Loop is evaluated in UFSAR. This is LOP and as a part of EC, it will be evaluated in UFSAR. But end result is the same

✱ ✱ - As identified in sec. 9.1 changes impacting this analysis consid should be in Items 11 & 17 loop to identify any zone-2 fault clearing time increase. Document this with consid. Also procedure may need revision to caution any EDMS condition 2 loads above 1 unit. It is ok at present & answer reflects present condition.

Design Analysis No.: BYR13-176 _____ **Rev:____000**

No	Question	Instructions and Guidance	Yes / No / N/A
16	Have vendor supporting technical documents and references (including GE DRFs) been reviewed when necessary?	Based on the risk assessment performed during the pre-job brief for the analysis (per HU-AA-1212), ensure that sufficient reviews of any supporting documents not provided with the final analysis are performed.	☒ ☐ ☐
17	Do operational limits support assumptions and inputs?	Ensure the Tech Specs, Operating Procedures, etc. contain operational limits that support the analysis assumptions and inputs.	☒ ☐ ☐ **

Create an SFMS entry as required by CC-AA-4008. SFMS Number: _45344._

Design Analysis Table of Contents

1. Purpose

The purpose of this calculation is to provide the logic and setting limits for a alogorithm that will be able to detect a single or double open phase in the high voltage (345kV) connection between the System Auxiliary Transformer (SATs) and the interconnection with the ring bus. An open phase event consists of a failure in the 3-phase supply in which one or two phase conductor(s) becomes disconnected from the 345kV transmission interconnection while the other phase conductor(s) remain intact.   This results in three different scenarios:

- The energized 345kV line shorts to ground on the transmission side, so there is fault current to be detected and cleared by the switchyard protection scheme. Since the switchyard protection scheme adequately protects against this condition, no further analysis is necessary.

- The energized 345kV line does not short to ground on the transmission side, so there may not be enough fault current to be detected and cleared by the switchyard protection scheme. The disconnected phase conductor(s) short to ground on the SAT end, connecting the SAT HV winding to ground.

- The energized 345kV line does not short to ground on the transmission side, so there may be no fault current to be detected and cleared by the switchyard protection scheme. The disconnected phase conductor(s) remain suspended above the ground at the SAT end and do not short to the ground on the SAT end.

This calculation examines the second and third scenarios, where the switchyard protection cannot be relied upon to clear the condition.

1.1.1 Algorithm Logic

The relaying scheme to detect the open phase consists of a customized SEL-451-5 relay with a user defined algorithm to monitor the currents on the high side of each SAT. The logic and setting limits for various parameters associated with the scheme are developed in this calculation. Evaluation of the relay and CT inaccuracies and the final setpoints are developed in calculation BYR13-177.

1.1.2 Determination of Setting Limits and Validation of Logic with EMTP Model

A model will be prepared using the Electro Magnetic Transients Program (EMTP-RV). The model includes a 3-phase representation of the system components, including the local transmission system, SATs and plant loads. The model is used to determine the SAT high side currents during various transmission and station events (stuck pole, faults, open phase, motor start, etc).

2. Inputs

2.1 Station Model

2.1.1 Transformer Data (Ref. 4.2)

Excitation Current and Losses

	SAT 142-1	SAT 142-2	SAT 242-1	SAT 242-2
Positive sequence exciting current	0.12%	0.10%	0.14%	0.12%
3-phase power rating	38 MVA	38 MVA	38 MVA	38 MVA
Excitation loss	36.045 kW	35.76 kW	38.493 kW	36.953 kW

Winding Voltage Ratings

Winding 1 (H-Winding) V rating	345kV (line to line) / 199 kV (line to neutral)
Winding 2 (X-Winding) V rating	6.9kV (line to line) / 3.98 kV (line to neutral)
Winding 3 (Y-Winding) V rating	4.16kV (line to line) / 2.4 kV (line to neutral)

Positive Sequence Impedances

Winding Pair	Spos Rating (MVA)	SAT 142-1 P (kW)	SAT 142-1 Zpos (%)	SAT 142-2 P (kW)	SAT 142-2 Zpos (%)	SAT 242-1 P (kW)	SAT 242-1 Zpos (%)	SAT 242-2 P (kW)	SAT 242-2 Zpos (%)
1-2 (H-X)	38	151.41	12.2	150.76	12.0	152.16	12.3	152.65	12.3
1-3 (H-Y)	22	122.30	10.4	120.34	10.4	121.43	10.1	122.32	10.3
2-3 (X-Y)	22	145.44	19.2	154.88	19.6	152.9	19.4	152.38	19.5

The zero sequence values are shown separately in Assumption 3.3 and Attachment D.

2.1.2 Low Voltage Loading

480V Bus Loading Totals for Maximum Loading Cases based on ELMS data for Condition 2 (Summer Full Load), (Ref. 4.6). See Attachment F for more detail.

2.1.3 Medium Voltage Motors

Medium voltage motor parameters and loading are based on ELMS data (Ref. 4.6.2) and motor vendor documents. The motor parameters and their source are described in Attachment E.

2.1.4 Not Used

2.1.5 Auxiliary Transformer Data

All auxiliary transformer unit substations feeding 480V buses are listed in ELMS input report (Ref. 4.6.1). The impedance, X/R and MVA rating is given for each transformer. The R and X values in per unit for each transformer are calculated and entered in EMTP. See Attachment F for details.

2.1.6 Byron Units 1 & 2 Generator Data

Byron Units 1 & 2 Generator Data (Ref. 4.50)

Parameter	Value
kVA	1,361,000 kVA
Power Factor	0.9
Rated Power (calculated)	1,224,900 kW
kV	25 kV
Speed	1800 rpm (4 poles)
Field Amps	8986 A
Xd	1.7283 pu
X'dv	0.3355 pu
X"dv	0.2490 pu
Xq	1.6544 pu
X'q	0.4813 pu
X"q	0.2479 pu
X0	0.1750 pu
XLm	0.2321 pu
T'do	7.729 sec.
T"do	0.047 sec.
T'qo	0.859 sec.
T"qo	0.068 sec.
Ra	0.00103 ohms 0.00224 pu on 1361 MVA base
Total Unit H	4.31 Mw-Sec/MVA (Ref.4.50)
Reactive Capability @ Rated PF & Load (Ref. 4.52)	Max = 600 MVAR Min ≈ 40 MVAR (based on Min Excitation limit setting)

2.1.7   Byron Main Power Transformer (Ref. 4.53)

Parameter	1W	1E	2W	2E
Serial No.	7002822	7002541	7002722	7002727
Connection	YnD1	YnD1	YnD1	YnD1
HV	345 kV	345 kV	345 kV	345 kV
LV	23.7 kV	23.7 kV	23.7 kV	23.7 kV
Rated Power @ 55oC	625 MVA	625 MVA	625 MVA	625 MVA
R% @ 625 MVA	0.1692%	0.1718%	0.168%	0.1652%
X% @ 625 MVA	8.4583%	8.5883%	8.3983%	8.2583%
Imp% @ 625 MVA	8.46%	8.59%	8.40%	8.26%

2.1.8   Byron Unit 1 Unit Auxiliary Transformers (Ref. 4.53)

Unit 1 UAT Data

Parameter	Value	Value
UAT	141-1 (Unit 1)	141-2 (Unit 1)
Connection	DYn1Yn1	DYn1Yn1
H-Winding	23.7 kV	23.7 kV
X-Winding	6.9 kV	6.9 kV
Y-Winding	4.16 kV	4.16 kV
Rated Power (OA/FA/FOA @ 55°C)	H – 36/48/60 MVA	H – 36/48/60 MVA
	X – 22.8/30.4/38 MVA	X – 22.8/30.4/38 MVA
	Y – 13.2/17.6/22 MVA	Y – 13.2/17.6/22 MVA
R pu @ 36 MVA	H/X – 0.012126	H/X – 0.011984
	H/Y – 0.049468	H/Y – 0.049468
	X/Y – 0.085565	X/Y – 0.08457
X pu @ 36 MVA	H/X – 0.122559	H/X – 0.122573
	H/Y – 0.173069	H/Y – 0.173069
	X/Y – 0.341255	X/Y – 0.333067
Grounding	X – 3.33 ohms	X – 3.33 ohms
	Y – 2 ohms	Y – 2 ohms

2.1.9   Equipment Capacitances Upstream of SAT Primary Bushings

The circuit connecting the Byron 345 kV ring bus to the SAT common connection consists of a CCVT, Motor Operated Disconnect (MOD), a revenue meter, and a 345 kV overhead line. A disconnect switch connects each SAT primary 345 kV bushings to the common connection (Ref. 4.92) The overhead line from the switchyard to the SATs is comprised of 2156 kcmil ACSR conductor spaced 20 ft apart in a horizontal row (Ref. 4.90). Unit 2 has a longer, and more conservative for this calculation, line length of approximately 1000 ft (Ref. 4.91). The Outside Diameter (OD) of 2156 kcmil ACSR

conductor is 1.762 in (Ref. 4.73). The capacitance of this equipment is based on the maximum values given in Annex B of Reference 4.93, unless otherwise noted.

Phase to Ground Capacitance of Equipment

Equipment	Phase-to-Ground Capacitance (pF) From IEEE C57.Ref. 4.5
345 kV Motor Operated Disconnect	200 [Ref. 4.93 Table B.7]
Overhead Line	Calculated – Section 7.2
345 kV Revenue Meter VT	450 [Ref.4.93, Table B.3]
345 kV Revenue Meter CT	450 [Ref. 4.93, Table B.3]
345 kV Transformer Bushings	1200 [Ref. 4.93, Table B.2]
345kV CCVT	2200 [Ref. 4.93, Table B.3]

2.2 RCP Undervoltage Protection

The reactor coolant pump (RCP) undervoltage protection scheme has a pickup setting of 76.4% voltage (nominal 6.9 kV) (Ref.4.34).

2.3 345 kV Transmission Network Data

2.3.1 345 kV Transmission Data (Ref. 4.68).

Attachment A documents what information provided in this DIT is used for this analysis.

2.3.2 345 kV System Voltage Range

The 345 kV switchyard voltage has a range of 0.95 pu to 1.05 pu (Ref. 4.94)

2.3.3 345 kV System Impedance Range

The 345 kV transmission system has been modeled in EMTP based on the methodology outlined in Attachment A. The system impedance calculated in Attachment A is based on ASPEN fault duty reports provided by ComED

2.3.4 345 kV Network Relay Time Delay (Ref.4.71)

Zone 1 faults on the ComEd 345 kV network will be cleared in 3-5 cycles by the primary relays and in 9-13 cycles by the breaker failure relays. A breaker failure time delay of 9 cycles exists for zone 1 faults. Zone 2 faults will be cleared in ~0.45 seconds (27 cycles).

3. Assumptions

Assumptions Not Requiring Verification

3.1 LRC for $I_2{}^2$t heating

To evaluate the $I_2{}^2$t heating that motors experience during an open phase at the motor terminals, a locked rotor current of 7 p.u. will be assumed. This value is equal to the highest starting current rating of any specific motor modeled in this analysis (See Attachment E) and is at the high end of starting currents specified in NEMA MG-1 (Ref.4.3). A higher locked rotor current provides conservative results for $I_2{}^2$t heating analysis, therefore this assumption does not require verification.

3.2 Motor Parameters

3.2.1 Motor Circuit Model

The EMTP-RV Nameplate Calculator is used to construct the motor circuit models. Motor nameplate data is input to the EMTP program, which then creates a single cage with deep bar factor circuit model. A fitting algorithm in EMTP-RV constructs a motor

model that will accurately reflect both the steady state and dynamic function of the motor. The simulations used in this analysis examine low frequency electromechanical dynamics for which these models are well suited (Ref.4.80).

3.2.2 Minimum Load Motors

The following parameters are used for the medium voltage minimum load motor models. This lumped medium-voltage motor load is used in the EMTP model to asses the algorithm performance at the specified minimum load condition.

Parameter	Value	Parameter	Value
Power Factor:	90%	Locked Rotor Current:	640%
Efficiency:	98.5%	Starting Torque:	90%
%Slip:	0.65%	Number of Poles:	4

The power factor and efficiency are selected to obtain load current that is equal to the required minimum load . These are in the range of typical industry values with minimal impact on simulated results (Ref. 4.3, 4.48, 4.49). The minimum load lumped-motor does not stall during the analysis so the analysis is not sensitive to the starting current and moment of inertia parameters. Therefore, this assumption does not require verification.

3.2.3 Load Torque Curve

The load speed-torque curve for all induction motors is a typical curve for variable torque loads (e.g. centrifugal pumps, centrifugal compressors, and fans) and resembles the curves shown in Attachment BM of the Dresden Aux Power Calculation DRE04-0019 (Ref. 4.87). The Dresden motors are a similar size and functions as the Byron motors.

$$\text{Torque} = 0.1 - 0.91 \cdot \text{Speed} + 3.21 \cdot \text{Speed}^2 - 1.47 \cdot \text{Speed}^3$$

Load Speed vs. Torque

$y = -1.47x^3 + 3.21x^2 - 0.91x + 0.1$
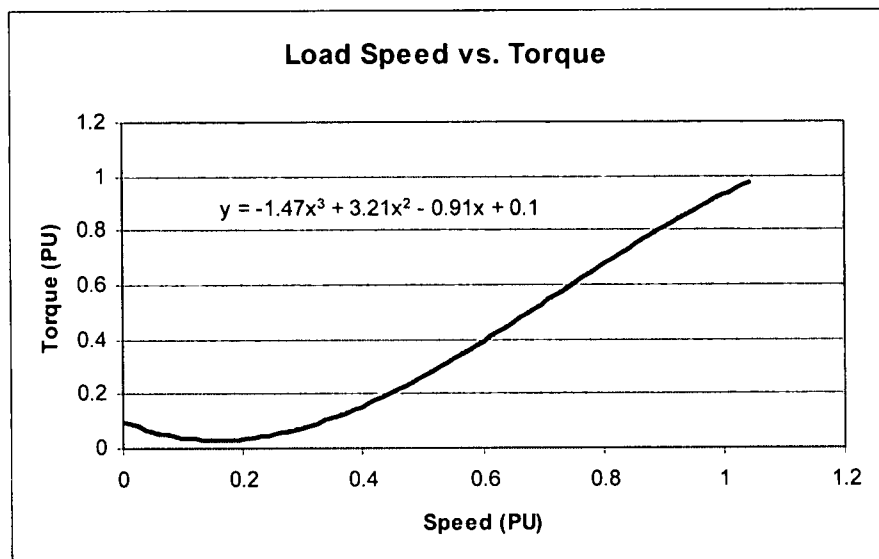
This curve will have a per unit torque of 0.93 at synchronous speed, which simply reflects that motors are typically oversized for their intended load. In order to use the BHP values in ELMS to produce the correct power draw, the curve will be shifted up so that a torque of 1 p.u. is produced at synchronous speed. Thus for Y=Torque and X=Speed, we have:

$$Y = 0.17 - 0.91 \cdot X + 3.21 \cdot X^2 - 1.47 \cdot X^3$$

Several medium voltage motors at Byron drive fans or rotary screw compressors. Torque curves for fans are similar to the pump curve above, while rotary screw torque curves will have a more concave shape. In the EMTP analysis, the running MV motors operate near synchronous speed. At this speed, the torque curves of different loads are very similar and any difference would not have significant effect on the results. Starting motors are included in the analysis to examine the effect that motor inrush current may have on the algorithm operation. The analysis does not examine the acceleration of the motor and load, so the torque curve used in that analysis is inconsequential.

It is also assumed for the purposes of this analysis that all low voltage lumped motor loads (which include pumps, fans, compressors, etc.) have the load torque equation as illustrated above. Although the curve illustrated above is not an actual representation of a load torque for these types of loads in the low speed region, it is accurate during steady state speed. Since the lumped low voltage loads will be operating at the steady state speed and the calculation conclusion shows the algorithm to be insensitive to load, this assumption is valid and does not require verification

3.2.4   Lumped Loads

Some medium voltage and all low voltage motors are modeled as lumped motors. Weighted averages of the power factor and efficiency of the motors being EMTP model into the composite model are calculated. These average values are used in the creation of the composite model in order to closely match the Watts and VARs drawn at the 480V load center. A starting current of 625% is usually used since this is representative of the LRC for motors of this size (Ref. 4.12. In several cases a starting current between 550% and 650% is selected to allow the EMTP-RV Nameplate Calculator to converge. A full load slip of 0.5% and an H constant of 0.75 (Ref. 4.12) are assumed to complete the model. All values used are typical and do not have a significant effect on the calculation since these motors operate in steady state and transient behavior is not analyzed, therefore this assumption is valid and does not require verification.

3.2.5   Synchronous Motors

There are three synchronous motors operating during the maximum loading scenario: Circulating water pumps A, B, and C. All three are identical with the electrical parameters outlined below. The synchronous motors are included in the model to provide accurate power flows on the auxiliary system. Therefore, the typical values provided below are sufficient. The model is not used to evaluate the dynamic operation of the synchronous motors; however some transients that are modeled may cause the motors to fall out of step. To ensure that the effect of an out of step motor's effect on the algorithm is examined, the motors are not tripped until the algorithm time delay has been exceeded. See the synchronous motor description in Attachment E for more detail.

Synchronous Motor Parameters	
Parameter	**Value**
Armature Resistance, Ra	= 0.0025 [Table 4 of Ref.4.47]
Zero Sequence Reactance, Xo	= 0.113 [Table 4 of Ref. 4.47]
Armature Leakage Reactance, Xl	= 0.15 [Typical]
d-axis Reactance, Xd	= 1.028 [Table 4 of Ref.4.47]
d-axis Transient Reactance, X'd	= 0.34 [Table 4 of Ref. 4.47]
d-axis Subtransient Reactance, X"d	= 0.253 [Table 4 of Ref.4.47]
Open Circuit Transient d-axis time constant, T'd0	= 7.5 seconds [Figure 73 of Ref. 4.47]
Open Circuit Subtransient d-axis Time Constant, T"d0	= 0.07 seconds [Typical]
q-axis Reactance, Xq	= 0.653 [Table 3-2 of Ref. 4.48]

Synchronous Motor Parameters	
Parameter	**Value**
q-axis Transient Reactance, X'q	= 0 [Table 3-2 of Ref.4.48]
q-axis Subtransient Reactance, X"q	= 0.298 [Table 3-2 of Ref. 4.48]
Open Circuit Transient q-axis time constant, T'q0	= 3 [Table 3-2 of Ref. 4.48]
Open Circuit Subtransient q-axis Time Constant, T"q0	= 0.090 [Table 3-2 of Ref. 4.48]

3.3 SAT Model

A single EMTP model is developed for all four SATs installed at Byron. The transformers are identical units, purchased under the same specification and built on the same production run. The SAT test reports in Attachment D show that the positive sequence excitation and impedance of the different transformers are very similar. In addition, the transformer test report indicates that the zero sequence short circuit tests were only performed on the transformer with serial number 6311-317 -- Byron U1, SAT 142-2 (Ref. 4.2.2). Likewise ABB has provided a single set of zero sequence excitation values for the common transformer design. Therefore, individual transformer models would be nearly identical. The calculation concludes that the algorithm will not be sensitive to small changes in the pant load that would be observed by individual SAT models, therefore a single model is acceptable.

3.4 Motor Saturation

For all motors, saturation is not simulated and saturation of leakage inductances is not simulated. The auxiliary system motors will not be subjected to the excessive voltages or frequencies that could cause saturation. Therefore, this assumption does not require verification.

3.5 Non-Linear Magnetization

The non-linear magnetization branch is excluded for all transformers. The auxiliary system transformers will not be subjected to the excessive voltages or frequencies that could cause saturation. In addition, the relay trip contacts are opened during transformer energization. Thus the algorithm will not be subjected to transformer magnetizing inrush current.

3.6 Unused

3.7 Motor Inertia

For all motors where data was unavailable the total inertia of the motor, coupling, and mechanical load was assumed to be 0.75. See reference 4.88.

3.8 LOCA Lumped Load

The motors that are EMTP model to construct the LOCA block start lumped motors are listed in Attachment F, and in aggregate exceed the motors examined in EC 365038 "Byron Block Load Starting". The purpose of the LOCA block start motors is to examine the effects that a block start may have on the algorithm. Considering the calculation results showing the algorithm to be not sensitive to starting motors, using a lumped motor for LOCA loads is acceptable.

3.9 Unused

3.10 Excitation System

The Byron excitation system is modeled with the SEXS (simple excitation system) model based on engineering judgment. This model has the general characteristics of a wide

variety of properly tuned excitation systems and can be used where an excitation systems detailed design is not known. Typical parameters for this model that represent an unknown but well-tuned excitation system are shown in Reference 4.53.

3.11 Source Impedance

The maximum voltage source model (used to represent the maximum grid source voltage magnitude and maximum short-circuit strength) is assumed to be an infinite source. This is acceptable since the SAT impedances are orders of magnitudes larger than the system impedances. Therefore, this assumption will not impact the results. For the unbalanced source, the magnitude and angle of the phase voltages are adjusted to apply the maximum expected zero and negative sequence voltages directly to the primary terminals of the transformer. The maximum expected zero and negative sequence switchyard voltages are determined in Attachment A. The source impedance for the minimum voltage source model (used to represent the minimum grid source voltage magnitude and minimum short-circuit strength) is determined in Attachment A.

3.12 Bus Transfer Timing

A circuit breaker total clearing time of 4.8 cycles (80 ms) and a dead bus time of 4.3 cycles (72 ms) is used in the fast bus transfer analysis, based on Figure 1 of Reference 4.12. The circuit breaker total clearing is based on the opening time plus arcing time. The dead bus time is based on the dead bus time with arcing. Arcing time is included because the 6.9 kV and 4 kV bus voltages will be close to nominal voltage during an open phase on the high voltage side of the SAT. Table 1 below shows a summary of the bus transfer timing sequence.

Table 1 – Post Open Phase Bus Transfer Timing Sequence [Ref. 4.12]

Action	Affected Bus(es)	Action Time (ms)
Open Phase Event Occurs	Energized	t+0
Open Phase Relay Trip	Energized	t+500
Circuit Breaker Opens & Arcing Extinguished	De-energized	t+580
Bus Transfer Complete (Breaker Closes)	Energized	t+652

Assumptions Requiring Verification

None

4. References

4.1   Not Used

4.2   SAT Test Reports

      4.2.1   Test report for SAT142-1, serial number 6311-321, performed on 9/07/1979 (Copy provided in Attachment D).

      4.2.2   Test report for SAT142-2, serial number 6311-317, performed on 4/17/1978 (Copy provided in Attachment D).

      4.2.3   Test report for SAT242-1, serial number 6311-320, performed on 9/27/1979 (Copy provided in Attachment D).

      4.2.4   Test report for SAT242-2, serial number 6311-318, performed on 9/06/1979 (Copy provided in Attachment D).

4.3   NEMA MG-1, Motors and Generators, Revision 1, 2007

4.4   Calc for System Auxiliary Transformer Loading, No. 19-AK-3, Rev. 0, 5/14/93.

4.5   One line 345kV Bus Diagram, Drawing number 6E-0-4000, Rev. G

4.6   ELMS – DIT No. S040-BYR-13080-00

      4.6.1   Input Reports B1A4141.MA4

      4.6.2   Output Report B1A414.MA4

4.7   Not Used

4.8   Not Used

4.9   Commonwealth Edison Company, 2010 Power Grid Voltage Analysis for Byron Generating Station, February 2010.

4.10   Not Used

4.11   Walkdown Observation Record, EC No.: 387608/387609, Byron U1 and U2 Serial Numbers (Copy provided in Attachment D)

4.12   Commonwealth Edison Co. Byron/Braidwood Units 1 and 2 Position Paper Bus Transfer dated April 6, 1993 (Copy provided in Attachment C)

References for Medium Voltage (MV) Motor Parameters

4.13   Calculation 19-AN-3 Revision 15

4.14   Byron VTIP F-2323, "Ingersoll Rand – Air Compressors

4.15   Electric Machinery Dwg 131C695M Sh 1 Rev C; Outline Syn Motor Dripproof Brushless DCX 1111

4.16   Byron VTIP F-2437

4.17   Induction Motor Performance, 19CB Size "BX", Ideal Electric and Manufacturing Co.

4.18   Motor Torque VS. Speed, 19CB Size "BX", Ideal Electric and Manufacturing Co.

4.19   Thermal Limit and Acceleration Curve, 19CB Size "BX", Ideal Electric and Manufacturing Co.

4.20   Induction Motor Performance, 19EA Size HD2 (DB), Ideal Electric and Manufacturing Co.

4.21   Motor Torque VS. Speed, 19EA Size HD2 (DB), Ideal Electric and Manufacturing Co.

4.22   Thermal Limit and Acceleration Curve, 19EA Size HD2 (DB), Ideal Electric and Manufacturing Co.

4.23   Induction Motor Performance, 19EA Size HD9 (DJ), Ideal Electric and Manufacturing Co.

4.24   Motor Torque VS. Speed, 19EA Size HD9 (DJ), Ideal Electric and Manufacturing Co.

4.25   Thermal Limit and Acceleration Curve, 19EA Size HD9 (DJ), Ideal Electric and Manufacturing Co.

4.26   Induction Motor Performance, 19FA Size HD12 (DM), Ideal Electric and Manufacturing Co.

4.27   Motor Torque VS. Speed, 19FA Size HD12 (DM), Ideal Electric and Manufacturing Co.

4.28   Thermal Limit and Acceleration Curve, 19FA Size HD12 (DM), Ideal Electric and Manufacturing Co.

4.29   Electric Machinery Dwg EE9877 dated 4/16/1979 (Speed – torque curve)

4.30   Electric Machinery Dwg 131C520M, Outline Drawing – Induction Motor, drip proof, Rev F

4.31   Byron VTIP F-2089

4.32   Calculation BYR98-122 Rev 0 (nameplate data, 1RC01PA / 1RC01PB / 1RC01PC / 1RC01PD)

4.33   Westinghouse Dwg 115E120 Sh 1 Rev A dated 05/01/1995 (inertia, 1RC01PA / 1RC01PB / 1RC01PC / 1RC01PD)

4.34   Calculation 19-AN-2 Rev 7

4.35   Joy Manufacturing Bill of Material 500826-2231 dated 2/8/79

4.36   Reliance Electric AC Motor Performance Data, V37527.000 dated 3/7/79

4.37   Joy Manufacturing Bill of Material 500826-2232 dated 2/8/79

4.38   Reliance Electric AC Motor Performance Data, V37962.000 dated 3/7/79

4.39   Westinghouse Electric Corporation S.O. No. 75-F-32352 dated 11/13/73

4.40   Westinghouse Electric Corporation Curve No. 663915

4.41   EC 390058 "CW Excitation Cabinet Upgrade Unit 2" Rev 000 Attachment B

4.42   Ingersoll Rand Curve No DHC770322-1 dated 3/22/1977

4.43   Louis Allis Curve No. 18562-1

4.44   Louis Allis Curve No. 18562-2

4.45   Louis Allis Curve No. 18562-3

4.46   Network Protection and Automation Guide by Alstom, First Edition.

4.47   Electrical Transmission and Distribution Reference Book, Central Station Engineers of the Westinghouse Electric Corporation

4.48   EPRI 1015241 "Power Plant Modeling and Parameter Derivation for Power Systems Studies", June 2007

4.49   IEEE paper "Protection of 3-Phase Motors Against Single-Phase Operation", L. Gleason and W. Elmore, December 1958 (Copy provided in Attachment C)

End of References for Medium Voltage (MV) Motor Parameters

4.50   DIT-BRW-2007-0019-04 (Generator Impedances and Time Constants)

4.51   Dwg. No. 6E-2-4001A, Rev N, "Station One Line Diagram"

4.52   Generator Capability Curves and Underexcitation Limiter Settings, Doc # BCB-1, Figure 20a, Revision 3 [Copy provided in Attachment E]

4.53   PSS/E Tutorial on Exciter information

4.54   Analysis No. Calc 19-AN-1, Rev 5B (Attach. C – DIT-BYR-2005-017)

4.55   through 4.67 Not Used

4.68   IEEE C37.013 – 1997 (R2008), "IEEE Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis"

4.69   Not Used

4.70   Not Used

4.71   Email from William J. Miller to John Bojan and Alan Hernadez on 9/27/2012, "RE: CONCERN: Time Delay Setting"

4.72   Not Used

4.73   Overhead Conductor Manual by Southwire, dated 1994.

4.74   Not Used

4.75   Not Used

4.76   DIT No. EE-TXP-01-BYS-2013-001-00, "Byron Area Transmission Model Data – Transmission Line and Fault Duty Data for Loss of Single Phase Study"

4.77   Not Used

4.78   Not Used

4.79   EPRI Power Plant Electrical Reference Series, Volume 6, Motors

4.80   IEEE PES Special Publication, TP-133-0, Modeling and Analysis of System Transients Using Digital Programs

4.81   Byron – Generator Transient Stability Study and Interim Generator Deliverability Study for Byron Generating Stations Units 1 and 2 MUR Upgrade, PJM Queue Positions V4-046 and V4-047 [Select pages provided in Attachment E]

4.82   Not Used

4.83   Not Used

4.84   EC 365038, Rev. 000 "Byron Block Start Loading"

4.85   CIGRE Technical Brochure 39, "Guidelines for Representation of Network Elements when Calculating Transients" – Working Group 02 (internal overvoltages) of Study Committee 33 (Overvoltages and Insulation Coordination)

4.86   Charging Current Data for Guesswork-Free Design of High Resistance Grounded Systems, IEEE Transactions on Industry Applications, Vol. IA-15, No. 2, March/April 1979.

4.87   Calculation DRE04-0019, Rev. 04 "Auxiliary Power Analysis for Dresden Unit 3", 09/14/2011

4.88   Yaeger, K. E. "Bus Transfer of Multiple Induction Motor Loads in a 400 MW Fossil Power Plant.", IEEE Transactions on Energy Conversion, September, 1988, pp 451-457.

4.89   Calculation 19-AN-4 "Switchgear Relay Settings"

4.90   Drawing 6E-0-1023B, Rev. E, "Plan of 345kV Switchyard Areas B & C"

4.91   Drawing M-3, Rev. U "Plant Development"

4.92   Drawing 6E-0-4000B, Rev. L "One Line Relay & Instrument Diagram of 345kV Bus – 4, 5, 6, & 7"

4.93   IEEE Std C37.011-2011. "IEEE Guide for the Application of Transient Recovery Voltage for AC High-Voltage Circuit Breakers".

4.94   PJM, Manual 14B: PJM Region Transmission Planning Process, Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures Revision 27, 04/23/2014

5. Identification of Computer Programs

The following programs were run on S&L PC numbers ZL8771 and ZL7944 using Windows XP Professional, Version 2002, SP3 Operating System

5.1   ElectroMagnetic Transients Program – Restructured Version (EMTP-RV) Version 2.4, S&L Program Number 03.7.847-2.4. Validation documents for this program are maintained in the Sargent and Lundy software library.

```
┌──────────────────────────────────────────────┐
│ ┄  AppList Controlled Files Audit Trail - Short ...  [X] │
│ ┌────────────────────────────────────────────┐ │
│ │      Acronym: EMTP_RV                       │ │
│ │  S&L Program No.: 03.7.847-2.4              │ │
│ │       Status: N                Type: 2      │ │
│ │  Effective Date: 01-06-2014                 │ │
│ │  Execution Date: 03-12-2014  14:13          │ │
│ │  Controlled Folder: C:\Program Files\EMTPWorks 2.4\ │ │
│ │                                             │ │
│ │  Secondary Folder: (n/a)                    │ │
│ │                                             │ │
│ │  ┌──────────┐                               │ │
│ │  │   OK     │      Print       Long Form    │ │
│ │  └──────────┘                               │ │
│ └────────────────────────────────────────────┘ │
└──────────────────────────────────────────────┘
```
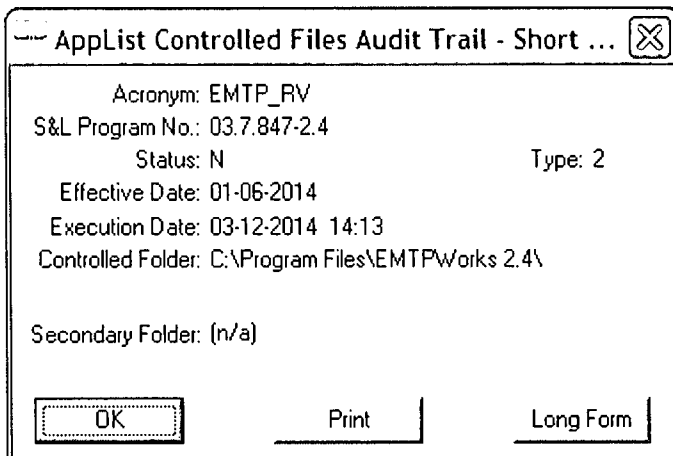
EMTP & Supplementary Files (See Attachments F and G)

Name △	Size	Type	Date Modified
1_BYR_Simple_script_rev0.dwj	34 KB	EMTPWorks JavaSc...	5/30/2014 7:10 PM
2_BYR_scriptvariables_rev0.dwj	15 KB	EMTPWorks JavaSc...	5/27/2014 9:22 AM
3_BYR_plantscriptfunctions_rev0.dwj	35 KB	EMTPWorks JavaSc...	5/28/2014 9:25 AM
4_SL_EMTP_FUNCTIONS_revB.dwj	20 KB	EMTPWorks JavaSc...	5/14/2014 5:05 PM
5_BYR_SourceCaseMatrix_rev0.dwj	5 KB	EMTPWorks JavaSc...	5/30/2014 7:08 PM
6_BYR_PlantCaseMatrix_rev0.dwj	33 KB	EMTPWorks JavaSc...	5/27/2014 1:06 PM
7_BYR_CombinedCaseMatrix_rev0.dwj	2 KB	EMTPWorks JavaSc...	5/27/2014 9:22 AM
BYR_Simple_R0.ecf	2,614 KB	EMTPWorks Design ...	5/30/2014 9:47 AM

6. Method of Analysis

This calculation uses the following steps to determine and verify an algorithm and settings that will be able to reliably and securely detect both single and double open phase events on the SAT high side.

- Propose an algorithm that can detect a single open phase using only the H winding current as input based on transformer electrical properties

- Propose an algorithm that can detect a double open phase using only the H winding current as input based on transformer electrical properties

- Estimate the bounding voltage unbalance possible on the transmission system

- Verify that the proposed algorithm is able to reliably detect an open phase by performing simulations using a full plant model that includes transmission system voltage variation and unbalance

- If necessary, adjust the algorithm logic and settings for correct performance based on the model results

- Determine the margin and setting limits that exists for each setpoint

- Determine a proper time delay that allows the algorithm to "ride through" grid transients, while still allowing a successful transfer to the UAT once an open phase is detected

6.1 Single Open Phase Logic

The algorithm logic for detecting a single open phase is divided into two strings in order to detect both a grounded open phase (Logic String 1) and an ungrounded open phase (Logic String 2). The logic is developed for a relay that measures the current in the H winding bushings.

6.1.1 Single Grounded Open Phase

The first logic string is designed to detect a grounded open phase. During a grounded open phase, the grounded phase of the transformer will be pulled towards 0 volts, while the other two phases remain near rated voltage. This voltage unbalance will cause significant zero sequence current to flow in the transformer regardless of the amount of secondary side load. The algorithm will use a time delay to provide coordination with transmission system relays. The proposed logic for detecting a grounded open phase is therefore:

IF
I_0>ZSCL1 (Zero Sequence Current Limit for Logic String 1)
THEN a grounded open phase is Detected

ZSCL1 is the algorithm setpoint that will be determined for this logic string and will be set above the highest possible I_0 when there is no open phase and below the lowest possible I_0 when there is a grounded open phase. This calculation considers grounded open phases with zero impedance to ground. The relay setting calculation will determine the Logic String 1 detection limit based on the final ZSCL1 setpoint (i.e. the maximum grounded open phase impedance that Logic String 1 can detect).

The zero sequence current that flows in the H windings of the transformer is largely dependent on the zero sequence magnetizing impedance of the transformer. For this reason, a detailed EMTP model of the transformer is developed and verified in Attachment D.

The limits for the ZSCL1 setting are described below:

ZSCL1 (Low Limit) – The lower setting limit for ZSCL1 is determined by the *maximum* zero sequence current that flows in the H windings when there is <u>no</u> open phase.

ZSCL1 (High Limit) – The upper limit for ZSCL1 is determined by the *minimum* zero sequence current that flows through the H windings during a grounded open phase.

6.1.2   Single Ungrounded Open Phase

A second logic string is added to detect a single ungrounded open phase. In a single ungrounded open phase, the magnetic coupling of the transformer core will allow the two healthy phases to impart the proper voltage onto the "open" H winding terminal. For an unloaded transformer, a balanced set of voltages will exist on the H terminals, and no zero sequence current flows in the H windings. Now, while the voltages on the three H terminals may be balanced, it is easy to see that the currents on these terminals cannot be balanced, since there is no current path for the opened phase. Therefore, the second logic string is based on the open (disconnected) phase not having any current flowing in it during an ungrounded open phase. In the following Boolean logic, it is considered that A phase is the open phase, and that $I_{A,B,C}$ refer to the individual phase magnitudes in Amps.

IF
$I_A = 0$ and $I_B > 0$ and $I_C > 0$
   THEN an Open Phase is Detected

This logic is immediately complicated by the fact that the microprocessor relay cannot reliably detect a zero current condition. Furthermore, a small amount of capacitive charging current may flow in the open phase due to the capacitance of equipment between the open phase fault location and the relay CT. Therefore it is necessary to replace the "0" in the above logic string with a relay setting that has taken into account the minimum current that the relay can detect and the maximum capacitive charging current during an ungrounded open phase. This setting will be referred to as MINDETC (Minimum Detection). It is also necessary to provide margin between what the relay will consider below MINDETC and above MINDETC, based on the minimum change in current that the relay can detect. This term will be referred to as LLDIFF (Low Level current Differentiation). With these two relay setting the Logic String 2 becomes:

IF
$I_A <$ MINDETC and $I_B >$ LLDIFF and $I_C >$ LLDIFF
   THEN an Open Phase is Detected

The MINDETC setting is above the excitation current of the transformer, it is therefore clear that some amount of load on the secondary windings is needed. The minimum amount of load required for detection will be referred to as MINLOAD.

6.1.2.1 Parallel Transformer Operation

At Byron, each unit has two identical SATs operated off a common feed from the switchyard. An open phase can – and did (at Byron) – occur on the common point prior to the "T" connection. Uneven transformer loading will cause a circulating current to exist in both SAT H windings even if an open phase exists upstream of the "T" connection. The circulating current exists in the SAT neutrals and the opened phase, which means that an Ia<MINDETC condition at the individual transformers does not exist. For this reason, it is necessary to not only monitor the six SAT phase currents (three for each

SAT), but also the phase currents flowing into the "T" connection from the switchyard. Following Kirchhoff's current law, this current can be calculated by simply taking the vectoral sum (I_{Vsum} in the diagram below) of SAT phase currents, so additional CTs are not required. The rest of this section will follow a convention where I_A is the open phase and the logic is written for the SAT_1 algorithm. The SAT_2 logic simply swaps the SAT_1 and SAT_2 terms.
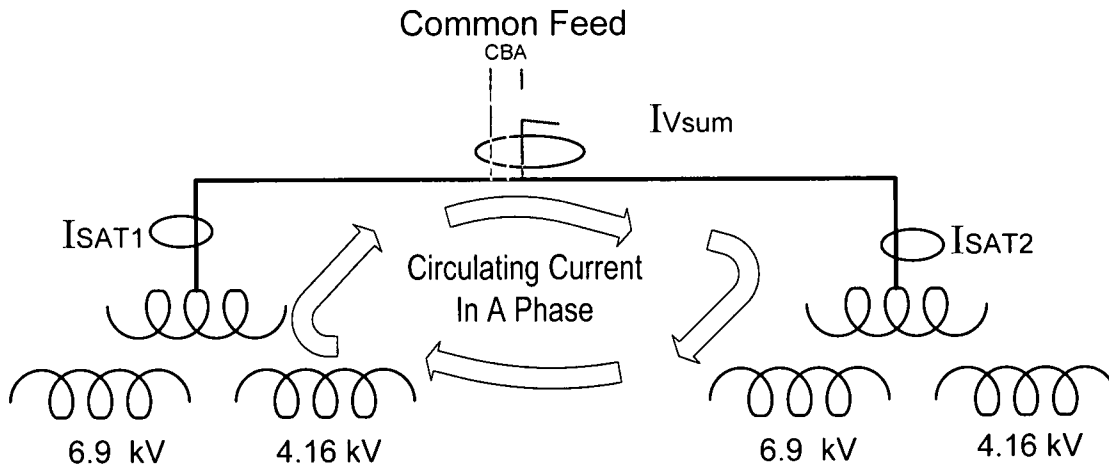
The logic string will be altered so that it checks for current unbalance in the common feed as well as current unbalance in the individual SAT feed. This logic will be able to detect an open phase at the common SAT feed.

IF
($I_{A\text{-}SAT1}$ < MINDETC and $I_{B\text{-}SAT1}$ >LLDIFF and $I_{C\text{-}SAT1}$ > LLDIFF) OR
($I_{A\text{-}Vsum}$ < MINDETC and $I_{B\text{-}Vsum}$ >LLDIFF and $I_{C\text{-}Vsum}$ > LLDIFF)
          THEN an Open Phase is Detected

Note that an open phase that affects only SAT_1 or SAT_2 could not result in a circulating current in the open phase – the open phase would exist below the "T" connection, so no path between the two transformers exists. Open phase events on the common SAT feed and an individual SAT feed are both examined using the plant EMTP model.

6.1.2.2 Logic String 2 Security Elements:

MINDETC and LLDIFF can detect all ungrounded open phases (with loading above MINLOAD). To ensure that the Logic String 2 open phase detection logic has detected a true open phase and not a condition that mimics the current unbalance seen during an open phase (e.g. an unbalanced fault), several additional logic elements and setpoint setting requirements are considered. These elements are specifically selected to distinguish a true open phse from a condition that has currents that mimic an open phase. These additions are examined in terms of the H winding phase current magnitudes and current sequence component magnitudes.

The Logic String 2 elements developed so far will be referred to as the detection elements, and the additional Logic String 2 elements will be referred to as the security elements. The detection elements will be used to determine if the transformer currents represent an open phase condition, i.e. an Open Phase has been *Detected*. However, the algorithm can be prevented from tripping until the security elements developed in this section are satisfied, i.e. Logic String 2 is *Secure* Thus Logic String 2 will become:

IF
(I_{A-SAT1} < MINDETC and I_{B-SAT1} >LLDIFF and I_{C-SAT1} > LLDIFF) OR
(I_{A-Vsum} < MINDETC and I_{B-Vsum} >LLDIFF and I_{C-Vsum} > LLDIFF)
>   **THEN an Open Phase is Detected**

AND
Logic String 2 Security Elements are Satisfied
>   **THEN Logic String 2 is Secure**

The Security elements must be satisfied before the algorithm can trip.

6.1.2.2.1   Not Used

6.1.2.2.2   Negative Sequence Current

A L-L fault on the secondary of an unloaded transformer will cause large currents in two of the H winding phases, and little current in the third phase. The L-L fault will also cause large amounts of negative sequence current to flow in the H windings, therefore an I_2 term, referred to as the Negative Sequence Current Limit for Logic String 2 (NSCL2) is added to the L2 logic string to provide security against L-L faults on the transformer secondary windings.

The NSCL2 Security Logic is:
I_2<NSCL2

Adding to Logic String 2:
IF
(I_{A-SAT1} < MINDETC and I_{B-SAT1} > LLDIFF and I_{C-SAT1} > LLDIFF) OR
(I_{A-Vsum} < MINDETC and I_{B-Vsum} > LLDIFF and I_{C-Vsum} > LLDIFF)
>   **THEN an Open Phase is Detected**

AND
I_2<NSCL2
>   **THEN Logic String 2 is Secure (for LL Faults)**

The limits for the NSCL2 setting are described below:

NSCL2 (Low Limit) – The lower setting limit for NSCL2 is determined by the *maximum* amount of negative sequence current that flows in the H windings during an open phase. The amount of I_2 is largely proportional to the amount of load on the transformer secondary windings.

NSCL2 (High Limit) – The upper limit for NSCL2 is determined by the *minimum* negative sequence current that flows through the H windings when there is *No* open phase during a L-L fault.

6.1.2.2.3   Zero Sequence Current

A zero sequence term, referred to as the Zero Sequence Current Limit for Logic String 2 (ZSCL2), provides security for sustained I_0 due to system unbalances, L-L faults on the SAT secondary, and L-G faults on the 480V system. The L2 logic string looks for one phase without current and two phases with current. A L-L fault or a 480V L-G fault will mimic a single ungrounded open phase because of the high current on two phases and low current on the remaining phase. These conditions will not have any I_0, but an ungrounded open phase will have I_0 provided the transformer is not unloaded. The ZSCL2 term allows the algorithm to differentiate between a fault that mimics an open phase and an actual open phase.

Zero sequence current that is nearly constant in magnitude and angle for longer than the algorithm time delay, or *sustained* I_0, in the transformer H windings is able to mimic a single ungrounded open phase by canceling any phase current that is 180 degrees out of phase with the I_0 current. In the illustration below, the "C" phase load current is partially canceled on the high side of the transformer by the I_0 present in the transformer H windings. Zero sequence current transients in the transformer H windings (e.g. for a ground fault on the grid) are not considered in this analysis because these transients are expected to be cleared by transmission line relays in less than the algorithm time delay [Ref. 4.71]. This analysis only considers sustained zero sequence current due to steady state power flows on an unbalanced grid. Attachment A contains the methodology and analysis of the sustained I_0 that may occur due to unbalances on the transmission network surrounding the power station.

Load Phasor   ┼   Background I_{Zero} ═   H Winding Phasor
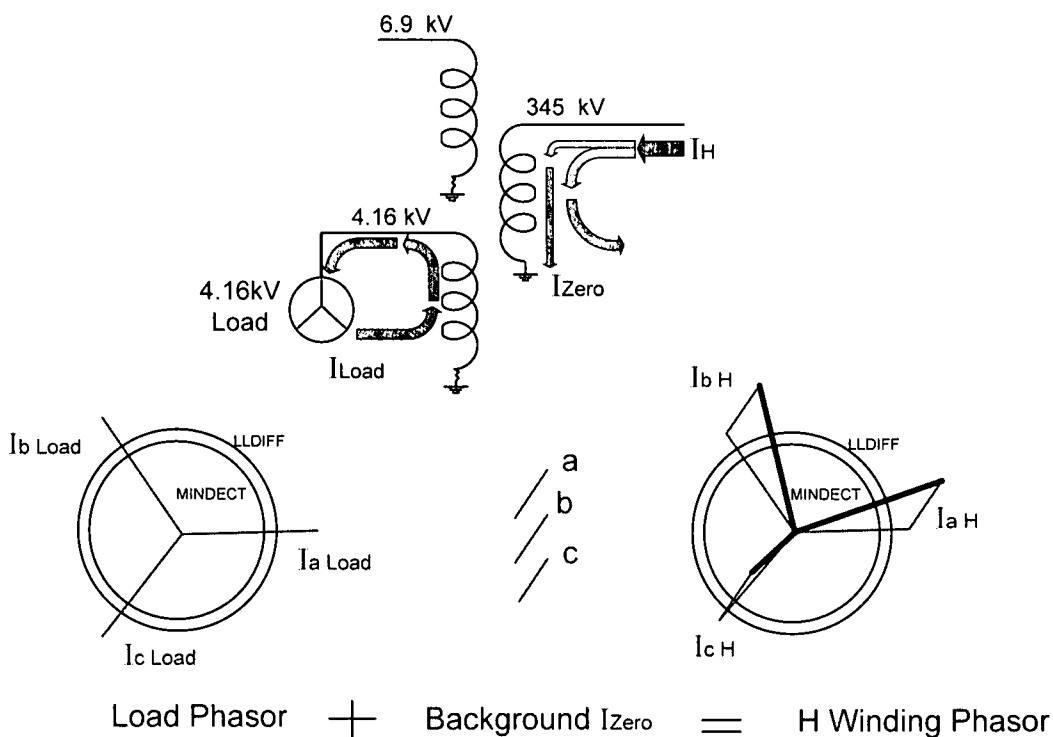
This cancellation of phase current shown in the above figure will only mimic an open phase – and possibly cause an inadvertent trip of the algorithm – at low loading levels. The amount of load (positive sequence current) needed to ensure that a phase current does not fall below MINDETC is equal to maximum amount of sustained zero sequence current (I_{0Max}) plus the MINDETC setting.

During a L-G fault at the low voltage level, the Delta-Y 4.16kV/480V unit substation transformers will have large current in two of the medium voltage phases and no current in the third, satisfying the L2 detection logic. However, the Delta transformer connection prevents any zero sequence current due to the L-G fault from reaching the open phase protection relay.

The ZSCL2 Security Logic is:

I_0 > **ZSCL2**

Adding to Logic String 2:

IF
($I_{A\text{-SAT1}}$ < MINDETC and $I_{B\text{-SAT1}}$ > LLDIFF and $I_{C\text{-SAT1}}$ > LLDIFF) OR
($I_{A\text{-Vsum}}$ < MINDETC and $I_{B\text{-Vsum}}$ > LLDIFF and $I_{C\text{-Vsum}}$ > LLDIFF)
　　　THEN an Open Phase is Detected

AND

I_2 < NSCL2
AND

I_0 > ZSCL2
　　　THEN Logic String 2 is Secure

The limits for the ZSCL2 setting are described below:

ZSCL2 (Low Limit) – The lower setting limit for ZSCL2 is determined by the *maximum* zero sequence current that flows in the H windings when there is <u>no</u> open phase event.

ZSCL2 (High Limit) – The upper limit for ZSCL2 is determined by the *minimum* zero sequence current that flows through the H windings during an ungrounded open phase.

6.2　Double Open Phase Logic

A double open phase event can be categorized into the following three categories:

- Double grounded open phase
- One ungrounded and one grounded open phase
- Double ungrounded open phase

In this section, each category of open phase will be described, and if necessary additional detection logic will be proposed for double open phase detection.

6.2.1　Double Grounded Open Phase

With both of the open phases grounded a substantial zero sequence current will flow in the faulted and healthy phases even under no load. The flux from the healthy phase will try to flow in the transformer legs of the two opened phases, however the two grounded phase conductors provide a path for current to flow from the grounded phase conductors through the H windings and back to the solidly grounded transformer neutral. The current will establish its own flux to oppose and force the magnetic flux from the healthy phase to flow in the transformer tank. The current will be equal in all three phases and primarily limited by the transformers zero sequence magnetizing impedance.

The level of fault current is high enough that the Logic String 1 for a single grounded open phase will also work for a double grounded open phase.

IF
I_0>ZSCL1 (Zero Sequence Current Limit for Logic String 1)
　　　THEN a grounded single open phase OR a grounded double open phase is
　　　Detected

Thus no additional logic is required for this scenario.

6.2.2 One Ungrounded and One Grounded Double Open Phase

Simulations show that a double open phase with one phase grounded alone does not cause significant fault current to flow in the transformer windings during a no load or light load conditions. Therefore, Logic String 1 is not able to detect this condition.

The healthy phase and grounded phase can have current flow in the H windings, while the ungrounded phase, since it is an open circuit, clearly cannot. Therefore the logic string to detect this condition will be identical to the Logic String 2 previously established for a single ungrounded open phase.

IF
(I_{A-SAT1} < MINDETC and I_{B-SAT1} >LLDIFF and I_{C-SAT1} > LLDIFF) OR
(I_{A-Vsum} < MINDETC and I_{B-Vsum} >LLDIFF and I_{C-Vsum} > LLDIFF)
          THEN a single ungrounded open phase OR a double grounded / ungrounded open phase is Detected.

Since this string uses the same detection logic, the security elements remain the same. The security elements established for a single open phase will not inhibit the tripping for a double open phase.

6.2.3 Double Ungrounded Open Phase

With two ungrounded open phases there will be no current flowing in the open circuited H windings of an unloaded transformer. Therefore this logic string will need to be similar to Logic String 2 and make use of MINDETC and LLDIFF logic terms.

Logic String 3 would have the following terms for a double open phase on phases A and B:

IF
I_A < MINDETC and I_B < MINDETC and I_C > LLDIFF
          THEN a double ungrounded open phase is Detected.

This string is similarly modified for parallel transformer operation to become:
IF
(I_{A-SAT1} < MINDETC and I_{B-SAT1} < MINDETC and I_{C-SAT1} > LLDIFF) OR
(I_{A-Vsum} < MINDETC and I_{B-Vsum} < MINDETC and I_{C-Vsum} > LLDIFF)
          THEN a double ungrounded open phase is Detected.

6.2.3.1 Ungrounded Double Open Phase Security

This string will be able to reliably detect a double open phase, however a L-G fault at the MV level, with no load on the transformer, could also mimic a double ungrounded open phase.

The security of the L3 detection logic during a L-G fault on an unloaded transformer will rely on the ground fault protection of the medium voltage distribution system. The main feeders to the medium voltage switchgear have ground fault protection that picks up at 200A with a time delay of 0.3 seconds [Ref. 4.89]. Therefore the existing ground protection scheme will clear the fault before the open phase relay picks up.

Similar to Logic String 2, the sustained zero sequence current could potentially mimic an open phase condition by causing one phase to be above LLDIFF while the other two remain below MINDETC. Therefore, a zero sequence current limit term is added.

This makes the entire Logic 3 String:

IF
($I_{A\text{-}SAT1}$ < MINDETC and $I_{B\text{-}SAT1}$ < MINDETC and $I_{C\text{-}SAT1}$ > LLDIFF) OR
($I_{A\text{-}Vsum}$ < MINDETC and $I_{B\text{-}Vsum}$ < MINDETC and $I_{C\text{-}Vsum}$ > LLDIFF)
   Then a double open phase is Detected

AND
I_0>ZSCL3
   Then the logic string is Secure

6.3   Minimum Load

As discussed in the previous section, when the algorithm is implemented in hardware, Logic String 2 and Logic String 3 require some amount of load to be on the transformer in order to detect phase current unbalances. This value is determined by the amount of load that will result in a high side phase current that is above MINDETC during normal operation and above LLDIFF during an open phase event.

Further, a certain amount of positive sequence current may need to be present in the transformer windings to ensure the relay is secure for all switchyard unbalance conditions as discussed in Section 6.1.2.2.3 The load required for this is considered when determining the minimum load in addition to the load needed to satisfy MINDETC. The relay settings calculation determines the final minimum loading level.

6.4   Modeling in EMTP

The Electro Magnetic Transients Program (EMTP-RV) is used to model the Byron Unit 1 SATs, plant loads and transmission system source. This program numerically solves the differential equations of the circuit to compute the actual time-domain waveforms for the voltages and currents. This approach has advantages over single-phase, frequency domain analysis software or conventional transient stability programs, such as PSSE or ETAP, in that it can model arbitrary, unbalanced phase arrangements, such as an open-phase event.

6.5   Transmission System Analysis

As discussed above, the several logic elements may be sensitive to voltage unbalance that exist in the switchyard. In order to provide algorithm settings that are not overly conservative, it is necessary to determine the bounding (minimum and maximum) levels of sequence voltage that may exist on the transmission network.

Unbalance is often defined in terms of a ratio of the maximum deviation of a phase voltage (or current) from the average of the total phases to the average of the phase voltage (or current), expressed in percent. Although voltage and current unbalance is often reported as a ratio, this analysis instead relies on the magnitude of the sequence voltages and currents at the switchyard because the algorithm logic depends upon the sequence currents in the transformer H winding.

The algorithm logic makes use of the symmetrical component sequence currents, namely, zero sequence and negative sequence currents in all Logic Strings, along with phase currents in Logic String 2 and Logic String 3. The magnitude of these sequence currents seen by the open phase detection algorithm, depends on the voltage unbalance in the Byron switchyard and the open phase condition.

An analysis of the voltage unbalance that may be present at the Byron switchyard is performed in Attachment A. The switchyard analysis uses a lumped model of the surrounding transmission system to determine the highest levels of voltage unbalance that may be present on the system due solely to transmission level power flows. The bounding values from this analysis will be used to develop and test the algorithm setting limits.

6.6   Plant Model

In order to provide a basis for the switchyard operating limits, account for interactions between the switchyard and the plant auxiliary system and provide an overall validation of the algorithm logic and setpoints, a EMTP model of the plant auxiliary system is developed. This model is used to simulate the following:

- Transformer excitation current unbalance in the presence of transmission system unbalance
- Open Phase Event followed by a Fast Bus Transfer
- Non-open phase events to establish algorithm limits for security
- Open phase events to establish algorithm limits for detection

The EMTP plant model will include two models of the open phase detection algorithm; both models will implement the logic described above. One algorithm model is set to the algorithm detection limits; the other algorithm model is set to the algorithm security limits.

6.6.1   Plant Auxiliary System Model and Analysis

The Unit 1 Auxiliary system loads were modeled using the ELMS data for Condition 2 Loading (see Attachment E). Each normally operating medium-voltage motor was modeled individually based on the data provided in Attachment E. Static loads were added and modeled as a single lumped PQ load at each bus. Low voltage buses were modeled with a single lumped motor and a single lumped PQ load connected to the low voltage side of each unit substation.

Full documentation of the EMTP model is provided in Attachment E.

6.6.2   Plant Operating Scenarios

The various plant configurations and operating scenarios are considered in this analysis are shown in Attachment B and includes medium voltage level faults, motor starts and various loading levels.

6.6.3   Open Phase Location

For Byron the following open phase locations were analyzed:

- The connection point of the SAT feed to the Switchyard Bus (upstream of common connection point)
- The feed from the common connection point to SAT 142-1 (downstream of the common connection point)

6.6.4   SAT Loading

The following loading conditions of the SATs are considered:

- No Load
- Minimum Load (see Section 6.3)
- Maximum ELMS loading (Condition 2 Summer Full Load)

- Single SAT Maximum Loading

6.6.4.1 No Load

The analysis includes cases where there is no load on the SAT. These cases demonstrate that the algorithm is both secure and able to detect a grounded open phase with no load on the transformer. Since the logic developed above clearly shows that the algorithm will not be able to detect an ungrounded open phase with no load on the SAT, no instances of this scenario are included.

6.6.4.2 Minimum Load

Cases that use minimum SAT load demonstrate that the algorithm is secure and able to detect ungrounded open phases at a minimum load level. A lumped load of approximately 0.65 MVA is used in the EMTP model. Since the algorithm logic does not require any load to detect a grounded open phase, there are no cases that combine minimum load with a grounded open phase.

6.6.4.3 Maximum Load

The maximum load used in the model is derived from ELMS Condition 2 (full load summer) loading. Maximum load cases include security, grounded and ungrounded open phase scenarios. These demonstrate proper algorithm operation at high loading levels.

6.6.4.4 Single SAT Configuration

At Byron it is possible to have only a single SAT in service, resulting in loading near the SAT's 65°C rise 67.2 MVA rating. Single SAT load cases include security, grounded and ungrounded open phase scenarios. These demonstrate proper relay operation at the upper limit of SAT loading.

6.6.4.5 Uneven SAT Loading

As described in the logic description above, uneven loading on parallel SATs can result in a circulating current during an open phase above the common SAT connection. Uneven SAT load cases include security and ungrounded open phase scenarios. A circulating current will not affect the grounded open phase logic, so those cases are not included.

6.6.4.6 Cross Tie Configuration

At Byron it is possible to cross-tie the safety bus of one unit with the safety bus of the other unit as described in calculation 19-AK-3 [Ref. 4.4]. In such a configuration, the SAT Y-Winding is loaded to near its 65°C rise rating of 24.6 MVA. The Single SAT loading configuration used in this analysis provides a loading on the Y winding near this amount (approximately 22 MVA), and in LOCA cases the loading on the Y winding exceeds what is analyzed in 19-AK-3, bounding the crosstie configuration. In addition, this calculation shows that the relay logic is not sensitive to heavy loading. Therefore, while the crosstie configuration is not explicitly modeled, it is bounded by this analysis.

6.6.5 Plant Model Runs

The bounding sequence voltages are determined in Attachment A. These voltage sources are combined with each of the plant operating scenarios. The algorithm model operation, currents and any other useful information is recorded and examined to ensure proper algorithm operation.

6.7   Algorithm Logic and Setpoint Limits

The results of the detailed model runs are examined to ensure the proposed algorithm logic will be able to detect all open phases. Each algorithm setpoint is examined to determine the range of its setpoint that will provide proper algorithm operation. Two algorithm setting limits, a low limit and a high limit, are given for each setpoint. These setting limits are provided to the relay setting calculation to provide final relay settings.

6.8   Algorithm Trip Time Delay and Post Open Phase SAT to UAT Bus Transfer

The microprocessor relay open phase protection scheme contains an algorithm to detect the open phase condition on the System Auxiliary Transformer (SAT) feed and trip the SAT. In order to ensure that this scheme is secure from tripping in the event of transmission line faults, a time delay is necessary to allow the transmission protection systems to clear the faults first.

Following the open phase detection and SAT trip, the SAT loads will be transferred to the Unit Auxiliary Transformers (UATs). In order for the post open phase bus transfer to be successful the following parameters are examined:

- Torque Developed by Motor During Bus Transfer

- Current Drawn By Motors During Bus Transfer

- Reactor Coolant Pump Undervoltage Protection

- Reacceleration of all Medium Voltage Motors

Therefore the lower bound of the time delay will be long enough to provide coordination with the transmission system, while the upper bound will be short enough to allow a successful bus transfer to the UATs after an open phase is detected.

6.9 I_2 Heating

During an open phase event, before the condition is detected and a bus transfer is initiated, the motor may be subject to voltage unbalance and excessive negative sequence (I_2) current. The negative sequence current will cause additional heating of the motors. The algorithm time delay will limit the motors' exposure to negative sequence current to 30-cycles and prevent excessive heating of the motors. This evaluation is included in Section 7.7.

6.10   UAT to SAT Transfer for Algorithm Security

The purpose of the UAT to SAT cases is to demonstrate the security of the open phase detection algorithm during this transfer. The bus transfer is a balanced operation similar to a large motor start, so it is not expected to cause a false detection.

6.11   Not Used

6.12   Capacitive Charging Current

As discussed in Section 6.1.2, the current on an ungrounded open phase may be nonzero due to the voltage on the open transformer bushing and the capacitance of equipment between the open phase fault location and the open phase relay CTs. The EMTP plant model includes a three-phase shunt capacitor to represent the total equipment capacitance for all equipment within the zone of protection of the open phase relay. The analysis verifies that the capacitive charging current during an open phase is less than the minimum current the relay can detect (MINDETC). The relay setting calculation determines the maximum phase-to-ground capacitance that may be connected within the zone of protection of the open phase detection relay.

7. Calculation

Attachment A contains the methodology, analysis and results for the local transmission system unbalances. The methodology and analysis of the detailed plant model EMTP simulation, and the results of the bus transfer analyses are presented in this section, and the results are contained in Attachment B.

7.1   Simplified Transmission Analysis

The system analysis provided the expected bounding negative and zero sequence voltages to support the open phase detection algorithm settings as discussed in Section 6. These bounding voltages are used in conjunction with both the simple and detailed plant models to provide a representation of the open phase detection algorithm's behavior for security and detection cases.

7.1.1   Bounding Sequence Voltages

The bounding sequence voltage magnitudes based on the transmission system model analysis are summarized below. The derivation of these limits is provided in Attachment A.

Bounding System Sequence Voltages

	Both Units Offline	Single Unit Online
Zero Sequence (V0)	1420 V	491 V
Positive Sequence (V1)	201830 V	206020V
Negative Sequence (V2)	4000 V	3443 V

7.2   Total Capacitance of Equipment Upstream of SATs [Ref. Section 2.1.9]

The capacitance per unit length of the line from the Switchyard to the SATs is calculated using the following equation [Ref. 4.93]:

$$C = \frac{2\pi\varepsilon_0}{\ln\left(\dfrac{d}{r}\right)} F/m ,$$

Where d is the equivalent phase spacing and r is the outside radius of the 2156 kcmil ACSR conductor (r = 1.762 in / 2 = 0.881 in). The equivalent phase spacing (geometric mean distance) is calculated as: $d = \sqrt[3]{D_{ab}D_{bc}D_{ca}}$ where D_{ab}, D_{bc}, and D_{ca} are the distances between phase conductors (phases A-B, B-C, and C-A, respectively). Thus, the total capacitance of the line is calculated as follows:

$$C = \frac{2\pi\varepsilon_0}{\ln\left(\dfrac{\sqrt[3]{20ft \cdot 20ft \cdot 40ft}}{0.881in} \cdot \dfrac{12in}{ft}\right)} \frac{F}{m} \cdot \frac{0.3048m}{ft} \cdot 1000ft = 2900pF$$

The total capacitance of equipment within the zone of protection of the open phase detection relay is therefore:

Capacitance of Equipment Upstream of SATs	
Common Equipment	**Phase-to-Ground Capacitance (pF)**
345 kV Disconnect	200
1000ft of Overhead Line	2900
345 kV Revenue Meter VT	450
345 kV Revenue Meter CT	450
345kV CCVT	2200
Total Capacitance	**6200 at Common SAT Connection**
Individual SAT Equipment	
345 kV Transformer Bushings	1200 on each SAT
345 kV Disconnect	200 on each SAT
Total Capacitance	**1400 on each SAT**

7.3   Setpoint Limits

The results of the EMTP model confirm that the algorithm logic developed in earlier sections is able to reliably detect an open phase event.

In the following section, the final setting limits of the algorithm setpoints are described. Each setting limit is selected such that a algorithm setpoint between the lower and upper limit will ensure proper algorithm operation.

7.3.1   Logic String 1

7.3.1.1 ZSCL1 Setpoint Limits

The EMTP model runs provide the following setting limits for ZSCL1:

Setting Limit	Description	Bounding Scenario	Ia	Ib	Ic	I1	I2	I0
ZSCL1 Low Limit	Maximum non-OP I0	Case 2316 - L-G Fault with No Load	25.00	0.47	0.50	8.20	8.14	8.65
ZSCL1 High Limit	Minimum Single GOP I0	Case 394- Grounded Open Phae A, No Load, Low Voltage	29.87	29.84	29.93	0.04	0.02	29.88
	Minimum Double GOP I0	Case 440 - Double Grounded Open Phases BC, Max Load, Motor Start	178.99	31.58	61.05	71.10	79.18	29.70

The low limit for ZSCL1 is selected to ensure the algorithm is secure during L-G faults. The high limit for ZSCL1 is selected to ensure the algorithm detects a solidly grounded open phase condition. Note the addition of impedance in the ground path may result in zero sequence current that is less than the high limit for ZSCL1. For maximum reliability, it is recommended that ZSCL1 be set as close as possible to the low limit. The relay setting calculation determines the maximum open phase to ground impedance that the scheme can reliably detect based on the final setpoint. The bounding limits for ZSCL1 determined from the EMTP analysis are shown below:

ZSCL1 (Low Limit) = 8.65 A
ZSCL1 (High Limit) = 29.70 A

7.3.2 Logic String 2

7.3.2.1 MINDECT Setpoint Limits

This calculation will use a minimum MINDETC setting of 0.8 A. The MINDETC setting is the minimum amount of current the relay is able to reliably detect. Since this is a function of the relay and CT hardware – and not the power system – this setpoint does not have separate Security and Detection limits.

MINDETC (Security & Detection) = 0.8 A

Phase-to-ground capacitance of equipment between the ungrounded single open phase fault location and the relay CTs can cause the current in the open phase to be non-zero. The open phase current was less than the preliminary MINDETC setpoint of 0.8 A. Therefore, capacitive charging current will not affect the reliability of the detection algorithm.

Setting Limit	Description	Bounding Scenario	Ia	Ib	Ic	I1	I2	I0
MINDECT Low Limit	Relay Capability	Setting determined by relay sensitivity, error and CT ratio						
	Maximum Single Ungrounded Open Phase Current	Case 52, Source 1, Min Load, Ungrounded Open Phase A at Common Connection	0.48	3.71	3.24	n/a	n/a	n/a
	Maximum Double Ungrounded Open Phase Current	Case 88, Source 1, Min Load, Double Ungrounded Open Phase AB at Common Connection	0.52	0.40	6.76	n/a	n/a	n/a

7.3.2.2 LLDIFF Setpoint Limits

The EMTP model runs provide the following limiting cases for LLDIFF:

Setting Limit	Description	Bounding Scenario	Pre-OP I1	Ia	Ib	Ic	I1	I2	I0
LLDIFF Low Limit	Adequate Separation from MINDECT	Determined in Relay Setting Calculation							
LLDIFF High Limit	Minimum healthy Phase Current during an Ungrounded Open Phase	Case 5004, Min Load, UG OP C	1.16	2.13	1.45	0.33	1.14	0.16	0.96
		Case 435, Double Open Phase, Min Load, GND OP C and UG OP A	1.21	1.65	56.65	11.37	18.23	17.16	22.07
		Case 5039, Max V, Min Motor Load, DOP UG CA	1.16	3.50	0.37	0.28	1.22	1.18	1.13

The lowest setting of LLDIFF is dependent on the relay hardware. The highest possible LLDIFF setting is dependent on how much the current in the healthy phases will increase during an open phase (the ratio of the positive sequence current before the open phase to the healthy phase currents after the open phase is referred to as the *Increase Factor*). The EMTP analysis results show that the *minimum* increase in healthy phase current during a single or double ungrounded open phase (the *Increase Factor*) was by a factor of 1.45 A / 1.16 A = 1.25

IncreaseFactor = 1.25

7.3.2.3 NSCL2 Setpoint Limits

The model runs provide the following limiting cases for NSCL2:

Setting Limit	Description	Bounding Scenario	Ia	Ib	Ic	I1	I2	I0
NSCL2 Low Limit	Maximum Ungrounded Open Phase I2	Case 461- Ungrounded Open Phase B, Max Loading, LOCA	240.54	0.05	243.38	154.12	118.25	35.94
		Case 293 - Ungrounded Open Phase A, GND Open Phase C, Motor Start	336.31	99.86	139.42	147.18	156.75	33.18
NSCL2 High Limit	Minimum non-Open Phase I2 with No SAT Load	Case 337 - L-L faults on Y winding, No SAT Load	287.18	287.12	0.06	165.80	165.77	0.00

The NSCL2 Low Limit cases show that there is significant I_0 present during a heavily loaded ungrounded open phase. Such a case could therefore be detected by both Logic String 1 – which looks for high I_0 – and Logic String 2. From a system protection standpoint, it does not matter which logic string detects an open phase, therefore if greater separation between the limits is required, the low limit for NSCL2 could be described as the highest amount of I_2 that is present in an open phase that would NOT be detected by Logic String 1.

NSCL2 (Low Limit) = 156.75 A
NSCL2 (High Limit) = 165.77 A

7.3.2.4 ZSCL2 Setpoint Limits

The model runs provide the following limiting cases for ZSCL2:

Setting Limit	Description	Bounding Scenario	Ia	Ib	Ic	I1	I2	I0
ZSCL2 Low Limit	Maximum background I_0 with Local Generation	Case 6601 - No Load, Max V_0 With Generatoin	0.27	0.26	0.17	0.06	0.00	0.23
	Maximum background I_0 Without Local Generation	Case 661 - No Load, maximum V_0 source	0.71	0.70	0.61	0.06	0.00	0.68
ZSCL2 High Limit	Minimum UGOP I_0	Case 3683 - Min Load, Ungrounded Open Phase B	1.56	0.34	1.93	1.14	0.19	0.86
		Case 5039, Max V, Min Motor Load, DOP UG CB	3.50	0.37	0.28	1.22	1.18	1.13

The unbalance inherent in the 345 kV transmission network (due to power flows through untransposed transmission lines) can create sustained I_0 flowing in the transformer primary windings that is larger than the I_0 that exists during an ungrounded open phase. This is illustrated from the above results which show that the *low* setpoint limit *without generation* (0.68 A) and the *low* setpoint limit *with generation* (0.23 A) to be near the *high* setpoint limit (0.86 A). Thus, it is not possible to use the ZSCL2 term to provide absolute security against false detection caused by transmission system unbalance. Therefore, the low limit for ZSCL2 will be based on relay hardware.

To provide security for sustained transmission system unbalance, a minimum load requirement may be added to ensure there is sufficient current in the transformer windings to preclude a false activation of the algorithm detection logic. This is further discussed in Section 7.5

As long as ZSCL2 is set below the high limit, this term will provide security for lesser amounts of switchyard unbalance without sacrificing any open phase detection and also provide security against false detections due to a 480V L-G fault.

The bounding limits for ZSCL2 are shown below.

ZSCL2 (Low Limit) = Relay I_0 Detection Limit
ZSCL2 (High Limit) = 0.86 A

7.3.3   Logic String 3 Setpoints

7.3.3.1   ZSCL3

The model runs provide the following limiting cases for ZSCL3:

Setting Limit	Description	Bounding Scenario	Ia	Ib	Ic	I1	I2	I0
ZSCL3 Low Limit	Maximum background I_0 with Local Generation	Case 6601 - No Load, Max V_0 With Generation	0.27	0.26	0.17	0.06	0.00	0.23
	Maximum background I_0 Without Local Generation	Case 661 - No Load, maximum V_0 source	0.71	0.70	0.61	0.06	0.00	0.68
ZSCL3 High Limit	Minimum I_0 Current during a Double Ungrounded Open Phase	Case 5039 - Min Load, Double Ungrounded Open Phase B and C	3.50	0.37	0.28	1.22	1.18	1.13

The bounding limits for ZSCL3 are shown below:

ZSCL3 (Low Limit) = Relay I_0 Detection Limit
ZSCL3 (High Limit) = 1.13 A

7.4   Algorithm Time Delay

This calculation uses an open phase time delay of 30 cycles. This is between the back up protection for the transmission system, which, based on the input from ComEd, has a 27 cycle Zone 2 fault clearing time (see email from ComEd in Attachment C) and the RCP undervoltage protection time delay. Further discussion regarding the algorithm time delay and timing tolerances is included in the relay setting calculation.

7.5   Security Load Requirement

As shown in detailed model results, the ZSCL2 and ZSCL3 high limits (minimum zero sequence current during open phase(s) conditions) are less than their respective low limits and therefore the algorithm is not guaranteed to be secure under low load conditions. The ZSCL2 and ZSCL3 Low Limit cases above show the values for the maximum sustained I_0.

Setting Limit	Description	Bounding Scenario	Ia	Ib	Ic	I1	I2	I0
ZSCL2 Low Limit	Maximum background I_0 with Local Generation	Case 6601 - No Load, Max V_0 With Generation	0.27	0.26	0.17	0.06	0.00	0.23
	Maximum background I_0 Without Local Generation	Case 661 - No Load, maximum V_0 source	0.71	0.70	0.61	0.06	0.00	0.68

As described in Section 6.1.2.2.3, the amount of load (positive sequence current) needed to ensure that sustained I_0 does not cause a phase current to fall below MINDECT is equal to maximum amount of sustained zero sequence current (I_{0Max}) plus the MINDECT setting. Based on the I_{0Max} values in the EMTP analysis, the amount of positive sequence current to ensure a secure Logic String 2 is given for grid conditions with and without a local generator connected.

With Generation (at least One Byron Unit Online, case 6601):
$I_{0Max} = 0.23$ A
$I_{1Secure} = 0.23A + MINDETC$

Without Generation (Both Byron Units Offline, case 661):
$I_{0Max} = 0.68$ A
$I_{1Secure} = 0.68A + MINDETC$

Based on the With Generation I_0 given above and a MINDECT setting of 0.8A, a minimum load of approximately 0.65 MVA is used in the final EMTP plant runs.

The final setpoints will be determined in the relay setting calculation.

7.6   Post Open Phase Bus Transfer Analysis

Following the open phase detection and SAT trip, the balance of plant induction motors and synchronous circulating water pump motors will be transferred to the Unit Auxiliary Transformers (UATs). The safety related loads will be restarted by the diesel generators. In order to determine if the post open phase bus transfer can be successful the following criteria are examined:

- Torque Developed by Motor During Bus Transfer
- Current Drawn By Motors During Bus Transfer
- Reactor Coolant Pump Undervoltage Time
- Reacceleration of all Medium Voltage Motors

The results of the bus transfer EMTP-RV simulations are provided in the attached tables of Appendix B.

7.6.1   Torque Developed by Motor During Bus Transfer and Short Circuit Condition

The results show that in all cases the torque developed by the motor during a bus transfer is less than the torque developed during a three phase fault. Since motors are designed to withstand a three phase fault at the motor terminals, this criterion is met.

7.6.2   Current Drawn By Motors During Bus Transfer

The dead, or slow, bus transfer was modeled by allowing the motor bus voltage to decay to zero before reconnecting it to a stiff source at motor rated voltage. The peak current drawn by a motor for this simulation is compared to the peak current drawn during a fast bus transfer. The results show that in all cases, the maximum asymmetrical current drawn by a motor during a fast bus transfer is less than the asymmetrical current drawn

during a slow bus transfer. Since motors windings are designed to withstand a slow bus transfer, this criterion is met.

7.6.3   RC Pump Reacceleration Time

The longest time that the reactor coolant pump voltage is below 76.5% voltage is 0.70 seconds.

7.7   I2 Heating

An AIEE paper "Protection of 3-Phase Motors Against Single-Phase Operation" [Ref. 4.49] states that the negative sequence current present in a starting motor with an open phase will be roughly equal to half of the motor locked rotor current (LRC). The reference paper further states that the positive rotation of a motor will not significantly affect the motor's negative sequence and the I_2 of a running motor is typically near the load current. As the open phase algorithm is designed to protect both starting and running motors, the greater I_2 of a starting motor is used here. Also note that the paper assumes that the open phase occurs directly at the motor terminals, however due to the tendency of the RAT transformer to balance the three phase voltages, the actual negative sequence currents present during an open phase on the SAT will be less.

If a conservative maximum negative sequence current of 7.0 pu is used (based on the largest locked rotor current used in this calculation, the I_2^2t during the open phase condition is equal to $(0.5 * 7.0)^2 \cdot (0.5) = 6.125$. The AIEE paper "Protection of 3-Phase Motors against Single-Phase Operation" [Ref. 4.49] states that motors are able to withstand an I_2^2t of 40, therefore the 30-cycle time delay is short enough to provide I_2^2t protection for the motor.

8. Results

8.1   Algorithm Logic

Logic String 1 (Single or Double Grounded Open Phase Detection)
IF

   $I_0 > ZSCL1$
   THEN a grounded open phase is Detected

Logic String 2 (Single Ungrounded or Double Grounded/Ungrounded Open Phase Detection)
IF

   $(I_{A-SAT1} < MINDETC$ and $I_{B-SAT1} > LLDIFF$ and $I_{C-SAT1} > LLDIFF)$ OR
   $(I_{A-Vsum} < MINDETC$ and $I_{B-Vsum} > LLDIFF$ and $I_{C-Vsum} > LLDIFF)$
   THEN an open phase is Detected
AND

   $I_2 < NSCL2$
AND

   $I_0 > ZSCL2$
   THEN Logic String 2 is Secure

Logic String 3 (Double Ungrounded Open Phase Detection)
IF

   $(I_{A-SAT1} < MINDETC$ and $I_{B-SAT1} < MINDETC$ and $I_{C-SAT1} > LLDIFF)$ OR
   $(I_{A-Vsum} < MINDETC$ and $I_{B-Vsum} < MINDETC$ and $I_{C-Vsum} > LLDIFF)$
   THEN an open phase is Detected
AND

   $I_0 > ZSCL3$
   THEN Logic String 3 is Secure

8.2 Relay Setting Limits

The Setting Limits for the relay setpoints are as follows:

	Setting Limit	Simplified and Combined Model Limits	Security or Detection (a)	Load Dependent (b)
Logic String 1	ZSCL1 Low Limit	8.65	Security	No
	ZSCL1 High Limit	29.77	Detection	No
Logic String 2 and Logic String 3 Detection	MINDECT Low Limit	Setting determined by relay sensitivity, error and CT ratio		
	MINDECT High Limit			
	LLDIFF Low Limit	Setting determined by relay sensitivity, error and CT ratio		
	LLDIFF High Limit (c)	Increase Factor = 1.25	Detection	Yes
Logic String 2 Security	NSCL2 Low Limit	116.6	Detection	No
	NSCL2 High Limit	167.2	Security	No
	ZSCL2 Low Limit	Setting determined by relay sensitivity, error and CT ratio		
	ZSCL2 High Limit	0.70	Detection	Yes
Logic String 3 Security	ZSCL3 Low Limit	Setting determined by relay sensitivity, error and CT ratio		
	ZSCL3 High Limit	1.13	Detection	Yes
Load Security	With Generation	0.23 + MINDECT	Security	No
	Without Generation	0.68 + MINDECT	Security	No

(a) This column indicates if a setting limit is bounded by a non-open phase event that could cause a false detection (security), or if it is bounded by an open phase event that the relay must operate for (detection)

(b) This column indicates if each setpoint limit will change if the minimum load model used in the simulation changes. In every case the limit is directly proportional to the amount of load - an increase in load will increase the limit. This can be used to predict how a load change my affect the relay settings once the final minimum load is determined in the relay setting calculation.

(c) The *IncreaseFactor* is defined as the minimum increase in healthy phase current during an ungrounded single or double open phase.

8.3   Algorithm Time Delay

The post open phase bus transfer analysis results show that a 30-cycle time delay (0.5 seconds) will allow the SAT loads to successfully transfer to the UATs. The longest time that the Reactor Coolant Pump bus voltage is below 76.5% voltage is 0.7 seconds for a post open phase bus transfer. Further analysis and discussion of the undervoltage protection setpoint, time delay, and timing tolerances is included in the relay setting calculation.

8.4   Plant Load and Algorithm Sensitivity

This calculation contains analysis that uses a variety of SAT loading and load models. In aggregate, the calculation analyses and results support the following conclusions:

8.4.1   The Algorithm is not sensitive to Changes in SAT Loading

The results show that Logic String 1 is able to detect a grounded open phase regardless of the load on the SAT. While Logic String 2 is sensitive to the load on the transformer, it is only sensitive to light loading conditions. A decreased load on the SAT will not affect the algorithm operation provided the load remains above the minimum load. Increased loading increases the security of the L2 logic string. The calculation shows correct algorithm operation when the SAT is at maximum loading, therefore this calculation will not need to be revised due to increased load on the SATs.

8.4.2   The Algorithm is Secure for Motor Starts and Bus Transfers

The LOCA starts, largest motor starts and bus transfer simulations show that the algorithm remains secure during load transients on the SAT. The algorithm is designed to detect unbalanced current flow, and as such is not sensitive to these types of electrically balanced events.

8.4.3   The Algorithm is not Sensitive to Most Plant Load Changes

As discussed above, the algorithm is not sensitive to heavy load or load transients. At light loading, the algorithm is only sensitive to the amount of load on the SAT, and not specific load parameters. The analysis does not need to be performed for routine changes to the plant loading, however the time delay setting of the algorithm could possibly be impacted by load/plant changes that affect the reacceleration time of the RCP motors. Such load changes could include significant changes to plant MV motors, UATs, MPTs or the generators. Sensitivity analysis with the EMTP model shows that the load on the SAT would need to increase by one to two MVA before the RCP reacceleration time would be meaningfully impacted. Thus, the replacement of a MV motor, UAT or MPT with one of similar ratings would not require reanalysis. The electro dynamic effect of a large load addition or similarly significant change would need to be examined and disposistioned at that time.

8.5   Transmission System Results

This calculation determines the bounding sequence voltages in the switchyard based upon four 345kV transmission lines connected to the Byron switchyard, and is valid for the current configuration of the switchyard. Future changes to the switchyard will not require a re-evaluation of the maximum sequence voltages since the existing analysis in Attachment A is bounding. Furthermore, replacement of the MPT with a transformer that has equivalent impedance (within 10%) to the existing transformer will not require the "with generation" analysis to be performed again.

9. Conclusions

With the algorithm setting limits established in this calculation, the algorithm can detect open phase conditions and be secure against faults. The setpoint tolerances are evaluated in calculation BYR13-177 to ensure that they do not exceed the setting of each particular setting.

The bus transfer analysis show that the algorithm should not false trip for a bus transfer from the UAT to the SAT.

The post open phase bus transfer analysis results show that a 30-cycle time delay (0.5 seconds) will allow the SAT loads to successfully transfer to the UATs. The longest time that the Reactor Coolant Pump bus voltage is below 76.5% voltage is 0.7 seconds for a post open phase bus transfer. Further analysis and discussion of the undervoltage protection setpoint, time delay, and timing tolerances is included in the relay setting calculation.

9.1   Model Update

It is expected that the EMTP model will remain bounding for most plant and transmission system modifications. The following changes will require the conclusions of this calculation to be re-verified or the analysis to be revised (Ref. Sections 8.4 and 8.5):

- Changes to the transmission protection/breaker zone 2 fault clearing time
- New loads in excess of 1 MVA above the ELMS Condition 2 Loading
- Replacement or major modifications to the SATs or SAT circuit will require the analysis to be redone.

ATTACHMENT 1
Design Analysis Cover Sheet

Design Analysis		Last Page No. [6] Attachment E Page E15	
Analysis No.: [1] BYR13-177		**Revision:** [2] 001 Major ☒ Minor ☐	
Title: [3] Unit 1 and 2 Loss of Phase Detection Relay Settings			
EC/ECR No.: [4] ~~389896, 380897~~ 405674 (MH) 5-17-16		**Revision:** [5] 000	

Station(s): [7]	Byron	Component(s): [14]	
Unit No.: [8]	00		
Discipline: [9]	ELDC	1PA55J-851PST11	
Descrip. Code/Keyword: [10]	E07	1PA55J-851PST12	
Safety/QA Class: [11]	Non-Safety Related	2PA55J-851PST21	
System Code: [12]	AP	2PA55J-851PST22	
Structure: [13]	N/A		

CONTROLLED DOCUMENT REFERENCES [15]			
Document No.:	**From/To**	**Document No.:**	**From/To**
Calculation 19-AN-1	From		
Calculation 19-AN-9	From		
Calculation BYR13-176	From		

Is this Design Analysis Safeguards Information? [16]   Yes ☐ No ☒   If yes, see SY-AA-101-106

Does this Design Analysis contain Unverified Assumptions? [17]   Yes ☐ No ☒   If yes, ATI/AR#: _____

This Design Analysis SUPERCEDES: [18]   in its entirety.

Description of Revision (list changed pages when all pages of original analysis were not changed): [19]
See Page 3 for revision summary.

Preparer: [20]	Piotr Wiczkowski	EMH for PRW per telcon	5/9/2016
	George Bikakis	George Bikakis	5/9/2016
	Print Name	Sign Name	Date

Method of Review: [21]   Detailed Review ☒   Alternate Calculations (attached) ☐   Testing ☐

Reviewer: [22]	Jan Wisniewski	Jan B Wisniewski	5/9/16
	Print Name	Sign Name	Date

Review Notes: [23]   Independent review ☒   Peer review ☐

(For External Analyses Only)
External Approver: [24]	Jan Wisniewski	Jan B Wisniewski	5/9/16
	Print Name	Sign Name	Date
Exelon Reviewer: [25]	MOHAMMED HAQ		5/19/16
	Print Name	Sign Name	Date

Independent 3rd Party Review Reqd? [26]   Yes ☐ No ☒

Exelon Approver: [27]	Brian Ledger	Brian Ledger	6/1/16
	Print Name	Sign Name	Date

Owner's Acceptance Review Checklist for External Design Analyses

Design Analysis No.: BYR13-177 _____ Rev: 001
Contract #: OO470441 _____ Release #: 44 _____

No	Question	Instructions and Guidance	Yes / No / N/A
1	Do assumptions have sufficient documented rationale?	All Assumptions should be stated in clear terms with enough justification to confirm that the assumption is conservative. For example, 1) the exact value of a particular parameter may not be known or that parameter may be known to vary over the range of conditions covered by the Calculation. It is appropriate to represent or bound the parameter with an assumed value. 2) The predicted performance of a specific piece of equipment in lieu of actual test data. It is appropriate to use the documented opinion/position of a recognized expert on that equipment to represent predicted equipment performance. Consideration should also be given as to any qualification testing that may be needed to validate the Assumptions. Ask yourself, would you provide more justification if you were performing this analysis? **If** yes, the rationale is likely incomplete.	☒ ☐ ☐
2	Are assumptions compatible with the way the plant is operated and with the licensing basis?	Ensure the documentation for source and rationale for the assumption supports the way the plant is currently or will be operated post change and they are not in conflict with any design parameters. If the Analysis purpose is to establish a new licensing basis, this question can be answered yes, if the assumption supports that new basis.	☒ ☐ ☐
3	Do all unverified assumptions have a tracking and closure mechanism in place?	**If** there are unverified assumptions without a tracking mechanism indicated, **then** create the tracking item either through an ATI or a work order attached to the implementing WO. Due dates for these actions need to support verification prior to the analysis becoming operational or the resultant plant change being op authorized.	☐ ☐ ☒
4	Do the design inputs have sufficient rationale?	The origin of the input, or the source should be identified and be readily retrievable within Exelon's documentation system. If not, then the source should be attached to the analysis. Ask yourself, would you provide more justification if you were performing this analysis? **If** yes, the rationale is likely incomplete.	☒ ☐ ☐

ANALYSIS NO. BYR13-177   REVISION NO. 001   PAGE NO. 1B of 21

Owner's Acceptance Review Checklist for External Design Analyses

Design Analysis No.: BYR13-177 _____   Rev: 001
Contract #: ___00470441___   Release #: _44___

No	Question	Instructions and Guidance	Yes / No / N/A
5	Are design inputs correct and reasonable with critical parameters identified, if appropriate?	The expectation is that an Exelon Engineer should be able to clearly understand which input parameters are critical to the outcome of the analysis. That is, what is the impact of a change in the parameter to the results of the analysis? If the impact is large, then that parameter is critical.	☒ ☐ ☐
6	Are design inputs compatible with the way the plant is operated and with the licensing basis?	Ensure the documentation for source and rationale for the inputs supports the way the plant is currently or will be operated post change and they are not in conflict with any design parameters.	☒ ☐ ☐
7	Are Engineering Judgments clearly documented and justified?	See Section 2.13 in CC-AA-309 for the attributes that are sufficient to justify Engineering Judgment. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐
8	Are Engineering Judgments compatible with the way the plant is operated and with the licensing basis?	Ensure the justification for the engineering judgment supports the way the plant is currently or will be operated post change and is not in conflict with any design parameters. If the Analysis purpose is to establish a new licensing basis, then this question can be answered yes, if the judgment supports that new basis.	☒ ☐ ☐
9	Do the results and conclusions satisfy the purpose and objective of the Design Analysis?	Why was the analysis being performed? Does the stated purpose match the expectation from Exelon on the proposed application of the results? If yes, then the analysis meets the needs of the contract.	☒ ☐ ☐
10	Are the results and conclusions compatible with the way the plant is operated and with the licensing basis?	Make sure that the results support the UFSAR defined system design and operating conditions, or they support a proposed change to those conditions. If the analysis supports a change, are all of the other changing documents included on the cover sheet as impacted documents?	☒ ☐ ☐
11	Have any limitations on the use of the results been identified and transmitted to the appropriate organizations?	Does the analysis support a temporary condition or procedure change? Make sure that any other documents needing to be updated are included and clearly delineated in the design analysis. Make sure that the cover sheet includes the other documents where the results of this analysis provide the input.	☒ ☐ ☐

ANALYSIS NO. BYR13-177   REVISION NO. 001   PAGE NO. 1C of 21

Owner's Acceptance Review Checklist for External Design Analyses

Design Analysis No.: BYR13-177 _____   Rev: 001
Contract #: ___00470441_____   Release #: _44_____

No	Question	Instructions and Guidance	Yes / No / N/A
12	Have margin impacts been identified and documented appropriately for any negative impacts (Reference ER-AA-2007)?	Make sure that the impacts to margin are clearly shown within the body of the analysis. If the analysis results in reduced margins ensure that this has been appropriately dispositioned in the EC being used to issue the analysis.	☒ ☐ ☐
13	Does the Design Analysis include the applicable design basis documentation?	Are there sufficient documents included to support the sources of input, and other reference material that is not readily retrievable in Exelon controlled Documents?	☒ ☐ ☐
14	Have all affected design analyses been documented on the Affected Documents List (ADL) for the associated Configuration Change?	Determine if sufficient searches have been performed to identify any related analyses that need to be revised along with the base analysis. It may be necessary to perform some basic searches to validate this.	☒ ☐ ☐
15	Do the sources of inputs **and** analysis methodology used meet committed technical and regulatory requirements?	Compare any referenced codes and standards to the current design basis and ensure that any differences are reconciled. If the input sources **or** analysis methodology are based on an out-of-date methodology or code, additional reconciliation may be required if the site has since committed to a more recent code	☒ ☐ ☐
16	Have vendor supporting technical documents and references (including GE DRFs) been reviewed when necessary?	Based on the risk assessment performed during the pre-job brief for the analysis (per HU-AA-1212), ensure that sufficient reviews of any supporting documents not provided with the final analysis are performed.	☒ ☐ ☐
17	Do operational limits support assumptions and inputs?	Ensure the Tech Specs, Operating Procedures, etc. contain operational limits that support the analysis assumptions and inputs.	☒ ☐ ☐

Create an SFMS entry as required by CC-AA-4008. SFMS Number: ___54847_____

Design Analysis Table of Contents

Revision Summary

Revision 0:

Initial Issue

Revision 1:

This revision is issued to update the MINDETC and MINLOAD equations for logic strings 2 and 3. The equations previously used a "less than" operator in the calculation, however, the SEL-451 relays are programmed with a "less than or equal to" operator. Therefore, this calculation is updated to be in agreement with the relay programming. Changes are made to the logic strings on Pages 6 and 7 and the trip logic diagram on Page 8 as indicated by revision bars. Additional discussion is added to the ground fault impedance sensitivity section on pages 16, 19, 20 and 21 for consistency with other stations in the fleet.

1.0   PURPOSE/SCOPE

A loss of phase site specific programmed microprocessor based protective relaying scheme is being developed for the Nuclear Units in the Exelon Fleet. This evaluation is for Byron Units 1 and 2.

The open phase detection scheme is a system consisting of a logic associated with the detection and security of the scheme. The fundamental premise and the objectives of the scheme are consistent with the Nuclear Energy Institute (NEI) "Open Phase Condition Initiative" APC13-28, October 10, 2013.

An open phase event consists of a failure in the 3-phase supply in which one or two phase conductor(s) becomes disconnected from the 345 kV transmission interconnection. This disconnection can result in three different scenarios:

- The energized 345 kV line does short to ground on the transmission side, so there is fault current to be detected and cleared by the switchyard protection scheme. Therefore, no further analysis is required for this scenario. This scenario occurred at Byron Unit 1 on Tuesday, February 28, 2012.

- The energized 345 kV line does not short to ground on the transmission side, so there is insufficient fault current to be detected and cleared by the switchyard protection scheme. The disconnected phase conductor shorts to ground on the System Auxiliary Transformer (SAT) end, connecting the SAT HV winding to ground.

- The energized 345 kV line does not short to ground on the transmission side, so there is no fault current to be detected and cleared by the switchyard protection scheme. The disconnected phase conductor remains suspended above the ground at the SAT end.

This calculation implements the results of the EMTP analysis for the second and third scenarios, where the switchyard protection cannot be relied upon to clear the condition. The analysis to determine I_a, I_b, I_c, I_0, I_1, I_2, I_{1sum}, I_{asum}, I_{bsum}, and I_{csum} quantities during the second and third scenarios is performed utilizing the Electromagnetic Transients Program Restructured Version (EMTP-RV) software. The EMTP-RV software model for the Byron transmission system interconnection, the SAT's, and the station electrical auxiliary system allows the determination of the above indicated current quantities to be made with a high degree of accuracy.

The purpose of this analysis is to select settings for the SEL-451-5 relays which are being installed at the 345 kV level to detect an open phase condition on the 345 kV line connections to SAT 142-1, SAT 142-2, SAT 242-1 and SAT 242-2.

The logic implemented is in Sections 2.2.1 through 2.2.5. The SEL-451-5 relays are shown on the relay and metering diagrams in Attachment B.

The settings for the following devices are developed in this calculation:

- SEL-451-5 (851PST11) for SAT 142-1, this relay is connected to the SAT 142-1 HV (primary side) bushing CTs secondary side

- SEL-451-5 (851PST12) for SAT 142-2, this relay is connected to the SAT 142-2 HV (primary side) bushing CTs secondary side

- SEL-451-5 (851PST21) for SAT 242-1, this relay is connected to the SAT 242-1 HV (primary side) bushing CTs secondary side

- SEL-451-5 (851PST22) for SAT 242-2, this relay is connected to the SAT 242-2 HV (primary side) bushing CTs secondary side

The following settings per relay need to be determined. The settings are

ZSCL1	**Z**ero **S**equence **C**urrent **L**imit for Logic String #**1**
MINDETC	**Min**imum **Det**ection **C**urrent
LLDIFF	**L**ow **L**evel Current **Diff**erentiation
NSCL2	**N**egative **S**equence **C**urrent **L**imit for Logic String #**2**
ZSCL2	**Z**ero **S**equence **C**urrent **L**imit for Logic String #**2**
ZSCL3	**Z**ero **S**equence **C**urrent **L**imit for Logic String #**3**
T_DELAY	**T**ime **Delay** (In Cycles) Prior to Triggering the Protective Control
MINLOAD	**Min**imum transformer **load** alarm setting. MINLOAD is expressed in Amps for this calculation.

The above mentioned relay settings are based on the following quantities:

- I_{Asum}, I_{Bsum}, I_{Csum}, representing the sum of total phase currents from the switchyard to both SATs

- I_A, I_B, I_C, representing the individual phase current of each SAT

- I_0 (zero), I_1 (positive), I_2 (negative), representing the sequence current quantities into each SAT

- I_{1sum}, representing the sum of total sequence currents from the switchyard to both SATs

2.0   INPUTS

The EMTP-RV analysis results are included in Reference 4.4. The applicability of the settings to detect the second and third scenarios are discussed in Section 8.2 of reference 4.4.

2.1   The SEL-451-5 relay has a minimum relay input phase current hardware detection limit of 0.02 A (Reference 4.2).

2.2   The open phase detection relay logic for Byron Units 1 and 2 has been determined analytically based upon the actual EMTP-RV results. For ease of reference the logic for two parallel SAT transformers 142-1 and 142-2 is reproduced below. This logic is also applicable for parallel SAT transformers 242-1 and 242-2.

The programmed algorithm consists of 3 main separate logic strings, with the phase currents expressed in primary amperes and the sequence current values expressed in primary amperes. The activation of logic strings L1, L2, or L3 will cause a trip after a time delay. In the three logic strings identified below the

Phase "a" current is the Phase with the minimum current which identifies the Open Phase. The Phase "b" and Phase "c" refer to the two other Phases which are **not** open circuited.

2.2.1 Logic string #1 (Single or Double Open Phase and Ground on SAT Primary) for SAT 142-1 and SAT 142-2

IF

$$I_0 > ZSCL1$$

THEN L1_T. A grounded open phase exists and the relay will initiate a Time Delay to **TRIP.**

I_0 is the zero sequence current through each SAT. Note that open phase and ground on SAT primary is detected under all loading conditions including no load conditions.

2.2.2 Logic string #2 (Single Ungrounded or Double Grounded/Ungrounded Open Phase on SAT Primary) for SAT 142-1 and SAT 142-2

IF

$(|I_{A142-1}| <= MINDETC$ **AND**

$|I_{B142-1}| > LLDIFF$ **AND** $|I_{C142-1}| > LLDIFF$

OR

$|I_{A142-1}+I_{A142-2}| <= MINDETC$ **AND**

$|I_{B142-1}+I_{B142-2}| > LLDIFF$ **AND** $|I_{C142-1}+I_{C142-2}| > LLDIFF)$

AND

$$I_0 > ZSCL2$$

AND

$$I_2 < NSCL2$$

THEN L2_T. Logic String 2 is secure and the relay will initiate a Time Delay to **TRIP.**

Note that I_0 and I_2 are the zero sequence and negative sequence currents through each SAT, respectively. The above logic string #2 detects an open phase on SAT Phase A primary. Identical logic is applied individually to phases B and C to detect an open phase on B or C. The above logic applies to transformer 142-1. Identical but mirrored logic with currents from transformer 142-2 apply to transformer 142-2.

2.2.3 Logic string #3 (Double Ungrounded Open Phase on SAT Primary) for SAT 142-1 and SAT 142-2

IF

$(|I_{A142-1}| <= $ MINDETC **AND** $|I_{B142-1}| <= $ MINDETC **AND**
$|I_{C142-1}| > $ LLDIFF

OR

$|I_{A142-1}+I_{A142-2}| <= $ MINDETC **AND** $|I_{B142-1}+I_{B142-2}| <= $ MINDETC **AND**
$|I_{C142-1}+I_{C142-2}| > $ LLDIFF)

AND

$I_0 > $ ZSCL3

THEN L3_T. Logic String 3 is secure and the relay will initiate a Time Delay to **TRIP.**

The above logic string #3 detects a double open phase on SAT Phase A and Phase B primary. Identical logic is applied individually to Phases B and C, Phases C and A to detect a double open phase on Phase B and Phase C, and Phase C and Phase A. The above logic applies to transformer 142-1. Identical but mirrored logic with currents from transformer 142-2 apply to transformer 142-2.

2.2.4   Minimum Load Alarm Logic

IF

$|I_{1(142-1)}| <= $ MINLOAD

OR

$|I_{1(142-1)}+I_{1(142-2)}| <= $ MINLOAD

THEN Minimum Load Alarm.

2.2.5   Minimum Load for Relay Operation

IF

(L2_T **OR** L3_T)

AND

NOT *Minimum Load Alarm*

THEN L23_T

2.2.6   Time Delay for Relay Operation

IF

(L1_T **OR** L23_T)

AND

Time > T_DELAY

THEN Trip

TRIP LOGIC DIAGRAM

Logic String #2

$|I_{A142-1}| <= MINDETC$
$|I_{B142-1}| > LLDIFF$
$|I_{C142-1}| > LLDIFF$

$|I_{A142-1}+I_{A142-2}| <= MINDETC$
$|I_{B142-1}+I_{B142-2}| > LLDIFF$
$|I_{C142-1}+I_{C142-2}| > LLDIFF$

$I_0 > ZSCL2$
$I_2 < NSCL2$

L2_T

Logic String #3

$|I_{A142-1}| <= MINDETC$
$|I_{B142-1}| <= MINDETC$
$|I_{C142-1}| > LLDIFF$

$I_0 > ZSCL3$

$|I_{A142-1}+I_{A142-2}| <= MINDETC$
$|I_{B142-1}+I_{B142-2}| <= MINDETC$
$|I_{C142-1}+I_{C142-2}| > LLDIFF$

L3_T

$|I_{1\ 142-1}| <= MINLOAD$
$|I_{1\ 142-1}+I_{1\ 142-2}| <= MINLOAD$

MINIMUM LOAD ALARM

L23_T

IF $I_0 > ZSCL1$
Logic String #1

L1_T

$Time > T\_DELAY$

TRIP ALARM

Relay Tripping Scheme

Trip

Relay Operation

DELAY
Time (Seconds)

True

Logic #1   Logic #2

$T_1, T_2 < DELAY$
$T_3 > DELAY$

False

0.0 T_1 T_2 T_3
Time (Seconds)

Relay Tripping Scheme

No Trip

DELAY
Time (Seconds)

Relay Timer Reset

Logic #1   Logic #2

True

$T_1 < DELAY$
$T_3 - T_2 < DELAY$

False

0.0 T_1 T_2 T_3
Time (Seconds)

Relay Tripping Scheme

Trip

Relay Operation

DELAY
Time (Seconds)

True

Logic #1

$T_1 > DELAY$

False

0.0 T_1
Time (Seconds)

The timer reset characteristic is such that it resets to zero with no time delay on dropout when there is no permissive trip signal. If a second permissive trip signal is received before the first permissive trip drops out, then the timer is **not** reset.

2.3   The setpoint ranges determined in Reference 4.4 by analyzing the EMTP-RV results for Byron System Auxiliary Transformers 142-1, 142-2, 242-1, and 242-2 are in primary (at 345 kV level) amps and listed below. MINDETC and LLDIFF are determined in Attachment A of this calculation. MINLOAD is a security setting and it is toggled based on plant configuration:

ZSCL1	= 8.65 – 29.77 A	ZSCL3	= 1.13 A
ZSCL2	= 0.70 A	MINLOAD	= 1.39 A or 1.84 A
NSCL2	= 116.6 – 167.2 A	T_DELAY	= 30 cycles

2.4   The 345 kV Transformers bushing CTs supplying the SEL-451-5 relays have a ratio of 600-5 A and they are operating on 200:5 A taps. See Attachment B and Reference 4.4. The accuracy class of the subject bushing CTs is C400 at 600:5 A tap. As per Reference 4.3, Sections 5.3, 5.4, and table 6, the accuracy limit of metering class CTs is doubled at 10% of rated current. For example the 1.2% metering class CT at 100% rated current is a 2.4% metering class CT at 10% of rated current.

2.5   The SEL-451-5 relay is able to detect a minimum change in current of 0.01 A (secondary current) (Reference 4.17).

2.6   The SEL-451-5 relay has a sequence accuracy of ±0.05 A plus ±3% and a phase current accuracy of ±0.05 A plus ±3% of setting above 0.25 A (secondary current) or 10.0 A primary current (Reference 4.13). The relay's guaranteed sequence accuracy at 0.25 A secondary current is specified (fixed error of 0.05 A is 20%) to be ±23%.

The SEL-451 relay has a quantization error (resolution of the analog to digital converter) that is scaled at 132 counts per secondary amp (See Section A.6.3.2 for details) (Reference 4.16).

2.7   The control room HVAC system is designed to provide a controlled temperature of 75°F ± 2°F in the auxiliary electric equipment rooms (AEER) (Reference 4.8).

2.8   Inputs for this for the CT Burden and accuracy calculation are documented within Attachment D. The inputs detailed include but are not limited to the following: CT ohms/turn, CT wiring, CT excitation and ratio correction factor curves, new and existing cable lengths, cable resistance and reactance, relay burdens, watthour meter burden, and transformer ratings and impedances.

3.0   ASSUMPTIONS

3.1   Assumptions Requiring Verification

There are no assumptions requiring verification.

3.2   Assumptions Not Requiring Verification

3.2.1   The relays will be installed in AEER and subject to control room environmental controls, therefore the calculation has not considered relay setting variation with ambient temperature in the range of 75°F ± 2°F (Input 2.7) as the settings are not expected to change for this small temperature range compared to the relay allowable operating temperature range of -40°F to +185°F.

3.2.2   The natural short term drift of the SEL-451-5 relay is considered to be ±0.0%. This value of ±0.0% is because the relay is a computer and not a traditional electromechanical relay. The setting logic is computer based and therefore not subject to drift.

3.2.3   The power factor of the SEL-451-5 relay burden is assumed to be unity. The unity power factor gives the most conservative voltage at the CT. Therefore this assumption is conservative and does not require verification.

4.0   REFERENCES

4.1   SEL 451-5 Protection, Automation, and Bay Control System (Date Code 20120220), Specifications Pages U.1.12 through U.1.17 (Attachment C, Pages C31 through C36)

4.2   "Open Phase Detection Logic using SEL-451-5 Relay – Proof of Concept Testing", SEL Project Number: P5234, dated August 24, 2012 (Rev. B), Retrievable as part of EC389896 and EC389897.

4.3   IEEE C57.13-1978, IEEE Standard Requirements for Instrument Transformers. (Excerpt included in Attachment E)

4.4   BYR13-176, Rev. 0, Unit 1 and 2 Loss of Phase Detection EMTP-RV Analysis.

4.5   E-mail on P5234 Question on Power Supply Drift, information transmitted on 9/7/2012 from Dennis Bradley (SEL) to Kirk Robbins (Exelon) (Attachment B).

4.6   Calculation 19-AN-1, Rev. 6, "Relay Settings for the Unit 1 Generator, UAT and SAT".

4.7   Bushing CT Exciting Current Curves from Transformer Test report BYR142-1 (Attachment E)

4.8   Byron/Braidwood - Updated Final Safety Analysis Report Section 9.4.1.1.2, "Power Generation Design Bases", Revision 12 - December 2008.

4.9   Power System Relaying Committee of the IEEE, "Relay Performance Considerations with Low-Ratio CT's and High-Fault Currents," IEEE Transactions on Industry Applications, Vol. 31, No. 2, March/April 1995, pp. 392-404.

4.10   GE Instrument Transformer Burden Data GET-1725D, Page 12 (Attachment E)

4.11   Markup of "Relay & Metering Diagram System Auxiliary Transformers 142-1 and 142-2", 6E-1-4016C (Attachment B)

4.12   ABB Instruction Leaflet 41-103H, "Type CO Circuit Opening Overcurrent Relay", Page 9 (Attachment E)

4.13   Email on SEL-451 Sequence Current Accuracy from Kirk Robbins (Exelon) to S&L with data provided by Bob Morris (SEL) dated 10-04-2012. (Attachment B)

4.14   Calculation 19-AN-9, Rev. 3, "Relay Settings for the Unit 2 Generator, UAT and SAT".

4.15   Markup of "Relay & Metering Diagram System Auxiliary Transformers 242-1 and 242-2", 6E-2-4016C (Attachment B)

4.16   Email on Verification of Design Input from Prasanna Muralimanohar (SEL) to S&L dated 03/17/2014. (Attachment B)

4.17   Email on Notes of the conversation with SEL on March 3, 2014, transmitted on March 5, 2014, from Dennis Bradley (SEL) to Sanjiv Shah (S&L) (Attachment B).

4.18   Westinghouse Advisory Notice NSD-B-92-03-RO, "Undervoltage Trip Protection", May 15, 1992.

4.19   ABB SSV-T Relay Manual, 41-766.7, November 1999.

4.20   Westinghouse Report WCAP-14036-P-A Revision 1, "Elimination of Periodic Protection Channel Response Time Tests", October 1998.

4.21   Calculation CN-TA-93-232, Rev. 001, "Byron/Braidwood SGTP with Reduced TDF: Locked Rotor/Shaft Break Analysis"

4.22   "Digital Simulation of Fault Transient Phenomena on EHV Transmission Lines Under Non-Linear High Impedance Arcing Faults", C. H. Kim, R. K. Aggarwal, A. T. Johns, IPST 99 – International Conference on Power System Transients, June 20-24 1999, Budapest – Hungary.

5.0   <u>IDENTIFICATION OF COMPUTER PROGRAMS</u>

5.1   Mathcad Version 14.35, S&L Program Number 03.7.548-1435.   Validation documents for this program are maintained in the Sargent and Lundy software library.

AppList Controlled Files Audit Trail - Short ...

```
Acronym: MATHCAD
S&L Program No.: 03.7.548-1435
       Status: 0                    Type: 2
Effective Date: 11-22-2013
Execution Date: 02-20-2014  13:29
Controlled Folder: C:\program files\Mathcad\Mathcad 14\

Secondary Folder: (n/a)
```

OK   Print   Long Form
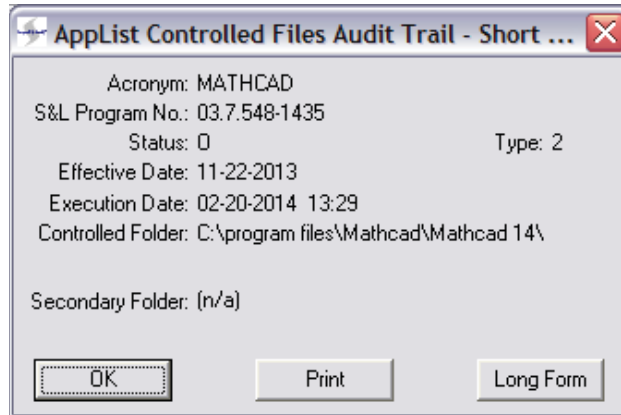
6.0   METHOD OF ANALYSIS & ACCEPTANCE CRITERIA

6.1   Method of Analysis

6.1.1   SEL-451-5 Relay Setpoints based on EMTP-RV Simulation Results Complete (Reference 4.4)

6.1.1.1   A relaying scheme has two alternative ways in which it can be unreliable: the scheme may fail to operate when it is expected to, or the scheme can operate when it is not expected to. Reliability is measured by both dependability and security. Dependability is defined as the measure of the certainty that the relays will operate correctly for all the faults for which they are designed to operate. Security is the measure of certainty that the relays will not operate incorrectly for any fault.

In calculating the settings the bias is towards dependability while always minimizing the potential for a false operation with a margin that accounts for the loop error tolerance. The calculated setting is verified by testing the logic in the test case results so that neither dependability nor security is compromised.

6.1.1.2   The logic for each relay and each relay logic string (L1, L2, and L3) is found in Reference 4.4.   This information is used to determine preliminary settings. The values of I_a, I_b, I_c, I_0, I_1, I_2, I_{1sum}, I_{asum}, I_{bsum}, and I_{csum} for each case are listed. The three individual relay logic strings L1, L2, and L3 are tabulated separately. The relay settings are updated using a margin and the total loop tolerances (in the appropriate direction).

6.1.1.3   The bushing CT ratio errors used for calculating each setpoint's total error are calculated in Attachment D. This CT error can be calculated and Ratio Correction Factor multipliers applied to obtain the exact primary CT current. It is a non-random error. Similarly the CT Phase Angle Errors can be calculated and therefore are non-random errors.

6.1.1.4   For the SEL-451-5 relay the following non-random errors are not considered:

- The relay accuracy with respect to temperature variation; because the temperature variation is small 75°F ± 2°F (Assumption 3.2.1) over a defined Operating Temperature range of -40° to 185°F.
- The relay accuracy with respect to control voltage variation; because there is no variation in current pickup for a ±10% variation in rated power supply voltage. (Reference 4.5).
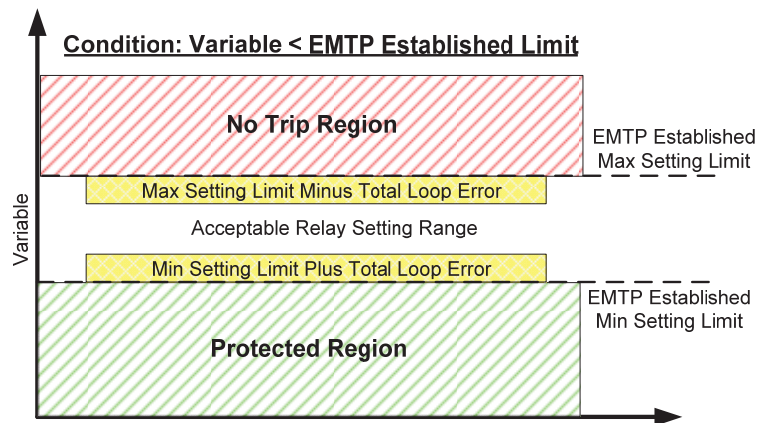
6.1.1.5   For the SEL-451-5 relay the following random errors are not considered because the microprocessor relay is digital and setting numbers do not drift or change (Assumption 3.2.2).

- The short term drift
- The setting error

The total random error is obtained by the SRSS method (Square root of the sum of the squares of the individual random errors).

Note that the SEL-451-5 relay is a microprocessor relay and does not require analog input methods to set the relay. Instead the settings are entered as exact digital numbers. Therefore, the metering and test equipment error is not considered in this setpoint calculation.

6.1.1.6   The total relay error in percent is equal to the sum of the random and non-random errors.

6.1.1.7   A time delay of 30 cycles or 0.5 s will be selected for the SEL-451-5 relay. This time delay is selected to prevent SEL-451-5 relay operation due to faults in the 345 kV switchyard cleared in its primary and zone 2 clearing time (See Section 7.2). In actual open phase conditions, the 0.5 second delay in the SEL-451-5 relay operation will not damage the motors due to negative sequence currents in the motor circuit (Refer to Reference 4.4). The 0.5 second time delay is short enough to prevent a unit trip by allowing critical motors to remain running (Reference 4.4).

6.1.1.8   The flow chart below illustrates the process used to determine the relay settings based on the results of EMTP-RV analysis. The calculation details including the CT and relay loop error considerations are described in detail in Attachment A.

```
┌─────────────────────────────┐
│ Obtain the Relay Setting     │
│ Limits From EMTP             │
│ Calculation (Each setting    │
│ has a Detection Limit and    │
│ the Security Limit)          │
└─────────────────────────────┘
              │
              ▼
┌─────────────────────────────┐
│ Develop the Error Adjusted   │
│ Relay Setting Limits (Error  │
│ Adjusted Detection Limit,    │
│ and Error Adjusted Security  │
│ Limit) by taking into        │
│ account the Margin, and      │
│ Accuracy of various          │
│ components.                  │
└─────────────────────────────┘
```

Are the Error Adjusted Detection Limit and the Error Adjusted Security Limit Overlapping? — Yes → Is Detection Limit Dependent on the Load on the Transformer? — No → Is Security Limit Dependent on the Load on the Transformer? — Yes → Use Modified Detection Limit as the Relay Setting for Subject Variable.

Are the Error Adjusted Detection Limit...? — No → Use Error adjusted Detection Limit as the Relay Setting for Subject Variable so that the Setting is Biased Towards Detection.

Is Detection Limit Dependent on the Load on the Transformer? — Yes → Use Error adjusted Detection Limit as the Relay Setting for Subject Variable...

Is Security Limit Dependent on the Load on the Transformer? — No → Is the Inequality in the Logic String "Greater Than" (>) for the Subject Variable?

Is the Inequality in the Logic String "Greater Than" (>) for the Subject Variable? — Yes → Use Error adjusted Detection Limit as the Relay Setting for Subject Variable...

Is the Inequality in the Logic String "Greater Than" (>) for the Subject Variable? — No → Use Modified Detection Limit as the Relay Setting for Subject Variable.

Condition: Variable > EMTP Established Limit

- Protected Region — EMTP Established Max Setting Limit
- Max Setting Limit Minus Total Loop Error
- Acceptable Relay Setting Range
- Min Setting Limit Plus Total Loop Error — EMTP Established Min Setting Limit
- No Trip Region

(Vertical axis: Variable)

Condition: Variable < EMTP Established Limit

- No Trip Region — EMTP Established Max Setting Limit
- Max Setting Limit Minus Total Loop Error
- Acceptable Relay Setting Range
- Min Setting Limit Plus Total Loop Error — EMTP Established Min Setting Limit
- Protected Region

(Vertical axis: Variable)

6.2   Acceptance Criteria

6.2.1 SEL-451-5 Relay
The relay setpoints satisfy all the dependability criteria such that the relay trips for open phase conditions under all conditions above minimum load. The relay setpoints must minimize, to the greatest extent practically possible, the security issues resulting in a false trip for any events the relay must not trip for.

6.2.2 Bushing CT Rating
The additional relay burden must not cause twice the CT secondary voltage developed during a fault to exceed the knee point voltage (Reference 4.9).

7.0   CALCULATIONS

7.1   The Relay Setpoint calculations for the SEL-451-5 relays at the 345 kV level are contained in Attachment A.

7.2   The open phase protection scheme time delay setting is provided to ensure that the scheme is secure during transmission grid disturbances and during all faults on the electrical auxiliary system, which are cleared without intentional time delay. A 0.5 seconds (30 cycles) time delay for SEL-451-5 relays has been determined in Reference 4.4.

7.3   The precision of the relay for various open phase conditions is as follows:

- For Single Grounded and Double Grounded open phase conditions, the L1 logic will be able to detect and trip for all conditions.

- For Single Ungrounded and Double Grounded/Ungrounded open phase conditions, the L2 logic string precision is based on the LLDIFF setting, which requires approximately 0.5MVA of load on the SAT.

- For Double Ungrounded open phase conditions, the L3 logic string precision is based on the LLDIFF setting, which requires approximately 0.5MVA of load on the SAT.

7.4   The CT burden and accuracy calculations are contained in Attachment D.

8.0   RESULTS

8.1   The complete results of analysis performed by this calculation can be found in Attachment A. Attachment A contains details of the Relay Settings Calculation including the errors of measurement of the CT, the SEL-451 relay, and the "Setpoint Limits" used in Calculation BYR13-176, "Unit 1 and 2 Loss of Phase Detection EMTP-RV Analysis" (Reference 4.4).

8.2   ZSCL1

After the CT errors and relay error have been accounted for the ZSCL1 setting limits are as follows:

ZSCL1 Low = 11.52A

ZSCL1 High = 24.76A

A setpoint of 11.52A is selected. A low setting in the allowable setting range increases the relay sensitivity in detecting an open phase. See Section 9.3 for further discussion regarding the sensitivity or the relay to an impedance grounded open phase condition.
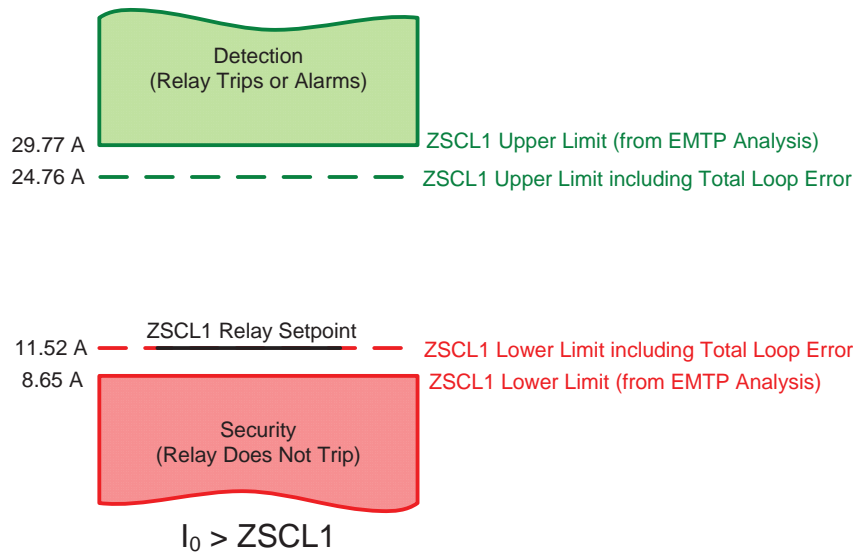
8.3   MINDETC

MINDETC is set at 1.16A based upon the relay sensitivity, CT ratio, and the total loop error.

8.4   LLDIFF

LLDIFF is set at 1.56A based upon the relay sensitivity, relay resolution, CT ratio, and the total loop error. At low loading, the SAT secondaries will maintain balanced voltages. Therefore, the power drawn pre and post single open phase will be the same. During a single open phase, the current of the healthy phases will increase by at least 25% on the SAT primaries.
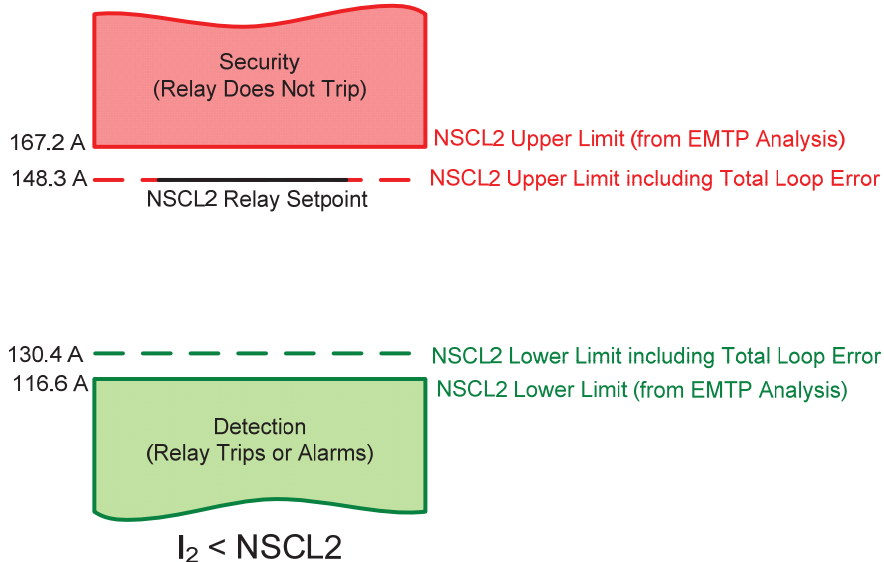
8.5   NSCL2

After the CT errors and relay error have been accounted for the NSCL2 setting limits are as follows:

NSCL2 Low = 130.4A

NSCL2 High = 148.3A

A setpoint of 148.3A is chosen. As discussed in section 7.4.2.3 of BYR13-176, an open phase with I_2 current at this level will have enough load on the SAT to cause I_0 current to be high enough to cause a trip of the L1 logic string. This setpoint ensures that the relay will be secure for L-L faults while not lessening the relays ability to detect an ungrounded open phase.

Security
(Relay Does Not Trip)

167.2 A — NSCL2 Upper Limit (from EMTP Analysis)

148.3 A — NSCL2 Upper Limit including Total Loop Error
NSCL2 Relay Setpoint

130.4 A — NSCL2 Lower Limit including Total Loop Error

116.6 A — NSCL2 Lower Limit (from EMTP Analysis)

Detection
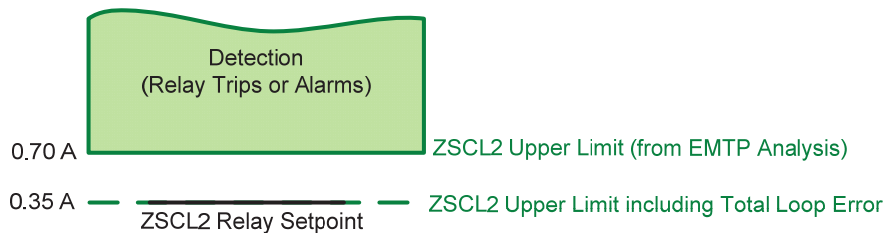(Relay Trips or Alarms)

$I_2 < NSCL2$

8.6   ZSCL2

After the CT errors and relay error have been accounted for the ZSCL2 setting limits are as follows:

ZSCL2 High = 0.35A

A setpoint of 0.35A is selected. To favor detection, the ZSCL2 setting selected is set based on the high setpoint limit after taking the total loop error into consideration.

Detection
(Relay Trips or Alarms)

0.70 A — ZSCL2 Upper Limit (from EMTP Analysis)

0.35 A — ZSCL2 Upper Limit including Total Loop Error
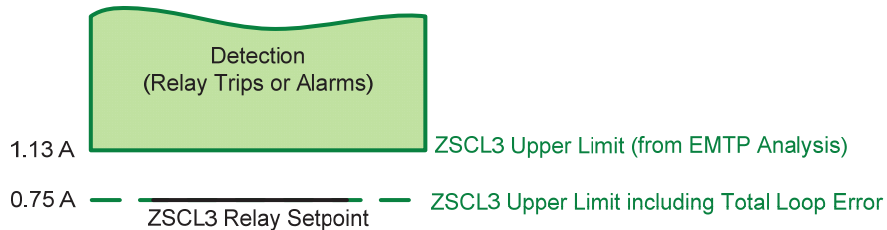ZSCL2 Relay Setpoint

8.7   ZSCL3

After the CT errors and relay error have been accounted for the ZSCL3 setting limits are as follows:

ZSCL3 High = 0.75A

A setpoint of 0.75A is selected. To favor detection, the ZSCL3 setting selected is set based on the high setpoint limit after taking the total loop error into consideration.

8.8 **MINLOAD**

After the CT errors and relay error have been accounted for the MINLOAD setting limits are as follows:

MINLOAD with Generation: 1.79A

MINLOAD without Generation: 2.27A

The MINLOAD settings are determined based on the setpoint limits after taking the total loop error into consideration. The appropriate MINLOAD setting is selected based on plant configuration. MINLOAD with Generation is 1.79A and selected as the setting when at least one generator is connected. MINLOAD without Generation is 2.27A and selected when both generators are offline.

9.0 CONCLUSIONS

9.1 Relay Settings

The specially programmed SEL-451-5 relay setpoints at the 345 kV level are as follows with their associated logic string (LS):

ZSCL1 (LS1)   = 11.52 A   MINDETC (LS2, LS3) = 1.16 A

ZSCL2 (LS2)   = 0.35 A   LLDIFF (LS2, LS3)   = 1.56 A

NSCL2 (LS2)   = 148.3 A

ZSCL3 (LS3)   = 0.75 A

T_DELAY (Common) = 0.5 s (30 cycles)

MINLOAD (At Least One Generator Online) = 1.79 A

MINLOAD (All Generators Offline) = 2.27 A

With the above settings the relay can detect open phase conditions while being secure against faults and expected system unbalances.

9.2   Coordination with Downstream Devices

The relay settings selected coordinate with downstream protective devices for line-to-line, line-to-ground, and balanced faults. The relay settings selected also coordinate with the Emergency Diesel Generator neutral relays.

9.3   Relay Impedance Sensitivity

The open phase detection scheme is designed for the solidly grounded (zero impedance) Single or Double open phase condition, or ungrounded (infinite impedance) Single or Double open phase condition. The solidly grounded Single or Double open phase condition is detected by Logic string #1, and ungrounded Single or Double open phase condition is detected by Logic string #2, and Logic string #3, respectively. The sensitivity of the open phase detection scheme in the presence of impedance is discussed below.

Under open phase condition the impedance may be present between the open phase conductor and the ground.
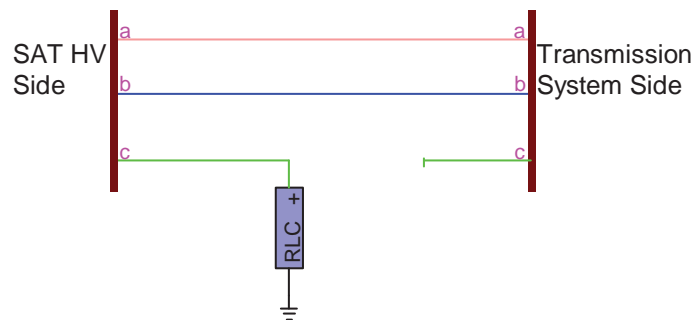
Impedance between Open Phase and Ground

Logic string #1 of the Open Phase detection scheme will detect a grounded open phase if the zero sequence current is equal to or greater than the ZSCL1 setting. For Byron Station the EMTP simulations have shown that the limiting impedances are 10kOhms for a single open phase to ground and 6kOhms for a double open phase to ground. That is the open phase to ground will be reliably detected if the impedance between the phase and the ground is less than 10kOhms and 6kOhms for Single Open Phase and Double Open Phase condition respectively. These impedance values are considered to envelope any practical open phase to ground impedance.

The open phase sequence time line:

T^{0-} -   Everything is operating normally.

T^{0+} -   Open Phase occurs

At this moment the voltage at the broken conductor on the SAT HV side (V$_{induced}$) is a function of SAT loading at Byron nuclear station as shown in the figure below. Please note that this voltage is not on the system (grid or switchyard) side of the open conductor. Therefore, the voltage shown in the figure below is due to the induced voltage in SAT on the open phase. Under the maximum loading of the SAT the voltage across the open phase conductor and ground is 112.6 kV. Because of the magnitude of the open phase conductor to ground voltage, 112.6 kV, the material that a broken conductor might touch will suffer a dielectric breakdown, and provide a low resistance path to ground or may establish an arc.

T$^{\Delta t}$ -   Some time Δt after the open phase event occurs, the conductor will touch the ground or touch the structure, breaking down the di-electric of any material which happens to be between the conductor and the available ground path, thus establishing the current path to the ground. Therefore, an open phase conductor on the HV side of SAT starts conducting current to the ground. At this point in time the induced voltage in SAT is divided between the zero sequence impedance of the SAT and the impedance between the open phase conductor and ground. Please note that the zero sequence impedance of wye connected transformer without buried delta winding is quite high. In such an event (e.g. at Byron) the majority of the induced voltage is across the transformer zero sequence impedance and a relatively small voltage magnitude appears between the open phase conductor and ground after the current starts flowing from open phase conductor to ground. Therefore, the measured voltage at the open phase conductor will not be nominal voltage after the path for the current is established.

Open Phase to Ground Voltage with Respect to Loading of SAT
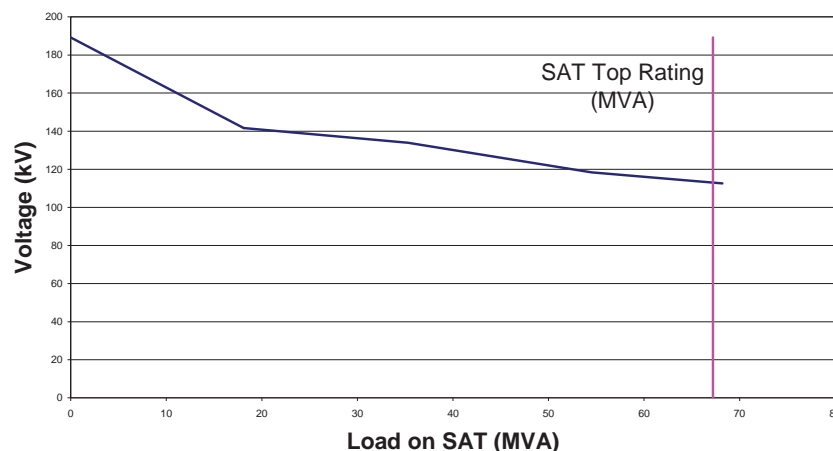
The methodology used for modeling high resistance arcing ground faults on high voltage transmission systems for digital simulations is identified in Reference 4.22. The fault resistance to ground using this methodology is shown to be 300 Ohms and is not dependent on voltage. Therefore, it is engineering judgment that the impedance to ground under an open phase condition shall not exceed 300 Ohms. Hence, the expected impedance between the open phase and ground conductor is either infinite or less than 300 Ohms.

The nominal voltage at Byron Station switchyard is 345 kV. At 345 kV the resistance to ground of any structure will not exceed a few hundred ohms (typically the maximum tower footing resistance at 345 kV would be 25 Ohms or less).

The maximum expected impedance to ground of 300 Ohms for a Single Open phase or Double Open phase condition (either with an arcing ground fault or through a structure) is less than 6kOhms, therefore, the Open Phase detection scheme developed for Byron station will reliably detect the above mentioned impedance between open phase and ground condition. Furthermore, the 345 kV transmission system protection schemes for the dropped line considers either ungrounded line (infinite impedance to ground) or only impedance of few ohms to ground. Thus, the design of the open phase detection scheme is consistent with the protection schemes for the transmission system.

Therefore, the Open Phase detection scheme developed for Byron station will reliably detect the impedance of 300 ohms between open phase and ground.

10.0 <u>ATTACHMENTS</u>

Attachment A: Relay Settings Calculation, SEL-451-5 Relay   A1 - A16

Attachment B: Relaying & Metering Diagrams, Miscellaneous   B1 - B17
SEL-451-5 Information

Attachment C: Doble, Omicron, and SEL-451-5 Relay Specs   C1 - C36

Attachment D: CT Burden and Accuracy Calculation   D1 - D7

Attachment E: CT Exciting Curve, CO-7 Energy Requirements,   E1 - E15
Watthour Meter Burden

ATTACHMENT 1
Design Analysis Cover Sheet
Page 1 of 5

Design Analysis			Last Page No. ⁶ Attachment ☒ Page ⁵
Analysis No.: ¹ BYR13-221 / BRW-13-0107-E		**Revision:** ² 000 Major ☒	Minor ☐
Title: ³ Open Phase Detection LOCA Analysis			
EC/ECR No.: ⁴ 389896 / 389897 / 390213 / 390214		**Revision:** ⁶ 4 / 4 / 2 / 2	

Station(s): ⁷	Bryon & Braidwood	Component(s): ¹⁴	
Unit No.: ⁸	1 & 2 (both stations)		
Discipline: ⁹	ELDC		
Descrip. Code/Keyword: ¹⁰	E15		
Safety/QA Class: ¹¹	Safety Related		
System Code: ¹²	AP		
Structure: ¹³	N/A		

CONTROLLED DOCUMENT REFERENCES ¹⁵

Document No.:	From/To	Document No.:	From/To
19-AN-3	From	BYR13-176	From
19-AN-7	From	BYR13-177	From
19-AU-4	From	BRW-12-0267-E	From
19-AU-5	From	BRW-12-0159-E	From

Is this Design Analysis Safeguards Information? ¹⁶   Yes ☐ No ☒   If yes, see SY-AA-101-106

Does this Design Analysis contain Unverified Assumptions? ¹⁷   Yes ☐ No ☒   If yes, ATI/AR#:

This Design Analysis SUPERCEDES: ¹⁸   N/A   In its entirety.

Description of Revision (list changed pages when all pages of original analysis were not changed): ¹⁹			
N/A: Initial Issue	*Eric Hope (Attachment H)*	*Eric Hope*	1/10/2014
Preparer: ²⁰	Craig M. Starr	*(signature)*	1/10/2014
	Jusuf Krvavac (Attachment D)	*(signature)*	1/10/2014
	Print Name	Sign Name	Date

Method of Review: ²¹	Detailed Review ☒ Alternate Calculations (attached) ☐ Testing ☐		
Reviewer: ²²	William G. Bloethe	*(signature)*	1/10/2014
	Piotr R. Wiczkowski	*(signature)*	1/10/2014
	Safa Alkhatib	*(signature)*	1/10/2014
	Print Name	Sign Name	Date
Review Notes: ²³	Independent review ☒ Peer review ☐		
	W.G.B reviewed calculation text, Attachments C, D & E		
	S.A. reviewed Attachments A, F, & G		
	P.R.W. reviewed Attachment B.		

(For External Analyses Only) **External Approver:** ²⁴	William G. Bloethe	*(signature)*	Jan 10, 20 14
	Print Name	Sign Name	Date
Exelon Reviewer: ²⁵	DARREL RIEDINGER	*(signature)*	1/16/14
	Print Name	Sign Name	Date

Independent 3ʳᵈ Party Review Reqd? ²⁶ Yes ☐ No ☒			
Exelon Approver: ²⁷	Brian Ledgar	*(signature)*	6/27/14
	Print Name	Sign Name	Date

ATTACHMENT 2
Owner's Acceptance Review Checklist for External Design Analyses
Page 1a of 1c

Design Analysis No.: BYR13-221 / BRW-13-0107-E **Rev: 0**

No	Question	Instructions and Guidance	Yes / No / N/A
1	Do assumptions have sufficient documented rationale?	All Assumptions should be stated in clear terms with enough justification to confirm that the assumption is conservative. For example, 1) the exact value of a particular parameter may not be known or that parameter may be known to vary over the range of conditions covered by the Calculation. It is appropriate to represent or bound the parameter with an assumed value. 2) The predicted performance of a specific piece of equipment in lieu of actual test data. It is appropriate to use the documented opinion/position of a recognized expert on that equipment to represent predicted equipment performance. Consideration should also be given as to any qualification testing that may be needed to validate the Assumptions. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐
2	Are assumptions compatible with the way the plant is operated and with the licensing basis?	Ensure the documentation for source and rationale for the assumption supports the way the plant is currently or will be operated post change and they are not in conflict with any design parameters. If the Analysis purpose is to establish a new licensing basis, this question can be answered yes, if the assumption supports that new basis.	☒ ☐ ☐
3	Do all unverified assumptions have a tracking and closure mechanism in place?	If there are unverified assumptions without a tracking mechanism indicated, **then** create the tracking item either through an ATI or a work order attached to the implementing WO. Due dates for these actions need to support verification prior to the analysis becoming operational or the resultant plant change being op authorized.	☐ ☐ ☒.
4	Do the design inputs have sufficient rationale?	The origin of the input, or the source should be identified and be readily retrievable within Exelon's documentation system. If not, then the source should be attached to the analysis. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐
5	Are design inputs correct and reasonable with critical parameters identified, if appropriate?	The expectation is that an Exelon Engineer should be able to clearly understand which input parameters are critical to the outcome of the analysis. That is, what is the impact of a change in the parameter to the results of the analysis? If the impact is large, then that parameter is critical.	☒ ☐ ☐
6	Are design inputs compatible with the way the plant is operated and with the licensing basis?	Ensure the documentation for source and rationale for the inputs supports the way the plant is currently or will be operated post change and they are not in conflict with any design parameters.	☒ ☐ ☐

ATTACHMENT 2
Owner's Acceptance Review Checklist for External Design Analyses
Page 1b of 1c

Design Analysis No.: BYR13-221 / BRW-13-0107-E **Rev: 0**

No	Question	Instructions and Guidance	Yes / No / N/A
7	Are Engineering Judgments clearly documented and justified?	See Section 2.13 in CC-AA-309 for the attributes that are sufficient to justify Engineering Judgment. Ask yourself, would you provide more justification if you were performing this analysis? If yes, the rationale is likely incomplete.	☒ ☐ ☐
8	Are Engineering Judgments compatible with the way the plant is operated and with the licensing basis?	Ensure the justification for the engineering judgment supports the way the plant is currently or will be operated post change and is not in conflict with any design parameters. If the Analysis purpose is to establish a new licensing basis, **then** this question can be answered yes, if the judgment supports that new basis.	☒ ☐ ☐
9	Do the results and conclusions satisfy the purpose and objective of the Design Analysis?	Why was the analysis being performed? Does the stated purpose match the expectation from Exelon on the proposed application of the results? If yes, **then** the analysis meets the needs of the contract.	☒ ☐ ☐
10	Are the results and conclusions compatible with the way the plant is operated and with the licensing basis?	Make sure that the results support the UFSAR defined system design and operating conditions, or they support a proposed change to those conditions. If the analysis supports a change, are all of the other changing documents included on the cover sheet as impacted documents?	☒ ☐ ☐
11	Have any limitations on the use of the results been identified and transmitted to the appropriate organizations?	Does the analysis support a temporary condition or procedure change? Make sure that any other documents needing to be updated are included and clearly delineated in the design analysis. Make sure that the cover sheet includes the other documents where the results of this analysis provide the input.	☐ ☐ ☒
12	Have margin impacts been identified and documented appropriately for any negative impacts (Reference ER-AA-2007)?	Make sure that the impacts to margin are clearly shown within the body of the analysis. If the analysis results in reduced margins ensure that this has been appropriately dispositioned in the EC being used to issue the analysis.	☐ ☐ ☒
13	Does the Design Analysis include the applicable design basis documentation?	Are there sufficient documents included to support the sources of input, and other reference material that is not readily retrievable in Exelon controlled Documents?	☒ ☐ ☐
14	Have all affected design analyses been documented on the Affected Documents List (ADL) for the associated Configuration Change?	Determine if sufficient searches have been performed to identify any related analyses that need to be revised along with the base analysis. It may be necessary to perform some basic searches to validate this.	☒ ☐ ☐
15	Do the sources of inputs **and** analysis methodology used meet committed technical and regulatory requirements?	Compare any referenced codes and standards to the current design basis and ensure that any differences are reconciled. If the input sources **or** analysis methodology are based on an out-of-date methodology or code, additional reconciliation may be required if the site has since committed to a more recent code	☒ ☐ ☐

ATTACHMENT 2
Owner's Acceptance Review Checklist for External Design Analyses
Page 1c of 1c

Design Analysis No.: BYR13-221 / BRW-13-0107-E **Rev: 0**

No	Question	Instructions and Guidance	Yes / No / N/A
16	Have vendor supporting technical documents and references (including GE DRFs) been reviewed when necessary?	Based on the risk assessment performed during the pre-job brief for the analysis (per HU-AA-1212), ensure that sufficient reviews of any supporting documents not provided with the final analysis are performed.	☐ ☐ ☒
17	Do operational limits support assumptions and inputs?	Ensure the Tech Specs, Operating Procedures, etc. contain operational limits that support the analysis assumptions and inputs.	☒ ☐ ☐

TABLE OF CONTENTS

1. Purpose & Scope

1.1. Background

On Monday, January 30, 2012, Byron Unit 2 tripped due to a component failure in the switchyard. An insulator on a bus support broke and grounded the high voltage bushing of the System Auxiliary Transformer (SAT), causing a short section of 345kV bus to become disconnected. This bus section was associated with the Phase "C" offsite source to the System Auxiliary Transformers (SATs). The event caused an open circuit on phase "C", however, neither the protective relaying system in the switchyard nor the plant detected the loss of Phase "C".

1.2. Purpose

An Open Phase Detection scheme has been installed on both units at the Byron and Braidwood stations. This scheme is designed to detect an open phase on any one phase of the offsite feeds to the System Auxiliary Transformers (SAT). It is required to demonstrate that with an accident condition present, the scheme will detect the open phase event (single or double open phase condition with or without ground) and transfer loads required to mitigate postulated accident conditions to an alternate source and ensure that safety functions are preserved. It is the purpose of this calculation to evaluate the impact an open phase event concurrent with a LOCA for Byron and Braidwood stations has on essential service function (ESF) buses, motors, and motor operated valves (MOVs).

1.3. Scope

The scope of this analysis is limited to analyzing the ESF buses at Byron and Braidwood. This analysis is only concerned with equipment fed from the SATs and since the Byron (Ref. 4.1.1) and Braidwood (Ref. 4.1.11) SATs for all 4 units are similar, an analysis of one unit is applicable to all units at both stations. Byron Unit 1 is analyzed in detail since it is the bounding unit[1]. Specific references in this analysis to Unit 1 Byron buses and equipment are also applicable to Unit 2 Byron buses and Unit 1 and 2 Braidwood buses.

The analysis will determine the following items[2] for the ESF buses listed below for the duration that the ESF buses/loads are connected to the unhealthy (open phase) source:

ESF 4.16 kV SWGR	**ESF 460 V SWGRs & MCCs**
SWGR 141	SWGR 131X & 132X & MCCs fed from these SWGRs
SWGR 142	SWGR 131Z & 132Z (Byron Only) & MCCs fed from these SWGRs

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[1] See Section 6.1 for discussion on why Byron Unit 1 is the bounding unit.

[2] The impact of block starting the ESF loads during an open phase event (single or double open phase condition with or without ground) for the duration of the time delay is analyzed in BYR13-176 (Ref. 4.1.1).

- The impact of the single phase block start of ESF loads on the bus protection scheme (overcurrent and undervoltage)
- The impact of the single phase block start of ESF loads on the motor protection scheme (overcurrent).
- The heating (I_2^2t) impact of single phase block start of ESF loads on the running and starting motors and MOVs.
- The impact of isolating ESF loads from the SATs during the starting sequence and then restarting the ESF loads on the emergency source.

2. Design Inputs

2.1. 345 kV System

2.1.1. The original EMTP model developed for "Loss of Phase Detection EMTP Analysis" calculations for Byron (Ref. 4.1.1, Attachment D, E, & F) contained a detailed model of the transmission system. However, for this analysis a detailed model of the transmission system is not used. An unbalanced voltage source with infinite short circuit strength (Assumption 3.2.9) is developed to obtain the maximum negative sequence voltage while still maintaining an unbalance within the 3% limit (Ref. 4.4.14) and meeting the constraints that are explained in detail in Attachments C and H of this analysis. This simplified source provides the maximum degree of unbalance, and therefore bounds the more detailed transmission system source.

Table 1 - Unbalanced System Voltage

Van∠θan kVRMSLL, deg		Vbn∠θbn kVRMSLL, deg		Vcn∠θcn kVRMSLL, deg		V2∠θ kVRMS, deg		NEMA % Unbalance
351.90	0.00	362.25	-118.00	362.25	118.00	6173.90	179.90	2.96

2.2. Transformers

2.2.1. Transformer models for the SATs, MPTs, UATs, and Unit Substation for Byron Units 1 and 2 were developed for the "Loss of Phase Detection EMTP Analysis" calculations (Ref. 4.1.1, Attachment D, E, & F). Note, for this analysis only the SATs and Unit Substations are used.

2.3. Cable Data

2.3.1. Cable models for Byron Units 1 and 2 were developed for the "Loss of Phase Detection EMTP Analysis" calculations for Byron (Ref. 4.1.1, Attachment F).

2.4. Load Data

The loading information is obtained from the ELMS "Load Summary by Bus (long form)" reports (Ref. 4.1.9). Loading Conditions 2 (LC-2, Full Load Summer) and 4 (LC-4, LOCA Shutdown) are used in these analyses.

2.4.1. Medium Voltage (6.6 kV and 4 kV) Motors

Most medium voltage motor models for Byron Units 1 and 2 were developed for the "Loss of Phase Detection EMTP Analysis" calculations for Byron (Ref. 4.1.1, Attachment F). However, it is necessary to add motors that start during a LOCA to the model. UFSAR Table 8.3-5, EC 365038, and the ELMS loading report (Ref. 4.1.7 through 4.1.9) are used to determine which motors start during a LOCA. Motor types that are added to the model are developed based on the input data from references 4.1.1, 4.3 and 4.1.9. The motor parameters are tabulated in Attachment B.

Table 2 – ESF MV Motors

Load #	Load Name	Bus	Notes
0VA01CA	Aux Bldg Supply Fan 0A	141	Previously modeled, Running prior to a LOCA, Does not start
1CC01PA	Component Cooling Pump 1A	141	Previously modeled, Running prior to a LOCA, Starts for LOCA (Note 1)
0WO01CA	Control Room Chiller Unit 0A	141	Previously modeled, Running prior to a LOCA, Starts for LOCA (Note 1)
0VA02CA	Aux Bldg Exhaust Fan 1A	141	Previously modeled, Running prior to a LOCA, Does not start
1AF01PA	AUX FEED WATER PUMP	141	Motor added to model, Starts for LOCA
1CS01PA	CONTAINMENT SPRAY PUMP	141	Motor added to model, Starts for LOCA
1SI01PA	SAFETY INJECTIONPUMP 1A	141	Motor added to model, Starts for LOCA
1RH01PA	RESIDUAL HEAT REMOVAL PUMP	141	Motor added to model, Starts for LOCA
1SX01PA	ESS SERV WTR PUMP 1A	141	Motor added to model, Starts for LOCA
1CV01PA	CENTRIFUGAL CHARGING PUMP	141	Motor added to model, Starts for LOCA
1CV01PB	Centrifugal Charging Pump 1B	142	Previously modeled, Running prior to a LOCA, Starts for LOCA (Note 1)
1SX01PB	Essential Service Water Pump 1B	142	Previously modeled, Running prior to a LOCA, Starts for LOCA (Note 1)
1CS01PB	CONTAINMENT SPRAY PUMP	142	Motor added to model, Starts for LOCA
1SI01PB	SAFETY INJECTIONPUMP 1B	142	Motor added to model, Starts for LOCA
1RH01PB	RESIDUAL HEAT REMOVAL PUMP	142	Motor added to model, Starts for LOCA
0WO01CB	CONTROL ROOM REFRIG UNIT	142	Motor added to model, Starts for LOCA
1CC01PB	COMPONENT COOLING PUM	142	Motor added to model, Starts for LOCA
0VA01CB	AUX BLDG VENT SYS SUPPLY	142	Motor not modeled, Does not run or start at the initiation of a LOCA
0VA02CB	AUX BLDG VENT SYS EXH FAN	142	Motor not modeled, Does not run or start at the initiation of a LOCA

1. Motors that are running prior to a LOCA are de-energized and restarted (Assumption 3.2.2)

2.4.2. <u>Low Voltage (460 V) Motors</u>

Most equivalent (lumped) low voltage loads (motors & static) for Byron Units 1 and 2 were developed for the "Loss of Phase Detection EMTP Analysis" calculations for Byron (Ref. 4.1.1, Attachment F). However, it is necessary to add motors that start during a LOCA. UFSAR Table 8.3-5, EC 365038, and the ELMS loading report (Ref. 4.1.7 through 4.1.9) are used to determine which motors start during a LOCA. Motor types that are added to the model are developed based on the input data from reference 4.1.1, and 4.1.9 and Assumption 3.2.1. The motor parameters are tabulated in Attachment B.

Table 3 – ESF LV Motors Modeled

Load #	Load Name	Bus	Notes
1VP01CA	RCFC FAN 1A LOW SPEED B	131X	Motor added to model, Starts for LOCA
1VP01CC	RCFC FAN 1C LOW SPEED B	131X	Motor added to model, Starts for LOCA
0VA03CA	AUX BLDG VENT CHAR BSTR FAN	131X	Motor added to model, Running prior to a LOCA, Starts for LOCA (Note 1 & Assumption 3.2.3)
1VP01CC	RCFC FAN 1C HIGH SPEED	131X	Motor added to model Running prior to a LOCA, Trips on LOCA (Assumption 3.2.4)
131X_Lumped	131X_Lumped	131X	Previously modeled but updated for this analysis (See Section 2.4.3), Running prior to LOCA,
131Z_Lumped	131Z_Lumped	131Z	Previously modeled but updated for this analysis (See Section 2.4.3), Running prior to LOCA,
1VP01CB	RCFC FAN 1B LOW SPEED B	132X	Motor added to model, Starts for LOCA
1VP01CD	RCFC FAN 1D LOW SPEED B	132X	Motor added to model, Starts for LOCA
0VA03CB	AUX BLDG VENT CHAR BSTR FAN	132X	Motor added to model, Running prior to a LOCA, Starts for LOCA (Note 1 & Assumption 3.2.3)
0VA04CB	FUEL HANDLG BLDGCHARC BSTR	132X5	Motor added to model, Starts for LOCA
132X_Lumped	132X_Lumped	132X	Previously modeled but updated for this analysis (See Section 2.4.3), Running prior to LOCA,
132Z_Lumped	132Z_Lumped	132Z	Previously modeled but updated for this analysis (See Section 2.4.3), Running prior to LOCA,

1. Motors that are running prior to a LOCA are de-energized and restarted (Assumption 3.2.2)

2.4.3. <u>Low Voltage Lumped Loads (Motor & Static)</u>

Most equivalent lumped low voltage loads for Byron Units 1 and 2 were developed for the "Loss of Phase Detection EMTP Analysis" calculations for Byron (Ref. 4.1.1, Attachment F). However, it was necessary to update the lumped low voltage motor portion of the lumped loads for the 480 V ESF buses (131X and 132X) to account for the individually modeled motors described in Section 2.4.2. It was also necessary to update

these lumped motors' circuit parameters (Shown in Table 4) as well as lumped motors 131Z and 132Z to ensure that the bounding motor phase currents and I_2^2t values are produced. As discussed in detail in Attachment C, a lumped motor with the following parameters will result in bounding motor phase currents and I_2^2t values.

Table 4 – Lumped Motor Bounding Parameters

η	pf	FL % slip	LRC pu
0.9	0.95	1.5	8.02

2.4.4. Motor Operated Valves (MOVs)

MOVs are considered in this analysis; however, based on Assumptions 3.2.5 and 3.2.6 and Sections 6.2.2.3 and 6.2.3.2 they do not need to be explicitly model to verify that they meet their acceptance criteria.

2.5. Protective Relay and Breaker Settings

2.5.1. SEL-451 Open Phase Relay

This analysis is concerned with the ESF auxiliary system during an open phase event concurrent with a LOCA. According to analysis BYR13-177 (Ref. 4.1.2) the open phase event will be detected and the relay will send a trip signal in 30 cycles (0.5 second) to the SAT 86 lockout relays, which will trip the 345 kV switchyard breakers.

The lockout relay is a type WL with model number 501A817G01, 503A804G01 or 656A830G01 (Ref. 4.4.12). However, the vendor documentation (Ref. 4.4.13) does not contain the model numbers provided so it was assumed that a coil that takes the longest time to operate (19 ms) is used (Assumption 3.2.7).

The 345 kV breakers are assumed to have an interrupting time of 5 cycles (Assumption 3.2.8).

Total time from SEL-451 actuation until SATs are tripped =

SEL-451 Time Delay + Lockout Relay Operating Time + 345 kV CB Interrupting Time =

0.5 s + 0.019 s + 5/60 s = 0.6023 s

2.5.2. Medium Voltage

This analysis is concerned with bus phase and ground overcurrent relays, bus undervoltage relays, and motor phase and ground overcurrent relays. Relay settings for medium voltage ESF switchgears are provided in analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4).

2.5.3. Low Voltage

This analysis is concerned with bus phase and ground overcurrent relays, bus undervoltage relays, and motor phase and ground overcurrent relays. Circuit breaker settings for low voltage switchgears are provided in analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6).

Low voltage motors and MOVs fed from MCCs are protected by Westinghouse FH Overload Relays as well as molded case circuit breakers (MCCBs). It is assumed that the minimum overload relay curve for any of the FH overload relays identified in Reference 4.4.1 is used for all low voltage motors (Assumption 3.2.5).

The magnetic (instantaneous) trip element for MCCBs feeding continuous duty motors is assumed to be set at 10 x FLA (Reference 4.4.15 & Assumption 3.2.10).

Based on Exelon Standard NES-E/I&C 10.01B (Ref. 4.4.15), the instantaneous trip element for MCCBs feeding MOVs where nuisance tripping is a concern is set at 2 times the nameplate LRC.

2.6.   Emergency Diesel Generator Sequencing

Based on the UFSAR Table 8.3-5 (Ref. 4.1.7) it takes approximately 12 seconds after a LOCA signal before any major loads are started on the emergency diesel generators. The diesel generators take 10 seconds to start and an additional 2 seconds is required for the bus voltage relaying interlock to reenergize the sequence logic and programmed sequence time delay for major loads.

3. Assumptions

3.1. Assumptions Requiring Verification

3.1.1. None

3.2. Assumptions Not Requiring Verification

3.2.1.
All assumptions related to the EMTP model development for Analysis BYR13-176 (Ref. 4.1.1) are applicable to model additions/updates (i.e. motors) made for this analysis unless otherwise specifically stated.

3.2.2.
There are some loads that operate in steady-state and also during a LOCA according to Reference 4.3. For this analysis it assumed that these loads start during a LOCA. However, it is also important to account for the pre-LOCA loading of the motor for the maximum loading conditions. To ensure that the model accounts for the maximum pre-LOCA loading while also accounting for the motor starting during a LOCA, these loads were modeled using two motors. One motor, considered the steady-state motor, will turn off once the LOCA starts, while the other motor, considered the LOCA motor, will start at the initiation of the LOCA. See Attachment B for more modeling details.

3.2.3.
According to EC 365038 (Ref. 4.1.8) there are three trains of Auxiliary Building Charcoal Filters with two Booster fans per filter. However, only one fan runs when the filters are in service. When a filter train is placed in service one of the booster fans receives an immediate start signal while the other booster fan start is delayed and only starts if the first fan fails to start. The logic shows that 0B (div 12), 0D (div 22 power) and 0F (div 21 power) receive the immediate start signal while 0A (div 11 power), 0C (div 21 power) and 0E (div 12 power) receive a delayed start signal. This logic shows that two booster fans on unit 2 receive an immediate start. However, since this analysis only considers Unit 1, two booster fans on Unit 1 were assumed to start. (0A on div 11 power and 0B on div 12 power). It is conservative to have more motors starting on the unit being analyzed.

3.2.4.
Reactor Containment Fan Coolers (RCFC) operate at high speed during normal plant operation and low speed during a LOCA. The high speed fans trip upon a LOCA signal and the RCFC low speed fans start. According to the UFSAR Table 8.3-5 (Ref. 4.1.7) the low speed fan will start 20 seconds after the LOCA signal. However, it was assumed to start at the initiation of the LOCA for this analysis. It is conservative to assume more motors starting on the unit being analyzed.

3.2.5.
Low voltage motors and MOVs are protected by Westinghouse FH Overload Relays. For the purposes of this analysis it is assumed that the minimum overload relay curve for any of the FH overload relay types identified in Reference 4.4.1 is used for all motors and MOVs. This is a conservative assumption for this analysis since a minimum overload relay curve decreases the tripping time, which increases the probability that these relays might trip on overcurrent during the open phase event.

3.2.6.
No standards exist which described the permissible thermal capabilities of an MOV with regard to negative sequence current. However, a letter from Baldor-Reliance to Flowserve-Limitorque (Ref. 4.4.11) states, "*Most curves published for Limitorque ratings*

show heating after a 10 second locked rotor condition....". Based on this statement, most MOVs can withstand a locked rotor condition for up to 10 seconds before starting to overheat. However, for the purposes of this analysis it is conservatively assumed that MOVS can only withstand a locked rotor condition for up to 5 seconds.

3.2.7. The SAT lockout relay model numbers provided in reference 4.4.12 were not listed in the vendor documentation (Ref. 4.4.13). For the purposes of this analysis it was assumed that coil used for this lockout relay has the longest operating time of 19 ms. This is a conservative assumption since a longer operating time will increase the total time it takes the ESF buses and motors to be safely isolated from the unhealthy (open phase) SAT(s) and provides bounding $I_2^2 t$ values.

3.2.8. The 345 kV switchyard breakers are assumed to have a 5 cycle interrupting time. Typical 345 kV switchyard breakers are either 2 or 3 cycles but 5 cycles is used for added conservatism since a longer operating time will increase the total time it takes the ESF buses and motors to be safely isolated from the unhealthy (open phase) SAT(s) and provides bounding $I_2^2 t$ values.

3.2.9. The unbalanced voltage system source is assumed to have an infinite strength (zero impedance). This is a conservative assumption as it allows the most negative sequence current to flow to the motors which increases the thermal duties these motors experience.

3.2.10. A molded case circuit breaker used in conjunction with a combination starter should have an instantaneous trip setting between 10-12 times full load current based on Exelon design procedures (Ref. 4.4.15). For the purposes of this analysis the instantaneous setting is assumed to be set at the lower end (10 x FLA) of the typical value. This is a conservative assumption for this analysis since a minimum trip current increases the probability that these breakers might trip on overcurrent during the open phase event.

4. References

4.1. Calculations & Analyses

4.1.1. Analysis No. BYR13-176, Rev. 0, - "Unit 1 Loss of Phase Detection EMTP Analysis" (Byron Unit 1 & 2)

4.1.2. Analysis No. BYR13-177, Rev. 0, - "Unit 1 and 2 Loss of Phase Detection Relay Settings"

4.1.3. Analysis No. 19-AN-3 R16 (Byron/Braidwood Unit 1) – "Protective Relay Settings for 4.16 kV ESF Switchgear"

      4.1.3.1. Minor Revisions 16A through 16D (Byron)
      4.1.3.2. Minor Revisions 16A through 16E (Braidwood)

4.1.4. Analysis No. 19-AN-7 R11 (Byron/Braidwood Unit 2) – "Protective Relay Settings for 4.16 kV ESF Switchgear"

      4.1.4.1. Minor Revisions 11A through 11E

4.1.5. Analysis No. 19-AU-4, R18 (Byron/Braidwood Unit 1) – "480 V Unit Substation Breaker and Relay Settings"

      4.1.5.1. Minor Revisions 18B,K,L,M,N, & O

4.1.6. Analysis No. 19-AU-5, R13 (Byron/Braidwood Unit 2) – "480 V Unit Substation Breaker and Relay Settings"

      4.1.6.1. Minor Revisions 13C,M,N, & P

4.1.7. B/B-UFSAR, Table 8.3-5 of Section 8.3 "Onsite Power Systems"

4.1.8. EC 365038, Rev. 0 (Analysis evaluates a block start following an SI signal)

4.1.9. DIT S040-BYR-13080-00, "ELMS Load Data for Transmission Network Analysis – Single Phase", date 10/23/2013

4.1.10. Calculation No. 19-AK-3 R0, "Calc for System Auxiliary Transformer Loading During Cross-Tie Scenario", Rev. 0, date 5-14-93

4.1.11. Analysis No. BRW-12-0267-E Rev. 0, "Unit 1 Loss of Phase Detection EMTP Analysis" (Braidwood Unit 1 & 2).

4.1.12. Analysis No. BRW-12-0159-E, Rev. 0, "Unit 1 and 2 Loss of Phase Detection Relay Settings" (Braidwood Unit 1 & 2)

4.2. Drawings

4.2.1. None

4.3. Motor Data from Passport (Included in Attachment E)

4.3.1. Auxiliary Feedwater Pumps

    4.3.1.1. Westinghouse Speed vs Torque & Current Curve 664834

    4.3.1.2. Westinghouse Thermal Limit and Acceleration Time vs Current Curve 664835

4.3.2. Containment Spray Pump

    4.3.2.1. Westinghouse Thermal Limit and Acceleration Time vs Current Curve 664833

    4.3.2.2. Westinghouse Speed vs Torque and Current Curve 664832

4.3.3. Safety Injection Pump

    4.3.3.1. Westinghouse Induction Motor Data Sheet, S. O. No. 74-F-18601, dated 11/12/73

    4.3.3.2. Westinghouse Speed vs Torque Curve 663624-B

    4.3.3.3. Westinghouse Time vs Current Curve 663625-C

4.3.4. Residual Heat Removal Pump

    4.3.4.1. Westinghouse Induction Motor Data Sheet, S. O. No. 74-F-12182 and 74-F-18815

    4.3.4.2. Westinghouse Speed vs Torque Curve 663446B

    4.3.4.3. Westinghouse Safe Time vs Current Curve 663448, dated 5/17/74

4.4. Standards, Papers & Misc. Vendor Data

4.4.1. Westinghouse Letter to Mr. Galanis (S&L) from J. A. Mitchell (Westinghouse), "Subject: Byron & Braidwood Stations 480 Volt Motor Control Centers F/L-2755", dated April 10, 1990 (FH Overload Relay Time – Current Characteristics Curves Included in Attachment E)

    4.4.1.1. Curve Sheet No. PTA 032480 Rev. 1, 1/11/85 (Type A or B, Size 1 or 2, 3 Pole, Compensated OLA's in any Size Enclosure and Non-Compensated OLA's in Enclosures Greater than 5500 in^3)

    4.4.1.2. Curve Sheet No. PTA 032880 Rev. 1, 1/11/85 (Type A or B, Size 1 or 2, 3 Pole, Non-Compensated OLA's in any Size Enclosures Less than 5500 in^3)

    4.4.1.3. Curve Sheet No. PTA 032680 Rev. 1, 1/11/85 (Type A or B, Size 1 or 2, 1 Pole, Compensated OLA's in any Size Enclosure and Non-Compensated OLA's in Enclosures Greater than 5500 in^3)

    4.4.1.4. Curve Sheet No. PTA 032980 Rev. 1, 1/11/85 (Type A or B, Size 1 or 2, 1 Pole, Non-Compensated OLA's in Enclosures Less than 5500 in^3)

    4.4.1.5. Curve Sheet No. PTA 012485 (Type A or B, Size 3 or 4, 3 Pole, Compensated OLA's in any Size Enclosure and Non-Compensated OLA's in Enclosures Greater than 5500 in^3)

    4.4.1.6. Curve Sheet No. PTA 012585 (Type A or B, Size 3 or 4, 3 Pole, Non Compensated OLA's in Enclosures less than 5500 in^3)

4.4.2. Cummings, P. G., Dunki-Jacobs, J. R., and Kerr, R. H., "Protection of Induction Motors Against Unbalanced Voltage Operation," *IEEE Transactions on Industry Applications*, Vol. IA-21, No. 4, pp. 778–792, May/June 1985.

4.4.3. Gleason, L. L., and Elmore, W. A., "Protection of 3-Phase Motors Against Single-Phase Operation," *IEEE Transactions on Power Apparatus and Systems*, Vol. 77, Part 3, pp. 1112–1119, December 1958.

4.4.4. Westinghouse Electric Corporation. "Applied Protective Relaying", Newark, New Jersey, 1976.

4.4.5. Ward, D. J., and Owen, E. L., "Motor Voltage Unbalance Limits on Three-Phase Systems", presented at the *Southwest Electric Distribution Exchange*, May 9, 1979.

4.4.6. Design Features and Protection of Valve Actuator Motors in Nuclear Power Plants (Report by Working Group PES-NPEC-SC4.7) – IEEE Transactions on Energy Conversion, Vol. 5, No. 3, September 1990

4.4.7. IEEE 741, "Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations", dated 2007

4.4.8. System Planning Operating Guide (SPOG) 1-1 for ComEd Transmission Planning Department, Rev 14 – "Generation Stations Operating Voltage level", dated 12-6-11

4.4.9. IEEE Paper No. PCIC-2001-29, -"Motor Primer – Part 2" (Select Pages Included in Attachment E)

4.4.10. Integral Energy Power Quality Centre, Technical Note No. 6 – "Voltage Unbalance", date October 2002. (Included in Attachment E)

4.4.11. Letter from Todd William (Baldor-Reliance) to Kyle Ramsey (Flowserve-Limitorque) – "MOV Motor Operator Thermal Capabilities with Regard to Negative Sequence Current", date June 26, 2012. (Included in Attachment E)

4.4.12. Email from Ali Avi (Exelon) to John Bojan (S&L) – "RE: Lockout Relay Model Number", date 1/7/2014 (Included in Attachment E)

4.4.13. Electroswitch Switches and Relays Technical Publication W-1, "Type W and W-2 Instrument and Control Switches, Type WL and WL-2 Multi-Contact Lock-Out Relays for Power Industry and Heavy Duty Industrial Applications", September 1, 1998 (Select Pages Included in Attachment E)

4.4.14. ANSI C84.1-2011, "Electric Power Systems and Equipment – Voltage Ratings (60 Hertz), January 17th 2012

4.4.15. Exelon Standard NES-E/I&C 10.01B, Rev 2, "Molded Case Circuit Breaker Selection and Setting Design Standard"

4.4.16. SOP-0204. "Computer Software Quality Policies and Requirements." Rev 10. 2/1/2013.

4.4.17. GAG-0204-01, "Computer Software Development, Procurement, Verification and Validation, Documentation Configuration Control, and Error Reporting", Rev 10, 2/1/2013.

5. Identification of Computer Programs

The following programs were run on S&L PC number ZL6278

5.1.   Microsoft EXCEL 2003, Service Pack 2

5.2.   ElectroMagnetic Transients Program – Restructured Version (EMTP-RV) Version 2.2, S&L Program Number 03.7.847-2.2. Validation documents for this program are maintained in the Sargent and Lundy software library.

5.2.1.   EMTP & Supplementary Files (See Attachments F and G for more information)

Name △	Size	Type	Date Modified
1_ByronLOCA_combined_script_revA.dwj	23 KB	EMTPWorks JavaSc...	1/10/2014 5:51 PM
2_ByronLOCA_ScriptVariables_revA.dwj	15 KB	EMTPWorks JavaSc...	1/10/2014 8:34 PM
3_byronLOCA_plantscriptfunctions_revA.dwj	44 KB	EMTPWorks JavaSc...	1/10/2014 1:41 PM
4_sl_emtp_functions_revB.dwj	19 KB	EMTPWorks JavaSc...	12/22/2013 7:57 PM
5_locaplantcasematrix_revA.dwj	11 KB	EMTPWorks JavaSc...	1/7/2014 5:55 PM
BYR_BRW LOCA EMTP MODEL R0.ecf	3,067 KB	EMTPWorks Design ...	1/10/2014 2:10 PM

6. Method of Analysis

6.1.   Evaluation Methodology

The calculation evaluates the impact an open phase event (single or double open phase condition with or without ground) on the Byron or Braidwood SATS concurrent with a LOCA has on ESF buses, motors and MOVs. Since the Byron and Braidwood SATs for all units are similar, only one unit is analyzed in detail. Byron Unit 1 is selected due to its higher loading as a result of the ESW Cooling Towers, larger Horsepower (hp) circulating water (CW) pumps, and control room ventilation loads (Ref. 4.1.8). For this analysis, the maximum loading condition considers all BOP loads to be connected to the SATs. This results in a bounding maximum pre-LOCA loading condition for cases that consider maximum loading conditions. A minimum pre-LOCA loading of 0.5 MVA per SAT (Ref. 4.1.1) is also used for some cases, while no loading is used for others. Using the pre-LOCA loading boundaries between the greatest loading of all units at both stations and no load ensures that this analysis is valid for the widest range of loading conditions.

The analysis will determine the following items for the ESF buses listed below for the duration* that the ESF buses/loads are connected to the unhealthy (open phase) source:

Medium Voltage SWGR	Low Voltage SWGRs & MCCs
4.16 kV ESF SWGR 141	480 V ESF SWGR 131X & 132X
4.16 kV ESF SWGR 142	480 V ESF SWGR 131Z & 132Z (Byron Only)

*According to analysis BYR13-177 (Ref. 4.1.2) the open phase event will be detected and the relay will send a trip signal in 30 cycles (0.5 second) to the SAT 86 lockout relays, which will trip the 345 kV switchyard breakers. Therefore, this analysis will analyze the following for the 0.6023 second (0.5 sec SEL 451 time delay + 0.019 sec. 86 lockout relay time delay + 5/60 sec breaker interrupting time) the ESF buses and loads are subject to an open phase condition.

- The impact of the single phase block start of ESF loads on the bus protection scheme (overcurrent and undervoltage)
- The impact of the single phase block start of ESF loads on the motor protection scheme (overcurrent).
- The heating (I_2^2t) impact of single phase block start of ESF loads on the running and starting motors and MOVs.
- The impact of isolating ESF loads from the SATs during the starting sequence and then restarting the ESF loads on the emergency source.

6.1.1.   Bus protection (overcurrent and undervoltage) scheme during single phase block start of ESF loads

Medium and low voltage bus protective devices are analyzed to ensure the ESF buses will not trip unexpectedly during the postulated event. The bus voltages and feeder currents are calculated using EMTP and compared with the bus protective device settings.

6.1.2. Motor protection scheme (overcurrent) during single phase block start of ESF loads

6.1.2.1. Medium Voltage Motors

Medium voltage motor protective devices are analyzed to ensure the ESF motors will not trip unexpectedly during the postulated event. The motor feeder currents are calculated using EMTP and compared with the protective device settings.

6.1.2.2. Low Voltage Motors

Low voltage motor protective devices are analyzed to ensure the ESF motors will not trip unexpectedly during the postulated event. As discussed in Section 2.4.2 & 2.4.3 only a select few low voltage motors are modeled individually while the remaining loads (motors & static) on a particular bus are represented as a lumped motor and static load. The lumped motors are updated as discussed in detail in Attachment C to ensure they will provide bounding values. The motor feeder currents are calculated using EMTP and compared with their protective device settings.

6.1.2.3. Motor Operated Valves

MOV protective devices are analyzed to ensure the ESF MOVs will not trip unexpectedly during the postulated event. See Sections 6.2.2.3 for detailed information on how the MOVs were analyzed.

6.1.3. Heating ($I_2{}^2t$) of starting and running motors during single phase block start of ESF loads (continuous motors and MOVs)

The open phase event causes a voltage unbalance to the induction motors and MOVs, which introduces a negative sequence voltage. This negative sequence voltage produces a flux in the air gap that opposes the rotation of the rotor and can produce high currents which can damage the motors due to overheating. See Section 6.2 on the machines' thermal capabilities and how it was analyzed.

6.1.4. Isolating ESF loads in the starting sequence due to open phase and followed by a restart

As previously discussed, the ESF loads that are required during a LOCA condition are susceptible to unexpectedly tripping and thermal damage ($I_2{}^2t$ heating) during the open phase condition before they are isolated by the open phase relay. Once isolated, these loads will need to restart on the EDGs. This analysis evaluates the ESF motors' protective devices and thermal capabilities to ensure that they can be successfully restarted on the EDGs and perform their safety functions.

6.2. **Acceptance & Screening Criteria**

Acceptance Criteria
The ESF loads need to be safely isolated from the SAT(s) before the individual loads trip and prior to thermal damage occurring to the motors to ensure that the ESF loads can be successfully/safely restarted on the emergency source.

Screening Criteria

The screening criteria summarized in Table 5 are used to ensure that the acceptance criteria are met. Figure 1 is an aid which shows the currents and voltages that are required to ensure that the ESF loads are safely isolated from the SATs and can transfer to the emergency diesel generators (EDGs). The subsequent sections (Sections 6.2.1 through 6.2.4) describe the methodology for determining these screening limits in more detail.

Table 5 – Screening Criteria Summary (Sections 6.2.1 through 6.2.4)

	Medium Voltage	Low Voltage
Bus Protection		
Undervoltage:	V > 0% for 1.8 sec.	V > 0% for 1.8 sec.
Phase Overcurrent:		
Main Feeder	No Trip [note 1]	I_x < 3200 A [note 2]
Load Feeder to Unit Subs or MCCs	I_v < 1600 A	I_y < 3200 A [note 2]
Ground Overcurrent:	$(I_{u,a} + I_{u,b} + I_{u,c})$ < 300 A & $(I_{v,a} + I_{v,b} + I_{v,c})$ < 5 A	$3I_{x,0}$ < 20,000
Motor Protection		
Phase Overcurrent:		
T.O.C Setting	No Trip [note 1]	No Trip [note 1 & 1a]
Instantaneous Setting	I_w < 213% LRC	I_z < 196% LRC I_d < 10 x FLA I_{MOV} < 200% LRC
Ground Overcurrent:	$(I_{w,a} + I_{w,b} + I_{w,c})$ < 5 A	n/a
Motor Heating		
Induction Motors	$(I_{w,2}{}^2)t$ < 20 pu	$(I_{z,2}{}^2)t$ < 20 pu
MOVs	n/a	I_{movLRC} < 5 sec.

1.   The relay/breaker take longer than 0.6023 second to trip for all current values (See Section 6.2.1 & 6.2.2)
      a. Thermal overloads take longer than 0.6023 second to trip for all current values (See Section 6.2.2.3)
2.   The minimum short time pickup (STPU) setting for either a main or load breaker is 3200 A. This minimum value is conservatively used for all low voltage buses. (See Section 6.2.1.2)
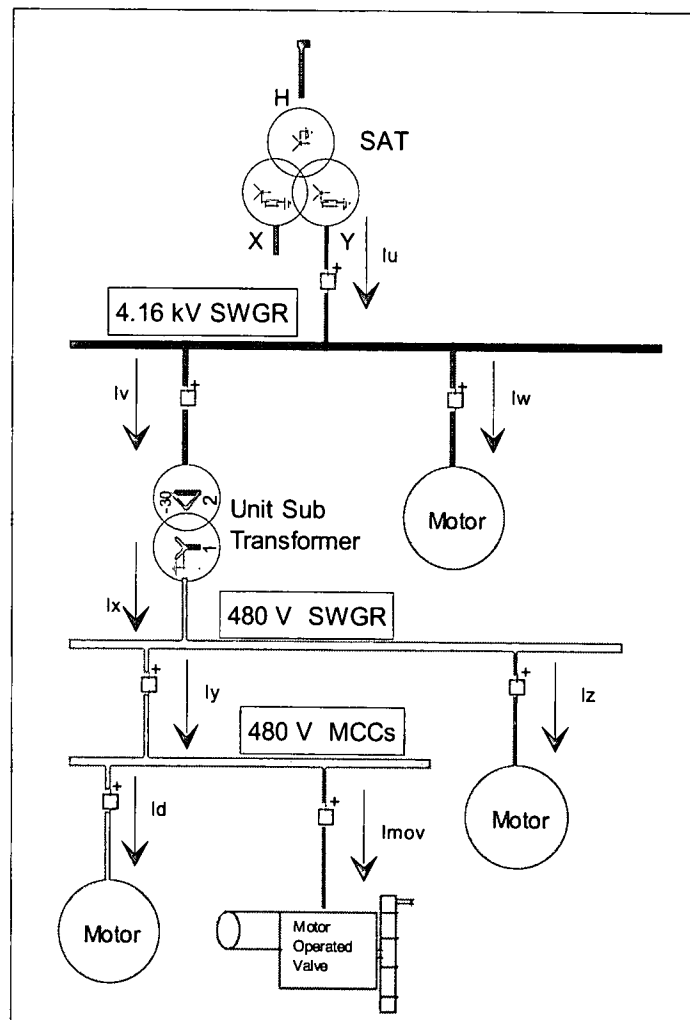
Figure 1 - Basic Byron/Braidwood ESF Bus Configuration

6.2.1. Bus Protection

The bus voltages and phase currents calculated using EMTP must show that the bus protective devices will not trip unexpectedly during the postulated event.

6.2.1.1. Medium Voltage Buses 141 & 142

Undervoltage:
According to Analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4), the primary undervoltage relay for ESF buses 141 and 142 is a Type CV-7 relay. The approximate actuation time for an undervoltage of 0% of bus rated voltage is 1.8 seconds. The open phase unbalanced condition will only last 0.6023 second until the ESF buses are isolated from the unhealthy source (SATs), therefore the primary undervoltage relays will not trip unexpectedly prior to the open phase relay safely isolating the ESF loads from the unhealthy SAT(s).

Phase Overcurrent:
Based on the relay setting sheets and coordination plots from Analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4),   the following feeder relay currents will trip the ESF medium voltage switchgears in 0.6023 or less if the current equals or exceeds the stated values.

- *Feed from SAT to Bus 141 & 142*

The minimum time it takes these time overcurrent relays to trip is approximately 1 second as shown in References 4.1.3 & 4.1.4. The open phase unbalanced condition will only last 0.6023 second until the open phase relay safely isolates the ESF buses from the unhealthy SAT(s). Therefore these phase overcurrent relays will not trip unexpectedly prior the open phase relay safely isolating the ESF buses from the unhealthy SAT(s) during the postulated event.

- *Feed from Bus 141& 142 to Buses 131X & 132X and 131Z & 132Z*

Based on the relay setting sheets and coordination plots from Analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4), the unit sub transformers will trip in 0.6023 second if the phase current is above approximately 2500 A for the X transformers (1000 kVA) and 1600 A for the Z transformers (750 kVA). If the calculated EMTP current is less than a bounding value 1600 A, the feeder overcurrent relay to these buses will not trip unexpectedly prior the open phase relay safely isolating the ESF buses from the unhealthy SAT(s) during the postulated event.

Ground Overcurrent:
Based on the relay setting sheets and coordination plots from Analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4), the bounding ground feeder relay setting (minimum current to trip the fastest) will trip the ESF medium voltage switchgears in 0.6023 second or less if the ground current equals or exceeds 300 A. If the calculated EMTP current (vector sum of the three phases) is less than a value of 300 A the ground overcurrent relays will not trip unexpectedly prior the open phase relay safely isolating the ESF buses from the unhealthy SAT(s) during the postulated event.

6.2.1.2. Low Voltage Buses 131X & 132X and 131Z & 132Z

Undervoltage:
According to Analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6), the 480 V bus undervoltage relay is a Type CV-7 relay. The approximate actuation time for an undervoltage of 0% of bus rated voltage is 1.8 seconds. The open phase unbalanced condition will only last 0.6023 second until the ESF buses are isolated from the unhealthy source (SATs), therefore the primary undervoltage relays will not trip unexpectedly prior the open phase relay safely isolating the ESF buses from the unhealthy SAT(s) during the postulated event.

Phase Overcurrent:
According to Analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6), a feeder breaker with current to low voltage switchgears and MCCs will trip in 0.6023 second or less if the current equals or exceeds a minimum of 3200 A (short time pickup - STPU). Note, this is the STPU setting for low voltage switchgear feeders with one MCC. Other feeders have higher settings but 3200 A is used for conservatism. If the calculated EMTP current is less than 3200 A the phase overcurrent protective

devices will not trip unexpectedly prior the open phase relay safely isolating the ESF buses from the unhealthy SAT(s) during the postulated event

Ground Overcurrent:
According to Analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6), ground overcurrent protection relays are used for the unit substation transformer neutrals. The ESF low voltage SWGRs will trip in 0.6023 second if the neutral grounding current for the unit substation transformers equals or exceeds approximately 20,000 A. If the calculated EMTP current $(3I_0)$ is less than 20,000 A the neutral grounding relay will not trip unexpectedly prior the open phase relay safely isolating the ESF buses from the unhealthy SAT(s) during the postulated event.

6.2.2. Motor Protection

6.2.2.1. Medium Voltage Motors

Phase Overcurrent
Based on the relay setting sheets and coordination plots from Analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4), the time overcurrent settings for medium voltage motors do not trip in less 0.6023 second. Therefore, the only potential concern of these motors tripping during the postulated event is on the instantaneous element. The methodology applied to the instantaneous setting of these motors is to set the pickup at 250% of LRC. This criterion is applicable to all motors with the exception of the Auxiliary Building Exhaust Fans. The instantaneous phase element for this motor is set at 213% of LRC according to References 4.1.3 & 4.1.4. If all of the motor feeder current calculated in EMTP are less than a conservative value of 213% of their LRC, the motor phase overcurrent relays will not trip unexpectedly prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event

Ground Overcurrent
Based on the relay setting sheets and coordination plots from Analyses 19-AN-3 and 19-AN-7 (Ref. 4.1.3 & 4.1.4), the ground overcurrent setting for all medium voltage motors is an instantaneous setting of 0.5 A (5 A primary). The ground elements are measured through a "dough-nut" current transformer. If the calculated EMTP ground current (vector sum of the three phases) is less than the setting of 5 A primary current, then the motors ground overcurrent relays will not trip unexpectedly prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

6.2.2.2. Low Voltage Motors

Phase Overcurrent for LV Motors Fed from SWGRS
Based on Analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6), low voltage motors fed from SWGRs are protected by power circuit breakers. These power circuit breakers have a long time and instantaneous unit. The long time unit takes longer than 0.6023 seconds to operate therefore, the only potential concern of these motors tripping during the postulated event is on the instantaneous trip element. According to Analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6), the minimum instantaneous phase element setting for any low voltage motor is set at 196% of LRC. If the motor feeder current calculated in EMTP is less than 196% of LRC the

low voltage motor phase overcurrent relays will not trip unexpectedly prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

Ground Overcurrent
Based on Analyses 19-AU-4 and 19-AU-5 (Ref. 4.1.5 & 4.1.6), ground overcurrent protection is not provided for individual low voltage motor feeders.

6.2.2.3. Low Voltage Motors and MOVs fed from MCCs

Low voltage motors and MOVs fed from MCCs are protected by Westinghouse FH Overload Relays as well as molded case circuit breakers. Conservatively assuming that the minimum overload relay curve for any of the FH overload relays identified in Reference 4.4.1 is used for all low voltage motors and MOVs (Assumption 3.2.5), a current 8 times nominal would take at least 4 seconds to actuate. Therefore, the only potential concern of these motors and MOVs tripping during the postulated event is on the magnetic (instantaneous) trip element.

Continuous Duty LV Motors fed from MCCs
The magnetic (instantaneous) setting for continuous duty motors is assumed to be 10 times FLA (Assumption 3.2.10). Only a select few low voltage motors fed from MCCs are modeled and analyzed in EMTP. If the motor feeder currents calculated in EMTP for the representative low voltage motors are less than a conservative value of 10 x FLC, then the MCCBs feeding continuous duty motors will not trip unexpectedly prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

MOVs fed from MCCs
Based on Exelon Standard NES-E/I&C 10.01B (Ref. 4.4.15), the magnetic (instantaneous) trip element for MCCBs feeding MOVs where nuisance tripping is a concern is set at 2 times the nameplate LRC. MOVs are not explicitly modeled in this analysis but the %LRC drawn during an open phase event for MOVs will be similar to the representative continuous duty motors modeled. If the motor feeder currents calculated in EMTP for the representative low voltage motors are less than 2 x LRC, then the MCCBs feeding MOVs will not trip unexpectedly prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

6.2.3. Motor Heating

6.2.3.1. Continuous Duty Induction Motors

Induction motors have a certain withstand capability against unbalanced voltages which is in terms of an integrated negative sequence per unit current squared times time in seconds (I_2^2t). According to references 4.4.2 through 4.4.5 (also described in detail in Attachment D) the I_2^2t capability of an induction motor is equal to or higher than 40. This thermal capability also needs to consider that these motors have the ability to perform a hot start (capable of 2 motor starts). To account for this a total thermal limit I_2^2t of 20 during the open phase event concurrent with a LOCA will be used as a bounding condition to ensure that the

motor has at least half of its thermal capability to start from the healthy source (EDGs).

The induction motors are subject to an unbalanced operating condition for 0.6023 second as described in Section 2.5.1. If the I_2^2t during this time is less than 20 pu then the induction motors are not subject to damage which is acceptable.

6.2.3.2. MOVs

As discussed in Assumption 3.2.6, no standards exist which described the permissible thermal capabilities of an MOV with regard to negative sequence current. However, a letter from Baldor-Reliance to Flowserve-Limitorque (Ref. 4.4.11) states, "*Most curves published for Limitorque ratings show heating after a 10 second locked rotor condition....*". Based on this statement, most MOVs can withstand a locked rotor condition for up to 10 seconds before starting to overheat. However, for the purposes of this analysis it is conservatively assumed that the MOVs can only withstand a locked rotor condition for up to 5 seconds. Since the open phase relay will isolate the MOVs from the unbalanced source in less than 5 seconds, the MOVs have the thermal capability to withstand the postulated event.

6.2.4. Motor capability to restart after being isolated from the SAT(s)

6.2.4.1. Response Time of Relays

As previously discussed, the ESF loads that are required during a LOCA condition are susceptible to unexpectedly tripping during the open phase condition before they are safely isolated from SATs by the open phase relay. The current requirements for the various protective devices summarized in Sections 6.2.1 and 6.2.2 need to be met to ensure that the protective devices will not unexpectedly trip and can be restarted on the EDGs. Also, even if the electromechanical and thermal overload relays do not trip during the open phase condition they will have experienced some overcurrent and the spring or bimetal strip will have moved a certain amount. This needs to be considered since this "priming" of the relays can potentially reduce the response time of these relays once restarted on the emergency diesel generators.

6.2.4.2. Thermal Capabilities

<u>Continuous Duty Induction Motors</u>
As discussed in Section 6.2.3.1 the ESF continuous duty motors are susceptible to thermal heating during an open phase event due to I_2^2t. According to references 4.4.2 through 4.4.5 (also described in detail in Attachment D) the I_2^2t capability of an induction motor is equal to or higher than 40. This thermal capability also needs to consider that these motors have the ability to perform a hot start (capable of 2 motor starts). To account for this a total thermal limit I_2^2t of 20 during the open phase event concurrent with a LOCA will be used as a bounding condition to ensure that the motor has at least half of its thermal capability to start from the healthy source (EDGs).

If the I_2^2t criteria established in Section 6.2.3 is met then the ESF motors have the thermal capability to restart on the EDGs after the postulated event.

MOVs
As discussed in Section 6.2.3.2 the MOVs are susceptible to thermal heating during an open phase event. According to reference 4.4.11, an MOV is capable of running at locked rotor condition for at least 5 seconds before starting to overheat. Since the open phase relay will trip the unbalanced source in 0.6023 second, the MOVs are only subject to heating for a small fraction of their capability. Therefore, the MOVs have the thermal capability to restart on the EDGs after the postulated event.

6.3. EMTP Model Methodology

A model of Byron Units 1 and 2 was developed using EMTP-RV for Analysis No. BYR13-176 (Ref. 4.1.1, Attachments D, E, & F). This EMTP-RV model, with the changes identified below, is used to analyze the behavior of the ESF auxiliary system during an open phase event concurrent with a LOCA.

Model Changes:
The EMTP-RV model developed for Analysis No. BYR13-176 (Ref. 4.1.1) was adequate for the purposes of that calculation; however, since this analysis is analyzing the motor and auxiliary system performance in more detail some changes to the ESF auxiliary system are needed. The changes are summarized below and discussed in further detail in Attachment B.

6.3.1. 345 kV System

The original EMTP model developed for "Loss of Phase Detection EMTP Analysis" calculations for Byron (Ref. 4.1.1, Attachment D, E, & F) contained a detailed model of the transmission system. However, for this analysis a detailed model of the transmission system is not used. An unbalanced voltage source with infinite short circuit strength is developed to obtain the maximum negative sequence voltage while still maintaining an unbalance limit with the 3% limit (Ref. 4.4.14) and meeting other constraints as discussed in detail in Attachments C and H of this analysis. This source provides the maximum degree of unbalance which produces higher I_2^2t and bounds the more detailed transmission system model for the purposes of this analysis. Also, an infinite source is used to ensure that maximum sequence currents are produced (Assumption 3.2.9).

6.3.2. Loads (Medium and Low Voltage Motors)

See Section 2.4 for details.

7. Numerical Analysis

7.1. Plant Cases

The "Loss of Phase Detection EMTP Analysis" calculation for Byron (Ref. 4.1.1) describes the various plant cases analyzed to help determine the analytical limits for the open phase relay. This analysis looks at a subset of those cases that consider an open phase concurrent with a LOCA. There are a total of 144 cases considered in this analysis which are summarized in Attachment A.

7.2. Simulation Sequence

The EMTP simulation was set up using the following sequence

1. *Initialization (0 – 1 second):* The auxiliary system is initialized using a balanced voltage source as described in Attachment B in more detail.

2. *Unbalanced Voltage (1 – 2 seconds):* The balanced voltage source is tripped while the unbalance voltage source is connected to the auxiliary system as described in Attachment B in more detail.

3. *Open Phase & LOCA (2 – 2.6023 seconds):* Once the auxiliary system has stabilized with the unbalanced voltage source an open phase and a LOCA are simulated for 0.6023 second (time ESF buses are connected to the open phased SAT(s) prior to the open phase SEL-451 relay safely isolated them as discussed in Section 2.5.1).

7.3. Measurements

EMTP-RV calculates and tabulates the per unit phase currents and I_2^2t and the ground currents to determine if the buses and motors could trip or be damaged during the open phase concurrent with a LOCA condition.

7.3.1. Phase Currents

The phase currents tabulated are the maximum per unit currents observed between the range of 2.167 seconds (2 second event time + 10 cycles) until the end of the simulation time. The 10 cycle delay was used to ensure fast transients that can occur when a motor starts in EMTP are ignored.

7.3.2. I_2^2t

The I_2^2t values tabulated are the maximum per unit values observed between the range of 2.167 seconds (2 second event time + 10 cycles) until the end of the simulation (2.6023 seconds = 2 second start time + 0.6023 sec [See Section 2.5.1]) for motors. Note, the I_2^2t is calculated throughout the entire simulation but the maximum value was observed and obtained through the state time range. Since the I_2^2t value is based on time the maximum values occur at the end of the simulation. This accurately provides the I_2^2t duty experienced by the motors for the 0.6023 second they are subjected to an unbalanced voltage condition.

7.3.3. Ground Currents

The motor ground currents tabulated (vector sum of **Ia + Ib + Ic**) and the transformer neutral ground current ($3I_0$) are the maximum values observed between the range of 1.967 seconds (2 second event time − 2 cycles) and the end of the simulation.

7.4. Results

The following tables summarize the maximum current values between the 144 cases (shown in Attachment A) for the motors and buses of interest.

Table 6 – Medium and Low Voltage Motor Results

Bus	Equipment Number	Equipment Name	Starting Current	Phase Currents (per unit)				pu of LRC	I$_2^2$T pu	Ground Relay (A)
				Ia	Ib	Ic	Max			
		MEDIUM VOLTAGE MOTOR PARAMETERS		**MEDIUM VOLTAGE MOTOR RESULTS**						
141	0VA01CA	Aux Bldg Supply Fan 0A	588%	2.91	3.18	2.93	3.18	54.0%	1.39	0.05
	1CC01PA	Component Cooling Pump 1A	579%	5.43	5.44	5.63	5.63	97.2%	2.81	0.05
	0WO01CA	Control Room Chiller Unit 0A	643%	6.17	6.23	6.38	6.38	99.3%	3.61	0.05
	0VA02CA	Aux Bldg Exhaust Fan 1A	703%	4.04	4.18	4.06	4.18	59.5%	2.31	0.05
	1AF01PA	AUX FEED WATER PUMP	586.0%	5.47	5.49	5.67	5.67	96.7%	2.87	0.05
	1CS01PA	CONTAINMENT SPRAY PUMP	580.0%	5.44	5.45	5.64	5.64	97.2%	2.82	0.05
	1SI01PA	SAFETY INJECTIONPUMP 1A	602.0%	5.63	5.64	5.83	5.83	96.8%	3.02	0.05
	1RH01PA	RESIDUAL HEAT REMOVAL PUMP	648%	6.08	6.09	6.30	6.30	97.3%	3.52	0.05
	1SX01PA	ESS SERV WTR PUMP 1A	575.0%	5.39	5.40	5.58	5.58	97.1%	2.77	0.05
	1CV01PA	CENTRIFUGAL CHARGING PU	635.0%	5.94	5.96	6.16	6.16	96.9%	3.37	0.05
142	1CV01PB	Centrifugal Charging Pump 1B	635%	6.15	6.23	6.36	6.36	100.2%	3.49	0.99
	1SX01PB	Essential Service Water Pump 1B	575%	5.56	5.64	5.75	5.75	100.1%	2.85	1.43
	1CS01PB	CONTAINMENT SPRAY PUMP	580.0%	5.68	5.77	5.88	5.88	101.4%	2.97	0.04
	1SI01PB	SAFETY INJECTIONPUMP 1B	602.0%	5.87	5.94	6.08	6.08	101.0%	3.19	0.04
	1RH01PB	RESIDUAL HEAT REMOVAL PUMP	648%	6.35	6.46	6.58	6.58	101.5%	3.71	0.04
	0WO01CB	CONTROL ROOM REFRIG UNIT	643.0%	6.32	6.44	6.53	6.53	101.5%	3.64	0.04
	1CC01PB	COMPONENT COOLING PUM	579.0%	5.68	5.77	5.88	5.88	101.5%	2.96	0.04
		LOW VOLTAGE MOTOR PARAMETERS		**LOW VOLTAGE MOTOR RESULTS**						
131X & 131Z	1VP01CA	RCFC FAN 1A LOW SPEED B	625.0%	5.40	5.64	5.40	5.64	90.3%	2.82	n/a
	1VP01CC	RCFC FAN 1C LOW SPEED B	625.0%	5.40	5.64	5.40	5.64	90.3%	2.82	n/a
	0VA03CA	AUX BLDG VENT CHAR BSTR FAN	802.0%	6.93	7.24	6.93	7.24	90.3%	4.65	n/a
	131X	131X_Lumped	802.0%	3.81	3.98	3.80	3.98	49.6%	2.22	n/a
	131Z	131Z_Lumped	802.0%	4.04	4.22	4.04	4.22	52.6%	2.40	n/a
132X & 132Z	1VP01CB	RCFC FAN 1B LOW SPEED B	625.0%	5.57	5.82	5.58	5.82	93.2%	2.92	n/a
	1VP01CD	RCFC FAN 1D LOW SPEED B	625.0%	5.57	5.82	5.58	5.82	93.2%	2.92	n/a
	0VA03CE	AUX BLDG VENT CHAR BSTR FAN	802.0%	7.15	7.47	7.15	7.47	93.2%	4.80	n/a
	132X	132X_Lumped	802.0%	3.69	3.86	3.71	3.86	48.1%	2.11	n/a
	132Z	132Z_Lumped	802.0%	4.48	4.68	4.48	4.68	58.4%	3.31	n/a
	0VA04CB (on MCC)	FUEL HANDLG BLDG CHARC BSTR FAN	750%	6.68	6.98	6.68	6.98	93.0%	4.19	n/a

Table 7 – Bus Feeder Current Results

Bus	Feeder ID	Ia (A)	Ib (A)	Ic (A)	Ground Relay (A)
MEDIUM VOLTAGE BUS FEEDERS		**MV BUS FEEDER RESULTS**			
141	Feed to Bus 141	4450	4460	4610	0
	Feed to Unit Substation 131X	382	383	394	0
	Feed to Unit Substation 131Z	217	226	218	0
142	Feed to Bus 142	3516	3522	3641	3
	Feed to Unit Substation 132X	466	469	484	0
	Feed to Unit Substation 132Z	89	93	90	0
LOW VOLTAGE BUS FEEDERS		**LV BUS FEEDER RESULTS**			
141	Feed to 131X MCCs*	2125	2222	2117	0
	Feed to 131Z	1965	2053	1956	0
142	Feed to 132X MCCs*	2613	2730	2622	0
	Feed to 132Z	804	841	804	0

*Buses 131X and 132X do not have main breakers but rather they have multiple feeder breakers to MCCs. The MCCs were lumped into one load (131X_Lumped and 132X_Lumped). It was conservatively assumed that all the MCCs are fed from one breaker.

8. Results & Conclusions

8.1. This analysis evaluated the impact an open phase event (single or double open phase condition with or without ground) concurrent with a LOCA has on the ESF motors and MOVs for both Byron and Braidwood stations.

The following analyses were considered:

- The impact of the single phase block start of ESF loads on the bus protection scheme (overcurrent and undervoltage)
- The impact of the single phase block start of ESF loads on the motor protection scheme (overcurrent).
- The heating (I_2^2t) impact of single phase block start of ESF loads on the running and starting motors and MOVs
- The impact of isolating ESF loads from the SATs during the starting sequence and then restarting the ESF loads on the emergency source.

Based on the following detailed discussions, Byron and Braidwood Units 1 and 2 the important to safety functions will be maintained and will be available to start on the emergency diesel generators during a LOCA concurrent with an open phase condition.

8.1.1. Bus protection (overcurrent and undervoltage) scheme during single phase block start of ESF loads

Medium and low voltage bus protective devices are analyzed and compared with the acceptance criteria to ensure the ESF buses will not trip during the postulated event. The feeder currents were calculated using EMTP as shown in Table 7. Based on the results there will be no unexpected trips prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

Medium Voltage Buses

Table 8 – Bus Protection Acceptance Criteria & Results for MV Buses

Bus Protection	Medium Voltage	Results (Trip/No Trip)
Undervoltage:	Note 1	No Trip
Phase Overcurrent:		
Main Feeder	Note 2	No Trip
Feeder to Unit Subs	$I_{max} \approx 500\ A < 1600\ A$	No Trip
Ground Overcurrent:		
Main Feeder	$(I_{,a} + I_{,b} + I_{,c})_{max} \approx 80\ A\ < 300\ A$	No Trip
Load Feeder to Unit Subs	$(I_{,a} + I_{,b} + I_{,c})_{max} = 0\ A < 5\ A$	No Trip

Note 1:
The voltages in EMTP were not tabulated since the type of primary undervoltage relay used for the ESF buses is a Type CV-7 relay and according to the relay calculations (4.1.3 through 4.1.6) the approximate actuation time for an undervoltage of 0% of bus

rated voltage is 1.8 seconds. The open phase unbalanced condition will only last 0.6023 second until the ESF buses are safely isolated from the unhealthy source (SATs), therefore the primary undervoltage relays will not trip unexpectedly prior to the SATs tripping during the postulated event.

Note 2:
The main feeds to Buses 141 and 142 take longer than 0.6023 second to trip regardless of the phase overcurrent magnitude (See Section 6.2.1.1). These main feeds will not trip during the postulated event.

Low Voltage Buses

Table 9 – Bus Protection Acceptance Criteria & Results for LV Buses

Bus Protection	Low Voltage	Results (Trip/No Trip)
Undervoltage:	Note 1	No Trip
Phase Overcurrent:		
Main Feeder (Note 2)	$I_{max} \approx 2200\ A < 3200\ A$	No Trip
Feeder to MCCs (Note 3)	$I_{max} \approx 3000\ A < 3200\ A$	No Trip
Unit Sub Neutral Grounding Overcurrent:	$3I_0 = 0 < 20{,}000\ A$	No Trip

Note 1:
The voltages in EMTP were not tabulated since the type of primary undervoltage relay used for the ESF buses is a Type CV-7 relay and according to the relay calculations (4.1.5 & 4.1.6) the approximate actuation time for an undervoltage of 0% of bus rated voltage is 1.8 seconds. The open phase unbalanced condition will only last 0.6023 second until the ESF buses are safely isolated from the unhealthy source (SATs), therefore the primary undervoltage relays will not trip unexpectedly prior to the SATs tripping during the postulated event.

Note 2:
The only low voltage ESF buses that have main breakers are buses 131Z and 132Z.

Note 3:
Buses 131X and 132X do not have main breakers but rather they have multiple feeder breakers to MCCs. The MCCs were lumped into one load (131X_Lumped and 132X_Lumped). It was conservatively assumed that all the MCCs are fed from one breaker.

8.1.2. Motor protection scheme (overcurrent) during single phase block start of ESF loads

Medium and low voltage motor protective devices are analyzed to ensure the ESF motors will not trip during the postulated event. The motor feeder currents were calculated using EMTP as shown in Table 6 and compared with their instantaneous protective device setting. Based on the results there will be no unexpected trips prior the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

Medium Voltage Motors

Table 10 – Acceptance Criteria Summary & Result for MV Motors

Motor Protection	Medium Voltage	Results (Trip/No Trip)
Phase Overcurrent:		
T.O.C Setting	Note 1	No Trip
Instantaneous Setting	$I_{max} \approx 102\%$LRC $< 213\%$ LRC	No Trip
Ground Overcurrent:	$(I_{,a} + I_{,b} + I_{,c})_{max} \approx 1.5$ A< 5 A	No Trip

Note 1:
As described in Section 6.2.2.1 the relays take longer than 0.6023 second to trip for all current values. The open phase unbalance condition will only last 0.6023 second until the ESF buses are safely isolated from the unhealthy SAT(s), therefore the time overcurrent relays will not trip unexpectedly prior to the SAT(s) tripping during the postulated event.

Low Voltage Motors & MOVs

Table 11 – Acceptance Criteria Summary & Results for LV Motors

Motor Protection	Low Voltage	Results (Trip/No Trip)
Phase Overcurrent:		
T.O.C Setting	Note 1	No Trip
LV SWGR Motors Instantaneous Setting	$I_{max} \approx 93\%$ LRC $< 196\%$ LRC	No Trip
LV MCC Motors Instantaneous Setting	$I_{0VA04CB} \approx 7$ x FLA <10 x FLA	No Trip
MOVs (Note 2)	$I_{MOV} \approx 93\% < 200\%$ LRC	No Trip
Ground Overcurrent:	Note 3	n/a

Note 1:
As described in Sections 6.2.2.2 and 6.2.2.3 the power circuit breakers long time unit and thermal overload relays take longer than 0.6023 second to trip for all current values. The open phase unbalance condition will only last 0.6023 second until the ESF buses are safely isolated from the unhealthy SAT(s), therefore the thermal/overload breaker and relay settings will not trip unexpectedly prior to the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event.

Note 2:
Based on Exelon Standard NES-E/I&C 10.01B (Ref. 4.4.15), the magnetic (instantaneous) trip element for MCCBs feeding MOVs where nuisance tripping is a concern is set at 2 times the nameplate LRC. MOVs are not explicitly modeled in this analysis but the %LRC drawn during an open phase event for MOVs will be similar to the representative continuous duty motors modeled.

Note 3:
The low voltage motors and MOVs to not have ground overcurrent relays.

8.1.3. Heating (I_2^2t) of starting and running motors during single phase block start of ESF loads (continuous motors and MOVs)

Medium and low voltage motors on the ESF buses were analyzed to ensure the motors will not be damaged during the postulated event. The I_2^2t values were calculated using EMTP as shown in Table 6 and compared with their capabilities. Based on the results all motors and MOVs have the thermal capability to withstand the postulated event.

Table 12 – Acceptance Criteria Summary & Results for Machine Thermal Capability

Motor Heating	Capability	Acceptable (Yes/No)
Induction Motors	$(I_2^2)t \approx 3.7$ pu < 20 pu	Yes
MOVs (Note 1)	$I_{movLRC} \approx 0.6023$ sec < 5 sec.	Yes

Note 1:
As described in Section 6.2.3.2 MOVs can withstand a locked rotor conditions for up to 5 seconds before starting to overheat. Since the MOVs are only subject to the unbalanced heating for 0.6023 second before the open phase relay safely isolates them from the unhealthy SAT(s) they have the thermal capability to withstand the postulated event.

8.1.4. Motor capability to restart after being isolated from the SAT(s)

   8.1.4.1. Response Time of Relays

   As shown in the sections above the overcurrent experienced during an open phase event concurrent with a LOCA does not cause any of the ESF buses or loads to trip unexpectedly prior to the open phase relay safely isolating the ESF loads from the unhealthy SAT(s) during the postulated event. As discussed in Section 6.2.4.1 the electromechanical relays and thermal overloads response time can be reduced once restarted on the emergency diesel generators based on the overcurrents shown in Table 6 and Table 7. However, since overcurrents only last 0.0623 second, there is reasonable margin between the trip settings and the overcurrents experienced during the event, and the major ESF loads will not be restarted on the emergency diesels until 12 seconds after the LOCA signal (Ref. 4.1.7), the electromechanical and thermal overload relays will reset and the response time of the relays should be as expected when restarting on the emergency diesel generators.

   8.1.4.2. Thermal Capabilities

   Continuous Duty Induction Motors
   As discussed in Section 6.2.3.1 the ESF, limiting the continuous duty motors to an I_2^2t value of 20 ensures that the motors are capable to start from the emergency diesel generators after being tripped from the unbalanced source. The I_2^2t values are less than 20 and therefore the motors are capable to restart on the EDGs after the postulated event.

MOVs

As discussed in Section 6.2.3.2 the MOVs an MOV is capable of running at locked rotor condition for 5 seconds before starting to overheat. Since the open phase relay will trip the unbalanced source in 0.6023 second, the MOVs are only subject to heating for a small fraction of their capability. Therefore, the MOVs have the thermal capability to restart on the EDGs after the postulated event.

8.2. Model & Analysis Update

The motors' have significant margin for both their phase currents and thermal capabilities. As shown in Table 6, the ESF motors during an open phase event concurrent with a LOCA will only produce phase currents on the order of 100% of LRC, which is half of the acceptance criteria, while the thermal duties are only ¼ of the acceptance criteria.

The bus protection has significant margin. As shown in Attachment A, MCCs fed from 132X have approximately a 20% margin while other buses have more. Note, this is assuming that 132X SWGR only has one MCC so in actuality the margin is even greater.
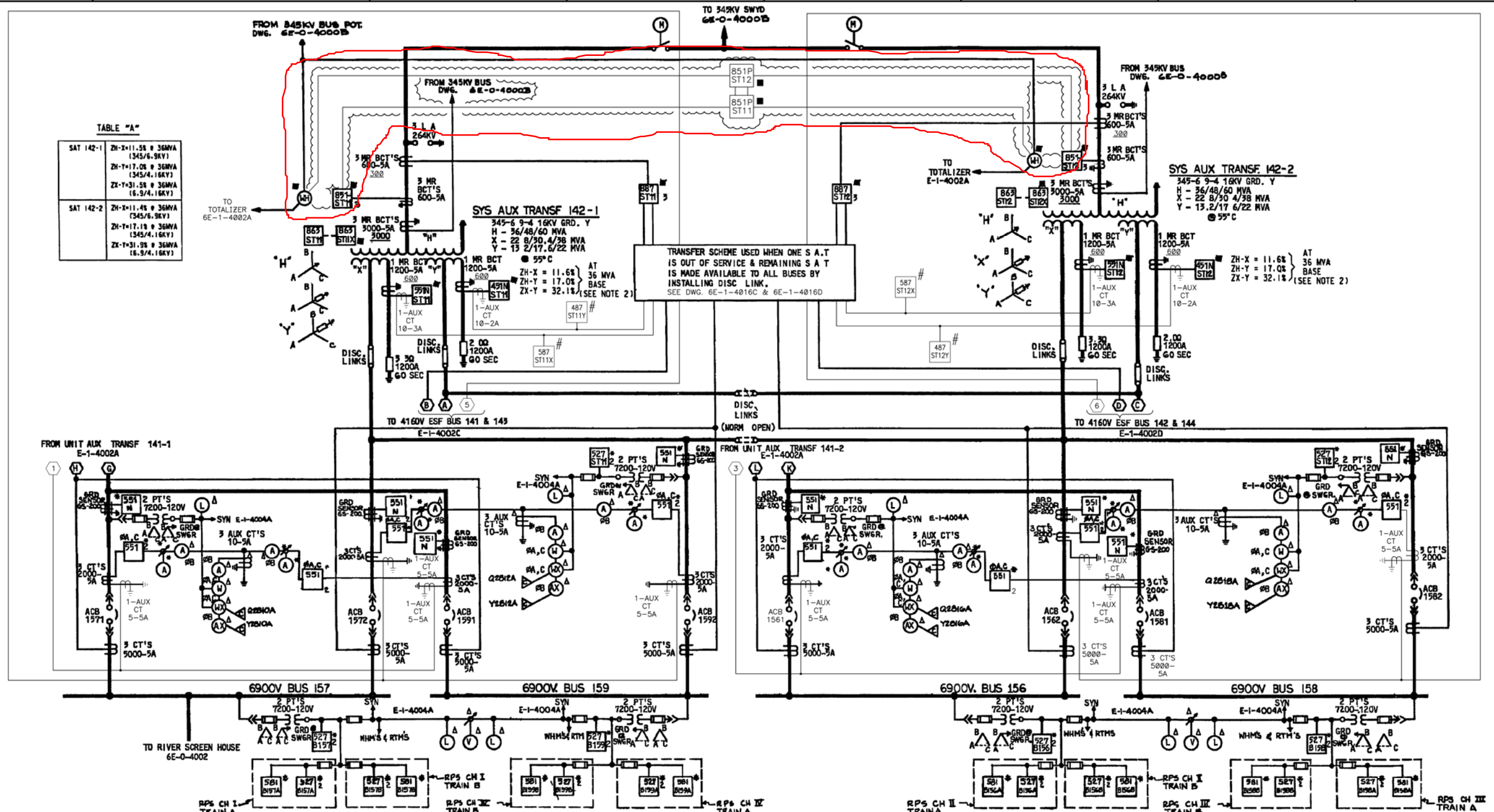
Since there is significant margin it is expected that the EMTP-RV model used for this analysis will remain bounding for most plant modifications at Byron and Braidwood.

9. Attachments

SINGLE LINE DIAGRAM
SYSTEM AUXILIARY TRANSFORMER
& 6.9KV SWITCHGEAR

6E-1-4002B

Exelon Generation
Byron Station 6 Unit: 1

NUCLEAR SAFETY RELATED
EQUIPMENT IS SHOWN
ON THIS DRAWING

6E-1-4016C

FROM 345KV SWYD

FROM 345KV SWYD BUS POTENTIAL (DWG. 6E-0-4100B)

WHM-ST11 WHM-ST12

TO SOLID STATE TOTALIZER SST-3 (6E-0-4030MP01)

TO SOLID STATE TOTALIZER SST-3 (6E-0-4030MP01)

5LA 264 KV MOTOR OPERATED DISCONNECT

5LA 264 KV MOTOR OPERATED DISCONNECT

FOR DIFF RLY PR30-887-ST11 6E-1-4016D

FOR DIFF. RLY PR9-887ST12 (6E-1-4016D)

THIS DWG. (E) 1PA23J — IAX082, ST1C0, ICX122, ICW051, IBW031, IAW011

1PA23J — IAX081, ST2C0, ICX121, ICW052, IBW032, IAW012 (F) THIS DWG.

PR27A,B,C 851ST11 CO-7 O.C. RLY

PR36A,B,C 851ST12 CO-7 O.C. RLY

587ST11X CO2 PR5

587ST11Y CO2 PR6

587ST12X CO2 PR7

487ST12Y CO2 PR8

SYSTEM AUX. TRANSF. 142-1
345KV GRD Y – 6.9/4.16KV GRD Y
H-36/48/60 MVA
X-22.8/30.4/38 MVA   AT 55°C
Y-15.2/17.6/22 MVA
ZH-X = 11.6% AT 36 MVA BASE
ZH-Y = 17.0% (SEE NOTE 2
ZX-Y = 32.1% (DWG.E-1-4002B)

SYSTEM AUX TRANSF. 142-2
345KV GRD Y – 6.9/4.16KV GRD.Y
H-36/48/60 MVA
X-22.8/30.4/38 MVA   AT 55°C
Y-15.2/17.6/22 MVA
ZH-X = 11.6% AT 36 MVA BASE
ZH-Y = 17.0% (SEE NOTE 2
ZX-Y = 32.1% DWG.E-1-4002B)

PR37 251N-ST12 CO-6 NEUT. GRD O C RLY

PR29 251N-ST11 CO-6 NEUT GRD O C RLY

PR28 251N-ST11 CO-6 NEUT. GRD. O.C. RLY.

PR38 451N-ST12 CO-6 NEUT GRD O C RLY

"H" WINDING "X" WINDING "Y" WINDING

HOT SPOT CT'S 6E-1-4030AP04

HOT SPOT CT'S 6E-1-4030AP06

DISCONNECT LINKS (NORMALLY CLOSED)

DISCONNECT LINKS (NORMALLY OPEN)

DISCONNECT LINKS (NORMALLY CLOSED)

TO 6.9 KV SWGR BUS 159 (6E-1-4017D)

TO 6.9 KV ESF SWGR BUS 157 (6E-1-4017B)

TO 4.16 KV SWGR BUS 143 (6E-1-4018C)

TO 4.16 KV ESF SWGR BUS 141 (6E-1-4018A)

TO 6.9 KV SWGR BUS 158 (6E-1-4017C)

TO 6.9 KV SWGR BUS 156 (DWG.6/20E-1-4017A)

TO 4.16 KV ESF SWGR BUS 142 (DWG.6/20E-1-4018D)

TO 4.16 KV SWGR BUS 144 (6E-1-4018D)

851PST11 SEL-451 TS1 TS3
851PST12 SEL-451 TS1 TS3

1PA55J — IAX082, ST1C0, ICX122, IAW011, IBW031, ICW051

1PA55J — IAW012, IBW032, ICW052, ICX121, ST2C0, IAX081

* – TEST SWITCHES 1PA55J-TS1, TS2, TS3 & TS4 HAVE INTERLOCKING BAR ON CURRENT SHORTING SWITCHES D THRU I.

REV	DATE	DESCRIPTION	PREP.	REVR.	APPR.
N	EDSF	FOR RECORD-INCORP. OF EC# 388209	EDSF	EDSF	EDSF

RELAYING & METERING DIAGRAM
SYSTEM AUXILIARY TRANSFORMERS
142-1 & 142-2

Exelon Generation

Byron Station 6 Unit: 1

BYRON STATION 6

SCALE : NONE
DATE : 08/21/00
DRAWN BY: BHD
ORG. BY : SO40

6E-1-4016C

SHEET NUMBER: SIZE: D E03

SCHEMATIC DIAGRAM
SYSTEM AUXILIARY TRANSFORMER
142-1 TRIPPING RELAYS

Exelon Generation
Byron Station 6 Unit 1

6E-1-4030AP01

SHEET NUMBER: SIZE: F   E07

SCALE : NONE
DATE : 08/21/00
DRAWN BY: BHD
ORG. BY : S040

REFERENCE DRAWINGS	
DWG. NO.	DESCRIPTION
E-1-4030 SERIES	S/D NOTES, LEGEND, REFERENCE DRAWINGS.
E-1-4154 SERIES	INT/EXT W/D ANNUN CAB. (BOP) 1PA30J.
E-1-4140 SERIES	INT/EXT W/D RLY & METERING PNL.1PA23J.
E-1-4420 SERIES	INT/EXT W/D SYS. AUX. TRANSF. 142-1.
E-1-4131 SERIES	INT/EXT W/D ANNUNCIAT. LOGIC CAB. 1PA19J.

Schematic Diagram — System Auxiliary Transformer 142-2 Tripping Relays

Exelon.

BYRON GENERATING STATION
UNITS 1 & 2

Byron Loss of Phase
Monitoring Plan Final Report
Revision 2

Sargent & Lundy Project No. 11330-247
Non-Safety Related

Sargent & Lundy LLC

| Prepared by | J. J. Bojan | | Date: 9/23/14 |
| Reviewed by | Sanjiv Shah | | Date: 9/23/14 |

Index:

Executive Summary:

Two open phase detection SEL 451-5 protective relays have been installed on each unit, one for each SAT. These relays have been operating in the "alarm only" mode to allow the station to gather data and evaluate the security (vulnerability to spurious trips) of the detection scheme. The results of the evaluation of the data will determine whether the trip function can be enabled. Each open phase detection relay is sensing the Phase A (Ia), Phase B (Ib) and Phase C (Ic) input current to the 345 kV primary windings. The current values (magnitude and phase angle) are then used within the relay to perform internal calculations to calculate for symmetrical components of the current, namely, values for zero sequence current (I0), positive sequence current (I1), and negative sequence current (I2). The resulting values are subsequently used as inputs to two logic strings to determine if an open phase has occurred. The first logic string will detect a single open phase with ground on the primary winding of the SAT. The second logic string will detect an open phase with no ground on the primary winding of the SAT. A third logic string is added by the updated algorithm and not installed in the relay during this report period; however, this logic string was reviewed against the data collected in the regression analysis. This logic string allows the detection of double open phase event

The SEL 451 Open Phase Detection relays at Byron Station Unit 1 and Unit 2 have been connected and operating since November 2012. During that time frame the relays have actuated to trip only during initial transformer energization. No other event has occurred to cause the relay trip logic setpoints to be exceeded. In addition, there has been no event that would have required the relay to actuate.

During this time frame numerous transmission system faults have occurred. These range from nearby, within 20 miles, to well over that distance. Those faults that can be correlated to relay triggered events have all been cleared in within 30 cycles, and normally within 10 cycles. This demonstrates the coordination between transmission system response to faults and the time delay setting on the relay to provide relay security from events that are cleared by the transmission system protective relaying system.

The transmission system faults do bring the negative sequence currents above their trip setpoints; however the MINDETC setpoint provides a threshold for detection and the time delay setpoint provides a threshold for relay security. The time delay setpoint allows the transmission system time to clear the fault. The MINDETC setpoint prevents the relay from operating unless only one or two phases are severely impacted by the fault. These measures have functioned to prevent spurious actuations of the relay during this monitoring period.

The plant events such as, unit trips, generator load changes, switchyard voltage level changes, large motor starts, diesel generator operations including synching to the grid, have all occurred during this monitoring period. In addition low load operation of the SAT's occurred during the Unit 2 outage. None of these events challenged the operation of the relay. While there were triggered events due to negative sequence currents being above the trip setpoint, the relay security features of MINDETC and the 30 cycle time delay adequately prevented any spurious operation of the relay. The zero sequence trip setpoint was only exceeded during transformer initial energizing.

Not every possible event that could impact the relay occurred during this monitoring period. However, the relay has been shown to have good security in the MINDETC and time delay setpoints. The interaction of plant events has been demonstrated to have very little impact on the relay measured currents. The relays have shown proper coordination with transmission events. All of which leads to a conclusion that the relay setpoint and logic features are robust and can be expected to make a spurious operation unlikely. The analysis that has been performed also supports this conclusion.

Based on the above, the recommendation is to enable the relay trip function with the installation of EC389896 Revision 4 for Unit 1 and 389897 Revision 4 for Unit 2 completed.

Purpose:

Background:

As a result of the open phase event that occurred on Byron Unit 2 on January 30, 2012, Exelon and S&L developed a relay scheme to detect an open phase on the offsite feed to the System Auxiliary Transformers (SATs) and initiate actions to separate the transformers from this feed on a detected loss of phase condition. This relay scheme utilizes microprocessor based relays with a custom algorithm. The algorithm was developed based on an analytical model of the station's Auxiliary Power System. Extensive efforts were made to validate this model by reproducing the transformer test results and current readings recorded during the actual open phase event. However, with any new protective relay scheme, concerns regarding security (i.e. vulnerability to spurious actuation) and dependability (i.e. vulnerability to not trip when required) of the scheme exist. The security of this scheme is critical because a spurious actuation will cause a loss of offsite power. Also, the analytical model included several assumed values because verified data was not available or was not obtainable. The relay scheme, therefore, is now operating in an alarm only mode. While in this mode, Exelon is monitoring the performance of the relay scheme for a period of time to gain confidence in the scheme, the relay settings and the analytical model used to develop the settings. The relay has the capability to capture and record raw and processed data. If correlated to actual system events, the data can be used to evaluate the relay performance

Engineering Changes EC389896 for Unit 1 and EC 389897 for Unit 2 installed two protective relays which will trip the System Auxiliary Transformers (SATs) 142-1 (242-1) and 142-2 (242-2) on a single open phase condition to protect the Unit Engineered Safety Features (ESF) and Non-ESF busses. During the monitoring period the new relays were operating in the alarm-only configuration. The relay tripping capability was isolated by open test switches.

The purpose of this report is to document the results of monitoring the relay operation during normal plant operations from December 2012 through March 2014, and to perform a regression analysis on the data collected to verify the relay operation with the updated algorithm. This monitoring was done to determine if the relays would spuriously trip for non-loss of phase conditions and if the relay will trip for a valid loss of phase condition. It was recognized that the likelihood of an open phase event during the monitoring period is considered extremely unlikely but possible. No open phase condition occurred during this period. However a wide range of events were observed. These include a Unit trip with a subsequent fast bus transfer, initial loading of a SAT, large motor starts/stops during low load outage conditions, Emergency Diesel generator operations including synchronizing to the grid and various transmission system faults.

Relay Description

This report reviews the function of the relay using the installed logic of the relay during the monitoring period. See attachment 2 for a description of that logic. Subsequent to this report the logic for the relay is being changed to incorporate the findings of this report, and to incorporate the findings of additional calculations that have been performed. The triggered events have been evaluated against the proposed new relay logic, and the results of that evaluation show that the relay, using the new relay logic, would not have spuriously tripped due to the conditions present in any of the triggered events (see attachment 9 Regression Analysis).

There are two loss of phase SEL 451-5 protective relays on each unit, one for each SAT. Each loss of phase relay is sensing the Phase A (Ia), Phase B (Ib) and Phase C (Ic) input current to the 345 kV primary windings. The current values (magnitude and phase angle) are then used within the relay to perform internal calculations to calculate for symmetrical components of the current, namely, values for zero sequence current (I0), positive sequence current (I1), and negative sequence current (I2). The resulting values are subsequently used as inputs to two logic strings to determine if a loss of phase has occurred. The first logic string will detect a single open phase with ground on the primary winding of the SAT. The second logic string will detect an open phase with no ground on the primary winding of the SAT. A third logic string is added by the updated algorithm and not installed in the relay during this report period; this logic string was reviewed against the data collected in the regression analysis. Refer to attachment 2 of this report for the setpoints and logic installed in the relay during this monitoring period.

The relay triggers used for the majority of the reporting period are as follows:

Quantity / Logic	Trigger Setting	Relay Word Bit
Existing Logic String 1 Trip	Rising Edge (Logical True)	LI_T
Existing Logic String 2 Trip	Rising Edge (Logical True)	L2_T
Front Panel Push Button #5	Rising Edge (Push Button Pressed)	PB5_PUL
Negative Sequence Current	> 0.60 Amps, primary [1]	PCT05Q
2nd Harmonic Current	> 5.25% of fundamental	PCT06Q
5th Harmonic Current	> 5.25% of fundamental	PCT07Q
Zero Sequence Current	> 5 Amps, primary	PCT08Q
LS2 Detection String= True AND LS2 Security String = False	Rising Edge (Logical True)	PSV60

Notes:
  1) Trigger setpoint for negative sequence current was increased from 0.3A to 0.6A in January 2013

The harmonic triggers were originally set in because the original logic for the relay used a harmonic block to act as a security element for some events. With further reviews and field experience, it was determined that the harmonics were not suitable for use as a security element, and were removed from the relay logic. They, however, remained in the trigger settings. As such the relay operation is not impacted, and does not utilize harmonics for the relay algorithm, other then the legacy aspect of providing a trigger.

Data Collection

To collect the data the relay detected, triggers were set to initiate a data recording. This recording, called a triggered event, recorded the primary current values and the sequence components of this current, namely, into negative and zero sequence currents, as well as determining the 2nd and 5th harmonic components present. The relay, once triggered would record approximately 1 second of this data and store it as a data file. This data file was then downloaded from the relay and printed out to determine the various current components present at the relay triggered event. These events are attached to this report as .pdf files in attachment 8. The electronic data files recorded by the relay are transmitted separate from the report and are available for review as needed.

The captured trigger events were then cross correlated with the station control room logs to attempt to identify if a station activity, such as starting a large motor, would affect the relay. This correlation is to review if normal or abnormal station activities can cause a spurious actuation of the relay.

The captured trigger events were also cross correlated with transmission system events. This was accomplished by sending a log of events to Commonwealth Edison and having them compare the time and date stamps of the triggered event against their transmission system event logs. This correlation is to review if normal transmission faults can cause a spurious actuation of the relay.

Inputs:

The report inputs consist of:
  • Relay files with triggered events. These are listed on Attachment 1, event log. There are over 500 event triggers reviewed during the monitoring period from December 2012 through July 2013. These consist of 177 events from SAT 142-1, 139 events from SAT 142-2, 240 events from SAT 242-1 and 175 events from SAT 242-2.
  • Control room logs that were obtained through the Exelon LAN.
  • Commonwealth Edison review of selected triggered events. The time and date for selected events were sent to Commonwealth Edison for review against their transmission system event log. The response identified system events that occurred at the approximate time of the relay trigger event. There were 20 relay events that are considered possible correlations.

References:

- Analysis BYR12-145 rev 0 (attachment 2a)
- "An Improved Transformer Inrush Restraint Algorithm" Bogdan Kasztenny and Ara Kulidjian, 53rd Annual Conference of Protective Relay Engineers (attachment 2b)

Method of Analysis

The relay files are read using the computer program from SEL "AcSELerator Analytic Assistant" version 2.3.21.6. This program converts the .csv (comma separated variable) file that is recorded by the SEL relay when a trigger event occurs. Using this program the contents of the .csv file can be displayed graphically as a chart, phasor diagram, or numerically. For all cases in the report the chart form was used.

The resultant chart was then reviewed to determine, in part, the following:

- What caused the trigger to actuate?
- Did, or would the relay have actuated to cause a trip?
- What type of event does the waveform suggest? Events such as a load starting, or a transmission system fault, or a low level transmission system imbalance?
- Did multiple relays trigger at the same time?

The triggered events were then compared to the station control room logs to check for any corresponding plant activity that may have caused the relay to trigger.

The triggered events that show up on more then one relay, and had a characteristic square wave of I0 and/or I2 with values a few amps above the baseline, were sent to Commonwealth Edison to compare to their transmission event logs. A large number of these events could not be correlated accurately to the Commonwealth Edison event logs. These are not recorded in the table below.

In addition to the above, the control room logs were reviewed to identify significant operations, such as an emergency diesel synch to the grid, large motor starts, to verify these did not cause a triggered event.

The above data was then reviewed to determine if there were any correlations. These correlations were then identified.

Discussion:

Transmission system event discussion:

Correlation chart between transmission events and relay triggered recordings

Relay				Transmission	
Relay	Trigger	Date/Time	File #	Time	Description
		Event 1			
142-1	PCT05Q	12.20.12 / 13.18.52	C4-11515	13.20.00	345kV line out of Nelson BC fault
142-2	PCT05Q	12.20.12 / 13.18.31	C8-10072		
		Event 2			
142-1	PCT05Q	12.20.12 / 13.39.12	C4-11516	13.40.58	345kV line out of Quad Cities AB fault
142-2	PCT05Q	12.20.12 / 13.38.50	C8-10073		
		Event 3			
142-1	PCT05Q	12.20.12 / 13.42.24	C4-11517	13.44.10	345kV line out of Quad Cities AB fault
142-1	PCT05Q	12.20.12 / 13.42.25	C4-11518		
142-2	PCT05Q	12.20.12 / 13.42.02	C8-10074		
142-2	PCT05Q	12.20.12 / 13.42.04	C8-10075		

		Event 4			
142-1	PCT05Q	12.20.12 / 20.01.33	C4-11530	20.03.19	345kV line out of Cherry Valley (see
242-2	PCT05Q	12.20.12 / 20.07.32	C4-35936		Note 1)
		Event 5			
142-1	PCT05Q	12.21.12 / 00.42.04	C4-11538	00.42.04	138kV line out of Cherry Valley –
142-1	PCT05Q	12.21.12 / 00.42.07	C4-11539		operated a number of times
242-1	PCT05Q	12.21.12/ 00.43.08	C4-19127		
242-1	PCT05Q	12.21.12 / 00.43.11	C4-19128		
242-2	PCT05Q	12.21.12 / 00.43.04	C4-35951		
242-2	PCT05Q	12.21.12 / 00.43.07	C4-35952		
		Event 6			
142-1	PCT05Q	4.10.13 / 06.16.57	C4-11684	06.20.14	Concurrent C-Grd faults on 138kV
142-2	PCT05Q	4.10.13 / 06.16.39	C4-10118		L15622/15626 at Cherry Valley (see
242-1	PCT05Q	4.10.13 / 06.17.56	C4-25910		Note 2)
		Event 7			
142-1	PCT05Q	4.23.13 / 14.05.52	C4-11705	14.09.18	A&B fault on 138kV line 12205 at
142-2	PCT05Q	4.23.13 / 14.05.34	C4-10124		Belvidere
		Event 8			
142-1	PCT05Q	5.1.13 / 20.46.22	C4-11710	20.29.59	Two A-C faults on 138kV line 11902 at
142-1	PCT05Q	5.1.13 / 20.46.25	C4-11711		Elroy
142-2	PCT05Q	5.1.13 / 20.46.04	C4-10126		
242-2	PCT05Q	5.1.13 / 20.47.21	C4-22411		
		Event 9			
142-1	PCT05Q	6.4.13 / 10.56.08	C4-11718	11.00	345kV L0401 Quad Cities, B Grd fault
142-2	PCT05Q	6.4.13 / 10.55.51	C4-10136		
		Event 10			
142-1	PCT05Q	6.7.13 / 14.23.13	C4-11719	14.28	345kV L15503 Nelson to Cordova, B
142-2	PCT05Q	6.7.13 / 14.22.50	C4-10137		Grd fault
242-1	PCT05Q	6.7.13 / 14.24.03	C4-18712		
242-2	PCT05Q	6.7.13 / 14.24.06	C4-22421		
		Event 11			
142-1	PCT05Q	6.8.13 / 12.21.35	C4-11722	12.25	345kV L0401 Quad Cities to Sub 91 B
142-2	PCT05Q	6.8.13 / 12.21.18	C4-10140		Grd fault
242-1	PCT05Q	6.8.13 / 12.22.31	C4-18715		
242-2	PCT05Q	6.8.13 / 12.22.35	C4-22424		
		Event 12			
142-1	PCT05Q	6.11.13 / 10.23.13	C4-11723	10.28	345kV L0401 Quad Cities to Sub 91 B
142-2	PCT05Q	6.11.13 / 10.23.23	C4-10141		Grd fault
242-1	PCT05Q	6.11.13 / 10.24.36	C4-18716		
242-2	PCT05Q	6.11.13 / 10.24.40	C4-22425		
		Event 13			
142-1	PCT05Q	6.11.13 / 17.33.33	C4-11724	17.36	345kV L0401 Quad Cities to Sub 91 B
142-2	PCT05Q	6.11.13 / 17.33.16	C4-10142		Grd fault
242-1	PCT05Q	6.11.13 / 17.34.29	C4-18717		
242-2	PCT05Q	6.11.13 / 17.34.32	C4-22426		
		Event 14			
142-1	PCT05Q	12.15.13/19.26.52	C4-11659	19.34	One C-Grd fault on 138kV L17113
142-2	PCT05Q	12.15.13/19.26.41	C4-11140		(TSS171 Wempletown to TSS194
242-1	PCT05Q	12.15.13/19.27.39	C4-18751		Sabrooke)
242-2	PCT05Q	12.15.13/19.27.57	C4-22461		
		Event 15			
142-1	PCT05Q	12.19.13/18.09.48	C4-11760	18.17	A-Grd fault on 138kV L11323
142-2	PCT05Q	12.19.13/18.09.38	C4-11141		(TSS113 Waterman to TSS83 Glidden

242-1	PCT05Q	12.19.13/18.10.35	C4-18752		to TSS94 Haumesser Road)
242-2	PCT05Q	12.19.13/18.10.54	C4-22462		
		Event 16			
142-1	PCT05Q	12.19.13/18.34.33	C4-11761	18.41	A-Grd fault on 138kV L11323
142-2	PCT05Q	12.19.13/18.34.34	C4-11142		(TSS113 Waterman to TSS83 Glidden
242-1	PCT05Q	12.19.13/18.35.20	C4-18753		to TSS94 Haumesser Road)
242-2	PCT05Q	12.19.13/18.35.39	C4-22463		
		Event 17			
142-1	PCT05Q	12.19.13/19.17.47	C4-11762	19.25	A-Grd fault on 138kV L11323
142-2	PCT05Q	12.19.13/19.17.37	C4-11143		(TSS113 Waterman to TSS83 Glidden
242-1	PCT05Q	12.19.13/19.18.34	C4-18754		to TSS94 Haumesser Road)
242-2	PCT05Q	12.19.13/19.18.53	C4-22464		
		Event 18			
142-1	PCT05Q	1.6.14/1.36.15	C4-11768	01.45	Two C-Grd faults on 69kV L69BT5-PT5 (TSS163 Roscoe Bert to TSS162 Pierpont). The line reclosed about 10 seconds after the initial fault and the 69kV breaker failed resulting in a breaker failure operation (BF time) Note that by design, the 69kV lines in Rockford do not use pilot or high-speed relay schemes so primary tripping may be time delayed.
142-1	PCT05Q	1.6.14/1.36.26	C4-11769		
142-2	PCT05Q	1.6.14/1.36.06	C4-11146		
142-2	PCT05Q	1.6.14/1.36.16	C4-11147		
242-1	PCT05Q	1.6.14/1.37.01	C4-18764		
242-1	PCT05Q	1.6.14/1.37.12	C4-18765		
242-2	PCT05Q	1.6.14/1.37.22	C4-22474		
242-2	PCT05Q	1.6.14/1.37.32	C4-22475		
		Event 19			
242-1	PCT05Q	1.24.14/8.00.14	C4-18769	08.07	B-Grd fault on 345kV L0404 (STA04 Quad Cities to ESSH471 Sterling Steel)
242-2	PCT05Q	1.24.14/8.00.36	C$-22480		
		Event 20			
142-1	PCT05Q	1.24.14/8.29.05	C4-11778	08.37	B-Grd fault on 345kV L0404 (STA04 Quad Cities to ESSH471 Sterling Steel)
142-1	PCT05Q	1.24.14/8.29.05	C4-11779		
142-2	PCT05Q	1.24.14/8.28.56	C4-11151		
142-2	PCT05Q	1.24.14/8.29.02	C4-11152		
242-1	PCT05Q	1.24.14/8.29.50	C4-18770		
242-1	PCT05Q	1.24.14/8.29.56	C4-18771		
242-2	PCT05Q	1.24.14/8.30.12	C4-22481		
242-2	PCT05Q	1.24.14/8.30.18	C4-22482		

Note: The referenced relay charts are in Attachment 3
Note 1: Relay 142-2 had an overwrite for the period of time where this fault was occurring and therefore did not have a record of this time frame.
Note 2: Relay 242-2 had an overwrite for the period of time where this fault was occurring and therefore did not have a record of this time frame.

The transmission event to relay trigger events comparison is made difficult since the time stamps used in the relays are not synchronized. The transmission system logs use a national standard as a time stamp and are automatically corrected to the standard. The relay time stamps are based solely on the inputted time when the relay was originally set along with natural instrument drift, and has no automatic corrections.

A second problem arises out of the relay overwriting files. The relay has a finite data storage capacity to store triggered event files, when triggered events exceed the data storage capacity of the relay the earlier files are overwritten. This results in data being lost and prevents all four relays from being able to have charts stored for each of the above listed events.

The above chart identifies the best estimates of the correlation between logged transmission events and relay trigger events.

These transmission system induced triggered events have some common characteristics. First, the phase currents show the impact of the fault. On a ground fault (see event 10) one phase will go high, and the two unaffected phases will reduce in magnitude. For a phase to phase fault (see event 1) the two faulted phases will increase, and have their phase angle difference reduced, while the unaffected phase reduces in magnitude.

In all cases though, the negative sequence current will show as a 'square wave' on the chart, with the rise and fall of the wave corresponding to the event initiation and conclusion. This negative sequence current frequently exceeds the trip setpoint of 0.6A. The zero sequence current does increase, but by a small amount on transmission system events. The impact of the ground fault out in the transmission system on the SAT is minimized by the impedance created by the distance from the fault, and the SAT internal impedance. The closer the fault is to the SAT the larger I0 will become. For all recorded cases, I0 was at most 2A, which is much lower then the zero sequence trip setpoint of 9.9A. In addition the recorded event duration never exceeded 20 cycles, and was normally less then 10 cycles for any transmission related events.

A time delay of 30 cycles is used to block a relay trip actuation; this was selected, in part, to coordinate with the transmission systems protection relaying. The recorded events confirm that the transmission system responded and cleared the events within that 30 cycle time delay during this monitoring period.

The MINDETC variable is used to detect a loss of phase condition and will prevent a relay trip actuation if all three phase currents are larger then 0.92A. This value for MINDETC, 0.92A, was selected, in part, to ensure that the event causing the negative sequence currents was an actual loss of phase, and not just an imbalance between the phases. The recorded events confirm that MINDETC did perform that function.

During the course of the monitoring period many events occurred on the transmission system. Events, such as lightning strikes, tornado damage, unit trips, line outages, and many other major events occurred. While the relay may have been triggered by some of these, the relay trip logic was never activated by any of these.

For all these events the relay did not trip. The negative sequence current was above the trip setpoint; however the time delay of 30 cycles and the requirement to have one phase less then MINDETC of 0.92A prevented the relay trip. No transmission event had a zero sequence current approach the trip setpoint. Therefore the relay security measures functioned as expected and prevented the relay from operating inappropriately for the transmission events that occurred during this monitoring program.

System Imbalance Discussion

A second type of transmission system configuration causing relay triggers is due to an apparent imbalance in the transmission system. Examples of this type of event are in Attachment 4 of the report. The negative sequence current is at 0.6A to 1A over long periods of time, oscillating around the trigger setpoint. These events can run for 12 triggers and up. Reviews of the operations log does not provide any correlation to the negative sequence current at the relay. These values are indicative of a slight system imbalance. While the negative sequence currents do exceed the trip value, and the time delay of 30 cycles is exceeded during some events, the requirements for MINDETC to detect an open phase prevented the relay trip. This detection feature, MINDETC, provides protection even during low load operations (above 1.3MVA loading or approximately 2.3A primary side) during outages where the SAT primary side currents can drop below 3A due to low loading.

None of the above transmission system related triggered events posed a challenge to the relay to operate spuriously. The relay detection measure of MINDETC and the security feature of the time delay functioned as designed, to prevent a spurious actuation.

Fast Bus Transfer:

On March 20, 2013 Byron Unit 2 tripped from power. An immediate consequence of the trip was that the loads that were on the Unit Auxiliary Transformers (UAT) fast transferred to the associated System Auxiliary Transformer (SAT). This event was captured on a trigged event on the relay on SAT 242-1, and it is attached as Attachment 5. The chart shows the rapid increase in SAT loading from 17A to 180A, then a reduction in the

total load to stabilize at 54A. The high spike is caused by the new loads closing into the SAT, and having been without power for a few cycles, the loads required a current inrush. This quickly, about 20 cycles, stabilized to the new load.

During the event the zero sequence currents rose to a peak of 5A and maintained a value above the trip setpoint for longer then 30 cycles. The relay trip was blocked by the detection feature provided by MINDETC in that the minimum current never dropped below the initial 17A. The zero sequence current is calculated by the relay based on individual phase current measurements. Inaccuracy in the phase current measurements can result in zero sequence current being calculated by the relay. After the event, the calculated zero sequence current is approximately 2-3% of the phase currents, which is within the range of error that is accounted for in the relay setpoints.   The negative sequence current rose to a peak of 7.6A and quickly, within 30 cycles, decayed to about 1.5A. This negative sequence current spike is expected immediately following the fast bus transfer because the motors being transferred to the SAT may be out of phase with the SAT source at the time of the transfer.

The fast bus transfer did not pose a challenge to the relay to operate spuriously. The relay detection measures of MINDETC functioned as designed, to block a spurious actuation.

Outage, low load discussion

The Plant Control Room Logs were reviewed for the Unit 2 outage. All of the triggered events were compared to determine if a triggered event corresponded to a plant event. After that review, the logs were checked to determine if any large loads were started or load swings occurred on the units. There were a number of large 4kV and 6.9kV loads started with the SAT at low load (5A) these included the RH, SI, CC, CS, CD/CB and CV pumps. These starts did not correlate with any triggered events. There were only two triggered events that show a connection of a plant event to the relay trigger setpoint.

On 4/11 an event was captured during the outage during EDG testing. There was approximately 5A of current flowing from one SAT to the other SAT during the diesel test. The current in all three phases at the common connection point was only around 1A because the output of the EDG nearly matched the Unit 2 load. The event report was captured because one phase at the common connection fell below MINDETC and the other two phases at SAT 242-1 were above LLDIFF. This condition met one of the criteria for open phase detection, with the MINDETC and LLDIFF current levels met. The relay did not actuate to trip since the negative sequence current, a second element required to detect an open phase was below its setpoint, and the zero sequence current was below its security value provided by NSCL1 (0.6A).

The above condition was discovered during the regression analysis. The relay logic for detecting an open phase upstream of the common connection point was modified to prevent the EDG operation from challenging the relay security limits.

On 4/12 while the unit 2 SAT's were loaded at 2.5A the 1B EDG had it's emergency start surveillance, where bus 142 is de-energized from the SAT, and the EDG starts and loads. This activity did not generate a triggered event. At 18:24 bus 142 was restored, and appears to have put a load on SAT 242-2. This did generate a triggered event on harmonics greater then 15% (see Attachment 6 chart 1). The SAT load increased from 2.5A to 5A on a slow increase. There was no challenge to the relay actuation since negative sequence and zero sequence currents remained below their setpoints for the whole event.

On 4/14 while the Unit 2 SAT's were loaded at 2.5A, there was a triggered event at 22.16 (Attachment 6 chart 2a and b), that appears to be a motor start.   A review of the station logs shows the 1B CD/CB pump being started at 22:13. The unit 1 pump should not impact the primary side current on the unit 2 SAT's, therefore this load is not considered to correlate with the triggered event. There were no other logged events within 1 hour of this triggered event that could have caused the load change on the SAT. There was no challenge to the relay actuation since negative sequence and zero sequence currents remained below their setpoints for the whole event.

The result of the review of the relay triggered events to the unit logs during the outage only indicated two possible correlated events. Both of these events triggered the relay on high harmonics. The negative sequence and zero sequence currents both remained below their trigger and trip setpoints. There was no challenge to the relay to spuriously operate. See attachment 6 Low Load Discussion for a more detailed explanation of the relay logic associated with these events.

Transformer loading and energizing

The transformer initial energizing was captured for both the SAT 142-1 and SAT 142-2 transformers on 11/12/2012 and for SAT 142-2 on 3/15/2014. This activity did cause the relay to trip. The same event occurred at Braidwood Station when the SAT's were initially energized. The cause of the relay actuation was zero sequence current greater then 10A for longer then 30 cycles.

The characteristic of the currents that caused the trip is due to the process of closing into the de-energized transformer. Initial magnetizing due to switching a transformer in is considered the most severe case of an inrush. When a transformer is de-energized, the magnetizing voltage is taken away, the magnetizing current goes to zero, while the flux follows the hysteresis loop of the core. This results in certain remnant flux left in the core. When afterwards, the transformer is re-energized by an alternating sinusoidal voltage the flux becomes also sinusoidal but biased by the remanence. The residual flux may be as high as 80-90% of the rated flux, and therefore, it may shift the flux-current trajectories far above the knee-point of the characteristic resulting in large peak values of current. The waveform created displays a large and long lasting dc component and assumes large peak values at the beginning (up to 30 times the rated voltage), then decays away after a few cycles, but its full decay occurs only after several seconds.   This is what caused the SEL relay to actuate to trip the SAT at Braidwood Station. (see reference 2 for more details)

This is a recognized issue with the relay setpoints. In addition, the cause of the trip is understood and it is expected that the relay trip setpoints will be exceeded. Currently the plant design requires that the relay trips be manually isolated during the transformer energizing activities.

There are triggered events that show the initial loading of the 142-1 and 142-2 transformers, these are in attachment 7. These events triggered due to high 2nd and 5th harmonics. The negative sequence currents and zero sequence currents stayed below there setpoint values, and did not challenge the relay actuation.

Relay Logic and Setpoint Updates

Several modifications have been made to the original logic and setpoints since the SEL 451 Loss of Phase relays at Byron Station Unit 1 and Unit 2 were originally installed and enabled in alarm only mode. The changes include: the addition of a third logic string to detect an ungrounded double open phase event, modification of the single ungrounded open phase detection string, and setpoint tweaks based on the final EMTP analysis. The analog event report data (current v. time) captured by the relays during the monitoring period was evaluated against the final relay logic and settings via computer simulation. This analysis is documented in attachment 9. The analysis concludes that the final relay logic and setpoints are secure for all events captured during the monitoring period.

The analysis conducted above identified two potential events that could have caused the relay to spuriously trip. A relay trip would have occurred for the C8_10045, C8_10046, and C8_10048 events captured on SAT 142-2. These events, and all other events recorded on 11/12/12, were captured during transformer energization. The relay picked up and timed out on the unbalanced current seen during transformer inrush. The relay will be manually disabled during transformer energization to prevent spurious trips. Therefore, these cases do not indicate a potential relay issue. Waveform plots for event C8_10046 are included in Attachment A.

The analysis also showed a potential spurious trip for the events captured on 4/11/13. These events were captured during a Unit 2 outage concurrent with EDG testing. During the event, there was approximately 5 A of current flowing from one SAT to the other SAT during the diesel test. The current in all three phases at the common connection point was only around 1 A because the output of the EDG nearly matched the Unit 2 load.

The event report was captured because one phase at the common connection fell below MINDETC and the other two phases at SAT 242-1 were above LLDIFF (note the original logic compares the calculated common connection point current with the individual SAT currents). The relay did not actuate to trip since the negative sequence current was less than NSCL1 (0.6A). However, these events exposed a vulnerability in the preliminary logic updates for single and double ungrounded open phase detection (LS2 & LS3), which were not implemented in the relay on 4/11/13. The logic for single and double ungrounded open phase detection upstream of the common connection point has since been modified to separate the comparison of calculated common connection point currents from the comparison of the individual SAT currents, thus eliminating the vulnerability during EDG testing. The final analysis shows that the 4/11/13 events would not challenge the security of the final relay logic and setpoints

The regression analysis was performed against the setpoints for the relay identified in BYR13-177 Rev0 Unit 1 and Unit 2 Loss of Phase Detection Relay Settings dated 3/19/14. The lessons learned from the transformer energization and the EDG testing, as well as updates to various calculations were used in determining these setpoints. As demonstrated in the attached "Regression Analysis of Byron Open Phase Detection Relay Event Reports" (Attachment 8) the setpoints described in the referenced calculation would not have created a spurious trip of the relay for those events, or any other of the captured events.

Conclusion:

The SEL 451 Loss of Phase relays at Byron Station Unit 1 and Unit 2 have been connected and operating since November 2012. During that time frame the relays have actuated to trip only during initial transformer energization. No other event has occurred to cause the relay trip logic setpoints to be exceeded. In addition, there has been no event that would have required the relay to actuate. The open phase condition that did occur was cleared by the undervoltage relays, and the fault was cleared before the 30 cycle time delay would have allowed the relay to actuate.

During this time frame numerous transmission system faults have occurred. These range from nearby, within 20 miles, to well over that distance. Those faults that can be correlated to relay triggered events have all been cleared in within 30 cycles, and normally within 10 cycles. This demonstrates the coordination between transmission system response to faults and the time delay setting on the relay to provide relay security from events that are cleared by the transmission system protective relaying system.

The transmission system faults do bring the negative sequence currents above their trip setpoints; however the MINDETC setpoint provides a threshold for detection and the time delay setpoint provides a threshold for relay security. The time delay setpoint allows the transmission system time to clear the fault. The MINDETC setpoint prevents the relay from operating unless only one or two phases are severely impacted by the fault. These measures have functioned to prevent spurious actuations of the relay during this monitoring period.

The plant events such as, unit trips, generator load changes, switchyard voltage level changes, large motor starts, diesel generator operations including synching to the grid, have all occurred during this monitoring period. In addition low load operation of the SAT's occurred during the Unit 2 outage. None of these events challenged the operation of the relay. While there were triggered events due to negative sequence currents being above the trip setpoint, the relay security features of MINDETC and the 30 cycle time delay adequately prevented any spurious operation of the relay. The zero sequence trip setpoint was only exceeded during transformer initial energizing.

The values recorded by the relay were within those expected for transmission events, and plant operation events. The exception is the I0 used for a trigger was set higher then the maximum predicted I0 in the EMTP transmission analysis. There were no instances, other then the transformer energizing activities, where I0 caused a triggered event. With the I0 trigger set at 5A and the I0 trip at 10A the monitoring period documented that the value for I0 was sufficiently high to differentiate events causing I0 from open phase events. In this manner the basis for the values used in determining the relay setpoint appear to be consistent with the actual negative and zero sequence currents measured by the relay.

Not every possible event that could impact the relay occurred during this monitoring period and no absolute conclusion can be drawn from a review of the events that did occur. However, the relay has been shown to have good security in the MINDETC and time delay setpoints. The interaction of plant events has been demonstrated to have very little impact on the relay measured currents. And transmission events have been shown to be properly coordinated with. All of which leads to a conclusion that the relay setpoint and logic features are robust and can be expected to make a spurious operation unlikely.

Based on the above, the recommendation is to enable the relay trip function with the installation of EC389896 Revision 4 for Unit 1 and 389897 Revision 4 for Unit 2 completed.

SAT 142-1 LOSS OF PHASE	ALARM NO: 1-20-E5 SETPOINT: None.

A.   PROBABLE CAUSE:

1.   Loss of phase on the high side of SAT 142-1.

B.   AUTOMATIC ACTIONS:

1.   Trip of SAT 142-1 and SAT 142-2.

C.   OPERATOR ACTIONS:

1.   IF all AC Power is lost, REFER to 1BCA 0.0, Loss of All AC Power Unit 1.
2.   IF only one 4KV ESF Bus (141 or 142) is deenergized and emergency procedures are NOT in effect, GO to 1BOA ELEC-3, Loss of a 4KV ESF Bus Unit 1.
3.   IF a loss of offsite power occurred and no Safety Injection has occurred, GO to 1BOA ELEC-4, Loss of Offsite Power Unit 1.
4.   If Diesel Generator started, DISPATCH operator to check for proper operation.
5.   INITIATE corrective action.
6.   RESET targets on Loss of Phase Relay 1PA55J-851PST11 by Pressing the "Target Reset" button.

D.   S.E.R. PRINTOUT:

1.   1058 SAT 142-1 LOSS OF PHASE ACTUATED.

E.   REFERENCES:

1.   S&L INSTRUMENT NUMBER: 1UL-AN023.
2.   S&L BOX NUMBER: 17.
3.   SENSOR DESIGNATION: 851PST11.
4.   ELECTRICAL PRINT: 6E-1-4016C, 6E-1-4030AP01.

SAT 142-2 LOSS OF PHASE

ALARM NO: 1-20-E6

SETPOINT: None.

A.   PROBABLE CAUSE:

1.   Loss of phase on the high side of SAT 142-2.

B.   AUTOMATIC ACTIONS:

1.   Trip of SAT 142-1 and SAT 142-2.

C.   OPERATOR ACTIONS:

1.   IF all AC Power is lost, REFER to 1BCA 0.0, Loss of All AC Power Unit 1.
2.   IF only one 4KV ESF Bus (141 or 142) is deenergized and emergency procedures are NOT in effect, GO to 1BOA ELEC-3, Loss of a 4KV ESF Bus Unit 1.
3.   IF a loss of offsite power occurred and no Safety Injection has occurred, GO to 1BOA ELEC-4, Loss of Offsite Power Unit 1.
4.   If Diesel Generator started, DISPATCH operator to check for proper operation.
5.   INITIATE corrective action.
6.   RESET targets on Loss of Phase Relay 1PA55J-851PST12 by Pressing the "Target Reset" button.

D.   S.E.R. PRINTOUT:

1.   1500 SAT 142-2 LOSS OF PHASE ACTUATED.

E.   REFERENCES:

1.   S&L INSTRUMENT NUMBER: 1UL-AN023.
2.   S&L BOX NUMBER: 17.
3.   SENSOR DESIGNATION: 851PST12.
4.   ELECTRICAL PRINT: 6E-1-4016C, 6E-1-4030AP02.

| SAT 142-1 |
| LOW LOAD/ |
| TROUBLE |

ALARM NO: 1-20-E7

SETPOINT: See Below.

A.   PROBABLE CAUSE:

1.   Low load on SAT 142-1
     (0.8 Amps input to 345 kV Winding approximately 500 kVA total SAT load).
2.   Fault condition detected in relay 851PST11.

B.   AUTOMATIC ACTIONS:

1.   None. However, under low load conditions, some loss of phase conditions
     cannot be detected.

C.   OPERATOR ACTIONS:

1.   Monitor front panel indications on Relay 851PST11 at Panel 1PA55J.
2.   Determine if alarm is caused by low load or relay trouble.
3.   IF alarm was caused by low load on SAT 142-1, THEN raise load on SAT to
     > 500 kVA to clear alarm.
4.   If alarm was caused by low load and cannot be cleared, THEN initiate 1BOL
     AP1.
5.   IF alarm was caused by Relay 851PST11 trouble (SER 1061), THEN INITIATE
     corrective action. Designate Operator to monitor ESF 4KV bus 'C' Phase and
     open affected SAT feed breakers within 30 seconds if voltage is below 3850V.
     See S.O. 12-006.

D.   S.E.R. PRINTOUT:

1.   1061 SAT 142-1 LOSS OF PHASE RELAY TROUBLE ACTUATED.
2.   1063 SAT 142-1 LOW LOAD ACTUATED.

E.   REFERENCES:

1.   S&L INSTRUMENT NUMBER: 1UL-AN023.
2.   S&L BOX NUMBER: 17.
3.   SENSOR DESIGNATION: 851PST11.
4.   ELECTRICAL PRINT: 6E-1-4016C, 6E-1-4030AP01.

SAT 142-2 LOW LOAD/ TROUBLE

ALARM NO: 1-20-E8

SETPOINT: See Below.

A.   PROBABLE CAUSE:

1.   Low load on SAT 142-2.
     (0.8 Amps input to 345 kV Winding approximately 500 kVA total SAT load).
2.   Fault condition detected in relay 851PST12.

B.   AUTOMATIC ACTIONS:

1.   None. However, under low load conditions, some loss of load conditions cannot be detected.

C.   OPERATOR ACTIONS:

1.   Monitor front panel indications on Relay 851PST12 at Panel 1PA55J.
2.   Determine if alarm is caused by low load or relay trouble.
3.   IF alarm was caused by low load on SAT 142-2, THEN raise load on SAT to > 500 kVA to clear alarm.
4.   If alarm was caused by low load and cannot be cleared, THEN initiate 1 BOL AP1.
5.   IF alarm was caused by Relay 851PST12 trouble (SER 1637), THEN INITIATE corrective action. Designate Operator to monitor ESF 4KV bus 'C' Phase and open affected SAT feed breakers within 30 seconds if voltage is below 3850V. See S.O. 12-006.

D.   S.E.R. PRINTOUT:

1.   1501 SAT 142-2 LOW LOAD ACTUATED.
2.   1637 SAT 142-2 LOSS OF PHASE RELAY TROUBLE ACTUATED.

E.   REFERENCES:

1.   S&L INSTRUMENT NUMBER: 1UL-AN023.
2.   S&L BOX NUMBER: 17.
3.   SENSOR DESIGNATION: 851PST12.
4.   ELECTRICAL PRINT: 6E-1-4016C, 6E-1-4030AP02.

	PROCEDURE NO. **1BOSR 8.1.1-1**	
Exelon Generation®		
BYRON STATION	UNIT NO. **1**	REVISION NO. **11**

PROCEDURE TITLE:
NORMAL AND RESERVE OFFSITE AC POWER AVAILABILITY WEEKLY SURVEILLANCE

Rev	Summary	IR/AT#	EC#	Procedure Database Tracking #
11	Revised for installation of Grand Prairie Line		396695	24014
10	Add BT 3-8. Change BT 3-7 to BT 7-8.		396695	21763
9	Matched wording in surveillance step to wording in Acceptance Criteria.			11147
8	Correct typo on Data Sheet D3 for ACB 1422 description.			10313
7	Separate SAT Feed breakers and Reserve Feed breakers into separate steps. Add requirement for SAT Feed breakers to be closed and connected to the ESF bus. Update acceptance criteria and Limitation and Actions to match Tech Spec wording.			10011
6	Formatting for human factoring and revised Data Sheet.			9875
5	Added clarifying statement for station switchyard and deleted an interpretation.			4-1679

NORMAL AND RESERVE OFFSITE AC POWER AVAILABILITY WEEKLY SURVEILLANCE

A.   STATEMENT OF APPLICABILITY:

This procedure applies to the weekly verification of operability of A.C. Electrical Power Sources in Modes 1-4.

B.   REFERENCES:

1.   Technical Specifications:

   a.   LCO 3.8.1

   b.   SR 3.8.1.1

2.   UFSAR:

   a.   Section 8.2, Offsite (Preferred) Power System.

   b.   Section 8.3, Onsite Power Systems.

3.   Station Procedures:

   a.   1BOL 8.1, AC Sources – Operating.

C.   PREREQUISITES:

1.   Receive permission from the Shift Manager or designated SRO licensed assistant prior to performing this surveillance by having the Data Package Cover Sheet signed and dated.

D.   PRECAUTIONS:

1.   None.

E.   LIMITATIONS AND ACTIONS:

1.   As stated in Technical Specification LCO 3.8.1.

2.   In the event the Acceptance Criteria is not met during the performance of this surveillance, immediately notify the Shift Manager to initiate procedure 1BOL 8.1 and review effect on Unit 2 AC Sources.

E. continued

3.   As required by the UFSAR, the AC power system should be considered as having 3 major sections, each of which must provide two physically separate and electrically independent circuit paths between the onsite power system and the transmission network (the transmission network excludes the station switchyard). The three sections are:

a.   The transmission lines entering the station switchyard from the transmission network.

b.   The station switchyard. (A common switchyard is allowed by GDC 17.)

c.   The overhead transmission lines, SATs, and buses between the SATs and the onsite power system.

4.   As required by LCO 3.8.1, two qualified circuits each consisting of:

a.   Physically separated transmission lines from the transmission system to the switchyard.

b.   Physically separated lines from the switchyard to the SAT Banks.

c.   The SAT Banks.

d.   A reserve feed via its associated crosstie to any opposite unit ESF bus.

F.   <u>MAIN BODY:</u>

> **<u>NOTE</u>**
> It is possible that a line has voltage, but is not connected to the transmission grid. [i.e. – the line would have no MW or line amps] If it is not clear whether the line is connected to the grid, TSO should be consulted to assist with determining line status.

1.   On the Data Sheet drawing, **CIRCLE** the appropriate status of the offsite power sources either energized or de-energized by observing BUS ALIVE lights, line amps and MW for all 345 KV lines.

F. continued

2.　On the Data Sheet drawing:

- **INDICATE** all CLOSED disconnects and breakers with an "X".

- **INDICATE** all OPEN disconnects and breakers with an "O".

- **INDICATE** the status of the U-1 and U-2 SAT links.
  Use an "X" to **INDICATE** the links INSTALLED.
  Use an "O" to **INDICATE** the links REMOVED.

3.　On the Data Sheet drawing, **TRACE** a single path along the dashed lines from any energized offsite power source to the Unit 1 SAT Bank.

> **NOTE**
> Lines 0621 and 0622 cannot be considered "Independent Transmission Ckts" since they are on a common tower.

4.　On the Data Sheet drawing, **TRACE** a second path from a second independent power source to the Unit 2 SAT Bank. This path cannot retrace over any portion of the path drawn in step F.3.

5.　**VERIFY** two independent paths exist from offsite power through the switchyard to the Unit SAT Banks based on completion of step F.3 and F.4. IF two independent sources are available, **CIRCLE** YES in the space provided on the Data Sheet. **(¢)**

6.　**VERIFY** NORMAL and RESERVE power 345KV buses energized by observing BUS ALIVE light lit and bus voltmeter indication. IF bus is energized, **CIRCLE** YES in space provided on Data Sheet. **(¢)**

- Normal power 345 KV bus is Bus 6.

- Reserve power 345 KV bus is Bus 13.

F. continued

> **NOTE**
>
> If a Low Load condition exists on SAT's, the 6.9KV (X) Bus Alive
> Light and the 4KV (Y) Bus Alive Light can be used to verify SAT's
> are energized.

7.   **VERIFY** NORMAL and RESERVE power SAT's available by observing X and Y winding megawatt and ampere indications. IF SAT's are energized, **CIRCLE** YES in space provided on Data Sheet. **(¢)**

- Normal power SAT is:

    o   142-1 and 142-2 or,

    o   U-1 SAT crosstie links installed and either 142-1 or 142-2.

- Reserve power SAT is:

    o   242-1 and 242-2 or,

    o   U-2 SAT crosstie links installed and either 242-1 or 242-2.

8.   **VERIFY** that 4160 ESF buses 141 and 142 are energized by observing BUS ALIVE light lit and bus voltmeter indication. IF energized, **CIRCLE** YES on the Data Sheet in space provided. **(¢)**

9.   **VERIFY** that 4160 ESF buses 241 and 242 are energized by observing BUS ALIVE light lit and bus voltmeter indication. IF energized, **CIRCLE** YES on the Data Sheet in the space provided. **(¢)**

10.   **VERIFY** that the following SAT Feed breakers are closed and connected to the ESF bus by indication of position and control power. IF the breakers are closed and connected to the ESF bus, THEN **CIRCLE** YES on the Data Sheet in the space provided. **(¢)**

- ACB 1412 SAT Feed Breaker to Bus 141

- ACB 1422 SAT Feed Breaker to Bus 142

- ACB 2412 SAT Feed Breaker to Bus 241

- ACB 2422 SAT Feed Breaker to Bus 242

F. continued

11. **VERIFY** that the following SAT Reserve Feed breakers are available by indication of position and control power. IF the breakers are available, THEN **CIRCLE** YES on the Data Sheet in the space provided. **(¢)**

    - ACB 1414 Bus 141 Reserve Feed Breaker

    - ACB 1424 Bus 142 Reserve Feed Breaker

    - ACB 2414 Bus 241 Reserve Feed Breaker

    - ACB 2424 Bus 242 Reserve Feed Breaker

12. At panel 1PA55J (U-1 AEER), **VERIFY** that the following SAT Loss of Phase Relays are operable by verifying the green ENABLED light is lit. IF the green enabled light is lit THEN **CIRCLE** YES on the Data Sheet in the space provided. IF the enabled light is NOT LIT THEN inform the unit Supervisor to implement the designated operator to monitor ESF 4KV bus "C" phase and open affected SAT feed breakers within 30 seconds if voltage is below 3850V. See Standing Order 12-006 (historical)..

    - 1PA55J-851PST11 Loss of Phase RLY SAT 142-1

    - 1PA55J-851PST12 Loss of Phase RLY SAT 142-2

G. ACCEPTANCE CRITERIA:

As a minimum the following AC electrical power sources shall be OPERABLE: (SR 3.8.1.1)

1. In Modes 1-4:

    a. Each class 1E 4160 volt bus energized from either transformer of the associated units normal System Auxiliary Transformer Bank, and

    b. Each class 1E 4160 volt bus capable of being powered from either transformer of the other units System Auxiliary Transformer Bank, with

       Each units System Auxiliary Transformer Bank energized from an independent transmission circuit from the offsite transmission network.

NOTE:
Lines 0621 and 0622 cannot be considered independent transmission lines since they are on a common tower.

| 0621 | ENERGIZED DEENERGIZED | 0627 | ENERGIZED DEENERGIZED | 0624 | ENERGIZED DEENERGIZED | 0622 | ENERGIZED DEENERGIZED |

4-5   3-4
3-8   10-14
8-14
10-11   11-12
5-6
7-8
12-13
6-7
13-14
L0626 CB

NOTE:
Future Line
0626

SAT 142-1   SAT 142-2
SAT 242-1   SAT 242-2

1412   1422
2412   2422
141   142
241   242
1414   1424
2414   2424

NOTE:
X=CLOSED
O=OPEN

DATA SHEET
Page 1 or 2

5.	Two independent offsite sources to the Unit SAT Banks are available.	YES **(¢)** / NO
6.		
	• Normal power 345 KV Bus 6 energized.	YES **(¢)** / NO
	• Reserve power 345 KV Bus 13 energized.	YES **(¢)** / NO
7.		
	• Normal power:	YES **(¢)** / NO
	○ SAT 142-1 and 142-2 energized or,	
	○ U-1 SAT crosstie links installed and either SAT 142-1 <u>or</u> 142-2 energized.	
	• Reserve power:	YES **(¢)** / NO
	○ SAT 242-1 and 242-2 energized or,	
	○ U-2 SAT crosstie links installed and either SAT 242-1 <u>or</u> 242-2 energized.	
8.		
	• 4160 volt ESF Bus 141 energized.	YES **(¢)** / NO
	• 4160 volt ESF Bus 142 energized.	YES **(¢)** / NO
9.		
	• 4160 volt ESF Bus 241 energized.	YES **(¢)** / NO
	• 4160 volt ESF Bus 242 energized.	YES **(¢)** / NO
10.		
	• ACB 1412 SAT Feed Breaker to Bus 141 closed/connected.	YES **(¢)** / NO
	• ACB 1422 SAT Feed Breaker to Bus 142 closed/connected.	YES **(¢)** / NO
	• ACB 2412 SAT Feed Breaker to Bus 241 closed/connected.	YES **(¢)** / NO
	• ACB 2422 SAT Feed Breaker to Bus 242 closed/connected.	YES **(¢)** / NO
11.		
	• ACB 1414 Bus 141 Reserve Feed Breaker available.	YES **(¢)** / NO
	• ACB 1424 Bus 142 Reserve Feed Breaker available.	YES **(¢)** / NO
	• ACB 2414 Bus 241 Reserve Feed Breaker available.	YES **(¢)** / NO
	• ACB 2424 Bus 242 Reserve Feed Breaker available.	YES **(¢)** / NO

DATA SHEET
Page 2 or 2

12.	
• 1PA55J-851PST11 Loss of Phase RLY SAT 142-1 operable	YES / NO
• 1PA55J-851PST12 Loss of Phase RLY SAT 142-2 operable	YES / NO

	PROCEDURE NO.		
Exelon Generation®	**2BOSR 8.1.1-1**		
BYRON STATION	UNIT NO. **2**	REVISION NO. **10**	

PROCEDURE TITLE:
NORMAL AND RESERVE OFFSITE AC POWER AVAILABILITY WEEKLY SURVEILLANCE

Rev	Summary	IR/AT#	EC#	Procedure Database Tracking #
10	Revised for installation of Grand Prairie Line		396695	24015
9	Add BT 3-8. Change BT 3-7 to BT 7-8.		396695	21764
8	Matched wording in surveillance step to wording in Acceptance Criteria.			11148
	Correct typo in first line of step 11 on Data Sheet.	862268		11780
7	Separate SAT Feed breakers and Reserve Feed breakers into separate steps. Add requirement for SAT Feed breakers to be closed and connected to the ESF bus. Update acceptance criteria and Limitation and Actions to match Tech Spec wording.			10012
6	Formatting for human factoring and revised Data Sheet.			9876
5	Added clarifying statement for station switchyard and deleted an interpretation.	245519		4-1678

NORMAL AND RESERVE OFFSITE AC POWER AVAILABILITY WEEKLY SURVEILLANCE

A.   STATEMENT OF APPLICABILITY:

This procedure applies to the weekly verification of operability of A.C. Electrical Power Sources in Modes 1-4.

B.   REFERENCES:

1.   Technical Specifications:

a.   LCO 3.8.1

b.   SR 3.8.1.1

2.   UFSAR:

a.   Section 8.2, Offsite (Preferred) Power System.

b.   Section 8.3, Onsite Power Systems.

3.   Station Procedures:

a.   2BOL 8.1, AC Sources – Operating.

C.   PREREQUISITES:

1.   Receive permission from the Shift Manager or designated SRO licensed assistant prior to performing this surveillance by having the Data Package Cover Sheet signed and dated.

D.   PRECAUTIONS:

1.   None.

E.   LIMITATIONS AND ACTIONS:

1.   As stated in Technical Specification LCO 3.8.1.

2.   In the event the Acceptance Criteria is not met during the performance of this surveillance, immediately notify the Shift Manager to initiate procedure 2BOL 8.1 and review effect on Unit 1 AC Sources.

E. continued

   3.   As required by the UFSAR, the AC power system should be considered as having 3 major sections, each of which must provide two physically separate and electrically independent circuit paths between the onsite power system and the transmission network (the transmission network excludes the station switchyard). The three sections are:

         a.   The transmission lines entering the station switchyard from the transmission network.

         b.   The station switchyard. (A common switchyard is allowed by GDC 17.)

         c.   The overhead transmission lines, SATs, and buses between the SATs and the onsite power system.

   4.   As required by LCO 3.8.1, two qualified circuits each consisting of:

         a.   Physically separated transmission lines from the transmission system to the switchyard.

         b.   Physically separated lines from the switchyard to the SAT Banks.

         c.   The SAT Banks.

         d.   A reserve feed via its associated crosstie to any opposite unit ESF bus.

F.   <u>MAIN BODY</u>:

> **NOTE**
> It is possible that a line has voltage, but is not connected to the transmission grid. [i.e. – the line would have no MW or line amps] If it is not clear whether the line is connected to the grid, TSO should be consulted to assist with determining line status.

   1.   On the Data Sheet drawing, **CIRCLE** the appropriate status of the offsite power sources either energized or de-energized by observing BUS ALIVE lights, line amps and MW for all 345 KV lines.

F. continued

2.   On the Data Sheet drawing:

- **INDICATE** all CLOSED disconnects and breakers with an "X".

- **INDICATE** all OPEN disconnects and breakers with an "O".

- **INDICATE** the status of the U-1 and U-2 SAT links.
   Use an "X" to **INDICATE** the links INSTALLED.
   Use an "O" to **INDICATE** the links REMOVED.

3.   On the Data Sheet drawing, **TRACE** a single path along the dashed lines from any energized offsite power source to the Unit 2 SAT Bank.

> **NOTE**
> Lines 0621 and 0622 cannot be considered "Independent Transmission Ckts" since they are on a common tower.

4.   On the Data Sheet drawing, **TRACE** a second path from a second independent power source to the Unit 1 SAT Bank. This path cannot retrace over any portion of the path drawn in step F.3.

5.   **VERIFY** two independent paths exist from offsite power through the switchyard to the Unit SAT Banks based on completion of step F.3 and F.4. IF two independent sources are available, **CIRCLE** YES in the space provided on the Data Sheet. **(¢)**

6.   **VERIFY** NORMAL and RESERVE power 345KV buses energized by observing BUS ALIVE light lit and bus voltmeter indication. IF bus is energized, **CIRCLE** YES in space provided on Data Sheet. **(¢)**

- Normal power 345 KV bus is Bus 13.

- Reserve power 345 KV bus is Bus 6.

F. continued

> **NOTE**
>
> If a Low Load condition exists on SAT's, the 6.9KV (X) Bus Alive
> Light and the 4KV (Y) Bus Alive Light can be used to verify SAT's
> are energized.

7.   **VERIFY** NORMAL and RESERVE power SAT's available by observing X and Y winding megawatt and ampere indications. IF SAT's are energized, **CIRCLE** YES in space provided on Data Sheet. **(¢)**

- Normal power SAT is:

    o   242-1 and 242-2 or,

    o   U-2 SAT crosstie links installed and either 242-1 or 242-2.

- Reserve power SAT is:

    o   142-1 and 142-2 or,

    o   U-1 SAT crosstie links installed and either 142-1 or 142-2.

8.   **VERIFY** that 4160 ESF buses 241 and 242 are energized by observing BUS ALIVE light lit and bus voltmeter indication. IF energized, **CIRCLE** YES on the Data Sheet in space provided. **(¢)**

9.   **VERIFY** that 4160 ESF buses 141 and 142 are energized by observing BUS ALIVE light lit and bus voltmeter indication. IF energized, **CIRCLE** YES on the Data Sheet in the space provided. **(¢)**

10.   **VERIFY** that the following SAT Feed breakers are closed and connected to the ESF bus by indication of position and control power. IF the breakers are closed and connected to the ESF bus, THEN **CIRCLE** YES on the Data Sheet in the space provided. **(¢)**

- ACB 2412 SAT Feed Breaker to Bus 241

- ACB 2422 SAT Feed Breaker to Bus 242

- ACB 1412 SAT Feed Breaker to Bus 141

- ACB 1422 SAT Feed Breaker to Bus 142

F. continued

11. **VERIFY** that the following SAT Reserve Feed breakers are available by indication of position and control power. IF the breakers are available, THEN **CIRCLE** YES on the Data Sheet in the space provided. **(¢)**

- ACB 2414 Bus 241 Reserve Feed Breaker

- ACB 2424 Bus 242 Reserve Feed Breaker

- ACB 1414 Bus 141 Reserve Feed Breaker

- ACB 1424 Bus 142 Reserve Feed Breaker

12. At panel 2PA55J (U-2 AEER), **VERIFY** that the following SAT Loss of Phase Relays are operable by verifying the green ENABLED light is lit. IF the green enabled light is lit THEN **CIRCLE** YES on the Data Sheet in the space provided. IF the enabled light is NOT LIT THEN inform the unit Supervisor to implement the designated operator to monitor ESF 4KV bus "C" phase and open affected SAT feed breakers within 30 seconds if voltage is below 3850V. See Standing Order 12-006 (historical).

- 2PA55J-851PST21 Loss of Phase RLY SAT 242-1

- 2PA55J-851PST22 Loss of Phase RLY SAT 242-2

G. ACCEPTANCE CRITERIA:

As a minimum the following AC electrical power sources shall be OPERABLE: (SR 3.8.1.1)

1. In Modes 1-4:

   a. Each class 1E 4160 volt bus energized from either transformer of the associated units normal System Auxiliary Transformer Bank, and

   b. Each class 1E 4160 volt bus capable of being powered from either transformer of the other units System Auxiliary Transformer Bank, with

      Each units System Auxiliary Transformer Bank energized from an independent transmission circuit from the offsite transmission network.

NOTE:
Lines 0621 and 0622 cannot be considered independent transmission lines since they are on a common tower.

0621 ENERGIZED DEENERGIZED

0627 ENERGIZED DEENERGIZED

0624 ENERGIZED DEENERGIZED

0622 ENERGIZED DEENERGIZED

4-5   3-4

10-11   11-12

3-8

10-14

8-14

5-6

12-13

7-8

6-7

13-14

L0626 CB

NOTE:
Future Line
0626

SAT
142-1

SAT
142-2

SAT
242-1

SAT
242-2

1412   1422

2412   2422

141   142

241   242

1414   1424

2414   2424

NOTE:
X=CLOSED
O=OPEN

DATA SHEET
Page 1 of 2

5.	Two independent offsite sources to the Unit SAT Banks are available.	
		YES **(¢)** / NO
6.		
	• Normal power 345 KV Bus 13 energized.	YES **(¢)** / NO
	• Reserve power 345 KV Bus 6 energized.	YES **(¢)** / NO
7.		
	• Normal power:	YES **(¢)** / NO
	o SAT 242-1 and 242-2 energized or,	
	o U-2 SAT crosstie links installed and either SAT 242-1 <u>or</u> 242-2 energized.	
	• Reserve power:	YES **(¢)** / NO
	o SAT 142-1 and 142-2 energized or,	
	o U-1 SAT crosstie links installed and either SAT 142-1 <u>or</u> 142-2 energized.	
8.		
	• 4160 volt ESF Bus 241 energized.	YES **(¢)** / NO
	• 4160 volt ESF Bus 242 energized.	YES **(¢)** / NO
9.		
	• 4160 volt ESF Bus 141 energized.	YES **(¢)** / NO
	• 4160 volt ESF Bus 142 energized.	YES **(¢)** / NO
10.		
	• ACB 2412 SAT Feed Breaker to Bus 241 closed/connected.	YES **(¢)** / NO
	• ACB 2422 SAT Feed Breaker to Bus 242 closed/connected.	YES **(¢)** / NO
	• ACB 1412 SAT Feed Breaker to Bus 141 closed/connected..	YES **(¢)** / NO
	• ACB 1422 SAT Feed Breaker to Bus 142 closed/connected.	YES **(¢)** / NO
11.		
	• ACB 2414 Bus 241 Reserve Feed Breaker available.	YES **(¢)** / NO
	• ACB 2424 Bus 242 Reserve Feed Breaker available.	YES **(¢)** / NO
	• ACB 1414 Bus 141 Reserve Feed Breaker available.	YES **(¢)** / NO
	• ACB 1424 Bus 142 Reserve Feed Breaker available.	YES **(¢)** / NO

DATA SHEET
Page 2 of 2

12.

- 2PA55J-851PST21 Loss of Phase RLY SAT 242-1 operable   YES / NO

- 2PA55J-851PST22 Loss of Phase RLY SAT 242-2 operable   YES / NO

FILE LOCATION: 2.05.0500

LCOAR
UNIT 1 SAT LOW LOAD CONDITION LOSS OF PHASE MONITORING

A.   NOTIFICATION

TIME/DATE:	BY:	TITLE:
PRESENT MODE:	APPLICABLE MODE(s): **All**	
INITIATING EVENT(s):_____ _____		
	CONDITION(S) Pg(s)	
NAME OF SM NOTIFIED: TIME/DATE:	☐ PLANNED ☐ UNPLANNED	
WAS AN IR WRITTEN? ☐ YES ☐ NO If NO, Reason:	RELATED WO/WR(s): _____ _____ _____ _____ _____ _____	RELATED CLEARANCE ORDER(s): _____ _____ _____ _____ _____ _____
Separate Condition entry allowed: **Yes**		

B.   ACTIONS

1.   COMPLETE, as required, the LCOAR Table per BAP 1400-6, checking all conditions to verify ALL applicable conditions are entered and followed.

LCOAR TABLE
UNIT 1 SAT LOW LOAD CONDITION LOSS OF PHASE MONITORING

Pg	COND	Any Of The Following CONDITIONS: CIRCLE applicable CONDITION(S)
2	A.	SAT 142-1 or SAT 142-2 LOW LOAD/TROUBLE alarm illuminated with low load condition indicated. (Note 2)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Low Load condition on any SAT. _____/_____ TIME DATE _____ SRO	A.1 Complete Attachment A for required actions to VERIFY all 3-phase voltages, VERIFY ESF loads have not tripped, and PERFORM a walkdown of switchyard lines to look for evidence of an open phase. (Note 1)	1 hour __n/a__/_n/a___ _____n/a_____ TIME DATE SRO AND Once per 8 hours. __n/a__/_n/a___ _____n/a_____ TIME DATE SRO

Notes:

1.   Completion Time, Date, and SRO initials are recorded on Attachment A.

2.   IF condition is expected due to planned evolutions, THEN this LCOAR need not be entered.

C.   RESTORATION

1.   An SRO shall determine the applicable surveillances and/or other actions required to demonstrate LCO restoration and LIST and/or MARK those that apply:

   a.   For the Initiating Event(s) in Section A (NOTIFICATION) of this LCOAR

☐   _____
☐   _____
☐   _____
☐   _____
☐   _____
☐   _____
☐   _____
☐   _____
☐   _____

TIME/DATE when these requirements are met _____ / _____ SRO

2.   Comments: _____
_____
_____

3.   Once all of the above requirements have been satisfactorily completed (with SM concurrence if appropriate), RECORD the Time and Date the LCO is met. TERMINATE the Action Requirements excluding any SPECIAL REPORT or SPECIAL ACTIONS and RETURN the affected Equipment/Unit to desired status.

SRO (NOT Duty S.M.): _____   TIME/DATE: _____/_____

Remarks and/or additional requirements: _____
_____

DUTY SHIFT MANAGER: _____   TIME/DATE: _____/_____

ATTACHMENT A

UNIT 1 SAT Low Load Condition Action Requirements

INITIAL PERFORMANCE DUE: **TIME** _____ **DATE** _____
INITIAL PERFORMANCE COMPLETED: **TIME** _____ **DATE** _____   SRO _____
SUBSEQUENT DUE EVERY: ____**8**____ HOURS

Next Due TIME/DATE	Performed TIME/DATE	All 3-Phase Voltages Satisfactory (Att. B)	ESF Loads NOT Tripped	NO Open Phase Evidence in Walkdown of Switchyard lines	SRO Review SRO
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				
_____/_____	_____/_____				

ATTACH ADDITIONAL COPIES OF THIS PAGE AS NECESSARY

ATTACHMENT B

UNIT 1 BUS VOLTAGE CHANNEL CHECKS

BUSSES	INSTRUMENT	CHANNEL CHECK		
		SET 1	SET 2	SET 3
Bus 141	1EI-AP054	SAT UNSAT	SAT UNSAT	SAT UNSAT
Verify 141 Voltage Selected		Phase CA	Phase CA	Phase CA
Bus 142	1EI-AP086	SAT UNSAT	SAT UNSAT	SAT UNSAT
Verify 142 Voltage Selected		Phase CA	Phase CA	Phase CA
Bus 143	1EI-AP055	SAT UNSAT	SAT UNSAT	SAT UNSAT
Bus 144	1EI-AP087	SAT UNSAT	SAT UNSAT	SAT UNSAT
Bus 156	1EI-AP033	SAT UNSAT	SAT UNSAT	SAT UNSAT
Bus 157	1EI-AP034	SAT UNSAT	SAT UNSAT	SAT UNSAT
Bus 158	1EI-AP033	SAT UNSAT	SAT UNSAT	SAT UNSAT
Bus 159	1EI-AP034	SAT UNSAT	SAT UNSAT	SAT UNSAT

ATTACH ADDITIONAL COPIES OF THIS PAGE AS NECESSARY