CIGRÉ-347

2020 CIGRÉ Canada Conference
21, rue d'Artois, F-75008 PARIS
Toronto, Ontario, October 19-22 2020

http : //www.cigre.org

Probability of Transmission Equipment Contingencies in Ontario Power System

Darin Chayka, Jingdong Ge, Aaron Cole, Hydro One Networks
Pedro Rebellon, Independent Electricity System Operator

SUMMARY

This paper presents the experiences of modeling the expected occurrence of transmission contingencies in the Ontario power system using historic performance statistics of transmission equipment owned by Hydro One Networks Inc. (HONI), with the goal of facilitating the operational planning of outages necessary for maintenance and construction work.

The historic data provided by HONI in the yearly submissions to the Canadian Electric Association Equipment Reliability Information System (CEA-ERIS) was used to develop a probabilistic model of outages by transmission circuit, using Poisson Distribution representation. The model parameters were calculated in various time frames to provide the expected occurrence of sustained outages of a single transmission circuit in a given time interval. The model was further enhanced with historic performance data to estimate the expected occurrence of sustained transmission outages due to contingencies affecting various transmission elements, such as multiple circuits without successful reclosure, or breaker failure protection operation.

The final part of the paper will provide examples of how the results can be used to facilitate the planning and scheduling of outage work by simplifying the actions to be included in the outage assessment as part of the re-preparation plans to mitigate contingencies while in the outage configuration.

KEYWORDS

Forecasting tools and risk analysis, C4 Power system technical performance, Asset Management

Darin.Chayka@HydroOne.com
Jingdong.GE@HydroOne.com
Aaron.Cole@HydroOne.com
Pedro.Rebellon@ieso.ca

1. INTRODUCTION

The Independent Electricity System Operator (IESO) is the Reliability Coordinator (RC) for the province of Ontario, Canada. Hydro One Networks Inc. (HONI) is the largest transmission and distribution owner and operator in the province, serving about 1.4 million customers.

The power system in the province of Ontario, Canada, includes about 30,000 km of transmission circuits at 115, 230 and 500 kV, has about 35 GW of installed generation, and serves about 24 GW of peak load. To maintain reliability, the IESO applies Ontario's market rules and criteria in the IESO-controlled grid, and applies the North American Electric Reliability Corporation (NERC) standards in the portion of the Ontario power system defined as "Bulk Electric System" (BES) by NERC.

The IESO is also a member of the regional reliability organization Northeast Power Coordinating Council (NPCC), and as such, the IESO applies the NPCC criteria in the portion of the Ontario power system determined to be the "Bulk Power System" (BPS) by the performance test described in the NPCC document A-10 "Classification of Bulk Power System Elements".

NERC standards require the study in the planning time frame of all events resulting in the loss of a single element ("single contingencies") as well as all events resulting in the loss of multiple elements ("multiple contingencies"). Single contingencies are respected in the operation of the Ontario power system in both NPCC BPS and NERC BES areas. Multiple contingencies are respected at all times in the NPCC BPS areas, and during storms only in certain parts of the NERC BES areas (NW Ontario).

This paper presents the experiences of modeling the probability of transmission contingencies in the Ontario power system using historic performance data of transmission equipment owned by HONI, for the operational planning of outages necessary for maintenance and construction work.

This paper is organized in the following format: Section 2 discusses HONI's system to monitor the performance of transmission equipment and yearly submissions to CEA-ERIS; Section 3 describes the development of a probabilistic model of outages for transmission circuit, using Poisson Distribution representation; Section 4 presents the use of transmission performance data in applications developed by HONI for power system outage planning. Finally, the conclusions and contributions of this paper will follow in Section 5.

2. MONITORING OF TRANSMISSION EQUIPMENT PERFORMANCE

HONI has been working with other Canadian transmission utilities to collect transmission equipment performance data through the Canadian Electricity Association (CEA) Equipment Reliability Information System (ERIS) since 1978. The ERIS covers all major transmission components, including transmission circuits, transformer banks, breakers, shunt capacitors, shunt reactors, series capacitors, and static compensators, etc. With detailed definitions of major components, subcomponents, forced and planned outages, event, and outage causes, it makes the benchmarking among CEA members meaningful and consistent through time.

CEA ERIS focuses on physical equipment performance only. This means that transmission equipment is reported by its physical attributes rather than operational designations. HONI transmission equipment inventory and outage data are collected against operational designations. The data is translated to physical equipment when they are reported to the CEA ERIS. HONI's transmission equipment outage database is also used for the North American Electric Corporation (NERC) Transmission Availability Data System (TADS) reporting.

In component outage data, there is a field to track common mode outages. A tower failure caused double circuit outages is an example of common mode outages. Furthermore, by tracking the event information, multiple outages can be grouped by the same event.

From the collected outage data, transmission circuit outage performance can be measured by per terminal-year for those terminal related outages or per 100 km-year for those circuit related outages. When both terminal and circuit related outages are combined, the circuit performance can be measured by per circuit-year. A transient outage is an outage with duration of less than 1 minute, which is normally for a successful auto-reclose of a circuit due to a transient fault. An outage with duration of 1 or more minutes is defined as a sustained outage. Sustained outages are less frequent than transient outages. The probability of a sustained common mode outage for multiple circuits is much lower than that of a single circuit outage.

The performance of transmission circuit breakers can be monitored under two different failure modes: i) **at rest**, when the monitoring of the circuit breaker alarms for an anomalous condition that may require the removal of the breaker from service (i.e. low air or SF6 pressure, trip coil or DC loss, etc.) or, ii) **under command**, when the breaker is called to open by protection relays but it fails to open or it opens slower than expected. This mode of failure results on a breaker fail protection operation, which opens additional circuit breakers to clear the fault.

The historic performance of HONI transmission equipment was used to derive models to estimate the probability of transmission equipment contingencies, as described in the following section.

3. PROBABILISTIC MODELING OF OUTAGES IN TRANSMISSION CIRCUITS

A probabilistic modeling of transmission contingencies can be developed using the Poisson Process and Poisson Distribution. An introduction to these items is provided in reference [1]. Below is a summary of the key concepts and equations used in these models.

The **Poisson Process** is a model for a series of discrete events where the *average time between events* is known, but the exact timing of events is random, and the events are **independent** of each other. Therefore, the occurrence of one event does not affect the probability of another event. Failures can happen back-to-back or have years in between due to the randomness of the process.

The occurrence of transmission contingencies in the power system meet the criteria listed above for the following reasons:

- They occur generally in a random manner,
- The average failure rate per unit of time is determined from the historic performance statistics, and
- Failures in the transmission system are independent from each other.

The **Poisson Distribution** enables us to find the probability of observing **k** events in a time period given the length of the period and the average number of events per time:

$$P(k\ events\ in\ time\ period) = \frac{\left(\frac{events}{time} \times time\ period\right)^k}{k!} \times e^{-\frac{events}{time} \times time\ period}$$

Poisson Distribution for probability of k events in time period

The expression “events/time * time period” can be simplified into a single parameter, **λ**, lambda, or the expected number of events in the interval. With this substitution the Poisson Distribution probability function can be written in the more compact form shown below.

$$P(k) = \frac{\lambda^k e^{-\lambda}}{k!}$$

Poisson Distribution probability of k events in an interval

The occurrence of one sustained outage on a transmission circuit will remove the circuit from service. Thus we set the number of events k = 1 in the Poisson Distribution probability function above.

In this section we illustrate the use of the Poisson Distribution to estimate the probability of occurrence of sustained outages of transmission circuits in the province of Ontario, as a function of circuit length and operating voltage levels (115, 230 or 500 kV).

The Poisson Distribution parameter **λ**, lambda, and the expected number of events in the interval, were derived from the historic occurrence of sustained transmission circuit forced outages during a 5-yr period for each voltage level with various time intervals as shown in table below:

Table 1: Example of 5-year sustained transmission circuit forced outage rates

Operating voltage	115 kV	230 kV	500 kV
Sample km of circuit	9,228	13,891	4,138
Number of sustained outages	413	135	18
Outage rate (# of outages per 100 km per year)	0.90	0.19	0.09
Outage rate (# of outages per 100 km per week)	0.0017	0.004	0.002
Outage rate (# of outages per 100 km per day)	0.0025	0.0005	0.0002
Average ratio of double circuit to singe circuit sustained outages	0.05	0.12	0

To calculate the Poisson Distribution probability of a sustained outage on a specific transmission circuit, the parameter **λ** for the circuit's voltage class is scaled by the relative length of the circuit to the reference of 100 km. For example, a 200 km circuit will have a **λ** twice as large. The inverse of the Poisson Distribution probability gives the time interval in which one sustained outage is expected.

Using the data shown above, the probability of sustained forced outages for a specific subset of transmission circuits can be estimated. The transmission flowgate shown in the figure below is used as an example. The time interval in weeks allows a more intuitive comparison with the duration of planned outages, for operational purposes. The scale is 2,000 weeks, which is comparable with the length of an average person's career. The NPCC criteria for loss of load expectation (LOLE) is 1 day in 10 years, or 520 weeks [2].

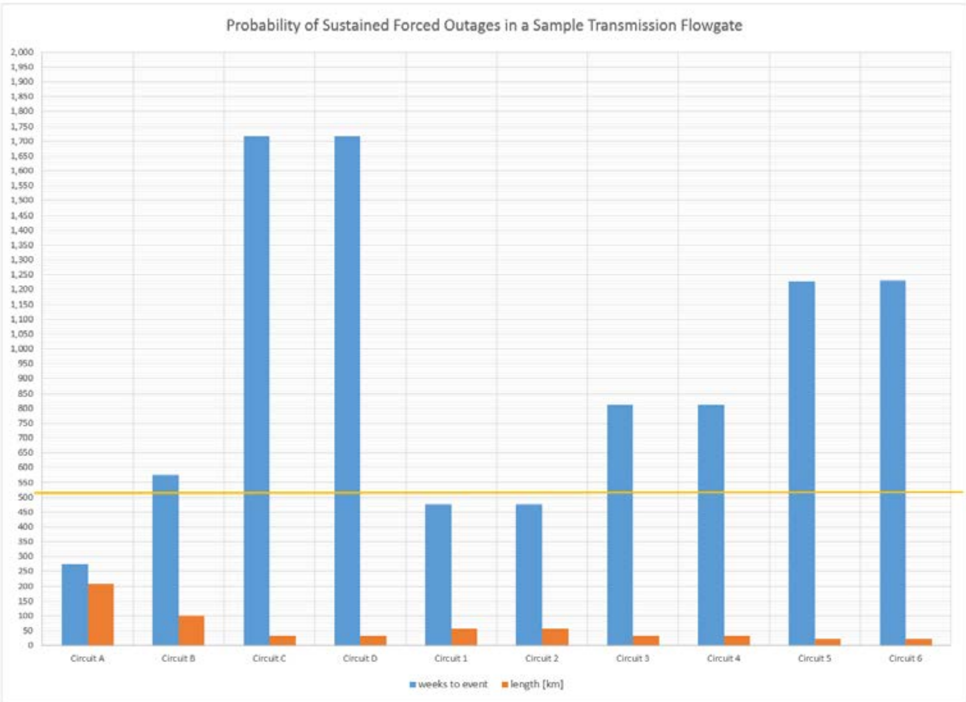

Figure 1: Estimated number of weeks for sustained outages on a Sample Transmission Flowgate

Once the probabilities of sustained outages in specific circuits are known, it is possible to estimate the probability of outages involving multiple circuits (i.e. circuits sharing the same towers). For the Sample transmission flowgate shown in figure 1 above the probabilities of sustained single and multi-circuit outages in a year are:

230 kV single circuit: one sustained forced outage in about 2.5 yr
230 kV double circuit: one sustained forced common mode outage in about 20 yr
500 kV single circuit: one sustained forced outage in about 3 yr
500 kV double circuit: no data for the 5 yr period – the analysis requires longer data collection period

The Poisson Distribution can also be used to find the probability of waiting time until the next event:

$$P(T > t) = e^{-\frac{events}{time} \times t}$$

Probability of waiting more than a certain time

The occurrence of transmission outages may be affected by a variety of factors such as seasonal weather patterns, geographical locations, exposure to environmental or other factors (lightning, trees, wildlife, pollution, etc.), equipment age and condition, design criteria, manufacturer, voltage of operation, and so on.

4. APPLICATIONS FOR POWER SYSTEM OUTAGE PLANNING

Using the data above, additional data, such as asset health metrics, coincident outage data, and historical weather statistics such as lightning strikes, can be used in the probabilistic determination of an N-1 scenario for power system outage planning. For example, in [3] the term Expected Energy Not Supplied (EENS) is used to represent the probability weighted energy not supplied as a result of a planning decision. Using the failure rates discussed in Section 2 and probability distributions from Section 3, the EENS for a planned equipment outage can be calculated using the following equation:

$$EENS = R \times \sum_{i=1}^{L} \sum_{j=1}^{O} E_{ij} \times D_i$$

Expected energy not supplied due to a planned equipment outage

- D_i is the average amount of load for a delivery point i in the set of all loads L exposed to single contingency interruption as a result of a planned equipment outage;
- E_{ij} is the expected value[1] of the probability distribution for a sustained unplanned outage j in the set of all known unplanned outage possibilities O that interrupts that load i; and,
- R is the estimated recall time for the planned work.

Figure 2 below depicts an example of a double circuit corridor with two normally dual supplied tapped stations A and B, each with delivery points 1 and 2. To calculate the EENS of a planned outage to one of the circuits we use the average load for each delivery point $\{D_{A1}, D_{A2}, D_{B1}, D_{B2}\}$ as well as the expected value for a failure of a circuit, one of its terminals, a load transformer, a low voltage bus, or one of its transformer secondary/bus tie breakers $\{E_1, E_{2C}, E_{2D}, E_{3A}, E_{3B}, E_{4A}, E_{4B}, E_{5A}, E_{5B}, E_{6A}, E_{6B}\}$.

[1] The expected value $E(X)$ represents that weighted average for a random variable X. For transmission contingencies, using the Poisson process described in Section 3, the expected value is λ, which is $\frac{events}{time} \times time\ period.$

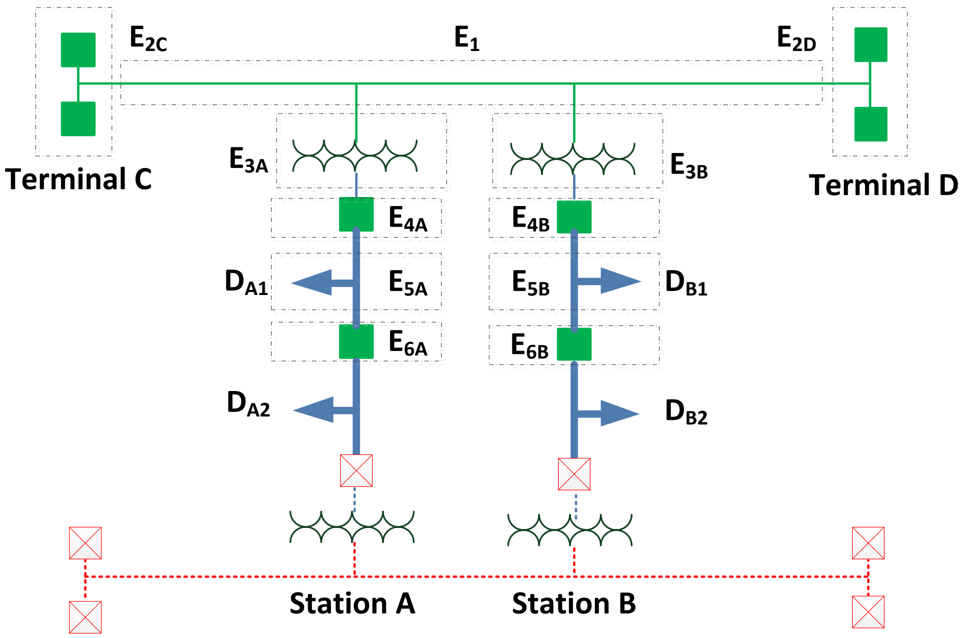

Figure 2: A simplified representation of two transmission lines with tapped stations

The EENS for the configuration in Figure 2 can be expanded into the following equation.

$$EENS = R \times ([E_1 + E_{2C} + E_{2D}] \times [D_{A1} + D_{A2} + D_{B1} + D_{B2}]) \\ + R \times ([E_{3A} + E_{4A}] \times [D_{A1} + D_{A2}] + [E_{3B} + E_{4B}] \times [D_{B1} + D_{B2}]) \\ + R \times ([E_{5A} + E_{6A}] \times D_{A2} + [E_{5B} + E_{6B}] \times D_{B2})$$

Using the average failure rates for each equipment type and voltage level described in Section 2, the EENS formula can be simplified into the following equation:

$$EENS = R \times ([E_1 + 2E_2 + 2E_3 + E_4] \times [D_{A1} + D_{A2} + D_{B1} + D_{B2}] + [E_5 + E_6] \times [D_{A2} + D_{B2}])$$

To streamline the analysis for planning, the EENS results can be pre-calculated for known Transmission System Outage Groups (TSOG) using average loads and failure rates for each month. Table 1 below, is an anonymized example set of double circuit corridors with varying voltage levels, circuit lengths, number of terminals, number of delivery points, and average monthly loads.

Table 2: A set of transmission circuits with their characteristics

Circuit	Voltage	Terminals	Length	Delivery Points	Monthly Average Load Range
Circuits E/F	230 kV	2	194 km	4	92 – 110 MW
Circuits G/H	230 kV	2	111 km	6	97 – 156 MW
Circuits I/J	230 kV	1	69 km	2	64 – 87 MW
Circuits K/L	230 kV	1	17 km	8	195 – 266 MW
Circuits M/N	115 kV	2	12 km	2	31 – 51 MW
Circuits O/P	115 kV	1	7 km	4	55 – 70 MW

The EENS for removing one circuit in each corridor from service for 5 days with a recall of 4 hours during each month is depicted in Table 2. Planners can linearly interpolate the EENS for a planned outage with different durations and/or recalls by using the ratio of days and/or recall times. Similarly, the simplification of the EENS formula with average failure rates can also be used for individual equipment outages at a tapped station. This can be calculated by removing the delivery point load contributions from other stations. Planners can then use manual, algorithmic or linear programing optimization techniques to minimize EENS while scheduling their work programs.

Table 3: Expected Energy Not Supplied (EENS) in MWh for example circuit planned outages

Circuit	Month											
	Jan	**Feb**	**March**	**April**	**May**	**June**	**July**	**August**	**Sept**	**Oct**	**Nov**	**Dec**
Circuit E	4.20	5.36	4.09	5.38	4.37	5.63	7.47	5.71	4.75	3.46	5.26	3.45
Circuit F	3.92	5.59	3.59	4.27	3.35	4.78	7.90	5.81	4.15	2.82	4.39	3.43
Circuit G	2.15	2.24	1.68	2.30	1.80	2.07	2.79	2.10	1.65	1.34	1.86	1.51
Circuit H	4.94	3.96	3.11	4.88	3.77	4.50	5.90	4.35	3.59	2.77	3.28	2.78
Circuit I	0.85	0.80	0.65	0.81	0.81	0.82	1.22	0.83	0.90	0.59	0.63	0.84
Circuit J	1.25	0.96	0.84	1.26	1.07	1.20	1.41	1.03	0.99	0.81	0.82	0.85

The EENS equation can be further enhanced with weighting to account for equipment aging, geography, local electrical areas and specific critical outage postures in both the long term and short term planning spheres. Likewise, reduction factors based on post contingency load transfer capabilities, average equipment restoration duration, and alternate supply configurations can be applied when available.

The data above can also be used to actively manage the performance of a single delivery point. HONI tracks the frequency of interruptions (interruption/year) and overall interruption duration (min/year) for its customer delivery points. These metrics are compared to internal standards of performance based on the average load of the delivery point and its historical performance. When a delivery point performs below specified standards it is considered an outlier. Once this is identified HONI works with customer to consider potential remedial actions to improve its performance.

The primary solution to improving systemically underperforming delivery points is through investment activities. These investment activities can take months to plan and years to implement. During the interim period until an investment or remedial action is realized or implemented, the poor performance of a delivery point can be mitigated by actively managing the risk of interruptions. To do so, the EENS equation can be augmented to calculate the Expected Delivery Point Interruptions (EDPI) that are caused by our upcoming planned work for a multi-circuit supplied delivery point using the following equation:

$$EDPI = \sum_{k=1}^{W} \sum_{j=1}^{O} E_{kj}$$

Expected number of delivery point interruptions for a delivery point as a result of a set of planned outages

- E_{kj} is the expected value of the probability distribution of a transient or sustained unplanned outage j in the set of all known unplanned outage possibilities O that interrupt the delivery point during a scheduled planned equipment outage k; in the set of all planned work W.

Table 3 below is an anonymized example set of dual supplied stations each with 2 delivery points. For each station, the total time from 2010-2019 where the station was exposed to a loss of transmission supply redundancy was calculated. Overlapping (or bundled) outages were removed to determine the effective exposure during the time frame. The expected number of coincident planned delivery point interruptions was calculated using the contingencies in Figure 2 and the loss of transmission supply redundancy duration. The actual number of coincident planned interruptions is provided for comparison.

Table 4: EDPI Predicted and Actual Coincident Planned Interruptions (2010-2019)

Station	Length of supply circuits	Number of transformers connected to supply circuit	Exposure to loss of transmission supply redundancy	Predicted Number of Coincident Planned Interruptions	Actual Number of Coincident Planned Interruptions
Station 1	194 km	4	250 Days	3.78	4
Station 2	17 km	3	380 Days	1.82	2
Station 3	7 km	2	399 Days	1.56	2
Station 4	12 km	1	395 Days	1.5	0

As potential enhancement, if the expected restoration times following an unplanned outage is determined, the EDPI equation can be changed to predict the expected interruption duration for a delivery point in a given timeframe.

The EDPI equation, its variants, and the delivery point performance standard can be used to strictly enforce work bundling and efforts to reduce outage durations/recalls to improve the future performance of the delivery point. However, it should not be used as justification to scrutinize outages related to equipment maintenance and capital investments, as these forms of work programs are crucial to improving delivery point performance.

5. CONCLUSIONS

In this paper a subset of the transmission equipment performance data collected by HONI was described, including the performance of transmission circuits. The performance data was used to develop a model using the Poisson Distribution probability to estimate the probability of sustained outages on transmission circuits as a function of circuit length and voltage class.

Afterwards, two probabilistic methods are presented to inform the operational planning of outages. These methods can be included in optimization processes and further enhanced with constraints to capture bundling opportunities, outage matrix monitoring, generator/customer outages, defect reporting, corrective measures and forecasted BES conditions to aid transmission outage planners in determining the best placing of outage postures.

Power system outage planning risk is constrained by spring freshet, excess generation scenarios, high loading periods and a heavy work program. The best outage window with respect to probability of equipment failures may not always be achieved. However, the probability of transmission equipment contingencies will aid post contingency (N-1) and re-preparation (N-1-1) plans.

BIBLIOGRAPHY

[1] W. Koehrsen, “The Poisson Distribution and Poisson Process Explained,” [Online]. Available: https://towardsdatascience.com.

[2] “Regional Reliability Reference Directory # 1 - Design and Operation of the Bulk Power System,” Northeast Power Coordinating Council, Inc., New York, 2019.

[3] W. Li, Risk Assessment of Power Systems, IEEE Press, 2014.