Electricity Transmission Reliability Management

By Marten Ovaere

Marten Ovaere is a PhD Researcher in the Center for Economic Studies at KU Leuven. He acknowledges financial help of the GARPUR project of the 7th European Community Framework Programme. He may be reacherd at marten.ovaere@kuleuven.be

Electricity is the backbone of modern society: we want electricity to be available at all times. However, uncertain generation and consumption; adverse weather; unplanned outages of lines, transformers, generation plants and large loads; loop flows; and forecast errors could cause major interruption for electricity consumers or a widespread network collapse. To prevent this, network operators (Transmission System Operator, Regional Transmission Operator or Independent System Operator) make decisions at different time horizons to apply different costly actions:

- System expansion: construction, upgrading, replacement, retrofitting or decommissioning of assets like AC or DC high-voltage transmission lines, substations, shunt reactors, phase-shifting transformers, etc.
- Asset management: monitoring the health status of network components, planning maintenance activities, repairing the components in case of failure, etc.
- Operational planning: congestion management, system protection, reserve provision, preventive actions, voltage control, decisions on outage executions, etc.
- Real-time operation: corrective actions, activation of reserves, reliability assessment, etc.

The ultimate goal of these actions is to ensure a reliable transmission system. Unfortunately, a completely reliable electricity supply comes at an infinite cost. Therefore, network operators need to determine an acceptable reliability level, by balancing the costs and benefits. A transmission network has an acceptable reliability level if with a high probability the voltage and frequency remain within an acceptable range.

A reliability criterion is a guiding principle for network operators to reach such an acceptable system reliability level. The above TSO management decisions should satisfy the reliability criterion at minimum socio-economic costs in the different time horizons.

N-1 Reliability Criteria

The N-1 criterion states that a system that is able to withstand at all times an unexpected failure or outage of a single system component, has an acceptable reliability level. This implies that some simultaneous failures could lead to local or widespread electricity interruptions. However, the N-1 criterion has achieved acceptable results over the past decades.

Variations of the N-1 criterion exist in multiple countries: N-0 during maintenance, considering double-line failures during adverse weather, stronger reliability criteria for cities or certain business districts, etc. (GARPUR, 2014). Likewise, the Dutch regulator has changed the reliability criterion to “N-1 during maintenance, unless the costs exceed the benefits” (de Nooij, 2010).

Reliability assessment generally consists of power flow analysis on a network model. For each contingency, the voltage level, voltage angle and power flow should be between certain limits. With the N-1 reliability criterion, the contingency list consists of failures of single lines, transformers, generation plants, large loads, etc.

Transmission reliability criteria were mostly developed in the 1950s and have been carried over essentially unchanged from the old regime of regulated vertically integrated monopolies (Joskow, 2006). However, these reliability criteria may be inefficient in the future system characterized by more decentralized decision makers, more uncertainty and variability, and more interconnected networks. Several aspects of the N-1 criterion are criticized.

1. It weights each component outage equally, irrespective of the probability of outage.
2. The rule lacks transparency about the reliability level of the system.
3. It does not take into account the cost of consumer interruptions.
4. The cost of attaining an “N-1 reliable electricity network” is not considered.
5. It lacks flexibility to react to changing network conditions: adverse weather, planned outages, etc.

In summary, the N-1 criterion lacks transparency and flexibility, and ignores the economic trade-off between costs and benefits. Hence, scholars are developing reliability criteria that respond to these criticisms. These reliability criteria are generally referred to as “probabilistic reliability criteria”.

Probabilistic Reliability Criteria

Probabilistic reliability criteria explicitly incorporate costs and benefits of reliability decisions and allow to quantify the reliability level. Figure 1 plots expected total costs (solid line) of the electricity market as a function of the reliability level ρ. The dotted line represents expected interruption costs, decreasing with the reliability level, while the dashed line represents the sum of all other expected electricity market costs, increasing with the reliability level.

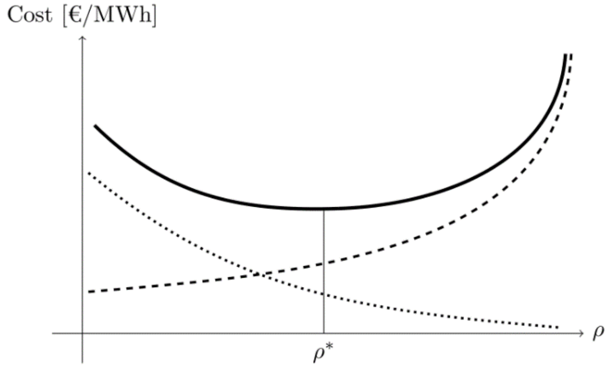

Figure 1 Total costs (solid line), interruption costs (dotted line) and all other electricity market costs (dashed line) as a function of the reliability level ρ.

The goal of probabilistic reliability management is then to determine and execute these actions that minimize total socio-economic costs. This is at the point where the marginal decrease of interruption costs equals the marginal increase of all other electricity market costs. This yields a certain optimal reliability level ρ*.

The expected interruption cost [$/h] is the product of the probability, the extent and the consequences of interruptions:

Expected interruption cost = probability*extent*consequences

That is, the TSO has to calculate the probability of a certain interruption [%], how much load is interrupted [MW], and the cost of interrupted load [$/MWh]. That is, probabilistic criteria take into account the consequences of an interruption and the probabilities of failure, instead of only considering single outages and treating all interruptions uniformly, as under N-1. They thus acknowledge the possibility of high-intensity low probability (HILP) events. The cost of interrupted load is generally represented by the Value of Lost Load (VOLL). The VOLL depends on the type of interrupted consumer, the duration and region of interruption, the time of occurrence, etc., but is usually assumed to be constant.

Deterministic vs. Probabilistic Reliability Criteria

Table 1 summarizes the main differences between the deterministic N-1 criterion and probabilistic criteria.

Despite the obvious advantages of probabilistic criteria over deterministic criteria, the N-1 criterion, or a variation of it, is still used by all network operators, because it is a straightforward and easily comprehensible decision rule. Network operators are starting to be aware of the economic inefficiencies of the N-1 criterion but the complexity, the huge amount of required stochastic input data, accurate VOLL estimates (CEER, 2010), and the computing power required are major barriers for probabilistic criteria.

	Deterministic N-1 criterion	**Probabilistic criterion**
Contingency list	Single outages	-All contingencies up to N-k system states -All contingencies up to a certain cumulative probability of occurrence
Probabilities	Not considered	Failure probability for each component
Consequences	Not considered	Interruptions are valued at VOLL

Table 1 Comparison of the deterministic N-1 criterion and probabilistic criteria

Towards Probabilistic Reliability Management

The necessary detailed data – failure rates, forecast errors, wind and solar data, demand data, maintenance planning, repair time, temperature and weather data (9 out of the 10 most risky days in 2010-2014 in the North American bulk power system were caused by adverse weather (NERC, 2015)) – are not yet available. However, advances in communication and information technologies facilitate gathering this data. For example, generation (since 2004), transmission (since 2008) and demand response (since 2011) availability data is already collected in the North American bulk power system (NERC, 2012).

With more data available, network operators can gradually introduce probabilistic methods into reliability management in the different time horizons. A starting point is to expand the contingency list to include high risk simultaneous failures. In addition, explicitly incorporating the cost of interruptions in reliability management clarifies the trade-off between the costs and benefits of reliability decisions.

We have a lot more to learn about reliability. The good news is that advances in communication and information technologies enable using the grid more efficiently, increasing reliability while lowering the costs, and accommodating an increasing share of renewable generation.

References

CEER. (2010). Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances. CEER, http://www.energy-regulators.eu.

de Nooij, M., Baarsma, B., Bloemhof, G., Slootweg, H., & Dijk, H. (2010). Development and application of a cost-benefit framework for energy reliability. Energy Economics, 32(6).

GARPUR. (2014). D1.2 Current practices, drivers and barriers for new reliability standards.

Joskow, P. L. (2006). Patterns of Transmission Investment. In Competitive Electricity Markets and Sustainability (pp. 169–235).

NERC (2015). State of Reliability. May 2015. Available at: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf

NERC: Reliability Assessment Guidebook, August 2012. Available at: http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf

---

IAEE/Affiliate Master Calendar of Events

(Note: All conferences are presented in English unless otherwise noted)

Date	**Event, Event Title and Language**	**Location**	**Supporting Organization(s)**	**Contact**
2016				
February 14-17	5th IAEE Asian Conference *Meeting Asia's Energy Challenges*	Perth, Australia	OAEE/IAEE	Peter Hartley *hartley@rice.edu*
April 24-26	9th NAEE/IAEE International Conference *Energizing Emerging Economies: Role of Natural Gas & Renewables for a Sustainable Energy Market and Economic Development*	Abuja, Nigeria	NAEE NAEE/IAEE	Wumi Iledare *wumi.iledare@yahoo.com*
June 19-22	39th IAEE International Conference *Energy: Expectations and Uncertainty Challenges for Analysis, Decisions and Policy*	Bergen, Norway	NAEE	Olvar Bergland *olvar.bergland@umb.no*
August 28-31	1st IAEE Eurasian Conference *Energy Economics Emerging from the Caspian Region: Challenges and Opportunities*	Baku, Azerbaijan	TRAEE	Gurkan Kumbaroglu *gurkank@boun.edu.tr*
September 21-22	11th BIEE Academic Conference *Theme to be Announced*	Oxford, UK	BIEE	BIEE Administration *conference @biee.org*
October 23-26	34th USAEE/IAEE North American Conference *Implications of North American Energy Self-Sufficiency:*	Tulsa, OK, USA	USAEE	David Williams *usaee@usaee.org*
2017				
June 18-21	40th IAEE International Conference *Meeting the Energy Demands of Emerging Economic Powers: Implications for Energy And Environmental Markets*	Singapore	OAEE/IAEE	Tony Owen *esiado@nus.edu.sg*
September 3-6	15th IAEE European Conference *Heading Towards Sustainability Energy Systems: by Evolution or Revolution?*	Vienna, Austria	AAEE/IAEE	Reinhard Haas *haas@eeg.tuwien.ac.at*
2018				
June 10-13	41st IAEE International Conference *Security of Supply, Sustainability and Affordability: Assessing the Trade-offs Of Energy Policy*	Groningen, The Netherlands	BAEE/IAEE	Machiel Mulder *machiel.mulder@rug.nl*
September 19-21	12th BIEE Academic Conference *Theme to be Announced*	Oxford, UK	BIEE	BIEE Administration *conference @biee.org*
2019				
May 26-29	42nd IAEE International Conference Local Energy, Global Markets	Montreal, Canada	CAEE/IAEE	Pierre-Olivier Pineau *pierre-olivier.pineau@hec.ca*
August 25-28	16th IAEE European Conference *Energy Challenges for the Next Decade: The Way Ahead Towards a Competitive, Secure and Sustainable Energy System*	Ljubljana, Slovenia	SAEE/IAEE	Nevenka Hrovatin *nevenka.hrovatin@ef.uni-lj.si*