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Review of the Current Status of Tools and Techniques for Risk-Based and Probabilistic Planning in Power Systems

Working Group
C4.601

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EXECUTIVE SUMMARY

Background on the Working Group

The CIGRE WG C4.601 on Power System Security Assessment was formed in August 2004, at the CIGRE Session 2004 and was given the charter to specifically look at the following needs in the industry:

1. The design of controls to enhance system security. This includes local device controls as well as system wide area controls and remedial action schemes.

2. Modeling of existing and new equipment required for power system analysis. (In this task it was felt that the most pertinent and timely activity was to look at the modeling and dynamic performance of wind generation systems.)

3. The design of monitoring systems for real time stability evaluation and control.

4. New analytical techniques for assessment of power system security. In addition to advances in computational methods, this includes the development of emerging approaches such as risk-based security assessment and the application of intelligent technologies.

To this end, all of the above subject matters were tackled by the Working Group. More specifically, the first three subject matters above have been addressed and three CIGRE Technical Brochures published as a result of the work of this Working Group, in 2007. This document addresses the fourth subject matter.

This final task of the WG was completed by a group of members and contributors constituting 65 experts from 18 countries. These included experts from equipment manufacturers, utility engineers, consultants and research organizations around the world. The work on this task started in April 2007 and was completed in March 2010.

Review of Potential Tools and Techniques for Risk Based and Probabilistic Planning in Power Systems

Historically, both transmission and operational planning studies and criteria were for the most part deterministic. In today's new market paradigm of separated generation, transmission and distribution entities most electric utilities still employ these traditional deterministic approaches for planning studies. As a result of the new market paradigm, the number of scenarios and uncertainties associated with day-to-day operations and planning of the power system has significantly increased. Thus, increasing attention is being devoted to probabilistic methods as these have the potential to deal with many of the uncertainties facing transmission planners in a more rigorous manner than current deterministic approaches. Because of the dimensionality introduced by the uncertainties in data and forecasts, an impossibly large number of deterministic studies might be required to assess each possible combination of outcomes. Furthermore, the probabilistic approaches allow the economic merit of investment proposals to be assessed. This could allow the planning function to move from a redundancy approach to an economic imperative while still satisfying the security criteria. Probabilistic techniques hold some promise of making these assessments more tractable.

Many regulators around the world and reliability standard organizations are starting to consider probabilistic and/or risk-based approaches to planning. Some tools and techniques exist for probabilistic planning, however, they may not necessarily be ready for application in the every day planning environment (e.g. problems with collecting all the necessary data, standardizing the tools and techniques, having commercially proven and ready software that have the tools ready for use etc.). This document serves as an overview of the present status of risk-based and probabilistic techniques and identifies:

- Why they are needed?
- What tools and techniques presently exist?
- What gaps and concerns exist with the present tools?
- What other possible approaches may be taken?
- What should be the goal of these approaches to complement existing deterministic methods?

The second chapter of the document is devoted to discussing and comparing the deterministic and probabilistic approach to planning and operations. In summary it can be said that the planning environment is changing with the unprecedented shifts to new generation technologies (e.g. renewables) and demand side responsiveness. The present deterministic methods may not be able to handle the large number of new considerations (variable generation, demand side integration, etc.) currently facing system and operations planners. In contrast, probabilistic planning approaches may be better able to handle such increasing scenarios and uncertainties, however, currently they suffer from a lack of effective tools to assist with the management of data (for example failure rates), the reliability assessment of alternatives; and the assessment of aggregate benefits over a range of operating conditions and development scenarios. Also, it is still not clear how multiple contingency events that result in major disruptions can be appropriately dealt with using current deterministic approaches and tools. Generation planning is also affected by the uncertainties in power system developments and has other challenges including; dimensioning transmission connections for the ultimate future generation capacity and generation build times that are appreciably shorter than the planning, consenting and construction times of transmission.

The third chapter provides a brief description of the salient features of the commonly used risk-based or probabilistic tools used for power system planning and operation studies as well as the gaps and limitations with the application of probabilistic based techniques and the existing tools.

Most of the existing programs can be generally subdivided into two different categories of (i) system adequacy evaluation, and (ii) system security assessment tools. Based on available information, the existing risk-based or probabilistic tools used for power system planning and operation studies are predominantly in the domain of adequacy. The majority of the existing adequacy evaluation tools were developed for generation adequacy assessment and composite generation and transmission system reliability evaluation. The fundamental approaches used in these probabilistic tools include direct analytical technique and Monte Carlo simulation method. Network solution methods adopted in the existing risked based tools include AC power flow, DC power flow and transportation models.

Chapter 4 presents discussions on some of the latest work and true needs for risked-based and probabilistic techniques in system studies. Discussion is provided on addressing high-impact low-probability events, the need for security assessment indices of a probabilistic nature for transmission planning, dynamic simulations in the context of dealing with uncertainties in the system model and modeling of blackouts and cascading events.

Finally, a summary is given in Chapter 5 together with proposed directions for future research.

The key conclusions drawn may be summarized as follows. Commercial software tools do exist for probabilistic assessment of system adequacy based on methods such as Monte Carlo for steady-state power flow analysis. However, these tools do have some gaps for improvement, namely:

- It is difficult to collect, prepare and maintain the data sets needed for such tools (i.e. reliability data, force outage rates etc.).
- Most of the existing tools cannot fully handle HVDC systems.
- Most of the existing tools cannot properly model the energy limited nature of hydro units. In most of these programs, hydro units are treated exactly the same as thermal units.
- In most tools the generation dispatch remains unchanged while assessing the various system states, which is unrealistic.
- Some tools recognize operating limits due to thermal, voltage and stability considerations; however, the problem is that these limits are assumed to be the same under all system operating conditions.
- Interpretation of the results can be complex.
- One cannot properly model cascading or islanding events or easily address HILP events.
- Cannot properly calculate bus reliability indices.
- It is not possible, or quite difficult to model multiple states or high order failure events for those programs using enumeration technique.
- For large interconnected system reliability analyses it is preferable that the number of transmission contingencies to be assessed should be reduced to a manageable size without sacrificing the accuracy of the final results. Presently, to our knowledge, none of the existing tools have any built-in algorithm to facilitate this. This is a subject for further research.
- It is difficult to properly incorporate into the analysis substation related outages, and operating procedures, constraints and security dispatch.
- Most existing tools have limited capabilities to address market related uncertainties such as:
    - Uncertainties related to power generation location, capacity, timing and availability for proposed new conventional and un-conventional energy sources.
    - Uncertainties related to future complexity of power transactions.
    - Uncertainties in future demand.
    - Uncertainties in future regulation/rules.

By contrast there are no widely used commercially available software tools that incorporate any rigorous probabilistic, risk-based or other methods for handling modeling uncertainties for time-domain dynamic simulations. Although recently there has been significant research into the application of risk-based and probabilistic techniques (e.g. since the 1980's), these techniques have not yet found their way into commercial software tools. This is understandable, because there are many significant challenges to utilizing such techniques which include, but are not limited to:

- The need for significantly more data and extensive data manipulation, processing, analyzing and complex operation which are beyond what is needed in the deterministic methods, which can become unacceptable for users.

- Complexity of dependant and independent variables. When we are faced with many independent and interrelated (dependant) events, variables, conditions, parameters, the calculation becomes quite involved and very complex.

- The interpretation and translation of probabilistic results and risk analysis in terms of simple applicable rule/actions are not straightforward.

- There is also a clear lack of risk based indices and criteria for security assessment, particularly for dynamic system behavior.

- Even with probabilistic methods, dealing with high-impact low-probability events (i.e. extreme or rare series of events) can be difficult.

Finally in summary it can be said that further research and development are needed to facilitate the full utilization of probabilistic and risk-based techniques and tools in day-to-day planning and operational studies. Such research should focus on addressing the data needs and data management issues, allowing for simple interpretation of results and addressing the major deficiency of industry wide acceptable risk-based indices and criteria.

CIGRE WORKING GROUP C4.601
ON POWER SYSTEM SECURITY ASSESSMENT

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LIST OF ACRONMYS AND TERMINOLOGY

AC	Alternating Current
AGC	Automatic Generation Control
CDF	Cumulative Distribution Function
CEA	Canadian Electricity Association
CHP	Combined Heat and Power
DC	Direct Current
DSI	Demand Side Integration
EENS	Expected Energy Not Served
EHV	Extra High Voltage
EPNS	Electric Power Not Served
ERIS	Equipment Reliability Information System
EUD	Expected Unserved Demand
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission (USA)
GADS	Generation Availability Data System (developed by NERC)
HILP	High-Impact Low-Probability event
HVDC	High Voltage dc
ISO	Independent System Operator
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MILP	Mixed Integer Linear Program
MWh	Megawatt Hours
N-1, N-2, N-x	These are symbolic ways of indicating the number of transmission elements that are out of service; e.g. N-1 means system condition with one transmission element (transformer or line) out of service.
N-G-1	Loss of a generator followed by system adjustment, and then followed by the loss of a single transmission element.
N-1-1	Loss of a single transmission element followed by system adjustment, and then followed by the loss of another single transmission element.
NERC	North American Electric Reliability Corporation (USA)
PDF	Probability Density Function
SCED	Security-Constrained Economic Dispatch
SOC	Self-organized criticality
SVC	Static Var Compensator
TADS	Transmission Availability Data System (developed by NERC)
TDSP	Transmission-Distribution Service Provider
Variable Generation	Variable generation differ from conventional and fossil-fired generation in a fundamental way: their fuel source (wind, sunlight, and moving water – e.g. tidal energy) cannot presently be controlled or stored. Unlike coal or natural gas, which can be extracted from the earth, delivered to plants thousands of miles away, and stockpiled for use when needed, variable fuels must be used when and where they are available – from reference [7] of chapter 2.

CHAPTER 1
INTRODUCTION

Historically, both transmission and operational planning studies and criteria were for the most part deterministic. In today's new market paradigm of separated generation, transmission and distribution entities most electric utilities still employ these traditional deterministic approaches for planning studies. Three major factors in recent years have made the ability to deterministically design and plan the system even more difficult than in the past. These are:

1. The liberalization (or deregulation) of the electric industry in most regions worldwide. As a result, the market tends to be a great influence on generation dispatch and the location of new generation facilities. Thus it becomes increasingly difficult for longer term horizons to predict the location and dispatch of generation and thus be able to plan for transmission upgrades and reinforcements.

2. The advent of renewable generation, most notably wind generation, has meant an added level of uncertainty to the generation dispatch and flow patterns [1]. This added variability to the generation also results in significant challenges in dimensioning the transmission system and operational planning.

3. The increased public concern over environmental impact of new transmission facilities means a greater need to be able to either find alternative means of extending the limits of the power system or to be able to better quantify the risks versus rewards of new facilities.

The concerns with uncertainties, such as those introduced by the influences mentioned above, have existed and the engineering community has always recognized this as a source of challenges in planning through the use of solely deterministic methods [2]. The core problem is that these well recognized challenges have not been seriously addressed. Many regulators around the world and reliability standard organizations are starting to consider probabilistic and/or risk-based approaches to planning. Some tools and techniques exist for probabilistic planning, however, they may not necessarily be ready for application in the every day planning environment (e.g. problems with collecting all the necessary data, standardizing the tools and techniques, having commercially proven and ready software that have the tools ready for use etc.). This document serves as an overview of the present status of risk-based and probabilistic techniques and identifies:

a. Why they are needed?

b. What tools and techniques presently exist?

c. What gaps and concerns exist with the present tools?

d. What other possible approaches may be taken?

e. What should be the goal of these approaches to complement existing deterministic methods?

The scope of this document is to look at both operational planning studies and transmission planning studies. Operational planning refers to studies related to at most a one year time window from the present. These studies are performed in order to help facilitate day to day operation of the system. As it is typically not feasible to build new major transmission facilities (or augment major existing facilities) within a one year time window, studies are typical performed on a yearly basis to look at how best to operate and utilize existing transmission facilities for the purpose of maintaining reliable and secure system performance under contingency scenarios during both off-peak and the forecasted peak load periods of the present year. This is what we refer to as operational planning.

Transmission planning is the process by which simulation studies are performed to look at extreme system conditions over many years while considering future load growth – typical horizons may be 5 to 10 years ahead. The goal here is to identify the most economic and technically sound transmission upgrade and/or new facilities required to maintain reliable and secure system performance as load and generation grow into the future.

One of the key focuses of power system security assessment is system dynamic performance[1]. Therefore, let us provide the most current definitions of some of the key factors being discussed here. From reference [3]:

"Reliability of a power system refers to the probability of its satisfactory operation over the long run. It denotes the ability to supply adequate electric service on a nearly continuous basis, with few interruptions over an extended time period."

"Security of a power system refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. It relates to robustness of the system to imminent disturbances and, hence, depends on the system operating condition as well as the contingent probability of disturbances."

Furthermore, a definition of risk can be given as:

Risk can be defined as the "effect of uncertainty on objectives", and "is often expressed in terms of a combination of the consequences of an event and the associated likelihood of occurrence"[2]. Thus, risk may be quantified as the product of the probability of a detrimental event occurring by the consequence of the event (i.e. Risk = probability × consequences).

With these definitions in mind, it can be seen that what we are concerned with is the ability to quantify the risk associated with contingencies in a power system both within the operational and transmission planning horizon and how this may impact the reliability, security and stability of the system. The next question is what is the best assessment method for identifying the most economic and technically sound approach to rectifying problems that are identified?

The definitions above should also clarify the distinction between risk and probability. Probability is the likelihood of an event occurring. Risk is the end result, i.e. likelihood × cost or consequence of occurrence.

Finally, there are many other risk factors associated with power system planning and operations, such as legal risks, political risks, environmental risks, and financial and market risks. Such issues are not discussed in this report and are outside the scope of work of CIGRE Study Committee C4 – System Technical Performance.

To address this subject matter, this document is organized as follows:

Chapter 2 provides an account of the present methodologies, both deterministic and probabilistic, and compares and contrasts them and thus provides a discussion of the prospective need for the application of probabilistic and risk-based approaches. Advantages and disadvantages of both deterministic and probabilistic methods are discussed.

Chapter 3 addresses what tools and techniques currently exist for probabilistic and/or risk based analysis, and where the major gaps and concerns are with these tools.

Chapter 4 presents discussions on some of the latest work and true needs for risked-based and probabilistic techniques in system studies. Discussion is provided on addressing high-impact low-probability events, the need for security assessment indices of a probabilistic nature for transmission planning, dynamic simulations in the context of dealing with uncertainties in the system model and modeling of blackouts and cascading events.

Chapter 5 summarizes the findings of this work and provides recommendations for future work.

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[1] Some consideration must be given to other factors such as steady-state thermal limits etc. even when discussing dynamic performance. So discussions of these other factors as pertinent are also presented in this report.
[2] Ref: ISO GUIDE 73:2009 Risk management — Vocabulary, First Ed.

CHAPTER 2

UTILITY NEEDS FOR RISK-BASED AND PROBABILISTIC TOOLS FOR PLANNING AND OPERATION

2.1 Introduction

This chapter deals with current approaches to transmission and generation planning with a view to identifying what tools and approaches can be developed to support transmission investment decisions.

Present practice for generation and transmission planning varies widely internationally. Liberalization and the introduction of markets have created competition in the generation sector. Transmission investment is closely aligned to generation investment and the lack of transparent long-range plans for generation has consequently created uncertainty for transmission planners. Further, the introduction of 'new' technologies, especially renewable technologies like wind generation, change the performance requirements of the transmission grid. Specifically, variable output and scalability of some renewable generation investments create further uncertainty for transmission planning and investment.

The planning and investment approaches for transmission are affected by a range of factors including:

a. The extent of liberalization or deregulation;

b. The investment framework for generation – merchant or centrally planned;

c. Transmission ownership and the regulatory framework governing new investment;

d. Reliability standards or mandatory requirements, if any, for both generation and transmission investment; and

e. The extent of government or policy driven incentives to ensure societal outcomes (for example, renewable energy targets).

Traditionally, generation and transmission planning were performed at the same time in accordance with long range plans developed by the vertically integrated, and often state owned, utilities. This planning process considered all relevant costs and benefits, effectively allowing co-optimization of transmission and generation investments. Today, the factors listed above, among others, have changed this paradigm significantly.

Consideration of the transmission planning function is occurring at a time when transformational change is expected in the demand for and utilization of transmission services. The transformational change is being driven largely by:

- Government policies on climate change, including initiatives to encourage renewable energy and reduce carbon emissions;
- emerging technologies that could change the economics of the supply side in ways that are likely to change the utilization of the transmission network (for example, carbon sequestration, geothermal, tidal energy);
- unprecedented interest in demand side participation and energy efficiency as efficient solutions to lowering emissions intensity and lowering costs;
- society's demands for higher reliability and quality of supply driven by increasing expectations of customers and the growing importance of 'digital' loads; and
- a move toward smarter network technology including smart metering and integration of remote monitoring and control technologies to assist in meeting these demands.

Existing transmission planning tools are largely centered on deterministic criteria that may not handle the additional uncertainties in a rigorous manner. However, while probabilistic approaches offer theoretical advantages, current practice indicates that there are some drawbacks to a 'pure' probabilistic approach. This chapter will look at various approaches that are currently being applied to the transmission planning and investment problem based on contributions from the Working Group members. Appendix A gives a slightly more detailed presentation of example case studies and present practice in specific systems.

2.2 High Level Overview of Current Approaches to Transmission Planning

There is increasing interest in probabilistic planning techniques because of the uncertainty faced by transmission planners. The following sections provide a short summary of current deterministic and probabilistic approaches to transmission planning.

2.2.1 Deterministic Planning

In deterministic security assessment, the secured/unsecured decision is founded on the requirement that each outage event in a specified list (contingency list) results in system performance that satisfies the chosen performance evaluation criteria. These assessments involve a large number of computer simulations defined by selecting a set of network configurations, a list of outage events and the performance evaluation criteria. The approach depends on the application of two criteria during study development [1]:

Credibility: The network configuration, outage event, and operating conditions should be reasonably likely to occur.

Severity: The outage event, network configuration and operating condition on which the decision is based, should result in the most severe system performance; i.e., there should be no other credible combination of outage event, network configuration, and operating condition which result in more severe system performance.

Representativity: To perform a system study adequately, the representation of the credible outage in the simulation by a model should represent the main features of the real outage events and covers a wide range of similar events.

The deterministic approach consists of 6 steps:

1. Select the time period (year, season) and loading condition (peak, partial peak and light load, etc);
2. Select the network configuration and generation schedule;
3. Select the contingency set. Usually all N-1 and, in some power systems, a few credible N-2 contingencies are considered;
4. Refine the operating conditions in terms of dispatch and voltage profile depending on conditions that reflect the balance between credibility and severity with respect to the selected events;
5. Perform a simulation of the events, and identify any that violate the performance evaluation criteria; and
6. Identify solutions for any event resulting in violation of the performance criteria.

The deterministic approach has served the industry well; it has provided high reliability levels without requiring excessive study effort [1]. Focusing on the most severe event and ignoring consequences and probabilities may lead to over investment in the transmission system or inappropriate prioritization of investments. The challenge is to refine the investment decisions, but to do so without reducing security margins to a point where the system operator can no longer provide a reliable supply.

The weakness of deterministic assessments is that they:

- Do not evaluate the unequal probabilities of events that lead to potential operating security limit violations.
- Do not evaluate the severity of such violations.
- Non-limiting events are ignored, even though they may reasonably require attention.
- Risk factors such as ambient conditions, substation configuration and line length are not taken into account even though they may affect the likelihood of an event occurring.
- The deterministic N-1 criterion could be based on the "worst" case as stated above. But the "worst" case may be missed, and also the violation may occur even at a "non-worst" case operating condition [2].
- Severe outages may be due to the failure of multiple network components. But for practical reasons, it is typically not possible for utilities to examine all N-2 or N-3 levels of security. The alternative is to bring risk management into planning practice and keep system risk within an acceptable level [2].
- The evaluation of risk and credibility behind the determination of technical and standard performance (contingency list, criteria and network configuration) are not evaluated using probabilities of occurrence.

The deterministic approaches vary from the commonly used criterion to tolerate a single failure (N-1) to various forms of this, including:

- N-G-1 where the prior outage of the largest relevant generator is taken into account;
- N-1-1 where the transmission system must tolerate an unplanned outage at the time another item or plant is out of service for maintenance[3]; and
- N-2 for locations where very high reliability is required, such as central business districts.

In the US (see Case 5 in Appendix A), for example, the following deterministic criteria might typically apply:

1. All N-1 contingencies on EHV systems
2. Select N-1-1 and N-2 contingencies based on the utilities experience of which outages are the worst for their system.
3. A few extreme scenarios that may, based on previous experience, have been quite devastating and frequent enough to warrant attention.

For the US case, the third criterion is essentially covering high impact low probability (HILP) events not captured by the usual deterministic criteria. Clearly, the planner will need to exercise judgment and deliver designs that provide the diversity and dimension necessary to avoid such high impacts even if the event probability is very low (e.g. multiple contingency). Delivery of such outcomes may require deterministic criteria (limiting the size of a switchyard) based on a generic probabilistic analysis (using for example a HILP probability of 1 in 100 years).

The definitions of a contingency are also of interest. For example, some utilities consider the loss of both circuits on a double circuit tower line (common mode of failure) as a single contingency, meaning that an N-1 analysis would capture this event.

[3] The N-1-1 criterion is applied at the time the maintenance is undertaken, rather than at the time of highest asset utilisation. It may be possible to meet N-1-1 during light load periods but, for some assets, lack of appropriate maintenance windows may drive earlier investment to reduce asset utilisation and allow maintenance to be scheduled.

Operationally, real time assessment and management of security is mainly deterministic and there is a close correlation between the planning and operating criteria. If the system operator is seeking to maintain N-1 security and the transmission grid has been designed for N-1, there should only be issues when forecast outcomes (like loads) are exceeded in real time.

Internationally there are many variations on the deterministic criteria listed above but it is common to have at least an N-1 standard for the transmission grid.

It is also important to consider the transformational change affecting power systems. The traditional approaches have assumed a largely inflexible demand with low elasticity to prices. The new paradigm may see much greater demand side participation and smart metering may deliver significant changes to the load shape (for example, attenuation of peaks and a general flattening of the load curve). Both of these factors, and there are others as well, will change the need for transmission augmentation and the efficacy of the deterministic approach. The levels of resilience once provided by the deterministic criteria may not be achieved in a new world with flatter load profiles.

Technology is also now a key consideration. Variable generation like wind and tidal is energy based rather than capacity based. Is it really appropriate to provide N-1 reliability based on nameplate rating for such energy systems? The high reliability of transmission systems may mean that an adequately reliable connection could be provided at 'N' security in association with special protection systems. The questions arise as to how one copes with questions like this under a deterministic framework where the value of the 'N-1' redundancy is not assessed and there is a real risk of over-investment and, potentially, reducing the viability of some projects because of excessively high transmission connection costs.

A further consideration is that some non-transmission alternatives, such as generation or a coordinated demand side response, may not have the same reliability as a transmission option. A deterministic model does not readily allow comparisons of these options. It may even result in an increase in overall costs if all non-transmission alternatives are required to achieve the same level of reliability as transmission (for example by investing in multiple generator units or over-contracting for a demand side response).

Planners can generally adapt their approach to accommodate a wide variety of special or unusual conditions but this relies on judgment as much as analysis and transmission customer and regulators are expecting greater accountability and justification for new transmission investments than ever before.

2.2.2 Probabilistic Planning

Increasing attention is being devoted to probabilistic methods as these have the potential to deal with many of the uncertainties facing transmission planners in a more rigorous manner than current deterministic approaches. Because of the dimensionality introduced by the uncertainties in data and forecasts, an impossibly large number of deterministic studies might be required to assess each possible combination of outcomes. Furthermore, the probabilistic approaches allow the economic merit of investment proposals to be assessed. This could allow the planning function to move from a redundancy approach to an economic imperative while still satisfying the security criteria. Probabilistic techniques hold some promise of making these assessments more tractable.

Some planning engineers may be concerned about a possible conflict between deterministic criteria and probabilistic reliability assessment. In fact there is no conflict at all. The N-1 criterion can be included in the planning process so as to ensure it is respected while performing a probabilistic planning process [2]. Typically this approach could be incorporated as a deterministic criterion acting as a safety net with a probabilistic assessment to confirm need, timing, priority and, potentially, whether a more substantial investment is justified. Further, the N-1 (or other deterministic) criterion can be used to enforce security requirements but the economic focus might mean that this is delivered by means of lower cost investments that may include participation of the supply and/or demand side to ensure the power system remains secure following a failure event.

One of the key criticisms on the deterministic approach is that it does not consider risks (probability × consequences) or probabilities. There is also no formal trade-off between reliability and the cost of achieving a certain standard. For example, an N-1 approach would not differentiate between a 10km transmission line supplying a highly meshed part of the network and a 200 km line supplying a less meshed load centre. Clearly both the probability of failure of the long line and the consequences of a failure could be higher.

Probabilistic approaches can provide insights to both probabilities of failure and consequences and thus allow a more informed view of the need and economic justification of a transmission investment. Similarly, the paper [3] gives an example of the potential benefits of probabilistic security assessment in operational planning versus a purely deterministic approach.

Probabilistic Planning Criteria

There are different approaches to setting probability criteria. The approach used depends on the utilities and the projects or studies to which the criteria are applied. For instance, different approaches may be used for bulk versus regional systems or transmission line versus substation enhancements.

Application of probabilistic methods can be considered in two ways:

- A pure probabilistic approach where all investments have to be justified according to the benefits they deliver, i.e. there is an optimal level of reliability where investment cost due to increasing reliability matches with the reduction of cost due to avoidance of unserved energy [4]. This is illustrated in Figure 2-1. The cost curve (from [5]) shows that ideally the investment cost gradually increases with higher reliability, while the customer cost associated with system failure decreases as the reliability increases. The dotted total cost curve shows a minimum where the two meet.

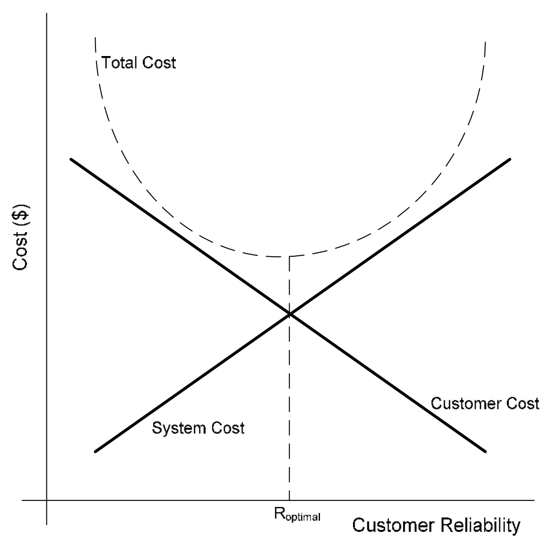


Figure 2-1: Total Reliability Costs – (diagram re-drawn but originally from [5]).

- As a supplement to a deterministic approach, such as N-1, where assessment of consequences and probabilities is used to prioritize investments and/or justify higher levels of investment in parts of the transmission grid where consequences are highest.

Both the above approaches are being used. VENCorp (Australia) (vencorp.com.au) and New Zealand (www.electricitycommission.govt.nz) use the former approach, although New Zealand retains an N-1 'safety net' for the main transmission system, referred to as the 'core grid'. An example of using probabilistic planning as a supplement to an N-1 criterion was reported by British Columbia Transmission Corporation in [6].

The probabilistic approach has a logical appeal in that it can deal with many sources of uncertainty and yield a basis for estimating the benefits of a particular investment. This requires an estimate of the expected unserved energy (EUE) and some means of valuing that unserved energy. This is a complex task that is often based on surveys.

Assessment Methods

Two broad approaches exist:

- Contingency Enumeration method, and
- Simulation method (viz Monte Carlo)

The contingency enumeration method relies on knowing each of the possible failure modes and the probability of each occurring. The overall probability of a failure affecting security can be assessed by considering each sequence of failures that result in a loss of supply by direct calculation.

The Monte Carlo method essentially uses a 'throw of the dice' random sampling of the possible failure modes with the sampling frequency related to the probability of a failure occurring. For reliable transmission systems, the number of samples needed to take account of the low probabilities may require a large number of simulations for each year to obtain an aggregate result that has converged to a stable mean. As each sample may require quite detailed analysis (at least a power flow but possibly time and/or frequency domain analysis as well), the computational effort could be considerable.

The difference between the two methods is in how to select outage system states whereas the system analysis in assessing consequence of outages is the same. Examples using Monte Carlo method are presented in [2, 5]. Tools to assist in the automated execution of studies and the management of the data and results would be particularly beneficial for both approaches.

Reliability Standards and Indices

There are several objective functions used in probabilistic planning. These are typically specified as the reliability outcome desired (possibly reflected as a target threshold of energy not served) or as a pure economic outcome.

The following sections discuss the reliability objective functions used with or contemplated for probabilistic planning applications.

Pure economic criterion:

This approach essentially states that the level of reliability that is achieved if all economic investments are implemented is the level of reliability that is desired. This approach is used in Victoria (Australia) and in New Zealand, where there is an added 'safety net' on those parts of the transmission grid where consequences of a failure are greater than 150 MW. For these parts of the New Zealand transmission grid a safety net of N-1 is provided.

In essence this criterion limits investment to cases where economic benefits can be proved to exceed costs. The actual reliability levels achieved in terms of common measurements like minutes off supply and unserved energy, become incidental.

These probability based approaches are based on models that require a good knowledge of both failure rates and economic consequences of a failure. A common criticism is that while the costs of an investment are easy to specify, the wide-ranging benefits are more difficult to quantify and may include (without limitation):

- The variability of the value of reliability to customers and the difficulty of selecting a monetary threshold where many different customers are served;
- Competition benefits (dynamic, allocation and productive efficiency effects of the investment when compared with the 'no investment' or 'alternative investment' cases);

- Investor confidence, reflecting the propensity of an investor to commit funds where there is a perceived or actual threat to reliability of energy supplies; and
- Benefits arising from mitigation provided for High Impact Low Probability (HILP) events.

A key point with the probabilistic and economic approach is that it is model based and there are a number of key assumptions supporting the model. Application of these models without due consideration of the validity of the assumptions could detract from the accuracy of the assessed benefits and result in over or under investment. An example of this relates to consideration of HILP events where there is often some common causal effect in play (storms, fires etc) that may provide a degree of inter-dependency of the failure rates. While these effects are easy to conceptualize, there are few commercially available tools to facilitate sensitivity studies to support an assessment of HILP event risks and consequences.

Determining consequences

The consequences of a particular contingency can be assessed in terms of unserved energy or, if the value of customer reliability has been estimated, the unserved energy can be converted into financial cost.

Load duration information may be required to form an assessment of consequences as a particular contingency may result in differing consequences depending on the loading of the transmission grid.

Estimating the value of customer reliability is challenging as different sectors will value reliability differently and have different levels of 'willingness to pay' for higher reliability. Estimates have been made based on surveys but there remains an element of subjectivity about any such valuation.

Determining probability

Determining the probability of an event is usually based on historical performance of similar equipment. Some issues include:

- there is a requirement for very good forced outage rate data for a wide variety of plants;
- the outage rates of transmission lines, in particular, may be affected by local conditions like keraunic levels and snow loading, making aggregation of data from other regions less reliable;
- a lack of useful data on high impact low probability (HILP) events;
- a requirement to specifically consider a risk policy together with the probabilistic approach; and
- the outage rates of equipment may be affected by maintenance history and operating conditions.

With respect to the last point, the issue is that the outage rate data is a distribution with a mean and a variance. If the mean or average data are used, the approach will be risk neutral. This would be appropriate for an economic investment where the objective is to economically address points of congestion. For an investment targeted at addressing a reliability problem, where the consequences may be a 'lights out' condition, it may be preferable to take account of the variances in the data and use, for example, a 90% probability of exceedance.

In summary, planners should have confidence in data accuracy and relevance when determining the probability of different events. For the overall determination of probability, it may be required to simplify the part of the system [4].

High impact low probability events (HILP)

HILP events are by their nature difficult to predict. Most major blackouts are a result of HILP events involving multiple contingencies and an unfortunate sequence of events. Trying to ascribe a probability to such HILP events is challenging. If the probability of each individual event is considered, the probability of the HILP event becomes vanishingly small.

For example, even if the consequences of a double circuit contingency are very high, the low probability (resulting from the product of two small numbers[4]) means that the average annual economic impact is small. This means that only low cost investments, such as Special Protection Systems (SPS)[5], can be made to protect against the consequences of the event.

An additional consideration is whether multiple failures can be considered independent events. For example, the failure of one circuit of a double circuit transmission line may have a failure rate of x events per year. Extension of this to say a double circuit outage has a failure rate of x_2 ignores the possibility that there might be a common macro event that could make the failure of both circuits a significantly higher probability. In Australia this is recognized operationally by defining the loss of both circuits of a double circuit line as a credible event if there are factors that may increase the probability of the event occurring (for example, a lightning storm in the area or fires near the line). In a probabilistic transmission planning framework, these macro events could increase the probabilities, and therefore the benefits of an augmentation, by several times.

One approach to HILP events is to consider the consequences of an event occurring. For example, loss of an entire substation is a very low probability event but it is (usually) conceivable. If the consequences of such an event are unacceptable from a public policy perspective, it may be necessary to invest to mitigate the consequences or probabilities of the event occurring. In terms of investment decision making, this can be informed by considering the possible range of HILP probabilities that would be required to justify the investment. If the probability range is credible, then perhaps the investment is justified. If the range is exceedingly low, then a high cost investment is likely to be unreasonable.

In general, as seen from the above discussion the issue arises as to how HILP events should be treated in the transmission planning process and whether this treatment should be probabilistic or deterministic.

Generation Planning

The above sections have focused on transmission planning. There are a number of similarities in approach to generation planning. Many power systems are now formed into markets and generation investment is a market outcome. However, other power systems maybe vertically integrated with a single authority controlling both transmission and generation investment. Nevertheless, both approaches should deliver efficient generation investment and many of the economic principles outlined above for transmission investment will also apply for generation.

Within a market environment, generation investors will be seeking to maximize their investment returns. Decision making will revolve around capital cost, fuel cost, risk and connection costs. A central planner will consider the same factors but has the advantage of being able to influence most of the factors.

The uncertainties in the generation sector are, in many cases, similar to those outlined for transmission. Increasing pressure to reduce emissions and favoring renewable energy technologies will drive investors to use scenario-based planning and probabilistic methods to assess commercial viability. Monte Carlo tools are often used to model market behavior and price outcomes. Commercial risk due to plant reliability can be modeled as part of the market modeling studies.

There are some interactions between transmission and generation planning that become quite complex in a market environment. Specifically, a central planner would normally take into consideration long-range generation plans to formulate the investment strategy for transmission. In a market environment, there is no longer a defined forward plan for generation and this introduces uncertainty as to the dimension of the transmission used to connect generation to the rest of the power system.

[4] For example, if two lines have a 1 in 20 year failure rate, the double contingency failure rate would be 1 in 400 years.
[5] Also, known as Remedial Action Schemes (RAS) or System Integrity Protection Schemes (SIPS).

This issue is most apparent for wind generation where there is uncertainty about how much wind investment there might be in a particular location and the resulting energy production with investment. Some approaches have been based on the size of the wind resource and result in a transmission connection dimensioned for more than the generation committed to go into the resource area. However, it is usually the transmission customer that bears the risk of over-investment if that amount of generation does not actually appear.

A similar problem is that generation investment in an efficient market appears 'just in time'. The time taken to build a generation plant is, in many cases, a lot less than the time taken to get all the necessary permits and consents to build a transmission line. The risk introduced by not having sufficient transmission connection to get a power station's energy to market could be decisive in whether the project proceeds or not.

A key issue for both transmission and generation planners is the ability to co-optimize transmission and generation investments. There are some central planning tools available (e.g. WASP, Markal) that allow a 'least cost' generation expansion to be defined but the model's treatment of risk, which will most likely be quite different to that of a market investor's view of risk.

At this stage there do not appear to be many tools available to assist in the co-optimization of transmission and generation investment costs in a market environment.

2.3 Key Issues

This section summarizes a number of issues that impact the transmission planning process. It is not an exclusive list but serves to illustrate some of the major issues that transmission planners must consider.

2.3.1 Generation Scenarios

The location of generation has a major impact on the capacity requirements of the transmission grid. The issue in a deregulated market is that generation development is no longer part of a central planning process. New generation will be located where and when investors choose. Long range plans for generation development are no longer available to transmission planners.

The approach used to deal with this uncertainty is to develop a number of generation scenarios that represent possible futures. The generation scenarios attempt to mimic rational investor behavior for a number of high level assumptions about key parameters such as fuel and capital costs.

For example, a generation scenario may be built up for a high level of renewable generation. The high level assumptions might include:

- A declining capital cost for renewable generation plant;
- A carbon tax or emission trading scheme that makes fossil generation less attractive; and
- The extent to which 'firming' of variable generation is required.

Using these and other assumptions, a potential generation investment program can be developed to meet the needs of the power system.

Having developed a generation investment scenario, the transmission planner can then assess the implications on the transmission grid and what transmission investment would be required to meet the applicable standards. Scenarios can also be weighted to assign probabilities of occurrence.

In practice, transmission plans and investments must be tested against several generation scenarios. The best transmission investments are those that deliver high value in the majority of the scenarios.

2.3.2 Generation Adequacy

Generation adequacy refers to the supply-demand balance and whether there is sufficient generation to meet demand, taking account of generator failures and peak demands in extreme weather. Generation adequacy depends on the stock of generation at any given time, the capacity of the transmission system connecting this generation to the load centers, and the peak demands.

Generation is typically less reliable than transmission, with expected forced outage rates (failure rates) of around 5% compared with transmission with generally less than 1%. It is important to develop a view on how much generation can reasonably be expected to be operating (or operable – able to run if required) in a region that is the subject of a transmission planning study.

If there is enough generation contained within an area, the impact of a lack of generation is an economic issue, as the consequence of one or more generators being unavailable is an economic one relating to the sub-optimal dispatch of must-run plants. However, if the consequence of a lack of generation is unplanned load reduction (load shedding), the customer impact is much higher and the investment need much more sharply focused.

Generation adequacy is an input into the development of generation scenarios, as one of the guiding principles for all generation scenarios is that they meet the resource adequacy required for a particular power system including MW reserve requirements to address the generation outages/failures.

A key aspect of assessing generation adequacy is data on the forced outage rates of generation in the area being studied. A recent example considered the San Francisco Bay area where the existing generators are aging and have higher than normal forced outage rates. The lower levels of availability and risk of not being able to meet forecast loads justified the investment in additional transmission capacity to the area.

A number of indices are used to identify generation adequacies based on both power and energy (viz LOLE, Loss of load expected; EENS, Expected energy not served) [4].

The challenge is to have tools available to assess generation adequacy in a robust manner. This can then be used as part of the justification to a regulator for new transmission investment.

2.3.3 Data Requirements

Key to the generation and transmission planning processes is the availability of technical and economic data, including:

- Load forecasts for a range of potential futures (such as high/medium/low economic growth);
- Generation capital costs for all likely generation technologies;
- Generation and transmission failure rates;
- Market design, regulatory and funding arrangements for new investments; and
- All technical and performance standards.

While these data are generally available, they are usually in a variety of databases and take time to compile and maintain. In addition, the basis for data collection may vary between utilities, making it difficult to compare international data. An example of this is the collection of forced outage rate data where several international standards apply and definitions of forced outages and partial forced outages can differ significantly.

2.3.4 Variable Generation

Renewable generation and wind in particular is an emerging issue. Typically, the fuel source (e.g. wind, water, tides, geothermal, solar) is not transportable. Thus, to be viable the developer needs to be able to make an economic case for investing in generating facilities at the site of the energy source, with the ability to transmit the power electrically to load centers. In most regions the ideal locations for wind plants are often both remote from load centers and from major transmission corridors. Many transmission owners are facing challenges in trying to justify transmission investments in the face of uncertain generation commitment.

Renewable generation such as wind, small hydro, geothermal, tidal, solar etc, poses a number of interesting challenges including:

- unlike many conventional generation investments, renewable investments are often scalable and can range from tens of megawatts through two orders of magnitude;
- transparency of investment plans is an issue because there is often intense competition for projects and investors are not necessarily forthcoming until the last possible moment to protect themselves from being pre-empted by a competitor; and
- for variable generation, energy balancing is a major issue that requires consideration and can affect the need and economics of potential generation and/or transmission investments.

Variable generation is also likely to affect the requirement for generation reserves. More reserves may be required, particularly if wind generators are not operated at below maximum capacity to provide reserves in the event of a frequency decline. Methods have been developed and demonstrated for providing MW reserve and inertial response from wind turbines [7].

A critical issue facing many investors in either transmission or generation is how to provide for transmission to these remote sites ahead of, or in time for, generation development. Because transmission may be a significant cost component for a wind developer, a high cost connection may render a project economically unattractive. However, if transmission was provided to a wind rich area, it is likely that more wind investors would be attracted to the site. This makes it difficult to judge the capacity of the required transmission connection. Cases 3, 4 and 6 in Appendix A provide some discussion of actual experience with variable generation integration, specifically wind.

In those countries where there are government initiatives to increase the amount of renewable energy, there may be pressure to build transmission to facilitate further generation investments. Who bears the cost of such investments should the predicted generation not appear is a major concern in some markets.

2.3.5 Reactive Power and Voltage Control

Reactive power cannot be transported over long distances and transmission plans must include consideration of voltage control across the whole grid. Generators and their excitation controllers provide voltage control in the areas of the transmission system where they are connected.

There are several voltage control issues that arise, including:

- Uncertainty as to where generators will locate;
- Withdrawal at short notice of (uneconomic) plant that is a key provider of reactive power in an area;
- Increasing levels of renewable generation, often connected at weak parts of the network, that do not have the voltage support characteristics of conventional synchronous generators;
- Displacement of conventional generation by variable generation, removing or reducing voltage controllability;
- Significant changes in power flow that can arise from variable renewable generation and the consequential effect on voltage control requirements; and
- Lack of market mechanisms to compensate for the provision of reactive power or voltage control services (for example, no mechanisms exist in Nordic countries or New Zealand).

Examples of where these sorts of issues are arising include Texas (Case2, Appendix A), where a variety of factors can lead to withdrawal or mothballing of plants, and in Europe, where high levels of wind generation can significantly change the utilization of the transmission grid (Case 6, Appendix A).

Transmission plans must therefore be robust to these uncertainties and tools are required to allow them to be assessed and confirmed for adequacy. As few regulatory authorities will authorize investment in reactive plants such as capacitors and Static Var Compensators (SVCs) on a 'just in case' basis – tools that provide a level of probability around the need would be most useful.

2.3.6 Congestion Impacts

Congestion is a major driver for transmission investment and planners must consider how market forces can affect utilization of the transmission grid. Factors that increase uncertainty about the extent and severity of congestion include the effects on transmission flows arising from:

- large scale investment in variable generation such as wind, solar and run of river hydro;
- regulatory policies such as climate change initiatives that change historic dispatch patterns; and
- demand changes in response to price signals, recognizing that prices can be high outside of peak load periods and prices in peak load periods may not always be high enough to signal a reduction in demand.

As investments to reduce congestion are undertaken for economic rather than reliability / security purposes, probabilistic tools that take account of a wide range of uncertainties are needed to develop the justification for the investment. Typically this is done using a variety of market modeling approaches.

2.3.7 Allocation of Transmission Investment Costs

The queuing of generator interconnection studies (or other forms of prioritization) lead to a number of issues; two of the biggest draw backs with this process are as follows:

1. It is conceivable that a certain transmission problem (the simplest example being, thermal overloading of a line) may not occur for the first N generators that appear on the system, while the $(N+1)^{th}$ generator causes the problem. Should generator number (N+1) be the only one paying for the upgrade costs? In this context, equity methods (viz Core, Nucleous, Shapely Value, Run-way methods etc) are getting more popular [8, 9].
2. For renewable generation, particularly wind generation, the deterministic approach of modeling all other generators in the queue at their peak capacity simultaneous with a peak system load is for the most part an unrealistic assumption. There is a significant body of evidence that it is quite rare to have all wind generating facilities on a system at peak output in coincidence with peak load. Nevertheless, at present there is no other systematic way available to transmission system owners for performing such studies. The down side of such an approach for wind generation is that the identified level of transmission upgrades may be more than necessary and therefore impose unnecessary additional costs on investment projects, possibly making it uneconomic.

Once the system impact study is completed and a system interconnection agreement signed, a follow-up study may be performed (often referred to as a facility study) to firm up the exact transmission upgrades and needs of the proposed generation facility in order for it to meet its power purchase agreement, i.e. not only to inject megawatts into the system, but to transport those megawatts to a specific load center with whom a power purchase agreement has been signed. In this step another complication often arises with renewable generating facilities such as wind. Due to the intermittency of wind facilities, such generators cannot enter into a firm commitment for power delivery. Instead most seek non-firm power purchase agreements which complicate the facilities study. It may require performing several sensitivities to generation dispatch to try to capture, as much as reasonably possible, the various conditions of power delivery from the plant.

In countries without the queuing system, the upgrades on the transmission system may be made when there is a demonstrable net market benefit of making the investment. This economically focused approach suffers from the problem that an economic loss – usually wind spill or out of merit generation costs – must be tolerated until that loss is greater than the investment cost to remove the congestion. The allocation of this loss may be unevenly distributed between the affected generators. If transmission access is via financial transmission rights, generators can manage their risk to an extent.

In all cases, tools that allow the intermittency of generation are required to assess the required level of transmission capacity, bearing in mind this is likely to change over time as more generation is built.

2.3.8 Load Characteristics

No aspect of the power system is perhaps more uncertain and constantly changing than the system load. It changes both in amount and characteristic as a function of geographic location and time. For any given power system, the variation of load on a daily cycle (daily load curve) is relatively well understood and based on historic data predictable to a large degree. However, the exact peak demand for a given year can never be predicted with certainty. Most planning studies will thus add a margin to the predicted peak load to cater for this uncertainty. For example, in the Western Electricity Coordinating Council (WECC) of the USA [10] an additional 5% increase in load is added to the 90/10 peak load case developed when studying voltage stability for a region for the purpose of accounting for such uncertainties – this, however, is clearly a deterministic approach. More specifically, this criteria essentially requires that for a load center, the load is considered to be reliably served if and only if voltage stability can be maintained up to a load level that is 5% greater than the forecasted peak load.

Load models, as we know, are very important in voltage studies and voltage stability studies. Even when using the simple static load models it becomes difficult to identify the composition of the loads and so derive the appropriate voltage exponents for the model.

What are far more complex to capture and account for are the variations in the dynamic characteristics of the load, namely:

- Load composition (the fractions of motor load, lighting, heating, power electronics, etc.)
- Characteristics of the each component (e.g. single-phase air-conditioning motors that are prone to stalling, high efficiency lighting, variable frequency drive motors etc.)
- Discontinuous load behavior (e.g. stalling of motors, motor load contactor drop out, drop out of discharge lighting and power electronic loads)

The difficulty is in identifying the reasonable range of potential variation in the load composition and characteristics and in identifying the suitable approach for aggregation of the load components into a suitable structure for planning studies. There has been much work in this area [11, 12, 13, 14, 15, 16, 17, 18]. Some recent studies have taken the approach of performing extensive sensitivity analysis to try to bound the problem and identify transmission options that are robust to such variations [19, 20, 21]. One recent major concern has been the observed delayed (several to tens of seconds in some cases) fault induced voltage recovery due to high concentrations of air-conditioning load [22, 23].

What is clear is that the load behavior drastically affects the results of any study as it relates to any form of stability analysis; this has been demonstrated in many large scale utility studies [20, 21]. Thus, there is a clear need to be able to capture credible variations in load behavior in both operational and transmission planning studies related to system dynamic performance and security. This is one area were some form of either risk-based or probabilistic analysis may be fruitful. It is doubtful that a purely probabilistic approach will be practical. A better approach may be to define bounds on the variations in the load composition and characteristics (perhaps based on surveys and statistical data) and to then specify necessary sensitivity analysis to test the robustness of chosen transmission plans to credible variations in load behavior.

2.3.9 Control System Influences

One uncertainty often neglected in power system planning studies is that of potential variations in power-plant (generation) control modes. In the context of modern conventional fossil fuel and hydro generators, there are a variety of control modes and features that can be varied inadvertently by plant staff. These include:

- Mode of control for the turbine-control system. The turbine may be under true governor control or under a combination of governor control and outer-loop MW control [24, 25, 26]. That is, the unit operator may chose to set the present output of the unit (as requested by the system operator) using a common feature in many modern units referred to 'MW-preset' or 'MW-controller'. These are slow proportional-integral (PI) regulators that act on the governor load reference set-point to maintain a certain megawatt output from the unit. Therefore, following a system disturbance that results in a frequency excursion, initially the unit's governor may respond to increase (decrease) the output of the unit for a frequency decline (increase), however, within tens of seconds to a minute the unit is promptly returned to its original megawatt output due to the outer-loop MW controller. This thus overrides the action of the turbine-governor and may be undesirable [25].

- Many modern power plants allow a facility to place the unit under either power factor control or constant reactive power (VAr) control. These controllers act much the same way as the outer-loop MW control in that they keep reactive power constant and so override the benefit of the automatic voltage regulator on the unit during a prolonged voltage disturbance.

- Supplemental controls such as the power system stabilizer (PSS) may be inadvertently disabled.

- Some modern designs of generating units incorporate automatic stator current limiters that can be even more restrictive of the unit's reactive power output than over-excitation limiters. If the action of these controls, on critical units, are not considered this may lead to overestimating voltage stability limits.

First and foremost, most reliability standards require that generating units must be operated in automatic voltage regulation (AVR) mode, that controllers such as power factor and VAr controllers should not be used and where available PSSs must always be in-service when the unit is on-line – or if out-of-service, this should be reported to the transmission system operator. In [25] it was recommended that similar monitoring for compliance by units that participate in frequency control is prudent. Thus, it may be assumed that these potential control mode changes and uncertainties need not be considered in studies since reliability standards, if enforced and monitored, should ensure that such changes are kept in check. Nevertheless, it may still be prudent to consider the risk and impact of such potential changes in plant control modes, because in some cases such mode changes may not be intentional, or reported automatically.

2.3.10 Operational Issues

There are some issues of detail with respect to the consistency between planning and operating criteria. For example, the use of short-term ratings has the potential to defer transmission investment. Following a contingency, the power system should be in a satisfactory state with all plant operating within ratings. The system operator could, for example, rely on 15 minute ratings provided there is sufficient generation to re-dispatch to bring equipment back to continuous ratings within the 15 minutes.

An issue is whether transmission planners should work to continuous or short-term ratings. One view is that the additional capacity in short-term ratings should not be used in the planning process because the system operator requires additional flexibility to deal with maintenance outages etc that are not routinely considered in planning studies.

With respect to probabilistic planning, the consistency between the planning criteria and the operating criteria is less clear and the latter are predominantly deterministic (for example, N-1 or N-G-1). This is less likely to be a problem where probabilistic planning is used to supplement deterministic planning and a minimum criterion of, say, N-1, is maintained in the transmission planning process.

If uncertainties are dealt with in a probabilistic planning approach and result in certain transmission investments, application of an operational criterion may result in more conservative constraints being applied that result in higher congestion. Unless this alignment is retained, the benefits used to justify transmission investments may not be delivered.

Operational Planning in the US

There are two main considerations in operational planning. The first is the planning and management of the power flows on the transmission system. The second is the planning and management of the balancing between load and generation. System planning currently addresses all of the concerns associated with management of the power flows on the transmission system and its interactions with generation. As probabilistic planning methods are developed for transmission management, it should be a relatively straight forward process to adapt those methods to operations. However, system planning currently addresses the balancing between load and generation on a limited basis. This discussion will address the limitations and possible solutions available to strengthen operations planning for the balancing consideration in the future.

<u>Planning for Adequacy:</u>

Current planning methods concentrate on achieving adequate capacity to assure that the peak load can be served to a given level of certainty, usually one day of Loss of Load Probability (LOLP) in ten years. It is then assumed that if adequate capacity is provided to meet the target, system operations will be able to convert that adequate capacity into a secure balance between load and generation. Some probabilistic planning methods provide for more in depth planning in that they also consider some of the economic costs associated with dispatch on an hour by hour basis as an aid to optimizing the planning solution.

This planning for adequacy has worked in the past because the generation technologies available and the historic load variability has resulted in operations that are not constrained significantly by the interactions between load variability and generation availability and flexibility. However, several systems have operated close enough to the limits of their balancing capabilities that operational problems have resulted from these interactions. These problems were first observed when these systems experienced negative shadow prices derived by their MILP (Mixed Integer Linear Program) operations planning programs during portions of their daily operations. These negative shadow prices were the first indications that additional considerations beyond adequacy must be considered as part of operations planning process, and therefore, system planning process.

The reader may consult Appendix C for an aside discussion on some of the issues related to frequency regulation in the new market paradigm.

2.4 Current Methods and Tools

Various organizations are dealing with many of the identified issues as they develop their transmission plans. This section describes some of the approaches currently being used and provides some pointers as to the types of planning tools that might be required to deal with the range of uncertainties affecting today's power systems.

2.4.1 Developing Generation Scenarios

A market modeling approach can be used to assess potential future generation investment scenarios. The approach involves simulating market outcomes. The market modeling approach seeks to replicate the investment decisions that might be made by a rational investor in response to the market signals and other incentives. The approach is data intensive but does deliver a future investment stream for each scenario that can then be used as an input to the transmission planning process.

An example of this approach is the underlying analysis of the Annual National Transmission Study conducted for the Australian National Electricity Market and published in a Statement of

Opportunities[6]. This analysis yields three potential generation investment scenarios for a range of high level assumptions.

Alternative approaches reflect a more centralized approach to generation planning and rely on a list of potential investments, each of which is assigned an effective long range marginal cost, based on assumed fuel and plant costs. Using a security criterion (or some other form of criterion like financial viability), investments are picked from this list and yield a generation investment stream. This approach can be made more specific by introducing a number of constraints reflecting the capability of the transmission system. An approach similar to this is being used in New Zealand[7].

Traditional tools, such as the Wien Automated System Planning (WASP) tool, can be used with various modifications to equally deliver future investment streams for scenarios. The WASP based tools were originally intended to deliver 'least cost' solutions and their relevance in markets stems from the view that if the market is efficient, it will deliver a least cost solution. There is probably scope for a review and reconsideration of such tools for use in a competitive market environment.

In some US and Canadian markets, it is possible to form a view of future generation investments from the queue of potential investments awaiting interconnection analysis. However, the relative position in the queue can change and technology or social policy (climate change) has the potential to significantly affect medium and long-term investments. Some form of generation scenarios is therefore likely to be required in these markets as well.

Scenarios can be selected according to projections in fuel cost, carbon taxes (or some cost driven by emissions trading). Government subsidies (such as for renewable energy) can also be incorporated by providing an offset to, for example, fuel costs or capital costs of plant.

As with most scenario-based planning, the problem of dimensionality arises. Five transmission options tested over five scenarios means 25 studies. Tools with faster computational times may address these issues.

New generation planning tools would assist with both power system and transmission planning. Ideally these tools would accept as inputs capital and fuel costs as well as utilization factors for variable generation such as wind or run of river hydro. An ability to introduce some form of co-optimization capability into the generation and transmission investment planning process in the present liberalized market paradigm would be a distinct advantage.

2.4.2 Generation Adequacy

There are many factors that need to be considered in determining the adequacy of generation, including:

- A range of demands (load), say from the 90th to the 10th percentile;
- Generator expected forced outage rates;
- Transmission capabilities and limits;
- Generator maintenance schedules, to the extent these are known in advance;
- Changes to the generation fleet (new investments, retirements, mothballing);
- Influence of variable generation (like wind, tidal, solar) on adequacy.

The manner in which these uncertainties are dealt with varies but includes:

- a Monte Carlo approach with many simulations of each year, using a time sequence approach modeling each hour of the year;

[6] www.nemmco.com.au
[7] Generation Expansion Model (GEM), www.electricitycommission.govt.nz

- as above but using load duration curves rather than time sequences; and
- deterministic approaches with simple rules for the amount of generation that must be considered in transmission planning reference cases.

In the case of the San Francisco Bay assessment, probabilities of different system states and frequencies of different events or their combinations were determined with the application of the Monte Carlo method. System representation for each single hour included probabilistically defined status of generators, lines and transformers; and their peak/off-peak status for a simulated hour. The 100 year simulations were conducted for the actual forced outage rate and duration distributions and separately for the industry distributions based on NERC data. The resulting values and their probability characteristics were determined following calculation and collection of data through the entire simulations.

These results were used as a foundation of the temporary California ISO Planning Standards for Greater Bay Area (http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf), defining combination of units, which should be removed from a base case before conducting Grid Planning studies (see Case 1 in Appendix A for more details).

2.4.3 Market Modeling

The Monte Carlo methods discussed for generation adequacy studies can be extended for use in modeling market outcomes. Repeated simulation of each year in a planning outlook period allows market outcomes to be estimated. Modeling the dispatch outcomes allows assessment of transmission utilization and needs.

The market models can also be extended to provide stochastic modeling of variable generation. This enables flow distribution and congestion assessments that can guide transmission planners.

Tools currently exist that enable time sequence and load duration curve Monte Carlo approaches but these tools have characteristics, perhaps unavoidable, that include:

- high data intensity, especially for large power systems and if bidding behavior is modeled;
- long computational cycles, depending on the extent of modeling;
- challenging validation and de-bugging cycles; and
- readily challenged because of their forecasting nature and dependence on assumptions and scenarios.

The complexity of market simulation currently requires simplifying assumptions. For example, a DC power flow based optimization method is used to clear the market all over the globe because of its simplicity (being linear model). But there is a price to pay – reactive power and voltage elements are neglected altogether. Apart from longer computational times, an AC power flow based optimization model also suffers from a non-convexity problem inherent in the non-linear problem. Market players seem to be not ready yet to accept the nodal prices for both active and reactive power. Some works have been reported in this field, for example [27, 28, 29, 30]. There is thus some risk that the representation of the grid may not correctly reflect some transmission constraints and therefore result in insecure dispatch outcomes. In New Zealand, the system operator has incorporated SFT (Simultaneous Feasibility Test) based on AC Load flow model and this tool talks with the market clearing engine in order to build the thermal constraints taking into account voltage and power factor.

The translation of the market simulation approach into operational tools has not yet been reported but could be useful if it can assist operators to identify potential security and congestion risks in advance of their appearance.

Close coordination of market modeling and power system analysis tools would be advantageous, allowing the physical power system, including outages and constraints, to be imported and used directly in the market simulations.

2.4.4 Load Modeling

Current approaches for load modeling are predominantly manual. Typically a complex load model is developed to represent the best available information on the loads supplied from a particular busbar. The parameters of this load model are then varied to identify the sensitivity of outcomes and impacts on any planned investments.

Load characteristics can be estimated from billing information on the composition of the load. For example, if billing information identified industrial, commercial, residential and agricultural loads, estimates of motor, converter, air conditioning, discharge lighting etc components of the load can be attempted. Much work is required in this area to confirm the adequacy or otherwise of such approaches.

Time domain studies to date have shown [31] a wide range of possible outcomes in voltage control and quality as load characteristics are changed. Conceptually, the approach could be automated to assess outcomes as load model parameters are varied but ultimately some form of correlation with measurements will be required.

Daily peak loads and hourly load curves are usually used. In many practical applications, the load model is usually represented, not by the actual daily or hourly levels, but by a smoothed curve by a restricted number of coordinate points such as daily peak load variation curve [4].

In order to calculate the annual expected load lost, the system load duration curve is approximated with a few number of steps (say 5 steps) with corresponding exposure probability [32].

2.4.5 Uncertainties and Risk associated with Demand Side Integration (DSI)

The demand side integration (DSI) consists in encouraging consumers to modify their level of electricity usage in order to realize peak shaving, valley filling and load shifting. The demand management does not necessarily decrease total energy consumption but could be expected to reduce the need for investments in transmission grid infrastructure and power plants. During certain peak load times, consumers / aggregated consumers could increase, decrease or cut their consumption in order to save money and to be remunerated as a participant in the electricity markets.

Generally, decreasing the consumption increases the security margins of the system. Nevertheless one could imagine various scenarios when the security margins decrease in case of significant load variation. In addition, DSI represents an alternative way for frequency control (primary response, AGC).

From the security assessment analyzes point of view there are several DSI issues that could arise, such as:

- difficulty in predicting the load profile during a large scale DSI. One can imagine social behavior problems mixed with technical issues.
- necessity of a reliable well developed telecommunication system that links a DSI company (service company or balancing entity) and every individual consumer.
- coordination between the participants (generators, DSI companies and grid operators) in terms of real-time load behavior awareness.
- necessity to consider the bounce to the normal operation. After the consumption is cut for an unspecified period of time, the load comeback to the grid could provoke serious problems if there is not any coordination between the DSI service companies and the other concerned actors.

Because of the general random characteristics of the DSI mechanism it may be difficult to integrate it (deterministically or probabilistically) in security assessment calculations, and thus it may be easier to regulate it using technical performance specifications.

2.4.6 Operational Tools

Operational tools currently exist to support system operators to deal with some of the uncertainties in today's markets and power systems. For example, there are a number of monitoring systems that provide indications of the power system's 'health'. There are also analysis tools that report on critical aspects such as voltage and transient stability.

Phasor measurement is now widespread and used in wide area monitoring systems and detection of the damping of inter-area electromechanical oscillation modes. Such systems assist the system operator to maintain security even though there is an increasing challenge to accurately predict power system performance. These systems will, for example, assist with the uncertainty around control system influences by alerting operators to situations where control systems may have been disabled or are malfunctioning. There is also potential for wide area monitoring systems to initiate (limited) control actions if parameters (such as voltage or frequency) exceed predetermined thresholds.

Online analysis tools are available to perform dynamic security assessment. Transient, voltage and oscillatory stability tools are currently available and are being deployed in several power systems [33]. The advantage of these online tools is that they typically reside in the energy management systems and assess performance of the power system at the time, taking account of equipment outages and dispatch patterns. These tools generate linear security constraints in terms of power flows in transmission circuits (or in the interface) and the respective voltage stability limits and transient stability limits. These constraints are then incorporated into the market clearing engine. Provided the models are accurate, these tools can provide a degree of confidence to the system operator if unusual operating conditions arise (for example, a combination of outages and high wind generation).

Further development of these tools to take account of other uncertainties (for example, load models, sudden changes in out from variable generators) would be desirable.

2.5 Summary

International transmission and generation planning practices differ quite widely and depend on a range of factors including:

- Market design
- Competitive or central planning
- Nature of transmission regulation.

In addition, technology developments and changing social and regulator requirements are driving many changes. Investors in both transmission and generation must now deal with increasing uncertainty and conventional approaches and tools may not be fully up to the task. There is an emerging requirement for changes to the traditional planning processes and for new tools that assist in the management of the many areas of uncertainty.

Particular areas of uncertainty include:

- Location and timing of new generation in competitive markets;
- Variable generation from renewable sources such as wind generation;
- Load forecasts and their impact on both generation and transmission investments; and
- Load modeling and its impact on power system security.

Traditional technical simulation tools (such as load flow, time and frequency domain applications) are widely used in dealing with the modern planning paradigm, sometimes being automated to examine a range of uncertain inputs.

The development of generation scenarios is an important input for the transmission planning process and several approaches have emerged, ranging from market modeling to reliance on more traditional tools previously used by vertically integrated utilities to deliver 'least cost' solutions.

With respect to transmission planning, the attraction of probabilistic planning is tempered by a lack of data and tools that allow correct representation of failure rates and associated costs. There is a need to develop tools that facilitate the assessment of economic benefits and allow data uncertainty to be estimated.

Even with deterministic planning criteria there are many aspects of uncertainty that would benefit by having tools that can assess the boundaries introduced by the uncertainties. Examples here include loads, load models, generator governor operating modes and variable generation sources.

Variable power flows from wind, tidal, solar and other similar forms of renewable energy are already presenting operational and transmission planning challenges. Correlations of wind energy output across geographically separated sites can cause significant changes in power flow and corresponding challenges in voltage control, line congestion and frequency regulation. Tools that allow consideration of stochastic variables to assess such impacts are needed.

Climate change mitigation measures, such as carbon taxes and emissions trading, may impact power flows on the power system and change the demands on the transmission system with respect to capacity and voltage control. Tools to readily allow sensitivity studies to such changes may be needed.

So in summary it can be said that the planning environment is changing with the unprecedented shifts to new generation technologies and demand side responsiveness. The present deterministic methods may not be able to handle the large number of new considerations (variable generation, DSI, etc.) currently facing system and operations planners. In contrast, probabilistic planning approaches may be better able to handle such increasing scenarios and uncertainties, however, currently they suffer from a lack of effective tools to assist with the management of data (for example failure rates), the reliability assessment of alternatives; and the assessment of aggregate benefits over a range of operating conditions and development scenarios. Also, it is still not clear how multiple contingency events that result in major disruptions can be appropriately dealt with using current deterministic approaches and tools. Generation planning is also affected by the uncertainties in power system developments and has other challenges including; dimensioning transmission connections for the ultimate future generation capacity and generation build times that are appreciably shorter than the planning, consenting and construction times of transmission.

Table 2-1 below provides a high level comparison of the current approaches to deterministic and probabilistic planning. The following chapters highlight the status of present tools and potential developments that could assist planners as they deal with the issues discussed in this chapter.

Table 2-1: Summary of the comparison between probabilistic and deterministic planning.

	Probabilistic Planning	**Deterministic Planning**
Contingency levels	Multiple levels of outages can be considered. Probabilistic planning tools can be used for analysis of multiple contingencies beyond N-2 events.	Automatic assessment of worst case scenarios limited to N-2 events due to computational intensity.
Economic decision making	Facilitates economic decision making for investments and provides basis for selection of the best alternative over a range of scenarios.	Often involves subjective judgment and is not useful to asses the economic worth of an investment
System utilization	Probabilistic planning allows increased utilization of assets. Some probabilistic operating tools may be required to realize this.	The system capacity is planned for worst-case scenarios, which have low probability of occurrence. As a result, system capacity utilization is not always efficient.
Consideration to external factors	With probabilistic planning external factors such as environment, social and economic benefits can be considered in the analysis although some are difficult to quantify in monetary terms.	Deterministic planning cannot adequately address external factors.
Selection and ranking of contingencies	A wide variety of contingencies can be selected based on operational criteria. Ranking of contingencies is also possible based on their historical occurrence rates.	A limited number of contingencies are selected based on extreme operating conditions. Economic ranking is not implicit but can be done.
Load profile	Load profiles can be selected based on hourly, daily, or annual patterns. Even seasonal load profiles can be selected. Much more information available on exposure to security risks.	Deterministic planning is based on seasonal Peak, Medium, or Low demand values. A real-time system simulation is normally not considered in the planning process
Analysis Conditions	Both steady state and dynamic conditions are used in probabilistic planning	No difference – both steady state and dynamic analyses are used to assess compliance with the deterministic criteria.
Reliability Indices	A variety of reliability indices can be calculated	Indices can be calculated but are not normally part of the deterministic criterion.
Criteria for planning process	The probabilistic planning process is still evolving and an analyst has to be careful in selecting models and input data.	The deterministic planning process is well established.
Availability of data	Data for probabilistic planning is difficult to obtain and the quality of the data will largely influence the outcomes. Few utilities maintain and ensure quality of data for probabilistic planning.	Power system models and applications are widely accepted and benchmarked. Not reliant on asset performance data.
Robustness of analysis	Probabilistic planning is often used in conjunction with deterministic planning to provide a check on robustness to the system as a whole.	A utility is satisfied with the use of deterministic planning alone. The planning is normally supported by additional economic and dynamic studies.

CHAPTER 3

CONCERNS AND GAPS WITH PRESENT PROBABILISTIC TOOLS

3.1 Introduction

With the advent of large scale utilization of variable sources for power generation, increased market competition and amplified transmission congestion, modern power systems are becoming more and more complex. This changing environment has introduced many uncertainties in the power industry and therefore has significant impacts on the reliability performance of power systems. The need to use risk-based and/or probabilistic tools in electric power system planning and operation, therefore, becomes extremely important given the increasing number of players and uncertainties involved in the electric energy market.

The benefits of utilizing probabilistic methods have been recognized since at least the 1930s and have been applied by utilities in power system reliability analyses since that time [1, 2, 3, 4]. Probabilistic reliability evaluation can be subdivided into the two categories of system adequacy and system security [5] as shown in Figure 3-1.

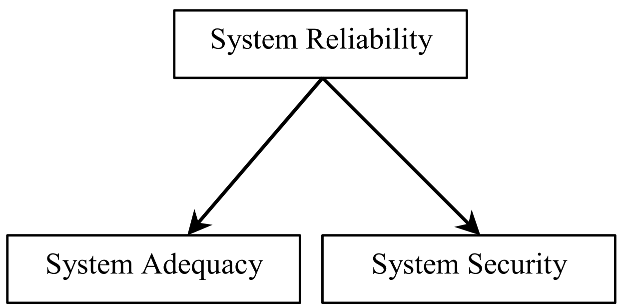


Figure 3-1: Subdivision of system reliability

The concept of adequacy is generally considered to be the existence of sufficient facilities within the system to satisfy the consumer demand. These facilities include those necessary to generate sufficient energy and the associated transmission and distribution networks required to transport the energy to the actual consumer load points. Adequacy is therefore considered to be associated with static conditions which do not include system disturbances. Security, on the other hand, is considered to relate to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever disturbances it is subjected. These are considered to include conditions causing local and widespread effects and the loss of major generation and transmission facilities [5].

Probabilistic security assessment is not a well researched area and currently no tools are available. The predominant application of probabilistic techniques is in the adequacy domain. These adequacy methods can be divided into the three general categories of generation adequacy assessment, composite generation and transmission system reliability evaluation and complete system reliability assessment [5] as presented in Figure 3-2.

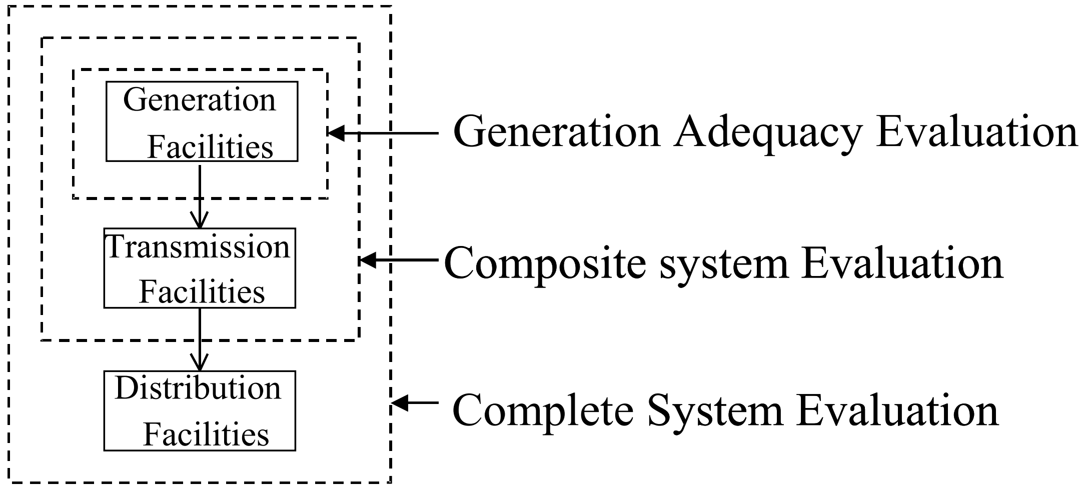


Figure 3-2: Areas of Power System Adequacy Assessment.

In generation adequacy assessment, the total system generation including interconnected assistance is examined to determine its adequacy to meet the total system load demand. Traditionally the transmission network and the distribution facilities are not included in a generation adequacy assessment. Increasing attention, however, has been given to the incorporation of transmission limitation and energy deliverability in generation adequacy assessment especially in recent years. Composite generation and transmission system reliability evaluation considers the generation and transmission as a composite system. The effect of load growth, configuration changes and facility additions can be studied and reliability indices can be evaluated for the overall system as well as for the individual buses. The complete system reliability evaluation includes all three power system functional zones of generation, transmission and distribution and is not easily conducted in a practical system due to the computational complexity and scale of the problem. The main objective of the complete system reliability evaluation is to conduct reliability assessment at the consumer load points. The consumer load point analyses are usually performed only in the distribution system.

The fundamental approaches used to calculate the risk indices in a probabilistic evaluation can be generally described as being either direct analytical evaluation (contingency enumeration) or Monte Carlo simulation. Analytical techniques represent the system by analytical models and evaluate the system risk indices from these models using mathematical solutions. Monte Carlo simulation, on the other hand, estimates the risk indices by simulating the actual process and the random behavior of the system. Both approaches have advantages and disadvantages, and each of them can be very powerful with proper application.

Although a great deal of effort has been devoted to the utilization of probabilistic techniques in power system reliability assessment, the existing tools have some limitations and gaps which are subject to discussion. This chapter presents a brief review of the salient features of the commonly used risk-based or probabilistic tools used for power system planning and operational studies. The chapter will also discuss the gaps and limitations with the application of probabilistic based techniques and the existing tools.

3.2 Summary of Existing Probabilistic Planning Tools

Considerable efforts have been devoted to develop risk-based or probabilistic tools for power system planning and operation studies. Some of the commonly used programs are summarized in Table 3-1. This table does not include those tools for evaluating distribution system or substation reliability for brevity. Most of the tools listed in the table are commercially available. A brief description of each of the programs is provided in the following subsections[8].

Table 3-1: Summary Table of Probabilistic Planning Tools

Probabilistic Planning Tool	Application	Contingency Selection / Network Solution	Web Address
1. TRELSS & TransCARE by EPRI	Composite	Analytical/AC or DC Power Flow	No
2. TRANSREL by GR USA	Composite and Transmission	Analytical /AC Power Flow	Yes
3. OSCAR by Kinectrics	Composite	Analytical or Monte Carlo/AC or DC Power Flow	No
4. PROCOSE by Hydro One Canada	Composite	Analytical /DC Power Flow	No
5. TPLAN by Siemens PTI	Transmission	Analytical /AC Power Flow	Yes
6. CREAM by EPRI	Composite	Monte Carlo/ DC Power Flow	Yes
7. MECORE by U of S and BC Hydro Canada	Composite	Hybrid Analytical and Monte Carlo/AC or DC Power Flow	No
8. NH2 by CEPEL Brazil	Composite	Monte Carlo/AC or DC Power Flow	No
9. CORAL by PSR, Inc.	Composite	Monte Carlo/ DC Power Flow	Yes
10. NARP by APA USA	Generation	Monte Carlo/ DC Power Flow	No
11. MARS by GE	Generation	Monte Carlo/ Transportation	Yes
12. SERVM by Astrape Consulting	Generation	Monte Carlo/ Transportation	Yes
13. PROMOD IV (MARELI) by Ventyx	Generation	Monte Carlo/ DC Power Flow	Yes
14. PowerFactory Reliability Analysis Tool by DIGSILENT	Generation and Composite	Analytical /AC Power Flow	Yes
15. UPLAN-NPM by LCG Consulting	Generation (security-constrained commitment and dispatch)	Monte Carlo/AC or DC Power Flow	Yes
16. GridView by ABB	Generation (security-constrained commitment and dispatch)	Monte Carlo/ DC Power Flow	Yes
17. ASSESS by RTE, France and NGT, UK		Monte Carlo/AC or DC Power Flow	Yes
18. REMARK by ERSE (former CESI RICERCA)	Generation and Composite	Monte Carlo/DC Power Flow	No

[8] The reader may also refer to Appendix 3 of a recent NERC report (http://www.nerc.com/docs/pc/gtrpmtf/Final_GTRPMTF_Rpt_to_PC-06-09-09.pdf) for a complementary discussion of software capabilities.

3.2.1 TRELSS and TransCARE by EPRI

Transmission Reliability Evaluation of Large-Scale Systems (TRELSS) is a five program software package that uses enumeration of generation and transmission contingencies to evaluate power system reliability. TRELSS is designed to aid electric utility system planners in the reliability assessment of composite generation and transmission systems. TRELSS computes reliability indices using a contingency enumeration approach, which involves selection and evaluation of contingencies, classification of each contingency according to specified failure criteria and accumulation of reliability indices. Three basic methods of reliability assessment are available in TRELSS: the system problem approach and contingency screening approach quantify reliability in terms of frequency, probability and severity of overloads and voltage violations. The capability approach, which includes application remedial actions including load curtailment, attempts to quantify system reliability all in terms of load loss indices consisting of probability, frequency, Expected Unserved Energy (EUE), Expected Unserved Demand (EUD) etc.

TRELSS uses both AC and DC load flow analyses for power system network solution. TRELSS can, therefore, be used to perform traditional deterministic analysis. Recently EPRI is working on a new program called Transmission Contingency Analysis and Reliability Evaluation (TransCARE) to replace TRELSS. Although TransCARE has been complete, it has not been officially released yet. All of the algorithms, models and calculations in TRELSS will have been carried over to TransCARE without sacrificing the modeling and mathematical rigor of TRELSS. It is expected that TransCARE will be much easier to use than TRELSS.

Web-link: www.epri.com (search for key word TRELSS)

3.2.2 TRANSREL by GR, USA

TRANSREL is a computer program to calculate reliability indices for bulk power systems, transmission systems, and /or station switchyard. TRANSREL uses contingency enumeration approach to evaluate power system reliability. The process mainly involves specifying contingencies and performing AC load flow analyses to determine system problems such as circuit overloads, bus voltage violations, bus separation or islanding. TRANSREL can be used as a stand-alone tool or can be used with Substation Reliability (SUBREL also developed by GR) to study the impact of station related outages on overall system reliability. A range of commonly used reliability indices can be calculated by TRANSREL. TRANSREL can be used in a variety of ways to estimate the level of customer service expected from a system improvement option.

In power system planning studies, TRANSREL can be used to:

- Compute reliability indices for a transmission network with a simulation of credible outages and user specified contingencies after quantifying system health and its response for different load flow scenarios.
- Compare alternative transmission configurations by computing a whole set of reliability indices and by providing data for the cost of outages.
- Provide a basis for risk/benefit analysis against investments.

As a system operating study tool, TRANSREL can be used to identify worst contingencies, evaluate the impacts of such contingencies, and identify effective remedial actions that can be used to optimize operation of the system during such contingencies.

Web-link: http://www.gri-us.com/downloads.html

3.2.3 OSCAR by Kinectrics

The Outage Scheduling and Reliability Analysis of Electric Power System (OSCAR) model is a computer program for analyzing the generation and transmission reliability of large power systems. OSCAR use both analytical and Monte Carlo simulation approaches. System states can be selected by using state enumeration (analytical) or Monte Carlo simulation (non-sequential or sequential). The performance of each selected state can be analyzed through an AC or DC power flow. The combining options are: State Enumeration with AC or DC power flow, Monte Carlo Non-sequential Simulation with AC or DC power flow, Monte Carlo Sequential (Chronological) Simulation with DC power flow.

Web-link: not available

3.2.4 PROCOSE by Hydro One

Probabilistic Composite System Evaluation Program (PROCOSE) was developed by Hydro One (formerly Ontario Hydro) primarily for reliability and production costing assessment of bulk power systems. The program uses a DC power flow model to simulate the operation of the power system during a specific period of time (hour, week, month, etc.) taking into account the random failures of generators and circuits, economic dispatch, fixed power injections, load profile during the study period and limits imposed on the transmission network. PROCOSE computes reliability indices using analytical models and computes system production costs and various reliability indices for individual buses and the system.

Web-link: Not available

3.2.5 PSS™TPLAN by Siemens PTI

PSS™TPLAN is an integrated, stand-alone computer software package for transmission reliability assessment. PSS™TPLAN is capable of conducting deterministic evaluation and/or probabilistic assessment of electric transmission system. PSS™TPLAN computes probabilistic reliability indices using analytical models. PSS™TPLAN also provides a basis for expanded applications available as add-on modules including:

- Measuring available transfer capability, Transfer Limits Assessment, due to thermal capacity and voltage constraints,
- Selecting effectively among transmission expansion options Interactive Expansion Planning,
- Identifying optimized, security-constrained generation dispatches Security-Constrained Economic Dispatch (SCED)
- Evaluating impact of substation reliability Substation Reliability Assessment (SRA).
- Identifying must-run resources, which provide for security in transmission constrained areas.

Web-link: http://www.pti-us.com/pti/software/tplan/

3.2.6 CREAM by EPRI

The Composite Reliability Assessment by Monte Carlo (CREAM) software is based on Monte Carlo sampling of equipment availability (generators and circuits, including weather-dependent and common-cause or dependent outages) and load level (including system load or bus load vector scenario). The analysis of a sampled scenario is based on a DC power flow model. Remedial actions and load curtailment are carried out by a linear programming routine. The program calculates the most commonly used reliability indices such as Loss-Of-Load Probability (LOLP) and Expected Power Not Supplied (EPNS) at both system and individual bus levels. The program is also able to produce the sensitivity of the reliability indices with respect to incremental reinforcements of generation capacities and circuit capacities.

Web-link:
http://my.epri.com/portal/server.pt?space=CommunityPage&cached=true&parentname=ObjMgr&parentid=2&control=SetCommunity&CommunityID=221&PageIDqueryComId=0

3.2.7 MECORE by U. of Saskatchewan and BC Hydro

MECORE was initially developed at the University of Saskatchewan and has been subsequently enhanced and applied by BC Hydro, Canada. MECORE program is currently owned by British Columbia Transmission Corporation (BCTC), Canada. MECORE program can be used to provide a wide range of reliability indices at the individual load points and for the overall composite generation and transmission system. It can be used to provide unreliability cost indices that reflect reliability worth. MECORE also utilizes linear programming methods to arrive at optimal power flows and optimal load curtailments. MECORE is based on a combination of Monte Carlo simulation (state sampling technique) and enumeration techniques. The Monte Carlo method can be used to simulate the system component states and to calculate annualized indices at the system peak load level. A hybrid method utilizing an enumeration approach for aggregated load states is used to calculate annual indices using an annual load curve. Monthly and seasonal indices may also be calculated. A strength of the MECORE model is its ability to calculate certain reliability indices for each individual-load point.

Web-link: not available

3.2.8 NH2 by CEPEL, Brazil

The NH2 software is designed for probabilistic reliability assessment of composite generation and transmission systems. It features advanced methods and models, which guarantee efficient and flexible additional analyses, such as:

- AC network modeling
- Power system solution environment comprising:
    - Power flow solution, by full Newton-Raphson
    - AC optimal power flow, based on interior point method, with minimum load shed objective function
    - Individual contingency analyses
    - Contingency list analyses (deterministic reliability assessment)
    - Probabilistic power flow
- Optimal power flow used for corrective measures
- Random behavior of generating units and transmission circuits are represented by Markovian models - two and multiple state models are available
- Common mode failure
- Reliability assessment by contingency enumeration or Monte Carlo simulation
- Traditional and frequency and duration reliability indices, stratified in three levels: system, area and buses
- Additional statistics: probability density functions of selected variables (power flows, voltages, etc.), failure mode indices, etc.

The NH2 software has been developed by CEPEL, the Brazilian research centre for electric power, in close cooperation with Eletrobras and other Brazilian utilities. NH2 is a very flexible and comprehensive tool for power system reliability evaluation. NH2 is the official reliability tool used by the Brazilian independent system operator. It is also the official tool used by the Brazilian transmission expansion technical committee, coordinated by the Brazilian Energy Ministry.

Web-link: not available

3.2.9 CORAL by PSR Inc.

Coral evaluates the composite generation and transmission supply reliability of large-scale power systems taking into account: (i) generation and transmission outages (ii) the effect of hydrological uncertainty on reservoir storage levels and hence on hydro production capacity (iii) load variation and

(iv) production uncertainty of renewable generation such as wind, biomass and small hydro. Reliability indices such as loss of load probability (LOLP) and expected energy not supplied (EENS) are estimated for each stage of the study period and disaggregated in terms of the contributions due to generation, transmission and composite outages. Bus and area indices are also estimated, as well as the expected bus-level marginal impacts of generation and transmission reinforcements. A combined Monte Carlo, stratification and enumeration scheme is used to represent the states of generation, transmission, load, hydro capacity and renewable production. For each selected/sampled state, a linearized optimal power flow is used to identify operating constraint violations and apply corrective measures. The severity of supply shortfalls is represented as the minimum load curtailment required to eliminate the operating constraint violations.

Web-link: http://www.psr-inc.com/psr/download/folders/coralfoldereng.pdf

3.2.10 NARP by APA

The N-Area Reliability Program (NARP) is a computer program for the calculation of reliability performance indices in a multi-area interconnected electric power system. System components modeled are the generating units in each area and the transmission links between areas. Thus, the program is intended primarily as a tool for generation capacity planning within the context of an interconnected power system. The program uses a Monte Carlo simulation approach to reflect the effects of chance events such as generator and transmission link failures as well as deterministic operating rules and policies. NARP uses a DC power flow model in performing simple load flow analyses on interfaces connecting generating systems.

Web-link: not available

3.2.11 MARS by GE

The Multi-Area Reliability Simulation program (MARS) enables the electric utility planner to quickly and accurately assess the ability of a power system, comprised of any number of interconnected areas, to adequately satisfy customer load requirements. A sequential Monte Carlo simulation forms the basis for MARS, which was jointly developed by General Electric and Associated Power Analysts. MARS calculates, on an area and pool basis, the standard indices of daily and hourly LOLE (days/year and hours/year) and expected unserved energy (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). In addition to calculating the expected values for the reliability indices, MARS (through a separate post-processor program) also produces probability distributions that show the actual yearly variations in reliability that the system could be expected to experience. MARS uses transportation model in performing simple load flow analyses on interfaces connecting generating systems.

Web-link: http://www3.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

3.2.12 SERVM by Astrape Consulting

The Strategic Energy and Risk Valuation Model (SERVM) is designed to simulate the operation of all types of resources to quantify generation reliability risks. The results of this model can help value energy limited resources, target optimal reserve margin, optimize maintenance budgets and limit seasonal risk in capacity contracts. The program can be used to evaluate the reliability of any electric system and its interconnected areas in terms of frequency of events (Loss of Load Events and Emergency Purchases), the magnitude of such events (MWh) and the economic impact of such events (societal and direct costs). SERVM is also able to evaluate reliability costs for both unserved energy and emergency purchases, therefore system planners can use the model to conduct value based reliability studies. SERVM is based on a chronological Monte Carlo simulation and uses transportation model in performing load flow analyses on interfaces connecting generating systems.

Web-link: http://www.astrape.com/index.php?file=products

3.2.13 PROMOD IV (MARELI) by Ventyx

Multi-Area Reliability (MARELI) calculates loss-of-load probability, expected unserved energy, and loss-of-load hours for a system in which inter-tie limitations and pooling agreements constrain the extent to which different areas within a system can or will support one another. The model can also be used to determine the effective capacity support provided to each area by virtue of its interconnections. MARELI is based on a Monte Carlo simulation and uses a DC load flow model. Applications for MARELI include:

- Assessing the availability of support from neighboring areas,
- Evaluating the need for additional transmission capability,
- Integrated planning within a power pool, and
- Identifying relatively reliable or unreliable areas within a network.

Web-link: http://www.ventyx.com/analytics/promod.asp

3.2.14 PowerFactory Reliability Analysis Tool by DIGSILENT

The DIGSILENT PowerFactory Reliability Analysis Tool incorporates standard reliability assessment features together with sophisticated modeling techniques that enable both generation adequacy and composite generation and transmission reliability assessment to be carried out. Generation pool adequacy analysis compares the total available generating capacity with the load demand. The purpose of the generation pool adequacy analysis is to identify the ability of generators to fulfill load demand in the case of an infinitely strong transmission and/or distribution system. Distribution and bulk power network analysis are both carried out by the "Network Reliability" analysis function. This comprises the assessment of interruption statistics for individual loads and bus-bars in distribution, sub-transmission and transmission systems. The calculation method combines fast topological analysis for fault clearance, fault isolation and power restoration, with AC load flow and optimization techniques for addressing energy at risk, load transfer and load shedding. The basic calculation method used is analytical state enumeration.

Web link: http://www.digsilent.de/Software/PowerFactory_Features/Reliability_Analysis/

3.2.15 UPLAN-NPM by LCG Consulting

The UPLAN Network Power Model (UPLAN-NPM) projects detailed physical and financial operations of electricity markets under conditions ranging from traditional regulation to today's post-restructuring competitive market structures. The day-ahead market is simulated in UPLAN by optimizing the commitment of resources for energy and all ancillary services taking into account transmission and interregional constraints. The commitment and dispatch algorithms incorporate both optimal power flow and resource scheduling to faithfully simulate the security constraints of a complete transmission network. UPLAN simulates overall day-ahead market using Security-Constrained Unit Commitment and Security-Constrained Economic Dispatch (SCED). In the first step, UPLAN schedules day-ahead resources in appropriate amounts and locations to meet forecast energy (loads) and ancillary services (reserves) requirements, while taking into account region-specific operating protocols as well as transmission constraints. Optimal Power Flow simulation is used to ensure that the final unit commitment can in fact obey all transmission constraints including line contingencies and generator outages. In its determination of optimal unit commitment subject to security constraints, UPLAN realistically characterizes generators' market participation based on opportunity or marginal cost-based bidding, with arbitrage, which is simulated via a state-of-the-art multi-commodity Nash equilibrium algorithm. For SCED, the OPF simulation may utilize either DC or AC power flow, and the system will be optimally re-dispatched to manage congestion while obeying transmission constraints such as line thermal limits, including use of post-contingency analysis for all specified contingencies under which the dispatch is required to remain secure. The two steps described above work interactively to realistically simulate day-ahead energy and ancillary service markets.

Web-link: http://www.energyonline.com/Products/Uplane.aspx

3.2.16 GridView by ABB

GridView is a software application developed by ABB Inc. to simulate the operation of an interconnected power system such as RTOs, ISOs, and Operating Pools. GridView is a market simulation and analysis software designed to deal with the most challenging issues facing planners and decision-makers in the electric energy industry today. It simulates security constrained unit commitment and security constrained economic dispatch in a large-scale transmission network. GridView is based on a sequential Monte Carlo simulation method. The simulation program mimics the operation of electricity markets by performing security constrained unit commitment and economic dispatch. In GridView it is possible to have a full representation of the transmission network in performing the security-constrained commitment and dispatch. The transmission network can be easily synchronized between power flow cases (in Siemens PTI PSS™E or GE PSLF™ format) and the GridView model. In addition to the detailed transmission network as represented in power flow case, the GridView model contains all transmission constraints, including all interfaces, contingency constraints, monitored lines, nomograms.

Web-link: http://www.abb.ca/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx

3.2.17 ASSESS by RTE, France and NGT, UK

ASSESS allows the application of statistical analysis and data-mining methods to the specific needs of power system security assessment (system planning and operation planning). Numerous situations are built, classified as acceptable or unacceptable, and then analyzed to find the operating parameters (voltages, flows) which best characterize the boundary between acceptable and unacceptable. The methodology also allows the characterization of a set of situations regarding their security level, their weak points, the way the security might not be assumed (voltage collapse, overflows, etc.).

ASSESS is a software platform that prepare the probabilistic data for specialized power system analysis specialized tools. The static tools are: METRIX (OPF in DC), TROPIC (OPF in AC). The dynamic tools are: ASTRE (long-term dynamics simulator dedicated to the study of voltage phenomena), EUROSTAG (dynamics simulator allowing a detailed study of transient, mid and long-term stability).

ASSESS generates systematic / random situations modeling the uncertainties. It is possible to model uncertainties on any variable defining the studied network (for example: consumption in a zone, lines and generators availability / unavailability, generation of a wind turbine site, devices maintenance, load shedding, exciter time constant, etc.).

Web-link: http://www.rte-france.com/htm/an/activites/assess.jsp

3.2.18 REMARK by ERSE

Reliability and Market (REMARK) represents a new tool proposed for the transmission planning process. The purpose of this tool is to conduct analyses of static reliability (or adequacy) of complex electric systems that operate in a liberalized market context and are divided into areas. This might then be a situation typical of European regional markets. In comparison to conventional planning tools, REMARK quantifies both indices generally used to assess reliability of electric systems and indices aimed at innovatively assessing from the economic point of view the effects and the eventual criticalities caused by the market structure on the transmission system evolution. The main features of REMARK are:

- Full network representation adopting the simplified direct current model;
- An Optimal Power Flow (OPF) algorithm;
- Probabilistic simulation of one year of operation of the power system using a non-sequential Monte Carlo method;
- Quantitative assessment of the reliability benefits;

- Quantitative assessment of the “economic” benefits (both substitution and strategic effect).

The adopted OPF consists of four different stages of increasing detail, respectively considering: (1) single-bus network model to identify generation inadequacies, (2) transmission constraints between market zones to identify also the scarcity of Net Transfer Capacity (NTC) between zones, (3) network constraints of the actual interconnections between zones, and (4) constraints of all transmission elements, to account for constraints within zones of the system. Increasing costs can be identified according to the progression of the stages.

REMARK also implements a stochastic wind generation model allowing the representation of correlation between wind sites. Please refer to Appendix D for a more detailed discussion on REMARK. Some valuable references related to REMARK are [6, 7, 8].

Web-link: not available.

3.3 Limitations and Gaps with the Existing Tools

Considerable published work over the last several decades has been devoted to the various aspects of reliability evaluation of generation, transmission and composite generation and transmission systems [1, 2, 3, 4, 5, 9]. Probabilistic risk-based reliability assessment approaches have been widely applied to the planning and operating of generating systems and a consistent set of probabilistic criteria have been accepted by electric utilities [9]. On the other hand, probabilistic-based approaches have been used for evaluating particular projects and planning related decision-making to the transmission systems in some instances [1, 2, 3, 4, 5, 9]. Technical papers published by CIGRE WG 38.03 [10, 11] have specifically addressed the state of the art of composite system reliability assessment prepared by experts representing utilities, universities and consulting firms. It is known that probabilistic security assessment in power system operations has been lagging efforts made in power system planning. Some efforts have been made [11] and papers presented at two panel sessions at the 1999 IEEE PES Summer Meeting [13, 14, 15] specifically focused on probabilistic security and risk-based dynamic assessments in the area of operation. Several authors have presented concepts and methodologies for integrated power system reliability (adequacy and security) assessments [16, 17]. However, the practical applications of various risk-based approaches in both planning and operation domains remains a topic of concern and even controversy [17].

As noted earlier the power utility industry worldwide has been undergoing tremendous changes. The importance of conducting risk-based reliability studies has been emphasized by researchers and industry due to the number of blackout events that have occurred across the globe in recent years. Large blackouts generally involve a number of complex interactions of events. IEEE CAMS Task Force on understanding, prediction, prevention and restoration from the cascading failures has published and provided a comprehensive overview of risk-based methodologies and tools that deal with vulnerability assessment for cascading failures in electric power systems [18, 19].

Currently the electric utility industry primarily focuses on applying deterministic planning standards that have served the industry well over the years and provide a good indication of the system performance. The IEEE PES Reliability, Risk, and Probability Applications Subcommittee’s TF paper [20] has compared probabilistic security assessment with deterministic security assessment within an operational context and identified the main advantages of using risk-based probabilistic criteria instead of the presently used deterministic criteria. The advantages of using complementary risk-based probabilistic criteria in transmission planning has already been recognized and implemented by Western Electricity Coordinating Council (WECC), one of seven NERC reliability regions [21]. Several authors have made attempts to model open-access electricity market conditions with transmission congestion issues and incorporate them into risk-based probabilistic methodologies presented in [6, 7, 22, 23].

Although a great deal of effort has been devoted to the utilization of probabilistic techniques in power system reliability assessment, it is widely recognized that there are some limitations and gaps with the application of proposed risk-based methodologies and the tools used to conduct probabilistic reliability studies. These limitations and gaps are grouped into several main areas of concern such as: data requirements, present industry practices, modeling issues and issues associated with electricity deregulation.

3.3.1 Data requirements

Any risk-based reliability calculation depends on data availability and requirements to support such studies. Limitations on data collection and system monitoring, inadequate system performance data (static and dynamic) and inadequate component performance data have been identified as a main cause of limited use of probabilistic methods in the past. There are, however, two good examples in this area. The Canadian Electricity Association (CEA) has developed the Equipment Reliability Information System (ERIS) [24] and the North American Electricity Reliability Corporation (NERC) has developed the Generation Availability Data System (GADS) [25]. NERC has also developed a Transmission Availability Data System (TADS) to which many utilities are required to contribute transmission outage data [26]. CEA has been collecting bulk transmission outage data since 1980 and NERC TADS has started to collect data on all 230 kV lines and above across all NERC regions since 2008 [27].

3.3.2 Present industry practices

While generation adequacy is universally probability based, transmission planning generally follows deterministic planning standards (see some discussion in Case 2 and 5 in Appendix A). These deterministic assessments are typically defined by selecting a set of network configurations (topology and unit commitment), a range of system operating conditions, a list of contingencies, and the performance evaluation criteria. In spite of the obvious limitations of deterministic criteria in risk assessment, the deterministic criteria have generally served the industry well thanks to its conceptual simplicity and the availability of computer programs such as GE PSLF™ and Siemens PTI PSS™E, and other similar programs. The traditional deterministic methods for transmission planning and operation may be inadequate in the new deregulated environment as the number of scenarios and uncertainties associated with the power systems are ever increasing (e.g. variable generation, random failures of equipment, load growth forecast uncertainties, energy import and export transactions on the volatile market, etc.). The old days of integrated resource planning, in which generation and transmission plans were coordinated [19], are largely gone. The difficulty with deterministic criteria is that, in terms of risk, the criteria may result in inconsistent decision-making [17]. Low-risk cases may be included in studies and high-risk cases omitted from studies, and these deficiencies may remain hidden because deterministic studies do not quantify risk. Bulk transmission systems are planned accordingly to present planning standards with an aim to provide satisfactory reliability to the customers. Today, reliability requirements of the system become even more stringent while the interest in reducing the cost continues to grow. Transmission owners are facing higher levels of uncertainty in their planning process than ever before.

3.3.3 Modeling issues

Specific modeling issues have been identified as part of the gaps and limitations in existing tools. Several issues such as modeling accuracy (sufficient contingency depth, reactive power representation) and computational efficiency are of concern. Another modeling limitation is that existing tools don’t recognize realistic operating practices. The load curtailment indices calculated by these models are therefore not meaningful. In general, there is one or more of the following practical limitations in some of the existing tools which are often cited by users:

- Most existing composite generation and transmission system assessment tools are designed for probabilistic reliability assessment of large AC systems and none of them can fully handle HVDC systems.
- Most existing tools especially those designed for adequacy assessment of composite generation and transmission systems, cannot properly model the energy limited nature of hydro units. In most of these programs, hydro units are treated exactly the same as thermal units.
- Some programs use an economic generation dispatch and others use a dispatch similar to that in the base case power flow. The problem with these types of dispatches is that they remain unchanged while assessing the various system states (generation, transmission and load).

- Some of the existing tools recognize some system operating limits imposed on the transmission network due to thermal, voltage and stability considerations. The problem here is that those limits are assumed to be valid under all system operating conditions when assessing the system reliability.
- Difficult and very time consuming to prepare reliability data files required by program.
- Complexity of analysis and interpretation of results.
- Cannot properly model cascading or islanding, power flow divergent cases, load curves and multiple section circuits (tap connections).
- Cannot properly calculate bus reliability indices.
- Inability or difficulty to model multiple states or high order failure events for those programs using enumeration technique.
- For large interconnected system reliability analyses it is preferable that the number of transmission contingencies to be assessed should be reduced to a manageable size without sacrificing the accuracy of the final results. It seems that none of the existing tools has the built-in algorithm to do this job.
- Cannot properly incorporate into the analysis substation related outages.
- Cannot properly include operating procedures, constraints and security dispatch.

3.3.4 Market Issues

Many of the existing probabilistic tools listed in the previous section have limited capability of recognizing and incorporating the increased uncertainties introduced by the deregulation of the electric utility industry. Although there is a long history of probabilistic techniques and applications in the planning domain, the modeling of various system parameters and the overall system reliability assessment methodology used in those existing tools are virtually the same as those used before the liberation of the utility business. Today, as a result of restructuring and deregulation, reliability tools should be capable to deal with a number of uncertainties. Under open-access electricity market conditions, transmission congestion issues have to be taken into consideration. For instance, in some cases generation cannot be delivered or load must be curtailed in specific areas due to transmission constraints. Price elasticity of demand and energy will introduce another form of uncertainty into the planning process. Demand side management technologies and conservation of energy already play a role in reducing energy use. The increasing utilization of renewable sources in electric power systems requires a better understanding of the impact of these variable energy sources on power system adequacy and security. Assessment methodology and tools are needed to examine and quantify the various issues associated with those highly variable energy sources. The flexibility/inflexibility of variable energy sources could be evaluated considering different aspects of power systems such as characteristics of renewable resources and load demand, grid infrastructure, interconnection, demand side management and system operational measures. It is believed that probabilistic or risk based tools should be able to address these issues and fill this gap. In a deregulated environment, dealing with uncertainties, given below, is of paramount importance.

- Uncertainty of power generation location, capacity, timing and availability of new conventional and un-conventional energy sources.
- Uncertainty in future complexity of power transactions
- Uncertainty in future demand
- Uncertainty in future regulation/rules

However, the present trends in the utility industry have resulted in the increased utilization of the system. It is time to look at the need for probabilistic assessment procedures, either as replacement for deterministic criteria or as a help to redefine deterministic criteria.

3.4 Summary

This chapter briefly describes the salient features of the commonly used risk-based or probabilistic tools used for power system planning and operation studies as well as the gaps and limitations with the application of probabilistic based techniques and the existing tools.

Most of the existing programs can be generally subdivided into the two different categories of system adequacy evaluation and system security assessment tools. Based on available information, the existing risk-based or probabilistic tools used for power system planning and operation studies are predominantly in the domain of adequacy. The majority of the existing adequacy evaluation tools were developed for generation adequacy assessment and composite generation and transmission system reliability evaluation. The fundamental approaches used in these probabilistic tools include direct analytical technique and Monte Carlo simulation method. Network solution methods adopted in the existing risked based tools include AC power flow, DC power flow and transportation models.

Although a great deal of effort has been devoted to the utilization of probabilistic techniques in power system reliability assessment, it is widely accepted that there are some limitations and gaps with the exiting tools used to conduct probabilistic reliability studies. The main areas of concern include data requirements, present industry practices, modeling issues and issues associated with electricity deregulation.

CHAPTER 4

THE NEED FOR MOVING TOWARDS PROBABILISTIC AND RISK-BASED APPROACHES FOR PLANNING, AND THE DIRECTION FOR FUTURE WORK

4.1 Introduction

With the understanding that the scope of work of CIGRE Study Committee C4 is focused on modeling, tools, techniques and methods of analyzing power system technical performance (with particular reference to dynamic and transient conditions) we need to now bring the discussions of the last two chapters into context and thus identify where the actual needs lie and where the present gaps are between the need and present tools.

The power system is a complex mixture of transmission, distribution and generation devices. Power systems around the world span over thousands of kilometers of land and in some cases are linked even thorough cables under sea. For planning and operational purposes, system operators and planners need to constantly consider potential outages of equipment and elements of the power system and allow for stable operation of the system through such events (or planned maintenance outages). There are many factors that influence both the steady-state and dynamic response of a power system. Inherently, these factors all are of a probabilistic nature, for example:

- Market forces and economics (see [1])
- The nature of a disturbance (type of fault, location of fault, duration of fault, etc.).
- The initial condition of the system prior to a disturbance (load level, load mix, generation dispatch, generation mix, power transfers over key interfaces etc.).
- The stochastic behavior of variable generation sources (e.g. wind, solar, tidal and other such energy sources) – this of course is a new phenomenon on the power systems of the world with the advent of large amounts of renewable generation coming on-line in the past decade or so.

All of the above factors have significant variations in them that vary on an hourly, daily, seasonal and yearly basis. Some can be more predictable than others. Historically, power system reliability assessment and simulation tools for such assessment (particularly for dynamic and transient behavior) have been based on deterministic criteria. This has been for the most part for ease of computation and lack of probabilistic data. It should, however, be understood that even in the context of such deterministic criteria and approaches there is an underlying appreciation for probabilistic phenomena. For example, consider the case where in current reliability assessment criteria in most countries system response to contingencies is categorized from N-1 to higher order events like N-2, with the emphasis on N-1 criteria. This inherently recognizes the fact that N-1 events are more likely. None-the-less, as presented in Chapter 2, there are significant limitations to a strict deterministic approach.

So we see the problem statement as follows:

> "How can one, with out introducing too much complexity, consider the probabilities and risks associated with power systems operations and planning in order to focus operational strategies and future investment on reaping the most reward in terms of system reliability and security improvement while minimizing the impact of the most likely disturbances? Furthermore, how should extreme events (high-risk low-probability) be considered / handled in analysis?"

In the next few subsections we present some means of approaching this problem and bridging the gap between current tools and the intended goal. The subjects that are touched on are:

- Probabilistic factors and the challenge with introducing them into operations and planning.
- Dealing with risk and probabilistic factors in addressing the analysis of cascading outages and blackouts.

- Possible approaches for introducing probabilities into planning studies related to system dynamic performance.

4.2 The Probabilistic Factors and the Challenge with Power System Operational and Planning Issues

Although certainly not complete, this is a brief list of the various sources of uncertainty in a power system:

- The constant variability of load (amount, type, characteristics)
- The probability of electrical network fault severity, type and location (can be estimated based on historic records)
- Variations in generation dispatch and stochastic behavior of variable generation sources (e.g. wind, solar, tidal etc.)
- The probability of the loss of a major generation facility or load center.
- The probability of given line outages and combination of line/transformer/generator outages for maintenance of due to failures (can be estimated based on historic records).
- Uncertainties in the control modes of major generation facilities (e.g. unit operators switching a unit from droop control to sliding pressure).
- Uncertainties in model parameters for representing system steady-state and dynamic behavior – although much of power system modeling is based on fixed parameter models (e.g. fixed generator impedances, time constants etc.), in reality many characteristics of power system components vary (at different levels) with temperature, aging and other environmental and operating conditions.
- The environment – that is, lightning, major storms and acts of nature.
- Economics and the market (this aspect is covered in [1]).

When we take the above factors into consideration, as documented in detail in Chapter 2, we are faced with the following key issues when trying to apply strictly deterministic approaches to planning:

- Variable generation like wind is energy based rather than capacity based, therefore it is not necessarily appropriate to provide N-1 reliability based on nameplate rating at peak-load.
- A further consideration is that some non-transmission alternatives, such as generation or a coordinated demand side response, may not have the same reliability as a transmission option.
- Planners can generally adapt their approach to accommodate a wide variety of special or unusual conditions but this relies on judgment as much as analysis and transmission customer and regulators are expecting greater accountability and justification for new transmission investments than ever before.

Thus, we need to augment deterministic methods with probabilistic and risk based approaches to better handle these key issues.

In the operating environment, every activity has to follow a set of rules and requirements. For example, if we consider Hydro Québec, in order to ensure adequate reliability, TransÉnergie has to respect Régie de l'Énergie decisions and NERC's rules. In the operational planning context, it is usual to see extensive dynamic simulation studies. Probabilistic and risk based view are less common. Based on real experience it is believed that there are real opportunities and there are also real challenges in applying these tools in this domain.

4.2.1 Fundamental Issues

One way to grasp the issues is to consider using a control analogy which is close to reality. Any power system network could be analyzed like a control loop with the following parts (as shown in Figure 4-1):

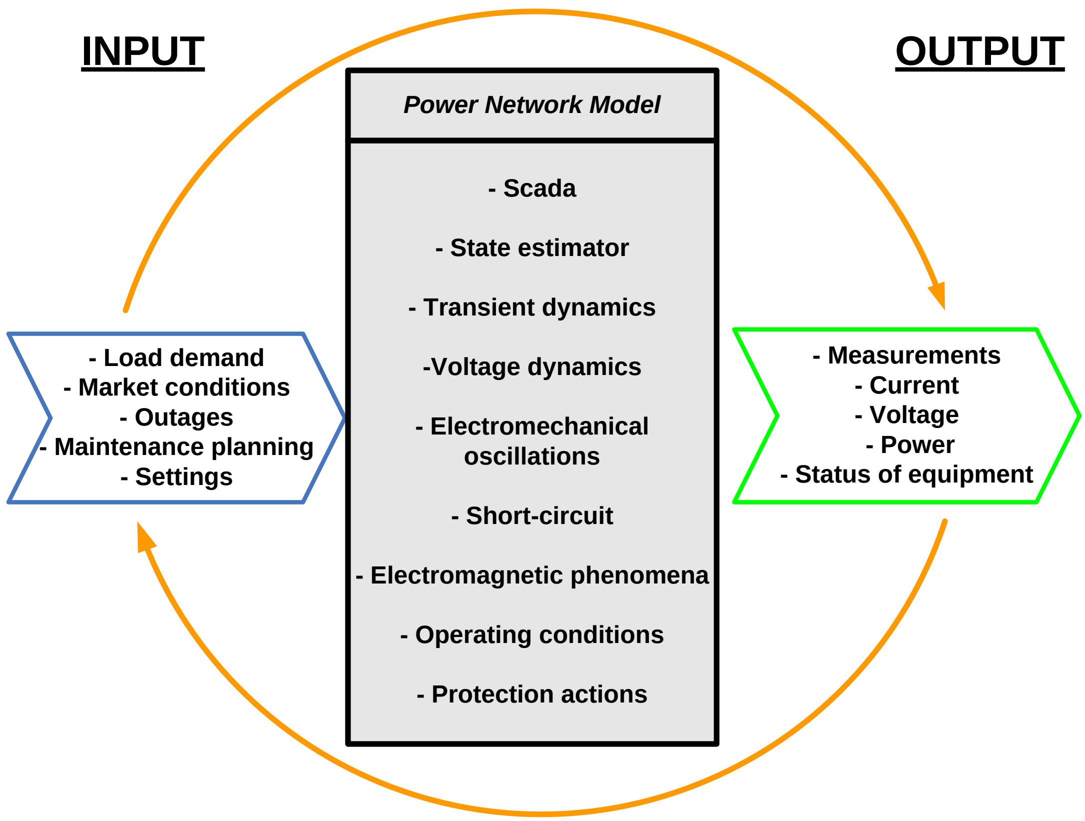


Figure 4-1: Analogy of a power system in the form of a control loop.

- (I)-Inputs: All factors which can determine the system condition like customer demand, need for maintenance, outage planning, "mother nature", etc. Some of the characteristics of these inputs are:

  a. Large degrees of freedom

  b. High variability

  c. High range of conditions and operations

  d. Fast changing condition: At any time, a sudden event can and will happen

- (M) - The model of the power network dynamics. Since it covers a large range of dynamics, the dynamics of the real power network is most often represented by a reduced model with adequate parameter and dynamic response. Some of its characteristics are:

  a. It is a model not reality

  b. Many parameters

  c. Many different types of equipment with varying representation and response

  d. Highly nonlinear

     - Complex calculation
     - Extrapolation of results not straightforward

- (O)- Outputs: Here are all observation points which are to be observed and monitored in order to respect reliability, security, demand, etc. Some of its characteristics are:

  a. It has to be measured and/or calculated

  b. Large amount of data

c. Highly interrelated

d. High fluctuations

4.2.2 Large application in operational planning

In this framework alternative fruitful application of probabilistic/risk based methods can be complementary with the deterministic methods. Some are:

- In the input, characterize its properties in term of probability and risk in order to represent its variability and high range of operation. Simple question as what to expect, when and how often could be answered (e.g. short-term load forecasting).
- In the model itself, some examples are what are its typical behaviors, how often can these occur, on which conditions/equipment/parameters do these typical characteristics most depend, what are the sensitivities and the risks to these conditions/equipment/parameters? Presently, such questions and analysis is done using mainly a deterministic approach, i.e. looking at the so-called "worst case" scenario.
- In the outputs, based only on measurements and historical data, determine how secure we are and what the risk is of different events happening.
- In the Input-Model combination: How is the model affected by different inputs (e.g. load, maintenance planning, outages) and their sensitivities and consequences on the power network.
- In the Output-Model combination: One typical question is to use measurements to determine how the model correctly represents the true dynamics (e.g. how to detect on-line, inappropriate settings of generators – see [2] for an example of on-line model validation). Thus, we may be able to capture varying dynamics.
- In the Input-Output combination : What are the correlation between input variables and output measurements, how scattered or dispersed, what can be learned
- In the Input-Model-Output combination: What are the consequences/and their risk that the power network can have unacceptable conditions and how often?

4.2.3 Challenges

In order to find application in day to day operational planning, in a repetitive way, these methods face many challenges.

- Human perspective: Users require a friendly interface, fast and pertinent results, simplicity of use and results that are not too complex to understand and manipulate.
- Extensive Data manipulation: If this approach required too much extensive data manipulation, processing, analyzing and complex operation which are beyond what is needed in the deterministic way, it would not be applied. Also the complexity of the tasks could rapidly become unacceptable for one user.
- Never 100 % sure: The method by definition tries to take account of uncertainty nevertheless in many cases operators like to know that the system is stable with certainty. It can be difficult to accept that your actual operating condition is stable with a probability of 90% or to determine the acceptable level of probability.
- Combining of dependant/independent variables: When we are faced with many independent and interrelated (dependant) events, variables, conditions, parameters, the calculation becomes quite involved. The simple picture of the tree, easy to understand by one person, is replaced with a mesh of combined trees and become like a network by itself and very complex to grasp and interpret.
- Much iteration, adjustments, processing, tunings are necessary in order to have complete and correct results. In the operational environment, the number of degrees of freedom has to be controlled and any possible bias has to be reduced and checked.

- Interpretation and translation of probabilistic results and risk analysis in terms of simple applicable rules/actions are not straightforward. In the operating environment, there are many constraints, conditions, implicit rules and processes which are difficult to model.
- It is difficult to deal with extreme or rare cases: Probabilistic approaches offer a good method for the most common cases. For extreme or very rare cases, however, the robustness of applying statistics is unknown (e.g. HILP events). There are some statistical methods available (e.g. extreme value theory) for problems with a few variables, but how these can be applied for complex systems, like power networks, is still a research topic.
- A lot of know how and expertise is required for validation and interpretation, in order to verify, analyze and interpret results.
- From a user perspective, it seems that there are many different methods available but there is little discussion of their advantages/disadvantages in terms of their application in the industry.

4.3 Analytical Methods for Vulnerability Analysis for Blackouts

Due to competitive natures of power markets, many power systems are suffering from insecure operations. The continued occurrences of large-scale blackouts in recent years, such as the Northeast blackout in North America on August 14, 2003, draw the attention of the world to the vulnerability of power systems.

The power generation, transmission, and distribution system is a critical infrastructure of our nation. Our livelihood and security depend upon the availability and quality of electrical energy. Disruptions of the power supply, such as blackouts, are one of the major threats to the well being of a nation's power systems.

Recent studies have shown that blackouts are caused by complex interactions of many factors [3, 4, 5]. For example, postmortem analysis of the 2003 August Blackout in North America-Canada [4] showed that the high-level causes of blackouts include inadequate understanding of the system, an inadequate level of situation awareness, an inadequate level of vegetation management, and an inadequate level of support from the Reliability Coordinator (RC). Thus far, researches and engineers have exerted considerable efforts in trying to understand, investigate and study the blackouts.

Reported studies showed that the probability distribution of blackouts versus size of lost load follows a power law [6, 7, 8, 9]. Other topics related to blackouts have been also investigated. Control strategies have been investigated in [10, 11, 12, 13, 14, 15], among which the islanding control strategy seems to have received the most attention. Blackout restoration is one important topic, and many research reports [16, 17, 18, 20, 21] on the rules, protection issues, simulation issues, and educational issues with regard to blackout restoration can be found in the literature. Blackout mitigation is another important topic that has been studied and some research results have been published in [22, 23, 24, 25, 26].

Vulnerability of power systems draws the attention of power engineers and researchers, which is a critical topic raised after the occurrence of 2003 August blackout. To assess the vulnerability for a given power system, blackout occurrence needs to be predicted at some extent. On the subject of the prediction of cascading blackouts very few studies have so far been conducted. A few researchers have conducted research on this issue [27, 28, 29, 30], but merely with regard to prediction of local and individual components related to blackouts. To date, the prediction of cascading blackouts is a new topic without being fully recognized.

4.3.1 Probability Properties of Cascading Failures

Power Laws in Blackout Size Distribution

Statistical analyses of North American blackout [31] show that the blackout size roughly follows an power law with a region having an exponent valued in (-1, -2) [8, 32, 33, 34, 35, 36]. Similar power law distributions of blackout size are observed in Sweden [37], New Zealand [38], Norway [39] and China [40], and these recorded data are studied in comparison by [41]. The power law implies that blackouts of all sizes can occur, and are much more likely than might be expected from the common probability distributions that have exponential tails [42].

Probability Distribution of the Time to Blackouts

Like the deterministic approaches and probabilistic approaches defined by Billinton, et al [43], two kinds of causes in the process of cascading failures are observed: deterministic causes and probabilistic causes, which work together to trigger blackouts.

Deterministic Causes

These causes are defined to be the events in the process of cascading failures that will certainly occur following a single or a series of events taking place. An obvious example of deterministic causes is the overload on certain lines due to a series outage of components.

Probabilistic Causes

Unlike the deterministic causes, probabilistic causes are defined to be the factors directly related to the actual system risk and the probabilistic or stochastic nature of system behavior and component failures. For example, Phadke, et al [44] stated that the failure of protective relays on its neighboring lines of the failed one may cause more lines to trip.

Based on the above two causes, the authors in [45] model the blackout triggers as occurring independently at constant rates so that the time between triggers has an exponential distribution. The probability of the trigger causing a further cascade is determined by considering events such as generation-load imbalance, voltage instability, frequency instability, branch overloads, and hidden failures. It then follows that the time to blackouts is a mixture of gamma distributions. Details of the derivation can be found in [45].

To be more specific, let $\boldsymbol{X_i}^{\boldsymbol{b}}$ be a Gamma random variable with shape parameter $\boldsymbol{k_i}$ and scale parameter $\theta_{\boldsymbol{i}}$; let $\boldsymbol{X}^{\boldsymbol{b}}$ be the life of the system that takes the value $\boldsymbol{X_i}^{\boldsymbol{b}}$ with probabilities $\boldsymbol{p_i}$, $1 \le \boldsymbol{i} \le \boldsymbol{I}_0$, where $\boldsymbol{I}_0$ is the maximal times of failure events before the occurrence of the blackout. The mixture of probabilities $\boldsymbol{p_i}$ satisfies $\sum_{\boldsymbol{i}=1}^{\boldsymbol{I}_0} \boldsymbol{p_i} = 1$. The distribution function of $\boldsymbol{X}^{\boldsymbol{b}}$ is given by

$$\boldsymbol{P}(\boldsymbol{X}^{\boldsymbol{b}} \le \boldsymbol{x}) = \sum_{\boldsymbol{i}=1}^{\boldsymbol{I}_0} \boldsymbol{p_i} \boldsymbol{P}(\boldsymbol{X_i}^{\boldsymbol{b}} \le \boldsymbol{x}), \tag{1}$$

and its density is

$$\boldsymbol{f}(\boldsymbol{x}) = \sum_{\boldsymbol{i}=1}^{\boldsymbol{I}_0} \boldsymbol{p_i} \boldsymbol{f}_{\boldsymbol{k_i},\theta_{\boldsymbol{i}}}(\boldsymbol{x}), \quad \boldsymbol{x} \ge 0. \tag{2}$$

From the NERC blackout data, Carreras et al. [8] and Chen et al. [33] observed that the distribution of times between blackouts has an exponential tail, which provide the evidence for theorems derived in [45]. In [36], the number of blackouts in a given time frame is fitted to a negative binomial distribution. [37] analyzes Swedish blackout data and fits the blackout times by a Poisson process.

Combination of Distributions of Blackout Size and the Time to Blackouts

To describe the statistic feature of power system blackouts in a more accurate extent, we need to consider together the probability distribution of blackout size and the probability distribution of the time to blackouts. By doing so, we could obtain a probability distribution of blackouts in three dimension space. For a specific time, the distribution follows the power law distribution; for a specific load level, the distribution follows the mixture of gamma distribution.

4.3.2 Applications of Probability Properties of Blackouts

Power system operators always wish to have an accurate assessment of system vulnerability, so that appropriate actions or measures can be taken to avoid the occurrence of blackouts in power systems. However, vulnerability assessment involves a lot of factors including system operating status, system potential weakness, system weakness in statistic perspective, component failure with high probability, system disaster with low probability, etc.

Prediction of power system blackouts is a new topic without being fully recognized. Generally to predict the occurrence of blackouts is a hard work, because it involves a large number of factors. Prediction of power system blackouts can be categorized into two groups: short-term (real-time) and long term (off-line). Short-term prediction deals with the occurrence of a single blackout, while long-term prediction copes with general cases or cases more in statistics features.

A natural question related to long-term prediction may be asked: is it possible to predict the occurrence of blackouts in a large time frame for a given power system? In statistics, this question can be answered: it is possible to predict the occurrence of blackouts if we know the probability distribution of blackouts.

Therefore, the probability distributions of blackouts are very important for the study of blackout prediction. Even though initial results about the probability distributions of blackouts have been obtained, accurate and more detailed probability properties of blackouts need further investigation.

4.4 Existing Techniques for Modeling Cascading Failures and Wide-Area Blackouts

4.4.1 Short Description of Selected Techniques

In recent years, considerable effort has been made to develop novel probabilistic approaches for explicitly modeling cascading failures leading to wide area blackouts. This section provides a short and exemplary introduction of a number of such approaches. A more comprehensive list of current techniques is given in [46].

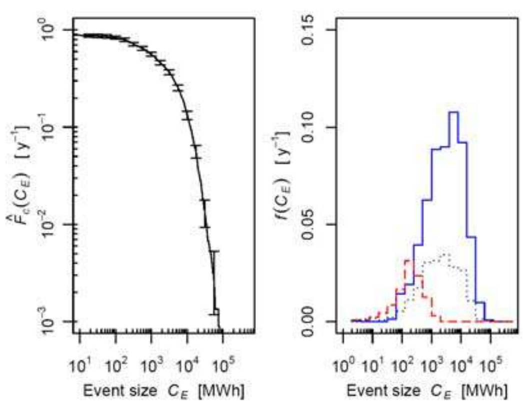
Mili et al. [47] as well as Chen and Thorp [48] highlight the necessity to consider the impact of undetected (or hidden) line protection system failures on the cascading stage of a blackout. In [47] an event tree based method is presented to assess the conditional steady-state probability of successive line outages due to hidden protection relay failures and overloads given a triggering event (i.e. a three phase short-circuit). The approach includes a fast screening method based on a continuation power flow algorithm to identify weak links in the network, the tripping of which lead to the highest probabilities of a widespread system failure due to voltage collapse. In [48] a similar algorithm based on the DC power flow model and a linear programming power re-dispatch is used to simulate cascading events due to line protection misoperations. Additionally, the influence of different load levels on the blackout probabilities is studied, whereby a critical point could be identified, at which the probability sharply increases. An integrated reliability index is proposed incorporating the whole spectrum of fluctuating load levels. Both simulation approaches ([47] and [48]) make use of an earlier work by Thorp et. al. [49] who applied the technique of “importance sampling” to overcome the computational problem of calculating the low probabilities of cascading disturbances in terms of the individual hidden protection relay failure probabilities. Both Rios et al. [50] and Ni et al. [51] presented an analogous power flow based algorithm to simulate blackouts due to cascading line overloads. In each case divergence of the power flow solution was taken as an indicator for voltage stability problems making load shedding necessary [50] or leading to an assumed system collapse [51]. In [50] cascading line tripping is modeled by including the probability of an operator intervention and initiating disturbance events are derived by combining Monte Carlo simulation with simplified modeling approaches for protection system failures and loss of generator synchronism. Makarov and Hardiman [52] developed a simplified algorithm for the simulation of cascading failures in large networks, whereby the sequences are started by a predefined set of initiating events triggering protection control groups. These events are ranked according to their probability, which is estimated by expert-judging, and their severity, which is calculated by using a heuristic formula based on the results of the cascading algorithm. The methodology proved to be useful for the identification of contingencies and served as a base for decision-making in transmission planning. Anghel et al. [53] introduce a time-dependent probabilistic approach incorporating a model for the utility response to line overloads, neglecting the influence of the response time on the occurrence of cascading line outages.

Other approaches try to overcome the problem of the immense computational expenses which are necessary to simulate cascading failures due to dynamic transients. DeMarco [54] developed a Hamiltonian like system of differential equations to represent the nonlinear dynamics of an R-L-C network model, whereby the discrete nature of an element failure is included by an approximating smoothed function. Based on these state-space equations, a single global Lyapunov (energy) function is constructed which in a deterministic manner allows a computationally more efficient identification of component failures along a time domain state trajectory. Parrilo et al. [55] applied the Karhunen-Loève decomposition and Galerkin projection technique to derive reduced order models approximating the dynamic network behavior, what significantly diminished the simulation expenses.

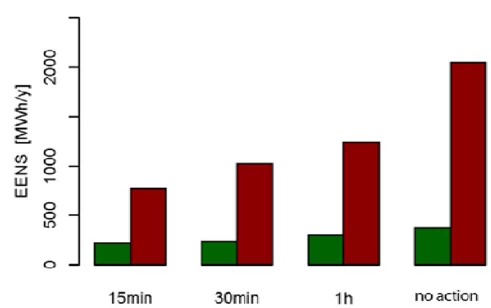
4.4.2 Object-Oriented Modeling

The vast majority of current approaches derive the cascading failure propagation by modeling the physical system response in a highly simplified manner, with limited stochastic parameters such as the behavior of protection systems. Many "hard-to-predict", yet decisive factors such as more sophisticated, time-dependent operator actions are neglected, as the incorporation of such complex interplays would lead to overwhelmingly complicated algorithms.

The issue of the operator behavior has been addressed by Schläpfer et al. [56], introducing an object-oriented modeling approach which allows the explicit integration of highly nonlinear, time-dependent effects and non-technical factors into a probabilistic reliability assessment. Thereby, the emergent behavior of the system results from the interactions of the individual components which make up the system. This allows calculating expected frequencies of power outages versus their size, representing the reliability of the system in a differentiated yet user-friendly way. Various simulation studies performed on both a virtual test system and on a model of the Swiss high-voltage grid confirm the suitability and feasibility of the developed approach (see Figure 4-2). The results of the new proposed method were compared with the outcome of classical (N-1) contingency analysis. A good match between both results was observed. Both approaches have identified the same weak structural regions of the transmission system.



a) Left: Cumulative blackout frequencies within the Swiss power system. The y-coordinates, $\hat{\boldsymbol{F}}_c(\boldsymbol{C}_E)$, indicate the number of expected events per year being larger than size C_E. Right: histogram indicating the distribution of the outages due to generation inadequacy (solid line), system splitting (dotted line) and intentional load shedding for line overload removal (dashed line) [56].



b) Influence of the operator response time after the occurrence of a line overload on the expected energy not supplied per year (EENS) for the test system. The right (dark-red) bar results from an increase of the system loading to 120% [56].

Figure 4-2: Blackout statistics.

4.4.3 Complex System Approaches

A number of approaches take a very global view to describe and analyze the overall performance of the electric power system with respect to wide-spreading blackouts. Most of them make use of recent advancements in complex system sciences and are still very academic. However, such approaches seem to gain momentum and eventually may provide useful qualitative inputs.

Plotting the cumulative frequency of past blackout incidents versus their size shows that the distribution of larger events decreases as a power function of the size (see also section 4.3). There are several theories trying to explain this pervasiveness of power laws in a wide variety of complex systems. Self-organized criticality is among the most popular ones, also with respect to cascading power failures. Self-organized criticality (SOC) means that a system evolves in such a manner that it always operates at conditions close to a critical point, where already a small perturbation may lead to abrupt and significant disruptions [57]. Thereby, large and small blackouts are coupled in such a way that measures to avoid small events such as the upgrading of a few transmission lines may even lead to an increased frequency of large wide-spreading events [58]. Based on these observations several models have been developed to describe such global system characteristics. Dobson et al. [59] used a simple algorithm of loading-dependent cascading failures without considering the specific physical characteristics of the power system and identified a critical loading at which the distribution function became subject to a power law corresponding to the real life blackout statistics. Loadings above this critical point led to a significantly higher risk of all components failing. Carreras et al. [60] used a DC power flow and optimal generation dispatch algorithm to simulate cascading line overloads. Similarly to [59] phase transitions at critical demand levels are found indicating an erratic increase of the probability of the amount of shed power, whose distribution becomes describable by the power law.

4.4.4 Summary

Market liberalization and the integration of distributed generation are leading to increasingly hard-to-predict interactions of technical components, relevant actors and the operating environment. This evolution, in turn, has triggered a significant research activity for the development of novel risk assessment approaches, being able to cope with the unprecedented operational complexity. This section has provided a short overview of such approaches for modeling cascading failures and assessing the risk of large-area blackouts. An emphasis is set on the object-oriented modeling approach, which enables system operators to assess contingencies beyond the classical (N-1) planning approach by considering additional complex impacts such as for example various operator response times.

4.5 A Probabilistic Approach to Power System Operation

The introduction of probabilistic approaches in power system operation is a significant challenge for researchers in modern power systems [61]-[73], also in the Italian context. Nowadays the operation of Italian HV transmission grid is performed by using deterministic criteria according to UCTE rules. A new probabilistic approach has been developed from the collaboration of ERSE (formerly CESI RICERCA), Milan, and the University of Genoa, Italy [74] and [75]. The following sub-sections briefly describe the salient features of such an approach, as well as some application results on the Italian transmission system models.

4.5.1 The PRA approach

The proposed approach aims at supporting operators to answer a key question, i.e.: what is the probability that a set of lines will trip in the near future? In fact the outage of several lines within a grid bottleneck would mean the system is exposed to cascade tripping and possibly to blackouts. Accordingly, risk indices have been defined as the probability distributions of tripping of given set of lines – in particular, transmission corridors – in their evolution with time. These indices are deemed representative of system robustness with respect to cascading outages.

Line tripping is considered due to the effect of exogenous and endogenous contingencies (initiating events) and the first stage of consequent cascading events ("quasi-immediate risk" evaluation). The latter are due to short circuit caused by increased line sag or, possibly, by overcurrent protection. Limiting the analysis to the first stage of the cause-effect sequence avoids simulation of the full cascading process, and implies that the time window for risk evaluation can be limited to 10-15 minutes. In fact, overload tripping typically occurs within such a delay from the initiating events and such an interval is generally sufficient to implement countermeasures aimed to enhance security.

Probabilistic models are defined for both initiating and consequent events. Concerning the latter, uncertainties regard either the overall system parameters needed to predict line flashover conditions, or the behavior of the overcurrent protections (e.g. due to protection settings, or errors in the measurement chain).

The methodology performs a "dynamic" risk assessment because the risk index is expressed by a time probability distribution of tripping of a given set of lines. Each initiating event may occur at any time within the analyzed window, thus affecting the probability density of overcurrent tripping of the remaining lines.

Contingencies are considered over an adequate neighborhood of the analyzed corridors. Thus it is convenient to define two kinds of line subsets:

- "Relevant" sets S_i, consisting of the lines possibly affected by initiating events. These are the network portions around, and generally including, the critical corridors;
- "Critical" sets C_j, representing the critical corridors for which the risk indices are calculated.

Relevant and critical sets are defined by operators based on previous network analyses and experience.

To formalize the methodology, the "tripping of a line" is identified as a random event [76] associated with its instant of occurrence and cause:

t_i : "time instant of tripping of line ***i*** due to any cause (i.e. initiating contingency or overload)"

t_{γ_i} : "time instant of tripping of line ***i*** due to initiating contingency"

t_{σ_i} : "time instant of tripping of line ***i*** due to overload"

Accordingly, the probability that line ***i*** will trip within time ***t,*** i.e. the ***cumulative distribution function*** (CDF) of t_i, is $p(t_i \le t) \equiv F_{t_i}(t)$, and its associated ***probability density function*** (PDF) is $f_i(t) = dF_{t_i}(t)/dt$. Similar expressions can be written for t_{γ_i} and t_{σ_i} , leading to the definition of $F_{t_{\gamma_i}}(t)$ and $F_{t_{\sigma_i}}(t)$.

Because of the "quasi-immediate risk" assumption, tripping can occur only as a result of contingency (initiating) events or first-stage consequent overload events. Therefore, tripping probability of line ***i*** can be expressed as:

$$p(t_i \le t) = p(t_{\gamma_i} \le t) + p(t_{\gamma_i} > t)p(t_{\sigma_i} \le t \mid t_{\gamma_i} > t) = F_{t_{\gamma_i}}(t) + (1 - F_{t_{\gamma_i}}(t))F_{t_{\sigma_i}}(t \mid t_{\gamma_i} > t) \qquad (3)$$

where the sign "|" indicates conditioned probability. The term $F_{t_{\sigma_i}}(t \mid t_{\gamma_i} > t)$ represents the probability that line ***i*** trips for overload within ***t***, under the condition that no initiating contingency has affected the line up to ***t***. To evaluate this contribution a ***contingency list*** **F** consisting of initiating events occurring within time ***t*** is defined. The probability of overload tripping is then obtained by summing all the contingency list contributions. As line tripping (due to both initiating contingencies and subsequent overload) can occur at any instant in between [t_0, t], an integral formulation is applied, relying on the probabilistic models of initiating contingencies and subsequent overload tripping. The latter consists of two parts: (1) the line sag model or, respectively, the characteristic of the overcurrent protection [77]; and (2) a stochastic model accounting for the uncertainties associated to previous phenomena. The line current at the different stages of contingency development is evaluated by load flow computation.

Equation (3) can be generalized to evaluate the probability of tripping of at least a specific set of ***x*** lines (i.e. 1, 2, …, ***x***):

$$p(t_1 \le t, t_2 \le t, \ldots, t_x \le t) =$$
$$= p(t_1 \le t) \cdot \prod_{k=2}^{x} \left[F_{t_{\gamma_k}}(t \mid t_{k-1} \le t, \ldots, t_1 \le t) + \left(1 - F_{t_{\gamma_k}}(t \mid t_{k-1} \le t, \ldots, t_1 \le t)\right) F_{t_{\sigma_k}}(t \mid t_{\gamma_k} > t, t_{k-1} \le t, \ldots, t_1 \le t) \right] \tag{4}$$

where the conditions $t_{k-1} \le t, \ldots, t_1 \le t$ refer to the tripping of lines ***k-1, …, l***, and the condition $t_{\gamma_k} > t$ refers to "not tripping" of line k within time t.

The methodology can be extended to provide also the probability of tripping of ***any*** set of x lines from a given network portion, e.g. a critical corridor. Further, other indices can be defined as the tripping probability of ***at least***, ***exactly***, or ***at most x*** lines of a corridor consisting of n lines. To this aim combinatorial analysis is applied to the probability of network configurations, i.e. the probability that some lines trip and some others do not.

In order to evaluate the term $p(t_{\gamma_i} \le t)$ in eq. (3), a probabilistic model of initiating contingencies due to exogenous phenomena has been developed on the basis of historical data series concerning electrical faults and meteorological phenomena in Italy. In the hypotheses of:

- mutual exclusiveness of initiating ***Exogenous Causes*** EC_j (mainly slow varying weather phenomena such as ***lightning***, ***snow and ice***, ***wind***, …) in the time window of risk evaluation
- statistical independence of events for a given exogenous cause

$p(t_{\gamma_i} \le t)$ can be expressed as a combination of the probability of occurrence of initiating contingencies conditioned by the considered exogenous causes. Since the occurrence of contingencies can be modeled as a Poisson process with a fault rate $\beta_i(t)$ which can be considered constant within a time window of 10-15 min (quasi-static line fault rate), the probability distribution and probability density of line failures due to initiating events take on exponential forms, with $t \ge t_0$ (being t_0 the current time) [76]:

$$p(t_{\gamma_i} \le t) = 1 - e^{-\beta_i (t - t_0)} \qquad f_{t_{\gamma_i}}(t) = \beta_i e^{-\beta_i (t - t_0)} \tag{5}$$

The model has been validated by considering the correlations between electrical and meteorological data.

4.5.2 Application examples

Some results are shown hereafter, drawn from the application of the tool to power flow models of the Italian EHV power system. The average fault rates λ of independent line tripping have been set to $2.85 \cdot 10^{-10}$ and $3.51 \cdot 10^{-10}$ faults/(km·s) for 400 kV and 220 kV lines respectively, i.e. the maximum average values resulting from the statistical analyses. The peak fault rate values are obtained by multiplying the average rates by 25 (KF = 25). Overload tripping is modeled by overcurrent protection model with low variance (quasi-deterministic behavior).

Figure 4-3 shows the probability distribution and probability density of having two specific lines tripped within time t. When dealing with very small quantities such as tripping probability it is useful to speak in terms of their logarithm not only for visualization, but also as a way to refer to them [78]. Additionally, criteria can be defined to trigger alarms, based on the order of magnitude of the probability or of the probability density: if a threshold is exceeded, it means the probability distribution is increasing too rapidly. The density-based criterion can be combined with the distribution-based criterion for more refined alarms. The alarm is associated to increasingly stressed situations, calling for countermeasures such as redispatching.

Actual criticality also depends on the time at which thresholds are violated: a high risk situation foreseen at the end of the time window allows more time for control actions. The alarm logic could account for this in issuing warnings.

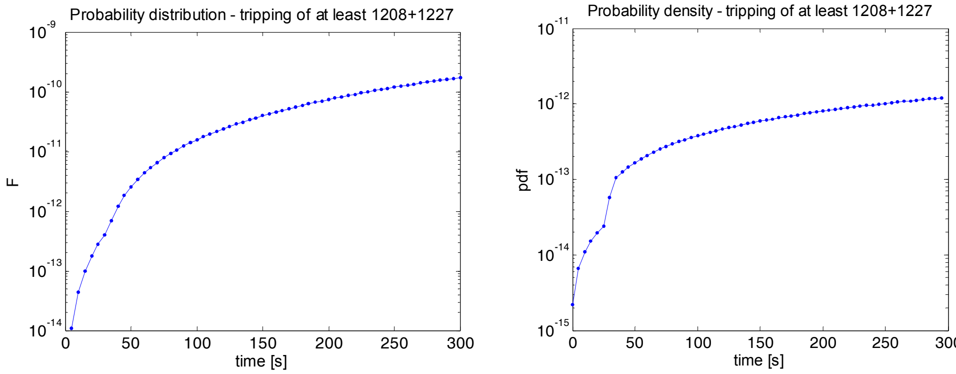


Figure 4-3: Probability distribution and density of the tripping of at least two specific lines.

Another important issue, to foresee possible cascading scenarios, is to evaluate the probability of tripping of at least x generic lines belonging to the critical set.

The analysis of the CDF curves and of the PDF curves for three values of x (x=1,2 and 3) and for different grid scenarios shows that the higher x the higher the impact of the increase of the fault rates on the probability of tripping. Table 4-1 is useful to clarify the previous statement. It reports the values of CDF at t=300s for the two values of KF and for the three values of x. The round brackets indicate how much the probabilities of tripping of at least 2 or 3 lines are lower than the probability of tripping of at least one line.

Table 4-1: Comparison of the tripping probability of at least x lines of set C in case of different KF values.

Case D	***KF=1***	***KF=25***
x=1	1.54×10^{-5} (1)	3.81×10^{-4} (1)
x=2	6.08×10^{-9} (~1/2500)	3.79×10^{-6} (1/100)
x=3	8.12×10^{-15} (~ 1/(2 billion))	1.27×10^{-10} (~ 1/ (3 million))

Thus, if the fault rate increases, very improbable events (like the tripping of at least 2 or 3 generic lines of the critical set) become more probable with respect to the reference case (the tripping of at least 1 line of the section). The case for x=3 is emblematic: if the fault rate increases by a factor equal to 25, the ratio between the probability of tripping of at least 3 generic lines of a critical section (a typical cascading scenario) and the tripping of at least 1 generic line of the section passes from $1 / (2 \times 10^9)$ to $1 / (3 \times 10^6)$.

4.5.3 Conclusions

Probabilistic approaches to evaluate security are increasingly needed not only in planning but also in operation. The proposed methodology evaluates technical risk indices aimed at power system operation support. The indices are defined as the probability of tripping of sets of lines, such as critical corridors, considering initiating contingencies and the first stage of consequent overload tripping. The methodology provides an insight into the early phases of cascading phenomena and allows evaluating the impact of different weather conditions on possible cascading scenarios. Statistical analyses on historical data series allowed the validation of a probabilistic model of weather-related initiating contingencies.

Obtained results show that risk indices present significant dynamics within the time horizon of analysis, which may allow defining specific warning criteria considering the indices time evolution.

With the final aim of evaluating cascading risk, interesting developments regard the enhancement of the probabilistic model in order to directly relate weather with failure rate, the introduction of dependent contingency model (common cause failure, like busbar faults or the loss of double circuit transmission lines), and more comprehensive evaluation of N-k contingencies impact by in-depth analysis of cascading events.

4.6 Addressing High-Impact Low-Probability Events

Throughout this document HILP events have been mentioned in the following context:

- The discussion of deterministic planning, especially in connection with the NERC requirement to evaluate a few extreme scenarios.
- The discussion of probabilistic planning, where issues of economics and adequate data were introduced.
- The discussion of operational issues, especially in connection with recent NERC efforts related to probability and the load-generation balancing problem.
- The discussion of risk, where it was observed that the issue of how to deal with the various risks is very challenging in the context of HILP events.

The issues (both planning and operational) associated with HILP events include:

- The dilemma of designing or operating the system to avoid high impact events, even though the event probability is low. Clear criteria for doing so are generally lacking.
- The benefits of system improvements may be difficult to quantify, especially for HILP events.
- The probabilistic and economic approach requires clear understanding of the underlying assumptions supporting these models.
- These events usually include multiple element loss, and these multi-element losses may not be independent, as is often assumed.
- Software may not be available to support the assessment of HILP event risks and consequences.
- The lack of useful data on HILP events.
- Because these events usually involve multiple element loss, the calculated probability of the HILP event becomes vanishingly small. Thus, the average annual economic impact is small, significantly restricting the investment that can be made to address such an event.
- It is not clear whether these events should be treated as probabilistic or deterministic, or a combination of both.
- The current approaches used may be inadequate, particularly when the many aspects of risk are considered.

Thus we see that HILP events should be considered in both planning and operational studies. There are several significant issues yet to be resolved including methods (numerous), data, and software adequacy. Some recent work is addressing these issues, but many are restricted to load flow or dc networks. Ultimately, methods, data and software taking into account the dynamic and non-linear aspects of the power system will be needed.

Blackouts have also been discussed in some detail in this chapter. Blackouts are certainly examples of HILP events, although a blackout is not always a result of a HILP event (see, for example [79]). Blackouts clearly illustrate these types of events occur, and provide an indication of the potential costs associated with these events. They also illustrate the loss of multi-element events occur much more often than one would expect assuming all events are independent. As suggested above, much development work is needed before HILP events can be adequately analyzed. Once sufficient knowledge of these events becomes available, the logical next steps would be developing tools to appropriately analyze a power system for HILP events, and addressing the issue in planning and operational requirements.

4.7 Potential Ways of Augmenting Existing Dynamic Simulation Methods for Approaching Probabilistic Analysis

Power system planners and operators routinely perform steady-state (power flow) analysis and time-domain dynamic simulations, for assessing stability and reliability of the power system. Time-domain dynamic simulations, in particular, are essentially performed in a deterministic way (see discussion in Case 5, Appendix A). That is, specific fixed parameters for all the various system dynamic components are used and specific events are simulated with an exact sequence of events. However, as discussed and illustrated in previous chapters all models are an approximation to the actual system and thus there are significant uncertainties in the various parameters that determine the state of the power system. Thus, the goal of system analysis is to take into account the nature of the phenomena under study with modeling techniques that acknowledge and minimize the impact of such unmodeled effects and uncertainties. Probabilistic methods are one approach to address such uncertainties. Also, as discussed in Chapter 2 although there are some established and commercial tools for applying probabilistic type analysis to power flow simulations, there are no such established commercial tools and techniques for dynamic simulations.

There has been significant research done related to the application of probabilistic techniques to dynamic simulations for system stability assessment. One such effort is reference [80]. Most of the original research in this regard investigated two potential approaches: (1) a direct transformation of random variables such that the entire process of stability analysis is performed stochastically or (2) methods such as Monte Carlo simulation, which is a well established method [80]. The advantage of direct transformation methods is that they are more mathematically rigorous. However, such methods are very complex and applying such a method to exceedingly large non-linear systems such as a power system is an insurmountable problem.

Monte Carlo methods generally use an approach as follows:

1. First one defines the range of possible values/variations for the event/system being studied.
2. Then one generates randomly within this range a large number of cases using a selected probability distribution (e.g. Gaussian).
3. Then we perform deterministic simulations for each set of randomly generated cases.
4. Finally we aggregate the results of all the simulations to come up with our final result.

The disadvantage of this approach for power system simulations is the tremendously large number of cases that will have to be generated due to the large number of variables in a power system model.

Some applications of such approaches are:

- Dynamic security studies using many grid situations. The idea is to determine the ‘operating space of the system’, and the likelihood of an outcome rather than a single result obtained from a deterministic approach.
- Distance-relay verification and the associated risk quantification. In order to check the performance of the protection strategy, short-circuits in different geographical points (that respect a probabilistic distribution) on a given transmission line or on all the system transmission lines could be simulated. The results show if the faults are observed by the right protection (see Appendix A, Case 7 for an example of applying probabilistic analysis for special protection system evaluation).
- Risk quantification in terms of critical clearing time. The critical clearing time is computed in case of short-circuits on all transmission lines. The obtained values are compared with the accepted limit. The generation dispatch and the lines availability vary according to some probabilistic laws. This kind of analysis allows detecting the operating schemes that are not appropriate to the grid topology.

- Risk quantification in terms of load shedding in case of frequency drops. Frequency relays are tuned in the interval [$f_{threshold}$ -ε; $f_{threshold}$+ε] around the rated frequency threshold. Probabilistic analyses allow quantifying better the impact of the threshold on the system security.

One method of reducing the computation burden associated with Monte Carlo type methods is to use trajectory sensitivity methods [81, 82, 83, 84, 85].

Trajectory sensitivities can be used to form approximate trajectories of a simulation for parameter sets that are perturbations from the nominal parameter values. The influence of parameter uncertainty can then be expressed as a bound around the nominal trajectory (see Figure 4-4).

It should be noted that some parameters can occasionally be ill-conditioning (non¬identifiability). There are two causes for such ill-conditioning:

1. the parameter has negligible influence on system behavior – in which case we are actually not particularly interested in parameter sensitivity since it has no significant influence on system behavior, or

2. the influences exerted by various parameters are closely coupled – this second situation, where parameters are influential yet they cannot be estimated can be troubling.

Trajectory sensitivities provide a numerically tractable approach to assessing the impact of uncertainty in parameters. Such sensitivities describe the variation in the trajectory resulting from perturbations in parameters. Small sensitivities indicate that uncertainty in the respective parameters has negligible impact on behavior. Large sensitivities, on the other hand, suggest that the respective parameters exert a measurable influence on behavior. It is important to minimize the uncertainty in the latter group of parameters. This can be achieved by estimating parameter values from measurements of system disturbances. The parameter estimation process seeks to minimize the difference between measured behavior and simulated response. This difference can be formulated as a nonlinear least squares problem, with the solution obtained via a Gauss-Newton process. Trajectory sensitivities provide the gradient information that underlies that process (see [2] for an example of parameter estimation/model validation for power plant equipment using non-linear least squares applied to on-line disturbance data; see also [86] for an example of using trajectory sensitivity to indentify influential parameters based on disturbance data)

The impact of uncertain parameters is generally not significant for unstressed conditions of the power system. As the stability margin reduces the system behavior becomes much more sensitive to parameter perturbations. It is particularly important to consider cases that are on the verge of protection operation.

An example, based on the IEEE 39 bus system, can be used to illustrate this process [81]. Parameters describing the load composition were assumed to satisfy a uniform distribution over a range of ±0.2 around their nominal values. Zone 3 protection on one of the major lines was considered, with Figure 4-4 showing the separation between the zone 3 mho characteristic and the apparent impedance seen by the relay. The dashed line in Figure 4-4 was obtained using the nominal set of load parameters. It suggests the zone 3 characteristic is not entered. The sensitivity-derived worst-case bounds on behavior are shown as solid lines, and the true (simulated) bounds are shown as dash-dot lines. The sensitivity-based predictions are very accurate over this crucial time period. Every selection of uncertain load parameters results in a trajectory that lies within the bounds shown in Figure 4-4. Notice that the lower bound passes below zero, indicating the possibility of a zone 3 trip.

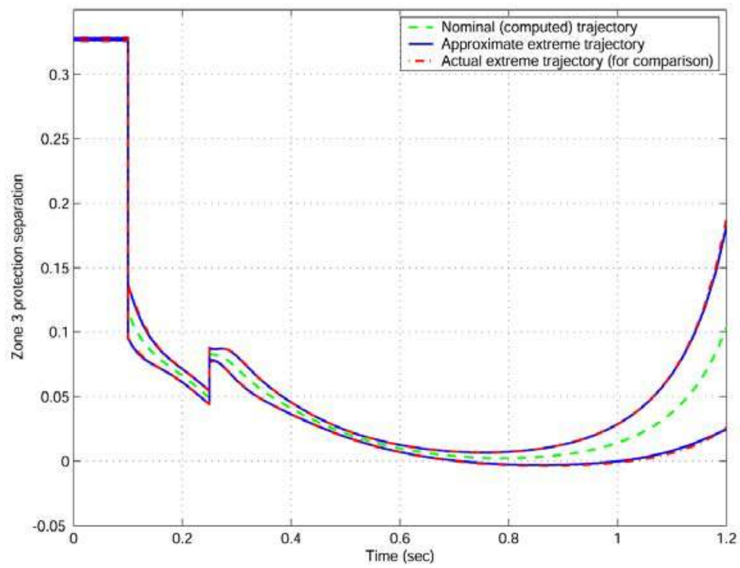


Figure 4-4: Example of trajectory sensitivity application showing Zone 3 protection operation assessment worst-case bounds for a simulated disturbance on the IEEE 39-bus test case (figure reproduced from [81]).

Alternatively a probabilistic approach can be used to assess this situation [81]. Based on Monte Carlo simulations the results of the probabilistic approach are shown in Figure 4-5. Note that if we draw boundary lines at the 95% confidence interval for the probabilistic approach in Figure 4-5, this corresponds very closely to the boundaries identified by the trajectory sensitivity method in Figure 4-4. The trajectory sensitivity approach has the clear advantage of requiring less simulation.

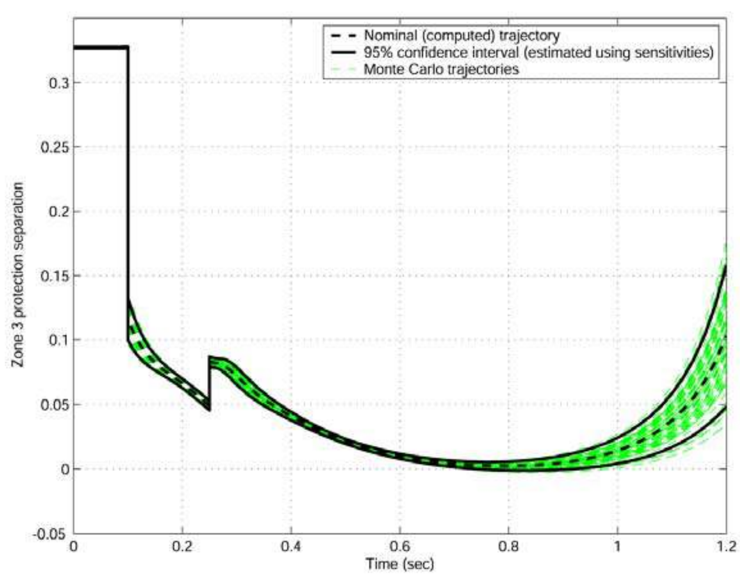


Figure 4-5: Zone 3 protection operation assessment, 95% confidence interval bounds. Results of a large number of Monte Carlo simulations, shown as dashed green lines (figure reproduced from [81]).

4.8 Determining the Gaps in Risk-Based Indices for Security and Dynamics

In the previous sections we have discussed various ways to augment deterministic simulation methods to introduce probabilistic and sensitivity methods for considering uncertainties in the model. One item that is significantly lacking in attempting to implement such methods is the availability of risk-based indices.

Probabilistic analysis has been widely accepted for generation system expansion studies for many years. In order to assess the gaps we are now experiencing in risk-based analysis of security and system dynamic performance, it may be of interest to recall the process with which reliability criteria for generation expansion were established in the industry, and compare with the present state of dynamic security studies.

Until the early 1970's most utilities were using deterministic (worst-case) criteria for determining their generation expansion planning. For reasons of comparison we can think of this deterministic approach as employing an N-1 (or N-n, n>1) type of criterion to determine the necessary generation capacity for each year or other time period of interest. Equivalently this was translated to a "constant reserve" kept to serve the maximum expected load. Similar constant reserves were (and are) also used during system operation for unit commitment and operational planning.

The main argument that proved effective against this deterministic, constant reserve approach was that all units are not identical with respect to their reliability. Older units tend to be more prone to failures and some units experience many more outages for various reasons. Luckily all generating companies always kept (and of course are still keeping) very close records of the availability of each of their units. It was thus evident to them that the above argument was indeed valid, as a reliable unit is much more valuable than an unreliable one. Also they could easily provide the data necessary (for instance the forced outage rate – FOR) to perform detailed reliability studies and compute various probabilistic indices.

Therefore the first steps towards the acceptance of probabilistic analysis were the realization of the inadequacy of deterministic criteria and the existence of data to make probabilistic (reliability) calculations. However, these are not enough. The final step was the determination of one or more probabilistic indices to be used and the determination of an acceptable threshold value to be maintained. One of the first such indices to be generally accepted was the loss of load probability (LOLP) and the "magic" value of 0.1 day per year (or one failure due to lack of generation every 10 years) was more or less universally recognized as a reasonable threshold.

Of course this is oversimplified, since there are many more indices used in reliability analysis, but the above discussion is aimed at identifying the necessary steps with which a probabilistic approach was more or less universally accepted. Focusing now on security analysis and dynamic studies we can indicate some more or less evident gaps.

1. The first problem relates to the mentality of utilities, operators and the general public towards system security that has to be radically changed in order to adapt to risk-based criteria. Somehow, the probability of a blackout (even though everyone knows that it has happened and is thus prone to happen again) is considered unthinkable. One could easily argue that the probability of unavailable capacity to meet the load is very similar to a blackout condition, however generation unavailability is easier to mitigate than a sudden loss of equipment and/or capacity that is usually the cause a serious disruption of service.

2. This leads to the second problem: what is the probability of a sudden loss of equipment due to controls misoperation, human error, short-circuits of various types? Even though there is abundance of data kept in thousands of digital relays per electric company, these are not always in the easily usable form of e.g. "generator unavailability" that can be readily translated to a probability of failure or a failure rate. Of course, for equipment such as transmission lines or transformers similar historical data to generators can be considered. However, the definition of an "event" or contingency for security analysis is quite more complex than an accumulation of simple unrelated "unavailability" events. Therefore more

complex parameters such as probability of failure due to "operation under stress" have to be introduced in order to assign a reasonable "probability" value to each multiple contingency.

3. Assuming that a probability value can be assigned to every contingency (of those already considered in the deterministic security assessment of the type already made by the System Operator) the relative impact of each contingency can be determined as in the deterministic study and weighted by the corresponding probability. Depending on the type of Security Assessment performed this could by a stable-unstable outcome, in which case an estimation of "instability probability" would result, or a quantitative measure, such as necessary load curtailment to maintain stability, thus leading to a loss of load expectation. The question is whether the one instability per decade is equally acceptable, as the 0.1 days/year LOLP value, in other words, even if we had the index how could we assign the threshold?

Following this discussion we can now come to identify the gaps that need to be bridged (at least partly) in order to introduce risk-based security analysis as a mainstream power system application. More specifically three types of gaps are clearly identified:

1. Data collection and processing needed to determine meaningful statistical modeling of various types of system failures and contingencies. Note that the type of contingencies depend on the nature of the security analysis performed, e.g. short circuit location and duration for transient stability assessment, multiple generating units and/or corridor failure for voltage security assessment, etc.

2. Computation of probabilistic indices that quantify risk of system failure. These should be both in the form of rate of occurrence of an undesirable system state (e.g. instability, or blackout per so many years) and that of minimum load curtailment per year to maintain system operation (e.g. a percentage of system load).

3. Thresholds based on these indices. This is the most difficult to determine provided all other gaps have been bridged. Is one blackout every 10 years acceptable, or should we make it every 100 years? One way to proceed around this problem is the evaluation of the cost for system reinforcement to reduce system risk. But this in itself is not an easy task.

4.9 Summary

This chapter has presented discussion on addressing high-impact low-probability events, the need for security assessment indices of a probabilistic nature for transmission planning, dynamic simulations in the context of dealing with uncertainties in the system model and modeling of blackouts and cascading events.

It is believed that we can draw the following major conclusions from the discussion here:

1. There is a need to make available more systematic ways of addressing the uncertainties in the power system model for planning and operation studies. This calls for the incorporation of risk-based and probabilistic techniques.

2. There has been significant research done into the application of risk-based and probabilistic techniques as early as the 1930's. However, these techniques have not materialized into commercial tools particularly for time-domain stability simulations. The main challenges are:

    a. As compared to deterministic tools, probabilistic tools will need a significantly larger amount of data input as well as extensive data manipulation, processing, analyzing and complex operations. This may become unacceptable for users.

    b. The complexity of dependant and independent variables. When we are faced with many independent and interrelated (dependant) events, variables, conditions, parameters, the calculation becomes quite involved and very complex.

c. The interpretation and translation of probabilistic results and risk-based analysis in terms of simple applicable rules and actions is not straightforward.

d. There is also a clear lack of risk-based indices and criteria for security assessment, particularly for dynamic system behavior.

e. Even with probabilistic methods, the difficulty remains in dealing with high-impact low-probability (i.e. extreme or rare cases) events.

These challenges need to be addressed before we can truly apply tools and techniques in the planning environment that move away from the present generally accepted deterministic tools. In this chapter we have also presented examples of some case studies. In addition, we have also presented discussion on emerging techniques such as trajectory sensitivity (see section 4.7) which can significantly help to address the issue of quantifying the effect of uncertainties in the power system model, but without the computational burden of direct probabilistic methods. Further work is needed to bring such techniques to the commercial engineering environment.

CHAPTER 5

CONCLUSIONS AND RECOMENDATIONS

This report has described important issues related to system planning: challenges, deterministic approaches, probabilistic approaches, where we are today, and the need for making probabilistic planning tools more feasible for expanded tasks. In general, the perspective has been either from the "local" transmission-distribution service provider (TDSP) level, or the independent system operator (ISO)/Regional or National Planning Authority level. In addition, it has been noted that planning studies can be short term in nature (planning horizon less than one year), termed operational studies, or longer term (many years into the future).

Table 5-1 lists many of the concerns entities may desire to address with studies, as well as many of the variables that may need to be considered. These concerns and variables were mentioned in this document. The basic topics of study type, study entity, study concerns and variables generate complex relationships. Table 5-1 shows some of these relationships. It is assumed that, in general, all levels conduct both operational and transmission studies. In this table an X indicates there is a relationship between a listed level (TDSP or ISO), planning horizon (operational or transmission) and one or more of the listed concerns or variables. For example, the first Concern listed is "balance Q supply & demand". The table indicates both TDSPs and ISOs have this concern, and this concern can be the subject of both Operational and Transmission planning studies. The relationships shown in the table are somewhat subjective, but will generally be true in most circumstances.

Table 5-1 illustrates some of the many facets of system planning. Obviously, system planning is very complex in a deterministic setting; and even more so in the usually more complex probabilistic setting. Future developments in probabilistic approaches need to ultimately include most of the items listed in the context of both level and type. In addition these future developments will need to include emerging concerns and variables.

In addressing some of the various studies and tasks shown in Table 5-1, power system planners and operators will perform various studies, and among the tools and techniques they use are power flow (steady-state) simulation studies and time-domain dynamic simulation studies. Presently, the majority of these studies are performed in a deterministic way. Certainly time-domain simulations are almost exclusively deterministic.

Commercial software tools do exist for probabilistic assessment of system adequacy based on methods such as Monte Carlo for steady-state power flow analysis (see Chapter 3). However, these tools do have some scope for improvement, namely:

- It is difficult to collect, prepare and maintain the data sets needed for such tools (i.e. reliability data, force outage rates, etc.).
- Most of the existing tools cannot fully handle HVDC systems.
- Most of the existing tools cannot properly model the energy limited nature of hydro units. In most of these programs, hydro units are treated exactly the same as thermal units.
- In most tools the generation dispatch remains unchanged while assessing the various system states, which is unrealistic.
- Some tools recognize operating limits due to thermal, voltage and stability considerations; however, the problem is that these limits are assumed to be the same under all system operating conditions.
- Interpretation of the results can be complex.
- One cannot properly model cascading or islanding events or easily address HILP events.
- One cannot properly calculate bus reliability indices.
- It is not possible, or quite difficult to model multiple states or high order failure events for those programs using enumeration technique.
- For large interconnected system reliability analyses it is preferable that the number of transmission contingencies to be assessed should be reduced to a manageable size without sacrificing the accuracy of the final results. Presently, to our knowledge, none of the existing tools have any built-in algorithm to facilitate this. This is a subject for further research.

- It is difficult to properly incorporate into the analysis substation related outages, and operating procedures, constraints and security dispatch.
- Most existing tools have limited capabilities to address market related uncertainties such as:
    - Uncertainties related to power generation location, capacity, timing and availability for proposed new conventional and un-conventional energy sources.
    - Uncertainties related to future complexity of power transactions.
    - Uncertainties in future demand.
    - Uncertainties in future regulation/rules.

By contrast there are no widely used commercially available software tools that incorporate any rigorous probabilistic, risk-based or other methods for handling modeling uncertainties for time-domain dynamic simulations. Although recently there has been significant research into the application of risk-based and probabilistic techniques (e.g. since the 1980's), these techniques have not yet found their way into commercial software tools. This is understandable, because there are many significant challenges to utilizing such techniques which include, but are not limited to:

- The need for significantly more data and extensive data manipulation, processing, analyzing and complex operation which are beyond what is needed in the deterministic methods, which can become unacceptable for users.

- Complexity of dependant and independent variables. When we are faced with many independent and interrelated (dependant) events, variables, conditions, parameters, the calculation becomes quite involved and very complex.

- The interpretation and translation of probabilistic results and risk analysis in terms of simple applicable rule/actions are not straightforward.

- There is also a clear lack of risk based indices and criteria for security assessment, particularly for dynamic system behavior.

- Even with probabilistic methods, dealing with high-impact low-probability events (i.e. extreme or rare series of events) can be difficult.

Finally in summary it can be said that further research and development are needed to facilitate the full utilization of probabilistic and risk-based techniques and tools in day-to-day planning and operational studies. Such research should focus on addressing the data needs and data management issues, allowing for simple interpretation of results and addressing the major deficiency of industry wide acceptable risk-based indices and criteria.

Table 5-1: Various aspects of operations and transmission planning[9].

Level			Planning Horizon	
TDSP	ISO	Concerns	Operational	Transmission
X	X	balance Q supply & demand	X	X
	X	transmission congestion	X	X
X	X	transfer limits	X	X
X	X	load forecasting	X	X
X	X	voltage magnitude	X	X
X	X	voltage stability	X	X
X	X	small signal stability	X	X
X	X	thermal overloads	X	X
X	X	reactive power reserve	X	X
X	X	lead time generation & transmission		X
X	X	angular (transient) stability	X	X
X	X	short term planning (1 year or less)	X	
X	X	long term planning (> 1 year)		X
	X	balance load & generation	X	
	X	frequency limits	X	
	X	real power reserve	X	
	X	efficient market		
	X	frequency control	X	X
X		coordinate transmission planning & investments among TDSP		
X	X	variable generation forecasting	X	
X	X	special protection systems	X	X
TDSP	**ISO**	**Variables**	**Operational**	**Transmission**
X	X	fault type	X	X
X	X	load (size, type, growth, diversity, weather effect)	X	X
X	X	heat demand	X	X
X	X	transmission equipment planned outages	X	
X	X	generation retiring		X
X	X	generation additions		X
X	X	changing governmental regulations & policies		X
X	X	changing technology		X
	X	dispatchable generation	X	X
	X	variable generation	X	X
	X	generator forced outages	X	X
	X	transmission equipment forced outages	X	X
	X	generation dispatch	X	X
	X	generator planned outages	X	
	X	fuel supplies (water, gas, etc.)	X	
	X	bidding behavior		
		changing economic conditions		X

[9] It is not claimed that this table is all inclusive; it is simply an attempt to illustrate the most common concerns and influential variables in studying such concerns.

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APPENDIX A – SOME SPECIFIC EXAMPLES OF PLANNING APPROACHES AROUND THE WORLD

Case 1 – San Francisco Bay Area

Country: USA

Focus: San Francisco Bay Area – Defining Grid Planning Assumptions

Liberalization: Energy and capacity market. Day ahead and balancing markets.

Generation expansion: Generators are owned by private corporations and invest when commercial. New investment arises as a result of market signals including energy and capacity prices. No central planning for generation and no disclosure regime for investment plans.

Transmission expansion: PG&E is principle Transmission Owner and can invest when approved by the regulator **-** CAISO. CAISO has planning authority and can approve new transmission investments if designated standards are met. Nationally, transmission reliability is coordinated through the North American Electric Reliability Corporation (NERC) and is regulated through Federal Energy Regulatory Commission (FERC).

Power system operation: CAISO is the independent System Operator and will dispatch 'must run' generation is required to avoid security violations.

Transmission Planning Study:

This is a brief outline of a recent study. The objective of this study was to demonstrate the appropriate reference cases for transmission grid expansion studies, taking into account the reliability of generation in the San Francisco Bays area. The study highlights the simulation and modeling tools needed to develop an understanding of the expected adequacy of generation in the area as this has a direct bearing on the need for transmission into the area.

The study was conducted in 2000 for the specific period when many aging generators in San Francisco Greater Bay Area experienced the increase in frequency and duration of forced outages. The average Forced Outage Factor (FOF) for the industry is about 3.8 %. For the Bay Area units, the average FOF was 7.6% and exceeded 30% for some units. Application of the traditional for this area "(N-1)&(G-1)" grid planning standard could result in insufficient reliability. The specific recommendations have been developed with the intention to achieve the same probabilities of undesirable events as with the ordinary equipment.

The Bay Area power supply was represented by 30 major generators, two 500 kV lines, two 230 kV lines and nine transformers, substantial for the import of power. Only forced outages of generators were considered in assumption that planned outages can be scheduled in off-peak time. The actual 5-year forced outage statistical data for the generating units was quite representative (10-40 status changes) and allowed calculations of the average and standard deviation values for time intervals of forced outages (T1) and between forced outages (T2).

Probabilities of different system states and frequencies of different events or their combinations were determined with the application of the Monte Carlo method[10]. System representation for each single hour included probabilistically defined status of generators, lines and transformers; and their peak/off-peak status for a simulated hour. The 100 year simulations were conducted for the actual T1 and T2 distributions and separately for the industry distributions, based on NERC data. The resulting values and their probability characteristics were determined following calculation and collection through the entire simulations.

[10] The @Risk 4.0 Risk Analysis tool of Palisade Corporation was used for the practical realization of the Monte Carlo simulation.

Table A-1 compares actual and NERC probabilities of simultaneous forced outages of generators. It can be seen that probabilities for three Bay Area units are comparable with probabilities for one average industry unit.

Table A-1: Probabilities of simultaneous forced outages of generators.

# of generators in forced outage	Bay Area data		NERC data	
	% of year	% of year if in peak	% of year	% of year if in peak
>=1	91	8.1	67	5.8
>=2	68	6.2	28	2.4
>=3	40	3.7	8.3	0.72
>=4	17	1.6	1.59	0.15
>=5	6	0.6	0.22	0.03

Table A-2 shows that the compliance with the criterion "(N-1)&(G-1)" for the maximum size generator (750 MW) allows one occurrence of limit violations in 20-25 years. Considering that the goal is to provide the same reliability level as with average industry generators, this frequency should be reduced to one occurrence in 45-50 years. This leads to considering about 900 MW instead of 750 MW or to the criterion "(N-1)&(G-1x750-1x150)", where (g-1x750-1x150) means simultaneous forced outages of a maximum size generator and one more generator about 150-200 MW.

Table A-2: Probabilities, durations and frequencies of peak hour outages of lines or transformers during forced outages of different MWs of generating capacity.

Unavailable MW in forced outage	Bay Area data			NERC data		
	% of year	hrs/year	occurrences/year	% of year	hrs/year	occurrences/year
>=100	0.0157	1.37	0.2 (once in 5 years)	0.00913	0.8	0.104 (once in 9.5 years)
>=300	0.0110	0.96	0.144 (once in 7 years)	0.00548	0.48	0.057 (once in 17.5 years)
>=500	0.0071	0.62	0.092 (once in 11 years)	0.00320	0.28	0.029 (once in 34.5 years)
>=700	0.0056	0.49	0.051 (once in 20 years)	0.00274	0.24	0.024 (once in 41 years)
>=900	0.0033	0.29	0.021 (once in 48 years)	0.00057	0.05	0.008 (once in 125 years)

These results were used as a foundation of the temporary California ISO Planning Standards for Greater Bay Area (http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf), defining combination of units, which should be removed from a base case before conducting Grid Planning studies.

Case 2 – ERCOT System

Country: USA

Focus: ERCOT

Liberalization: Energy and capacity market. Day ahead and balancing markets. ERCOT is a non-government corporation that is responsible for operating the market and approving new transmission investment. The Texas Public Utility Commission performs an oversight function relative to ERCOT.

Oncor is a regulated lines business with no ownership or control of generation.

Generation expansion: Generators are owned by private corporations and invest when commercial. New investment arises as a result of market signals including energy and capacity prices. No central planning for generation and no disclosure regime for investment plans. In ERCOT, generation owners are free to place new generation wherever they may choose, subject to certain non-market realities such as governmental air and water quality permits.

Transmission expansion: Oncor, as a transmission provider, is required to connect these generation resources to the grid. There is a process that must be followed that includes transmission studies, securitization for monies to be expended by the transmission owner to build facilities to connect the generator, and connection contracts that specify, among other things, each parties responsibilities. There is no queue, or first in – first out process in ERCOT. Generation resources can generally be connected to the system as soon as they are ready to operate. Note, however, that connection to the grid does not always mean full plant output to the grid is possible at all times.

Power system operation: The Electric Reliability Council of Texas (ERCOT) operates the electric grid and manages the deregulated market for 75 percent of the state (www.ercot.com).

Transmission Planning Issues:

The issues identified in this report relate to uncertainty in:

- Which (of many possible) generation projects will be committed;
- Which existing generators will be de-commissioned (or mothballed) at short notice;
- How to align transmission line investments (3-5 years) with generation investments; and
- How to deal with the potentially wide range of load characteristics in dynamic studies used for transmission planning purposes.

The above brief description suggests a straight forward and friendly environment for generation owners to connect their equipment to the transmission system in ERCOT. Similarly, transmission planning should be a fairly straight forward process. However, certain realities add great uncertainty to the planning process. Virtually every generation developer that comes to the initial interconnection meeting with Oncor is completely confident their plant will be built and supplying power to the grid at the earliest possible time. For wind plants that can be 12 to 18 months from the first meeting date. For combined cycle plants, that can be as little as 24 months, while coal and nuclear plants can take 4 years or longer. The reality is between 25 and 50 percent of these plants are never built. Of those that are built, a significant number are not completed and ready to supply power to the grid at the time originally stated. Needless to say these realities result in uncertainty, not only for the transmission planning process, but for other areas as well, such as designing and building connection points, operator training, etc.

There are features of the process that helps Oncor deal with this uncertainty. Studies are not performed until contracts are signed and fees are paid. Materials are not purchased and construction begun until an interconnection agreement is signed and financial documents for securitization are in place. However, these do not give complete clarity on how to plan the transmission system. For example, the ERCOT rules allow us to only include publicly announced generation projects in interconnection studies. While this is a reasonable requirement, it can lead to misleading conclusions in interconnection studies because often significant unannounced generation is planned in the same area. So while the results of an interconnection study might suggest the transmission system can support a certain amount of generation from a particular site, the site may very well have to share the transmission capacity with these yet unannounced plants. And given that all, some, or perhaps none of these announced or unannounced plants will be built, or built years after they are first proposed, it is quite a challenge to plan the transmission system.

Fortunately, the time it takes to complete transmission projects often works well with the time it takes to build new generation projects. For example, line and terminal equipment upgrades often do not require regulatory approval, and often can be completed by the time the generator is ready to supply power to the grid. New transmission lines can take a minimum of three to five years or more to obtain regulatory approval and be built, with most of that time being needed for activities related to regulatory approval. As indicated above, some types of generation can be built in a shorter time than can new transmission lines. Thus, once the need for a new transmission line is established, some of the uncertainty as to which generation projects will actually be built and when diminishes due the time needed to obtain approval and build new lines.

Prior to the mid 1990s the predominant generation resource in ERCOT was conventional technology gas fired plants. Large, efficient combined-cycle plants became popular toward the end of the 1990s, and several such plants were built in ERCOT. From about the year 2000 onward, wind generation has been popular, and many wind plants have been built and connected to the transmission system in ERCOT. These generation additions have resulted in numerous conventional gas fired generators being mothballed. They were simply not economical to run. Because Oncor is a wires company and owns no generation, these sometime significant changes (mothballing of plants) only become known to us when they are publicly announced by the generator owner. Secession of plant operations can happen in a matter of a few days, but usually occurs a few months after the announcement.

Mothballing of units can have interesting consequences for the transmission system. On the one hand it can free up capacity for new generation. On the other hand, we have had a situation where mothballing a unit reduced transfer capacity. To complicate things even more, we have had mothballed units brought back on line due to changing economic conditions. Most of the units that have been mothballed were built during the time of integrated utilities. That means in many cases the transmission system associated with the mothballed plant was built specifically to carry power from that plant to a specific load center. The freed-up transmission capacity may or may not be optimal for newer plants wishing to connect to the grid.

Finally, we have a situation where several conventional gas fired power plants are located in an area where air quality is a concern. Because of these air quality concerns, it is unlikely additional generation will be built in this area of high load growth. Governmental entities can and do change the allowed power plant emissions, and the way these emissions are calculated. The generation owners may have the technology option of modifying their plants to reduce certain types of emissions, usually at considerable cost. From a transmission planning perspective this situation results in several risks. The units may only be economical to run for peaking service during limited times of the year. The units may not be able to run due to emission restrictions. The emissions rules could change further restricting or prohibiting the operation of these units. The owners could apply advanced emissions technology to these units thus increasing the amount of run time. The owners could mothball the units for a variety of reasons. The owners could mothball some units and modify others to meet emissions restrictions. Obviously, there are many possible outcomes, and they are all outside the control of the transmission provider.

Why are these units important enough to mention them here? They provide critical reactive support for the largest load area in ERCOT. Because of the conditions described above and the fact that reactive power cannot be transmitted over long distances as can real power, it is unlikely the new generation that is being added to the system will provide reactive support to this large load area. So, there is a risk that the units will not run when needed for reactive support because it is not economical. Fortunately ERCOT has a mechanism to operate units out of economic order. It is possible some or all of the units cannot run due to emissions restrictions. It is possible some or all of the units will be mothballed at some unknown date. It is possible these units can become unavailable in a matter of a few days. Replacement reactive sources can easily take two years or more to design and build.

Obviously, the transmission owner can add dynamic reactive devices to the system which can reduce or eliminate the dependence and uncertainty associated with these units. However, the regulated transmission owner must justify the capital expenditure to the Public Utility Commission (PUC). Given all the risks associated with generation availability mentioned above, it would seem reasonable to install some back-up dynamic reactive devices. This would seem especially prudent considering the generation could become unavailable in a matter of days, but it takes at least two years to add dynamic reactive devices. Having said that, it turns out the planning criteria in ERCOT does not justify "just in case we need it" major equipment additions. One must demonstrate a credible contingency violates an ERCOT planning criterion, or demonstrate the cost of a transmission system addition is less than the economic benefit (reduced losses, reduced generation run out of economic order, etc.) derived from the addition, excluding contingencies.

In the above paragraphs I have described some of the uncertainties related to generation faced by Oncor as we plan the transmission system. These uncertainties do affect the timeliness of transmission additions, as well as congestion and other factors that affect both the cost and quality of electric service. It would be very helpful to have industry developed consensus methods to deal with uncertainties such as these.

Load:

Load modeling may be the most neglected area in stability studies. This is unfortunate because load characteristics can affect the outcome of both transient angular stability and voltage stability studies. Load characteristics can affect the outcome of studies intended to assess the frequency response of power systems (see reference [79] of Chapter 4). This condition is not from lack of trying to characterize load. Several major efforts over the past 20 to 30 years have attempted to "get a handle" on the load characterization. The problem is aggregate load at most switching stations vary so much in composition, characteristic, and amount over a matter of hours, days, and weeks. One can test a generator to determine its characteristics, and unless something unusual happens, these characteristics will not change for many years. Similarly, one can test an air conditioner, automated welder, refrigerator, pump motor, television, computer, electric range, fluorescent lighting, etc, and their individual characteristics will likely not change over time very much either. However, at least two problems arise that have to do with the large numbers involved. First is the large number and variety of load devices. Consider televisions. The characteristics of CRT, LCD, and plasma televisions are different. Does that difference affect their load characteristics, especially during transients? Since there are several manufacturers of LCD televisions, do the differences in manufacturer's design affect the load characteristics in a significant way? As indicated above, one can test all the load devices to obtain their characteristics, but as should be apparent, the shear number and variety make this an impractical task. Complicating things further is the fact that the technology used for any load type can change fairly quickly. For example, 5 to 10 years ago most televisions and computer monitors used CRT technology. Five or 10 years from now, it is likely CRT technology will be little used for these applications.

The second problem is identifying which devices are actually in use. Given the large number of electrical devices, that could be a great challenge. Consider two types of load. It is probably reasonable to assume refrigerators turn on randomly, and thus some average value for refrigerator load can be used. Similarly, it is probably reasonable to assume television load is greatest during the evening hours between the time people arrive home from work and the time they go to bed. So while it seems we might have a good idea when these two load types are most likely to be on, there can be exceptions. In North America, North American football is extremely popular, and usually played on the weekends in the early afternoon. Television usage increases as fans watch their favorite teams play, and refrigerator usage increases because it is customary to have refreshments during the game. While this example might not be a critically important load in terms of magnitude or type, it does illustrate the difficulty of identifying which loads are on at any given time.

Because there is such variety in load types and characteristics, one approach that has been taken to reduce this large volume is to concentrate on the load types that are most likely to affect the overall system response. In ERCOT, and other places as well, the largest load type during many hours of the summer is air conditioning. EPRI and others have recently tested various residential air conditioning units, both in terms of equipment manufacturer and equipment technology. Important characteristics such as stall voltage and contactor drop-out have been identified for individual air conditioning units. However, when the test data is taken as a group, the stall voltage becomes a range of voltages, as does the contactor drop-out voltage. A similar statement can be made for many of the important air conditioner motor parameters. While the results of this testing are very important, they still do not give one simple "answer" to how to represent an air conditioning load in system studies. How does one use a range of values to characterize air conditioning load?

When one looks at the Oncor distribution system, other uncertainties can be seen. The distribution system has evolved over time, so there has been more than one design approach used over the years. Examples include overhead or underground conductors, different voltage ratings, different conductor ratings, capacitor location and switching philosophy, etc. Some loads are served as three-phase loads, but many are served as single-phase loads. While a deliberate attempt is made to balance the load among the three phases, some unbalance is a reality because, as mentioned above, the load at any given metering point can vary greatly. Single-phase distribution implies single-phase loads, such as air conditioning motors. However, the more popular transient stability programs assume balanced three-phase networks and loads, and thus only model the positive sequence network. It is certainly a big leap to assume a single phase distribution system and load can be modeled as a balanced three phase load. While the origins of the current approach probably have to do with hardware limitations of the past, the shear size of numbers, as mentioned above, might make changing the approach too unwieldy to be useful. Looking a little more closely at the distribution system, one notices that a distribution feeder can be several thousand feet (hundreds of meters) long. The voltage is not the same at every point on the distribution feeder, even if capacitors are added at various points. Couple that with the range of motor stall and contactor drop-out voltages, and it is not obvious how to characterize a distribution feeder for dynamic simulation. And if one were to characterize one distribution feeder in a very detailed and accurate manner, it is very unlikely that characterization would apply to all feeders. It might even be difficult to determine for which other feeders the detailed characterization could be applied.

From the above, it should be clear that characterizing load for stability studies can be a complex task. Load characterization is extremely important, and can affect study results. A load characterization that suggests there are problems when there are none can result in expensive, unneeded system upgrades. Similarly, load characterization in studies that incorrectly suggest there are no problems can be extremely costly when the inevitable event exposes the truth. Great detail in characterizing load might bring greater accuracy, but the cost associated with great detail might not be practical. Instead, the ideal would be to characterize all the uncertainties about the load in a way that does not over tax the utilities ability to collect and maintain the data, results in load models that do not over tax the available hardware or software, and give simulation results that have a high level of confidence the simulations will match real world events.

Case 3 – Australia – Generic View

Country: Australia (Generic)

Focus: Australian National Energy Market (NEM)

Liberalization: Energy only market. All energy traded and settled through the pool. Financial trades occur outside of the physical market (e.g. hedges, futures, caps). All generators must sell into the pool.

Generation expansion: Generators are owned by private and state corporations and invest when commercial. New investment arises as a result of market signals including energy prices, particularly the shortage price (currently set at AUD$10,000/MWh). There is no central planning for generation and no disclosure regime for investment plans.

Transmission expansion: Each state within the NEM control area has a Transmission Owners (TOs). Some of these have planning authority while others rely on an independent planning body (South Australia and Victoria).

AEMO (the Australian Energy Market Operator[11]) publishes an annually a report on transmission augmentation opportunities – in 2009, the National Transmission Statement[12] (NTS) and in previous years the Annual National Transmission Statement.

[11] In July 2009 AEMO became the National Transmission Planner for Australia.
[12] http://www.aemo.com.au/planning/nts2009.html

From 2010 AEMO will publish a National Transmission Network Development Plan, which will replace the NTS.

Power system operation: AEMO operates both the physical market and the power system and has full accountability for power system security.

Transmission Planning Issues:

The issues identified in this report include:

- Coordination of transmission plans and investments across a number of transmission owners and planners;
- Taking account of uncertainty associated with new generation investment;
- Lead times for transmission investments;
- Modeling generation dispatch in the compulsory pool; and
- Increasing levels of variable generation.

Australian Experience with Probabilistic Planning:

In Australia most transmission network planning is based on deterministic planning criteria. Exceptions to this are AEMO's planning approach in Victoria[13] and some inter-regional planning initiatives, such as work undertaken by Powerlink Queensland and TransGrid on an interconnector upgrade between Queensland and New South Wales. AEMO's NTS identifies, through market simulations, transmission augmentations with potential net market benefits.

Some Transmission Network Service Providers (TNSPs) also use elements of probabilistic planning to establish five-year strategic network plans for the determination of capital expenditure allowances as part of their regulatory reviews.

Areas of uncertainty in transmission planning

There are a number of areas of significant uncertainty in the transmission planning process in Australia. While load forecasting is still perhaps the most significant of these, generation expansion is also a major source of uncertainty in transmission planning. The National Electricity Market (NEM) has been operating in Australia since 1998, and under NEM arrangements TNSPs have no role in generation planning, but must anticipate and respond to generation developments. In addition, in recent years there has been a rapid increase in the penetration of wind generation into the electricity supply in some regions of the NEM, and this has introduced further uncertainty because of the variable nature of the wind generation outputs and short lead times for developments.

The major sources of uncertainty in transmission planning in Australia might be summarized as follows:

1. Load forecasting (including load growth and load diversity)
2. Generation expansion uncertainty - where and how much and when generation will be added to the power system.
3. Generation dispatch – how will the generation be dispatched in the future.
4. Affect on network constraints-How will the generation affect the network limits (this depends on 3), but also, potentially on the type of generation (wind turbines have very different dynamic and voltage stability characteristics to thermal or hydro plant, for example.)

[13] Transmission planning in Victoria was until July 2009 undertaken by VenCorp, which subsequently became part of AEMO.

5. Impact of variable generation on operation of the power system (in operational planning timeframes, and for longer-term planning and reliability of supply considerations)

6. Potential for large load developments with short lead-times.

Justification of network augmentations in Australia's National Electricity Market

In Australia there are two ways of justifying new large transmission augmentations under the National Electricity Rules (through the Regulatory Test [14]): they can be either:

- required for reliability purposes or
- justified as providing net market benefits.

To calculate net market benefits requires market simulation of future operation of the market. This involves:

- modeling the impact of a proposed augmentation on the network (in terms of network constraint equations).
- comparing the market simulation results with and with out the augmentation to determine the net present value in terms of capital deferment (deferment of or removing the need for new generating plant), reliability benefit, operational cost savings and competition benefits[15].

Up to now most augmentations have been justified based on reliability requirement, and under most state-based arrangements the reliability criteria are deterministic. Most TNSPs have a legal obligation to meet reliability standards, whereas the incentive for market benefit augmentations are invoked by the regulatory regime – the incentive to invest being balanced by the need to demonstrate a market benefit.

AEMO's approach to planning is designed to ensure that system performance and security standards set out in the National Electricity Rules (NER) are addressed in the most economic manner. This approach is detailed in their electricity transmission network planning criteria document, which is available in their website.

The key components of AEMO's Victorian planning approach are as follows:

- Technical assessment is conducted using deterministic techniques to satisfy requirements as per the NER. This assessment identifies the operational actions to maintain system security for specific system conditions - such actions normally involve network switching, generation re-dispatch, or load shedding.
- An hour-by-hour simulation of the future systems across a range of demand and generation scenarios is conducted. For each scenario, the system operational actions are determined.
- AEMO, for planning in Victoria, uses a market model of the NEM to calculate generation dispatch for any particular demand level. The amount of market modeling work depends on complexity of the problem.
- NEM market model is not used to evaluate the simple constraints, such as constraints of radial connections.
- Financial value of operational actions (generation re-dispatch and load shedding) is calculated. The regulatory test provides guidance on the generation bidding behavior that must be used within the market analysis. Forecast load shedding is valued based upon an appropriate Victorian Value of Customer Reliability (VCR).

[14] The Regulatory Test is soon to be replaced by the Regulatory Investment Test for Transmission (RIT-T) which combines both limbs of the Regulatory Test.
[15] The RIT-T includes additional benefits streams.

- Probabilistic planning assessment is used to account for the uncertainty in the system conditions for factors such as: demand forecasts, generation unavailability, and network contingencies, to estimate the aggregate actions and associated most likely value of operational actions. This approach is developed to strike a balance between the cost of addressing network constraints and the benefits to consumers from addressing those constraints.

Through the 1990s TransGrid (New South Wales TNSP) explored the application of probabilistic planning based on a Monte Carlo simulation of generation development and operation and modeling of the outage behavior of the transmission system. TransGrid now applies largely deterministic criteria with some consideration of the risk associated with customer supply reliability level agreements. TransGrid also considers scenarios of future generation developments on a probabilistic-weighted basis. The scenarios reflect future views of load growth, greenhouse gas initiatives, water availability in drought years and interconnection development. This leads to a capital expenditure forecast and the strategic development plan for the transmission system that is used to determine a 5-year ex-ante capex allowance. At the project justification stage other studies are undertaken using the most relevant and recent data.

Powerlink Queensland uses a planning methodology for augmentations to its main grid that:

- considers a 10% probability of exceedance medium economic growth load forecast;
- considers outage of the most significant generating unit in a zone; and
- considers a range of generation development scenarios.

In developing their most recent revenue proposal to the Australian Energy Regulator (AER) Powerlink used a probabilistic approach for forecasting likely capital expenditure required over the revenue period. Powerlink engaged consultants to develop likely themes that would impact on augmentation needs. Powerlink's consultant used:

- five different load development scenario;
- two different inter-regional trade scenarios;
- two gas development scenarios;
- two greenhouse options (carbon tax or no carbon tax) each of which was assigned a probability.

This leads to forty different network development plans, based on defined, deterministic development criteria. Powerlink then assesses the set of plans to determine the set of augmentations required for all scenarios, and those less likely to proceed. The capital expenditure forecasts then reflect the probability-weighted costs of the development plans.

The general approach outlined above for Powerlink Queensland and TransGrid has also been used by some other TNSPs in Australia, with some variations.

Load Forecasting

Load Forecasting for Australia's National Electricity Market is undertaken by TNSPs using a variety of approaches. Some use high level economic information to develop their forecasts while others use a combination of high-level economic information and aggregation of projections from distribution network owners. Information on the load forecasting process is published annually in AEMO's Statement of Opportunities and in the Annual Planning Reports of TNSPs, which are published on their websites.

Market Simulation and Generation Expansion

In 2009 AEMO produced a National Transmission Statement (ANTS) the purpose of which is to examine current transmission capability and future opportunities for network augmentations in the main transmission network. Future potential augmentations are examined through market simulations that take into account:

- historical generation bidding behavior;
- generator forced outage rates and planned outages;
- availability and location of generation energy sources (such as coal and gas supplies);
- impact of government energy policies and incentive;
- load projections;
- committed generation and transmission projects;
- transmission projects required to meet statutory reliability requirements; and routine projects (such as capacitor installations) that are typically required to maintain transmission capability for increasing loads.

The generation bidding strategies are tuned by "backcasting" whereby simulated results for the previous year are compared with actual generation and power flows between regions.

In 2009 the NTS projections were made for 20 years assuming that new transmission projects could be developed beyond the third year.

The database on which the simulations are based is made available to participants in the market for their own studies, including to TNSPs who may use this database or develop their own data for market simulations.

Experience with assessing the value of potential augmentations suggests that projecting generation expansion is one of the most complex and difficult elements of the process.

Another related source of uncertainty is the impact of the augmentation on generation developments beyond the study period. Since transmission assets have long lives some assumptions must be made as to whether the impact of an augmentation will continue beyond the study period.

Impact of new generation on network capability

A further area of uncertainty relates to modeling the impact of new generation on transmission capability. This particularly relates to impact on transient and oscillatory stability. Transient stability is affected by the generator technology and the inertia of the plant and its location. Oscillatory stability can also be affected by the use or otherwise of control systems such as power system stabilizers. The impacts of new generation on network stability limits can only be approximated until plant has been designed. This adds some risk that projected increases in transmission capability from network augmentations may not be realizable in practice.

Value of Lost Load

One of the important variables when assessing the benefits of an augmentation is the value that one places on loss of supply to customers. In practice the value of supply depends on a wide variety of factors including the type of customer load, the length of the supply loss and whether the supply loss is known in advance. The $/MWh number that is used will have a significant impact on the benefit attributable to an augmentation. The value of lost load may also vary over time in a way that is very difficult to predict. One option that is used by TNSPs and in the NTS is to examine the sensitivity of net benefits to a range of values for loss of supply. AEMO applies the Value of Customer Reliability (VCR) based on its consultation with stakeholders and consumers. AEMO applies either an average

Victorian VCR (presently AU$29,600/MWh) or sector specific value, as considered most appropriate on a case-by-case basis.

Wind Generation Modeling – Australian Experience

The treatment of wind generation in planning depends on the purpose of the assessment. The following paragraphs describe some of the different approaches that have been employed.

a) Modeling Wind Generation for Assessing Available Reserve Margins:

Typically peak load conditions occur in summer in Australia (except in Tasmania). In South Australia, which currently has the highest level of wind generation of any Australian state, peak load typically occurs under hot conditions with low wind speed, and analysis of historically information by ESIPC[16] has suggested that output of 8% of capacity should be assumed for summer (10% probability of exceedance) demand conditions. In neighboring Victoria a figure of 23% output at summer maximum demand conditions has been proposed.

b) Modeling wind generation in market simulations:

There are two main approaches to modeling wind plants in market simulations, either:

- netting off their contribution to meeting demand (i.e. the energy and demand projections are demands after wind generation – there is then uncertainty as to how to adjust the annual load traces to take account of new wind generation); or
- modeling the wind traces explicitly.

In the NTS market simulations the wind generation traces are used for some wind plants. Wind generation traces developed for each hour of the simulation. The traces need to reflect:

- location and capacity of existing and committed generation
- expected wind pattern;
- expected capacity factor across the full year;
- diversity factors between different wind generating plants; and
- expected output under peak load conditions.

In the NTS a fixed expansion plan was used for wind plants up to 2020, to account for the effects of a government incentive program (the expanded Renewable Energy Trading scheme), the impact of which was not captured in the generation expansion algorithm.

c) Modeling Wind Generation for network planning:

For traditional thermal or hydro generation it can be assumed that for high load conditions up to100% of the plant capacity will be available (excepting forced outages), and this provides a reasonable level of certainty in assessing the need for new transmission that removes transmission network limitations between generation and load centers. Wind generation typically provides a much lower level of reliability benefit (compare 100% with 8% for wind), which makes it quite difficult to assess the need for new transmission that would reduce the transmission limitations between wind plants and load centers. Typically transmission to support the connection of wind plants to load centers would need to be justified under the market benefits part of the Regulatory Test, but the reliability limb of the test is applied where the wind generation is a component in meeting the necessary supply to the state load.

[16] now part of AEMO

d) Modeling Wind Generation in Load Flow and Stability Studies

For the purpose of managing power system security it is necessary to develop network constraint equations which describe capability under all credible conditions including the possibility that wind plant capacity can be achieved at high demand and high temperature conditions. If the output of the wind plant can be controlled, then the NEM dispatch algorithm can trade of the dispatch of wind plants and other generation to optimize dispatch outcomes and ensure the network flows remain with in network capability. Wind plants are allowed to register as "semi-dispatched" - the wind plant operators submit bids for generation on a five-minute basis, based on available generation, and wind plant generation output can be reduced where necessary via the central dispatch process to maintain power system security. Under this arrangement wind plants that would otherwise overload transmission network elements when operating at high output levels are able to be connected to the national grid without risk to the network.

e) Modeling to understand the operational impacts of wind generation

In recent years AEMO (and its predecessor NEMMCO) as system operator has been very interested to understand the potential operational impacts of wind generation. Three scenarios have been of particular interest:

1. When a powerful wind front passes across a region the wind plant outputs can change by significant amounts over short time frames. Such steep wind fronts are not uncommon in South Australia, which is also home to the largest number of wind plants. Under very high wind speeds protection systems on the wind turbines can act to shut them down to avoid equipment damage. Under these circumstances it is possible to get very high outputs followed soon after by very low outputs. The impact can be to require additional frequency control services from generators in order to prevent overloading of transmission. Analysis and prediction of such events requires review of historical information on wind plant generation patterns and extrapolation based on wind patterns in other locations and on projected types of generation pattern. The solution proposed by the electricity industry in Australia involves implementing a sophisticated wind and wind generation forecasting tool and requiring future wind plants to be fitted with mechanisms to reduce their output, so that they the wind generation output can be reduced prior to the onset of a wind front.

2. Under very high temperature conditions wind turbines may trip on over-temperature. In Australia high demand conditions are typically associated with high temperatures, so loss of wind generation output at high temperatures is of interest for the assessment of supply adequacy.

3. Increasingly wind generation is connected to remote parts of the grid. This remote generation can displace generation located closer to load centers leading to voltage stability issues if not correctly managed.

Case 4 – Danish Example of a Probabilistic Approach to Planning to Account for Independent Power Producers

Country: Denmark

Focus: Example of Probabilistic Planning in Denmark

Transmission Planning Issues:

Along with a steady increase of decentralized production and a transition to a more liberalized electrical power market, the planning of the grid - at the level of transmission - becomes increasingly complicated. A power transmission system holds superior elements such as components with probability of power failure, load from the lower grid, stochastic power production from windmills dependent on weather conditions and decentralized heating from electric power generation. Hence, it is relevant to provide a tool of analysis which can be applied to analyze the power grid in general.

This tool must take stochastic properties and simultaneity factors into consideration and for this purpose a probabilistic tool for planning of the grid at the level of transmission has been prepared.

Stochastic models of load, windmill power production, decentralized production and constrained heat production from central district heating plants are included in this example. The models are applied in a model of a realistic grid with the probability of failure of lines and transformers. The models of load and decentralized production of heat production are dependent on the time of the day and year. In the model of windmill production, a correlation has been implemented to allow the planning tool to take the properties of the windmill production into account. The constrained heat production from the central district heating plants is dependent on the time of the year.

With regard to the constrained heat production, the requisite production is distributed between the central district heating plants according to their marginal price, after the decentralized production has been deducted the load requirements. This provides an optimal distribution of production in proportion to the costs of the central district heating plants. Should an overload of the grid occur the power production will be redistributed to avoid overload.

The results of the proposed simulation program on the grid model provide information about power overflow, power deficiency, non-distributed energy and power flow distribution on the grid lines. An N-1 analysis is performed on all the grid lines, which provides information about where a reconstructing of the grid is most economical. The simulation results provide information about variation of the day and year for the implemented models. For more information, see [1-2]

References:

[1] Master thesis in Danish: *Probabilistisk netplanlægning på transmissionsniveau*, June 1997. Aalborg University, Denmark. J. Bech, B. Bak-Jensen, C. G. Bjerregaard, P. R. Jensen.

[2] B. Bak-Jensen, J. Bech, C. G. Bjerregaard and P. R. Jensen, "Models for Probabilistic Power Transmission System Reliability Calculation", *IEEE Transactions on Power Systems*, Volume 14, Issue 3, Aug. 1999 pp.1166 – 1171.

Case 5 – USA Generic [1]

Country: USA (Generic)

Focus: Generic Present Deterministic Approach to Planning in the USA

Liberalization: Energy and capacity market. Day ahead and balancing markets. LMP ISOs are non-government corporations that are responsible for operating the market and approving new transmission investment.

Generation expansion: Generators are owned by private corporations and invest when commercial. New investment arises as a result of market signals including energy and capacity prices. No central planning for generation and no disclosure regime for investment plans.

Transmission expansion: There may be many Transmission Owners (TOs) within the ISO's control area. There may also be several state based regulatory authorities that have jurisdiction over all or some aspects of approving or giving consent for transmission investment.

Power system operation: ISOs operate the system and dispatch 'must run' generation to avoid security violations. Financial Transmission Rights are used to manage risks associated with congestion. The ISO's must approve transmission investment plans and generally run a queue system to prioritize connection studies for new generators.

Transmission Planning Issues:

The issues identified in this report relate to uncertainty in:

- Which (of many possible) generation projects will be committed;

- Which existing generators will be de-commissioned (or mothballed) at short notice;
- How to align transmission line investments (3-5 years) with generation investments; and
- How to deal with the potentially wide range of load characteristics in dynamic studies used for transmission planning purposes.

The generation proposal process in today's North American deregulated markets gives little consideration to the potential transmission issues. This is driven by two factors, (i) that much of the economics is determined by the cost and vicinity of the fuel source, and (ii) because generation owners/developers do not typically have the data or expertise to look at all the transmission issues in detail. At the final stage of the process, the proposal is submitted to the transmission owner (or Independent System Operator), who then performs a study to evaluate the impact of the proposed generation on the transmission system, and thus assess the need for transmission upgrades or investment necessary to inject the full capacity of the power plant into the system. In the US, typically this process follows a "queue of interconnection requests". There is a definite position associate with each application. A system planning model is developed for each study based on applicants in the queue that are ahead of the applicant under study. Two of the biggest draw backs with this process are as follows:

1. It is conceivable that a certain transmission problem (the simplest example being, thermal overloading of a line) may not occur for the first N generators that appear on the system, while the $(N+1)^{th}$ generator causes the problem. Should generator number N+1 be the only one paying for the upgrade costs?
2. For renewable generation, particularly wind generation, the deterministic approach of modeling all other generators in the queue at their peak capacity simultaneous with a peak system load is for the most part an unrealistic assumption. There is a significant body of evidence that it is quite rare to have all wind generating facilities on a system at peak output in coincidence with peak load. Nevertheless, at present there is no other systematic way available to transmission system owners for performing such studies. The down side of such an approach for wind generation is that the identified level of transmission upgrades may be more than necessary and therefore impose unnecessary additional costs on investment projects, possibly making the uneconomic.

Once the system impact study is completed and a system interconnection agreement signed, a follow-up study may be performed (often referred to as a facility study) to firm up the exact transmission upgrades and needs of the proposed generation facility in order for it to meet its power purchase agreement, i.e. not only to inject megawatts into the system, but to transport those megawatts to a specific load center with whom a power purchase agreement has been signed. In this step another complication often arises with renewable generating facilities such as wind. Due to the intermittency of wind facilities, such generators cannot enter into a firm commitment for power delivery. Instead most seek non-firm power purchase agreements which complicate the facilities study. It may require performing several sensitivities to generation dispatch to try to capture, as much as reasonably possible, the various conditions of power delivery from the plant.

In addition to all of the above, transmission owners (in collaboration with ISOs) need to perform overall system transmission and operational planning studies. This is shown in Figure A-1.

For transmission planning, the process often starts with collaboration between transmission and distribution owners (often the same company) to collect load profile data and based on this data to develop a load forecast for future years. In the US it is typical for planning studies to develop what are know as 90/10 load forecasts (or 1 in 10 year peak cases). That is, for each future year to be studied a load profile in the planning model is based on the forecasted peak hour load on the system (often summer peak) such that there is a 90% chance that the peak load will be at or below this level and a 10% chance that the peak load might be above this level. This is presently considered to be acceptable by most planning standards in the US. Such peak load cases are then typically developed in the following sequence:

1. For the present year summer peak load
2. For the next five years of summer peak load
3. Occasionally for a horizon year (e.g. looking ten years into the future)

In vertically integrated utilities, item 3 above was common practice. In today's liberated market structures this is the most challenging aspect of the planning process since the transmission owner has little control on the process of generation planning and sitting, as discussed above. Therefore, developing a case that is more than four to five years into the future becomes exceedingly difficult at best. The cases developed are then studied in detail.

For operational planning, the focus is the first set of cases developed – that is, present year peak conditions. Operational studies look at identifying any special remedial action plans needed for the coming summer months, since building or upgrading transmission assets is not an option.

For the future year cases studies are performed to identify the need for and potential transmission facility upgrades to resolve imminent problems – this is traditional transmission planning. In parallel with this process queries are made to equipment vendors (vendors of breakers, transformers, FACTS devices, capacitors, transmission lines etc.) to identify the lead time and cost of various capital investment options in order to properly incorporate them into the planning process. Thus, the process is inherently somewhat iterative.

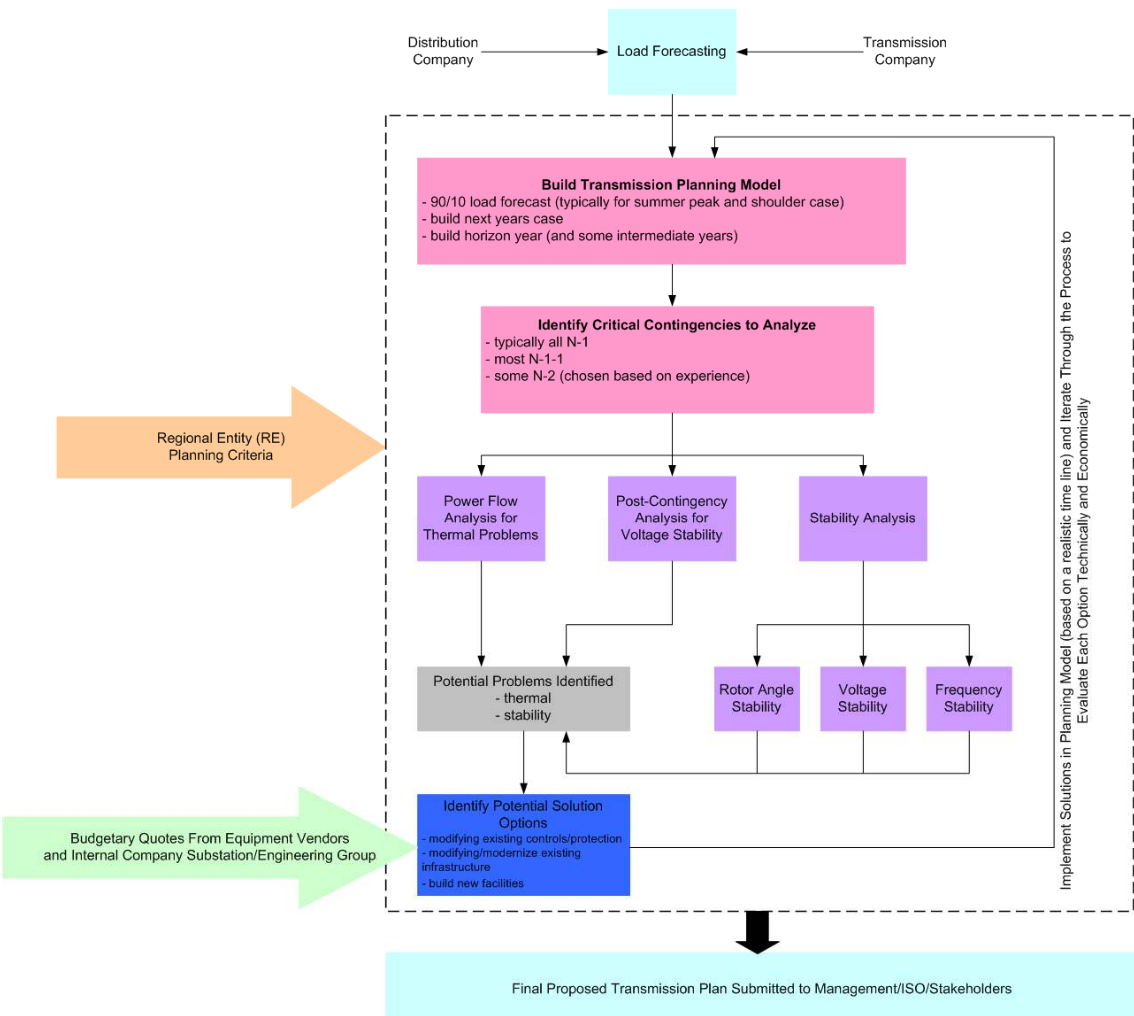


Figure A-1: Diagrammatic representation of the deterministic planning process.

Typically, the approach to planning studies taken presently is purely deterministic. Models are developed, various generation dispatch scenarios are considered based on potential new generation and potential weather patterns that might affect hydro facilities and other renewables. In addition, apart from the peak load cases, some off-peak cases will also typically be studied. In each case a routine set of contingencies are studied in both power flow (steady-state) and time-domain (dynamic) simulations. The contingency lists often include:

1. All N-1 contingencies on EHV systems
2. Select N-1-1 and N-2 based on the utilities experience of which outages are the worst for their system.
3. A few extreme scenarios that may, based on pervious experience, have been quite devastating and frequent enough to warrant attention.

Typically, the actual load and other device models are fixed once the cases to be studied have been developed. Based on this discussion, it can be seen that the major gaps with the present planning process are as follows:

- The challenge of dealing with the uncertainty in generation type, location and dispatch particularly in future and horizon year planning processes.
- The challenge in general of dealing with large pockets of renewables such as wind. Deterministic methods, of assuming all the wind generation is on-line simultaneously at their peak capacity, are too onerous and yet there are few systematic alternative ways that lend themselves to being performed using traditional planning tools.
- The lack of assessment of risk versus reward. This would include looking more systematically at the sensitivity of study results to various uncertainties particularly in load modeling and generation dispatch.

References:

[1] P. Pourbeik and R. Dugan, "Scoping Study for Identifying the Need for New Tools for the Planning of Transmission and Distribution Systems: Converting the Legacy Infrastructure into an Intelligent Grid", ***EPRI Technical Report, Product ID # 1015285*****, June 2007. (available for download at www.epri.com)**

Case 6 – Probabilistic Planning in Denmark

Country: Denmark

Focus: Probabilistic Planning Considerations in a System with a high Amount of Wind Power and Dispersed Generation

Transmission Planning Issues:

Wind Power and Combined Heat and Power in Denmark

During the last 30 years the Danish power system has been through a development from a system primarily based on thermal condensing electricity production to a system with a very high penetration of combined heat and power production (CHP) and wind power production, especially in Western Denmark, see power and energy balances in Figure A-2 and Figure A-3.

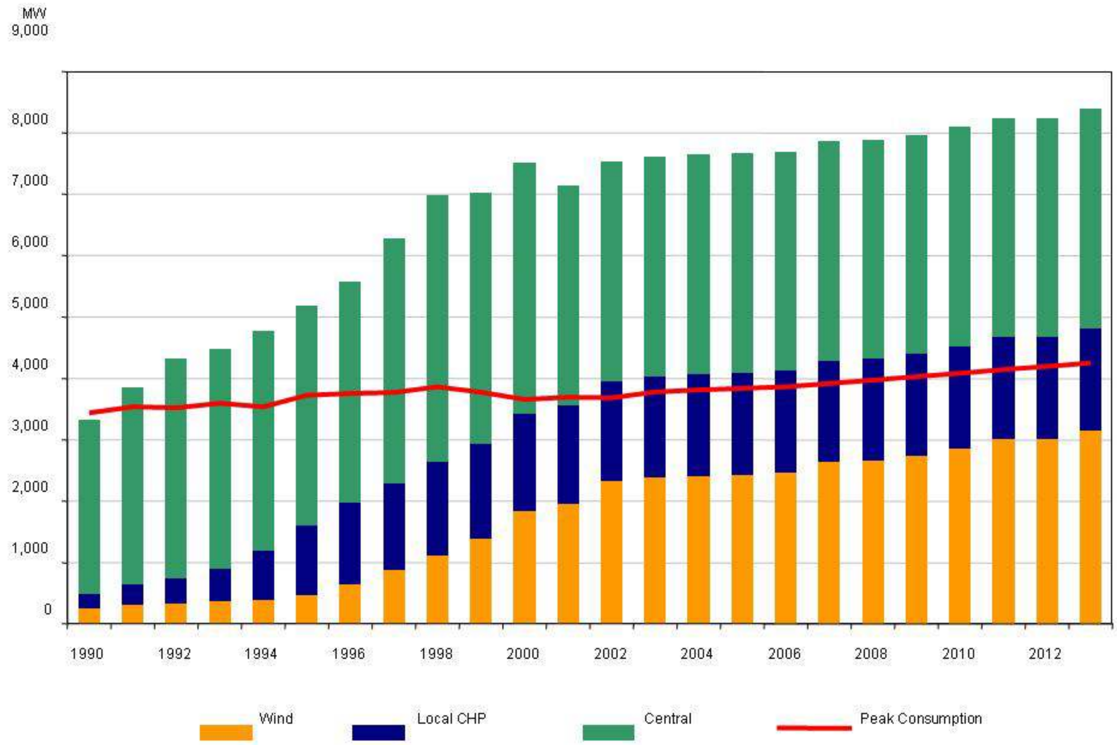


Figure A-2: Power Balance in Western Denmark.

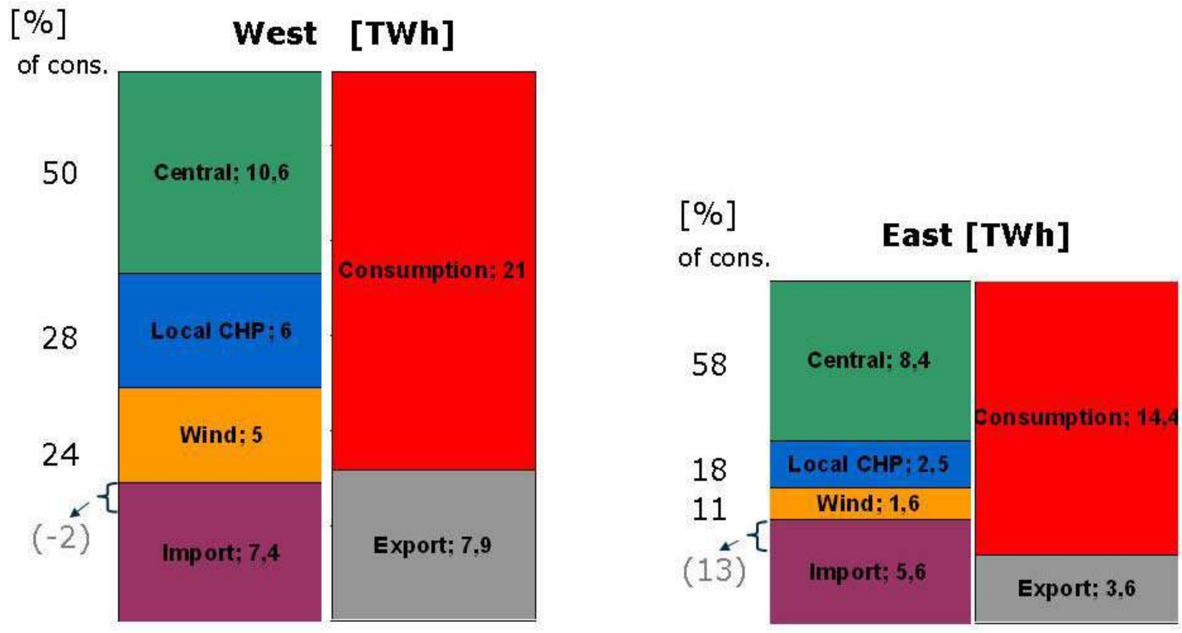


Figure A-3: Energy Balances.

The penetration level, being defined as the relation of installed production capacity to maximum/minimum load, respectively, today has for wind power a value of 65%/171% and for CHP units a value of 46%/121% in the Western Danish system, while the values for the Eastern Danish system are less, see Table A-3.

Table A-3: Production and Load Capacities for both Danish Systems 2007.

	Western Denmark	Eastern Denmark
Min. Load [MW]	1,400	900
Max Load [MW]	3,700	2,700
Central Power Plants [MW]	3,400	3,800
Local CHP Units	1,700	650
Wind Turbines	2,400	750
Penetration Level Wind [%]	65 … 171	28 … 83
Penetration Level CHP [%]	46 … 121	24 … 72

In 2005 CHP production made up to 55% of the total production and wind power about 18% of production, and a significant further increase is expected until the year 2025, see Figure A-4.

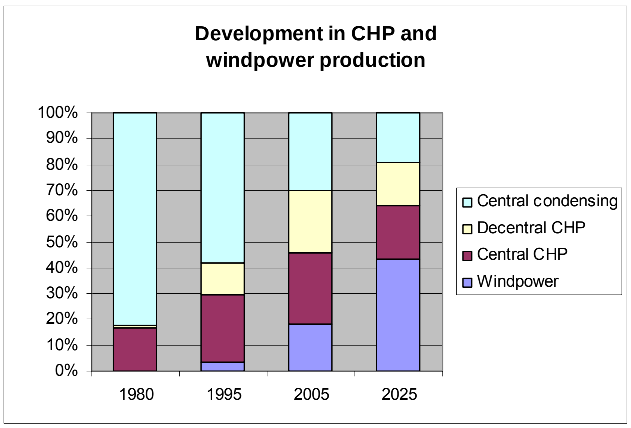


Figure A-4: Electricity Production divided on Wind Power, CHP and Condensing Technology.

This increased amount of dispersed production related to either heat demand or available wind power is a challenge with respect to balancing electricity production and demand in daily operation, but also during system planning. Here the adequacy of power as well as of energy plays an important role concerning aspects of reliability.

Security of supply is defined as the probability of electricity availability for the consumers. It is affected by sufficiency on the one hand, and operational security on the other hand.

Sufficiency can be described as the amount of resources in relation to demand, with resources being composed of energy resources, production capacity and transport capacity. Looking at wind energy being a fluctuating energy resource with not an unlimited forecast quality the production capacity is directly dependent on actual energy feeding by the wind.

Operational security is looked upon as a measure for system characteristics to withstand disturbances or interfering actions. Wind turbines increase the demand for system services (reserve and control power), but they also have an ability to reduce this demand and to deliver the respective contribution themselves. These characteristics should optimally be used in order to minimize the socio-economic costs.

During the system planning process, security of supply has to be ensured and estimated for the future power system. This is among other things done by calculating reliability indices like expected unserved energy ("EUE"), electric power not served ("EPNS") and loss of load probability (LOLP). Concerning the calculation of loss of load probability (LOLP) the availability of wind power and CHP is essential.

Probabilistic methods can be a helpful tool with respect to the calculation of system adequacy for systems with a high amount of stochastic production.

This chapter deals with the estimation of future system adequacy, referring to LOLP calculations in a power system dominated by CHP and wind power.

The Challenge of Balancing a System with a High Amount of Wind Power

In Denmark, the high amount of wind power capacity has led to a system with a wind power production sometimes being beyond the electricity demand. Furthermore the production situation is quite dynamic and might during some hours change from a situation with the wind power production being higher than electricity demand ("surplus situation") to a situation where wind power covers only a small fraction of a high demand. An example is given in Figure A-5, showing the first two weeks in January 2005.

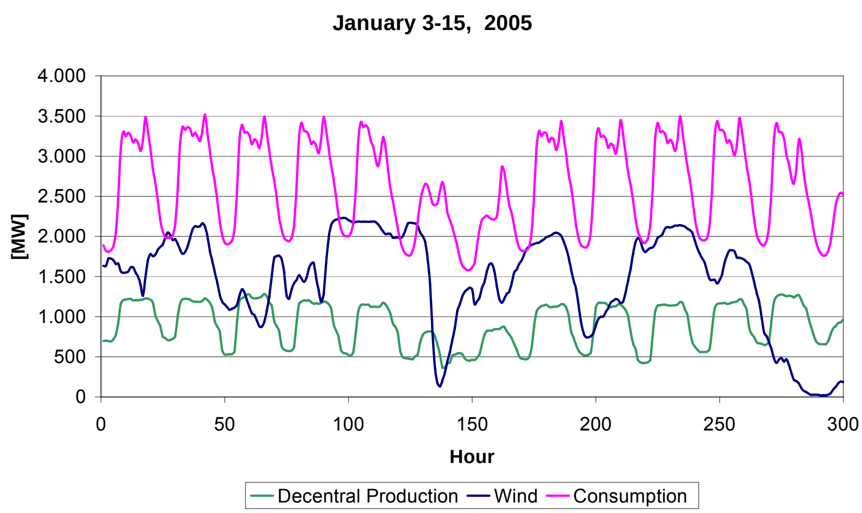


Figure A-5: Consumption, Wind Power and CHP production (Data source. www.energinet.dk).

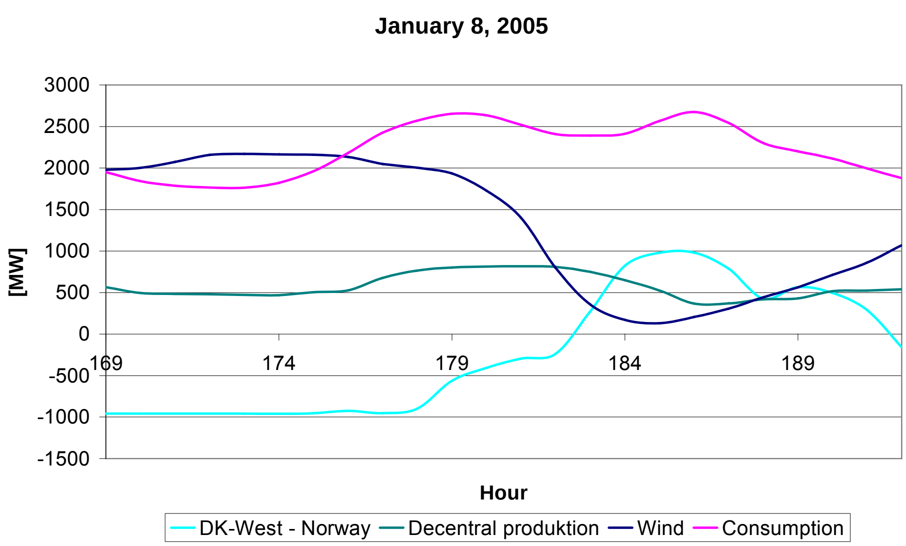


Figure A-6: Storm Front passing Western Denmark.

On January 8th the wind contribution changed from a surplus to being shut down due to a storm front passing by. During a period from noon until afternoon the wind power reduced from almost 100% to 5% percent of nominal capacity, while the electricity demand increased during the same period by

47%. Figure A-6, showing only the respective day, visualizes that the lost power could be balanced by an increased import from Norway.

This example shows clearly, how these situations until now have been solved: by a combination of production planning including prediction of wind power production and by an exchange of power with neighboring countries, having either a high amount of hydropower (Norway/Sweden) or thermal condensing power plants (Germany).

Thus, for the Danish TSO the interconnections to neighboring systems are of vital interest. In both Danish systems there is interconnection capacity to export 40 % of the production capacity, and to import 70 % of the consumption.

Load and production uncertainties have continuously to be balanced. This can generally either be done utilizing domestic reserves or using external reserves via the interconnections.

However, the availability of foreign reserves is not constant, as is illustrated in Figure A-7, showing the positive activated regulation power in red, the available domestic regulation capacity in blue and the available foreign regulation capacity in violet. Thus, domestic flexibility should be increased as far as possible. This is also important knowing that in the neighboring systems a significant increase of fluctuating resources is expected, and consequently the interconnections will be available even less for balancing. It will not be possible, that both neighbors rely on the respective other one to balance the own wind power. This has to be taken into account already during the planning phase of the own power system, optimally the planning processes have to be coordinated.

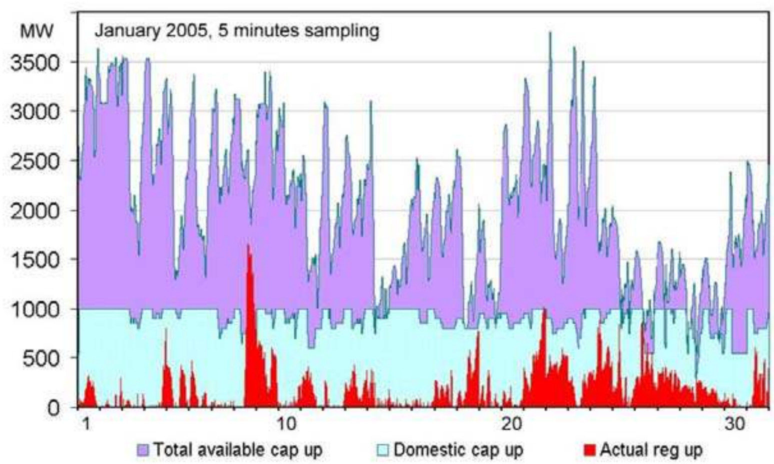


Figure A-7: Positive Regulating Power in January 2005.

Defining the maximum penetration of wind power production as the quotient between maximum wind power production and the sum of minimum load plus exchange capacity, as is done in [1], the maximum penetration in the Western Danish system today reaches a value of 54 %.

This maximum penetration becomes a stochastic value assuming that the numerator and denominator are Gaussian distributions characterized also by a correlation coefficient to each other [2].

Expected Development of Wind Power Utilization in Denmark

According to the governmental strategy from January 2007 Denmark has the objective of significantly increasing the wind power production from offshore wind power parks during the next decades. This will lead to a system with a wind power penetration between 100% and 260%. This increase in stochastic production will further increase the challenge in balancing the power production and consumption, see Figure A-8.

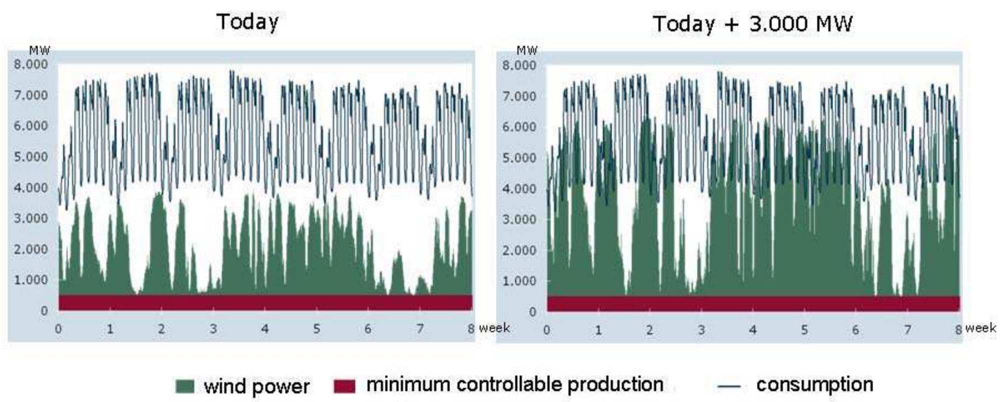


Figure A-8: Wind Power Production Today and Tomorrow.

After the Government published its strategy a commission including the Danish TSO published a list of possible locations for another 4,600 MW offshore wind power [3].

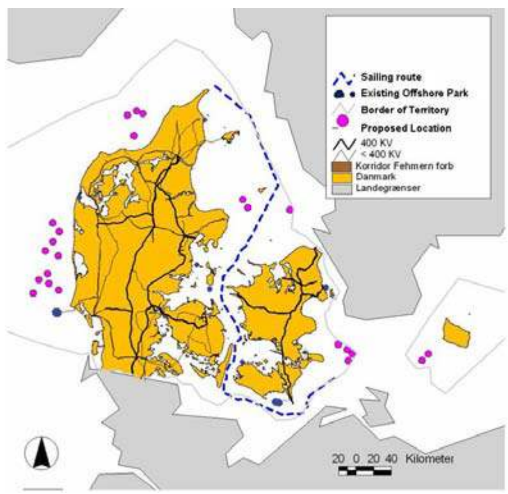


Figure A-9: Possible Locations for Offshore Parks, Source: [3].

This planning security is important for the Danish TSO to be able to start with variant comparisons, where to electrically connect the offshore parks to gain an optimal security of supply, avoiding network congestions on the one hand and reducing correlated wind production being connected at the same point of common coupling on the other hand.

In this context only a limited impact of improvements of wind energy production forecasts is expected, because the forecast quality is naturally limited with respect to the geographical extension of an area, especially for the output of a single park.

The area of Denmark has an extension of about 300 km north-south and 300 km west-east. With offshore parks being installed mainly at the west coast the correlation of the respective wind production is evident. While the on-land wind turbines are subject to a smoothening effect due to their geographical distribution, the only possibility to smooth out the production correlation for the power system is to connect parks from a similar area to different points in the grid. This helps also with respect to power fluctuations, which are unexpected to be forecasted to their full extent, see Figure A-10.

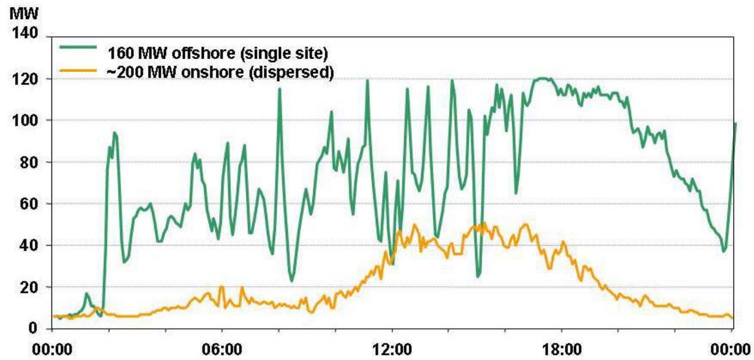


Figure A-10: Production of Single Offshore Site (160 MW) and Dispersed Onshore Sites (200 MW).

To increase security of supply measures on regional and system wide level have to be investigated, see Figure A-11.

On regional level currently technical measures are implemented in the Danish grid on distribution level, which aim at a basic restructuring of the system architecture.

Presently Energinet.dk executes a cell controller pilot project (CCPP) defining a demonstration area of a real distribution network ("cell"), where a new concept implementing new communication systems and new controllers into the production units of a region (cell) is being tested.

The following ambitions are aimed at [4], [5]:

- in case of a regional emergency situation reaching the point of no return the cell shall disconnect itself from the high voltage grid and transfer to island operation balancing production and load at every instant
- after a total system collapse the cell has black-start ability to a state of island operation.

On system wide level together with the Transmission System Operators of the Nordic neighbors Norway, Sweden and Finland different investigations are executed, as also is illustrated in Figure A-11:

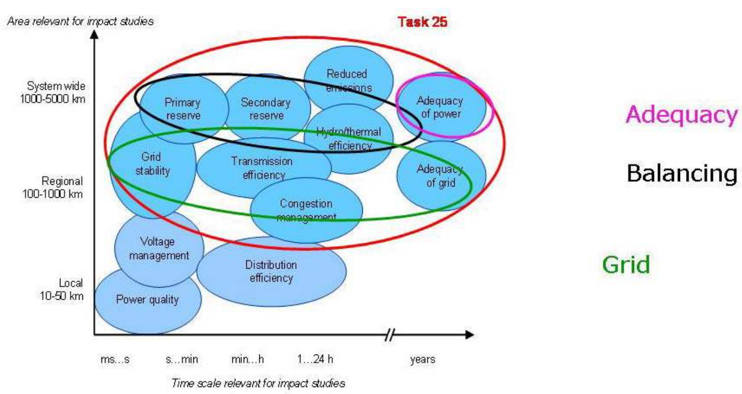


Figure A-11: Area and Time Scale for Impact Studies, Source [6].

In the context of adequacy investigations, reliability indices are calculated to estimate the future adequacy of power and energy. As mentioned above, the availability of wind power and CHP are important for the calculation of the LOLP.

Wind Power Availability

In the analysis of system adequacy the wind power is typically set to zero in deterministic calculations. The wind power might not be available in a critical load situation. By using probabilistic tools the wind power can be included in the calculation of probability of unserved energy.

The availability for offshore and land based wind power have different characteristics and are shown in Figure A-12.

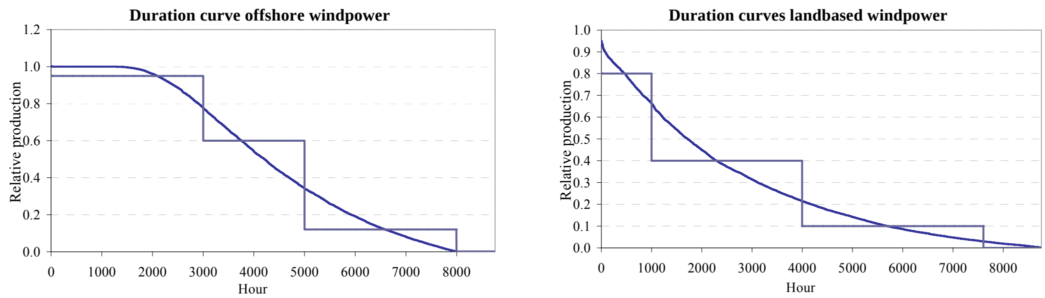


Figure A-12: Duration Curves for Wind Power: Offshore (left) and Land Based (right).

The figures are based on statistical information from wind power in Denmark.

The availability of offshore wind power is significantly higher than land based wind power.

For the probabilistic calculation of security of supply the correlation between wind power production and power demand is essential. A correlation between electricity demand and wind power is found, but the correlation is relatively low (typically below 0.20), see Figure A-13. This correlation might be increased by introducing a better price signaling to the electricity consumers in the future.

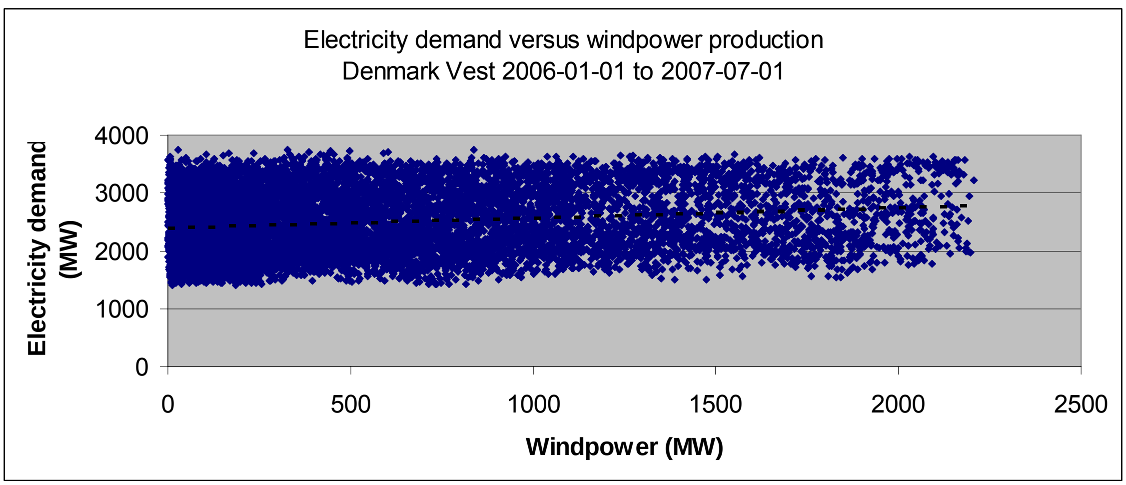


Figure A-13: Correlation between Electricity Demand and Wind Power Production in Denmark West.

Currently in Denmark the implementation of the instrument of price elastic demand is discussed, see Figure A-14. Thereby the elasticity coefficient of the demand curve is varied on the one hand, but afterwards this interacts with the production curve due to changes in import and export, which moves the production curve horizontally.

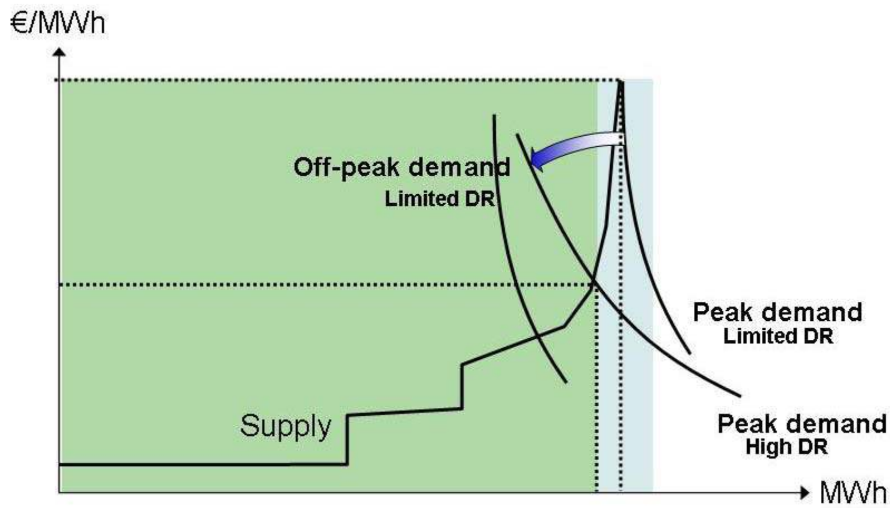


Figure A-14: Principle of Demand Response.

CHP-Power Availability

In Denmark more than 50% of the thermal electricity production is based on combined heat and power production. Thus, the contribution from CHP-electricity in the power adequacy cannot be neglected. In the period 1980-2005 the dispersed production was optimized to a tariff payment with three price-levels (peak-, high- and low-load). From 2005 the major part of all CHP-production is compensated according to spot-market prices. This has increased the participation of dispersed CHP in system adequacy, and a correlation of more than 0.8 is typically found between electricity demand and CHP-production, see Figure A-15.

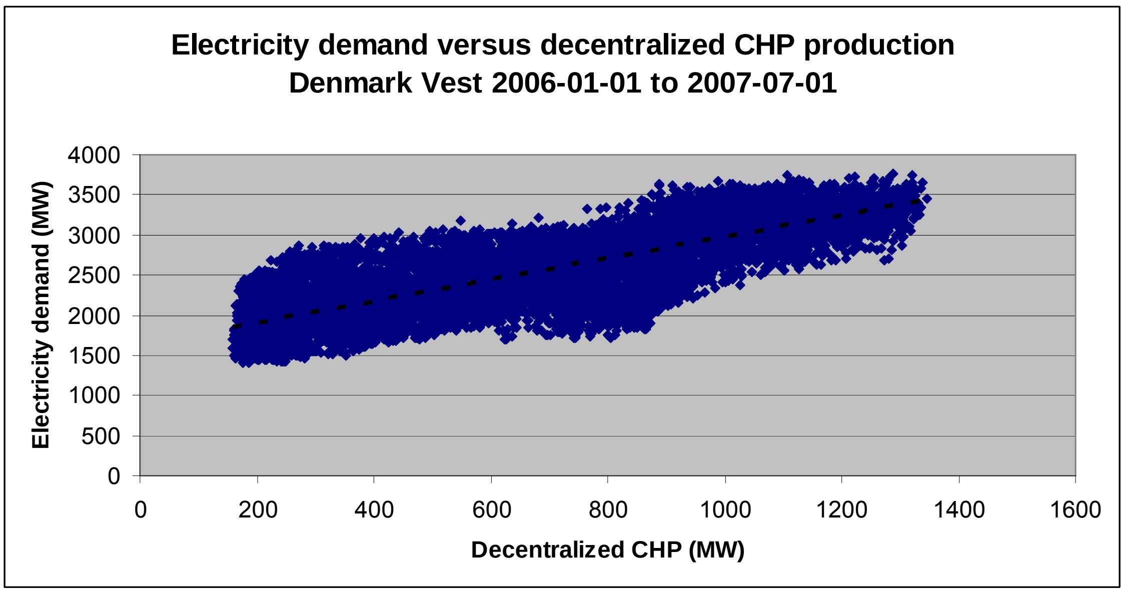
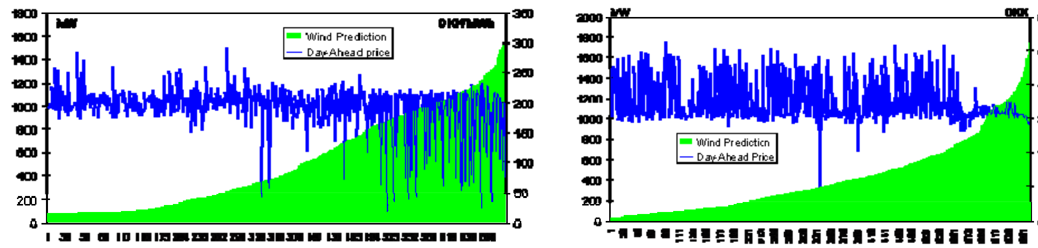


Figure A-15: Correlation between Electricity Demand and CHP-Production in Denmark West.

The dispersed CHP-production in Denmark had originally been designed to produce according to heat-demand. Separate electricity production is expensive for these units, and typically no cooling device is available at the plant. A relatively high heat storage capacity is available due to heat storage systems at the plant and due to high heat capacity in the district heating network.

In case of power shortage in the system, the CHP-units will typically be available for production. When the wind power capacity in the future is further extended, and the market gets even more volatile, it might be profitable for the CHP-plants to deliver system services and power backup even at times where no heat demands exist. There is a certain dynamics available, but in summer times, when there is limited heat demand, the dynamics is less than during the winter.

Since 2005 after redesigning the electricity market CHP units came stepwise to working on market terms. Since then the dependency of high wind prediction and low spot prices could be reduced, as shown in Figure A-16. Situations with exporting energy produced by wind turbines for a very low - even zero - price have been reduced. This helps also to relieve the transmission system, because the probability for congestions due to production of electricity by CHP units at times when there is an electricity surplus due to wind infeed, decreases.



a) February 2004 b) February 2006

Figure A-16: Dependency of Wind Power Prediction and Spot Price at Nordpool.

Probabilistic Calculation of System Adequacy

The Danish TSO Energinet.dk uses probabilistic tools developed in the Nordic region (MAPS) developed by Vattenfall or starts to use a tool like Assess/Metrix developed by RTE for calculation for system adequacy. MAPS is an abbreviation of: "Multi Area Analysis of Large Electrical Power Systems".

Both tools are used to estimate e.g. the effect of changes of reserve capacity, different load situations and different amounts of interconnections.

MAPS delivers reliability indices for each single simulated area as well as for the whole Nordic area. The Nordic system is divided into 16 areas, as is shown in Figure A-17.

Figure A-17: Simulation Area of MAPS Tool, Source [8].

MAPS includes generation as well as transmission and is based on a non-sequential Monte-Carlo method.

Indices such as EPNS, EUE and LOLP are finally delivered.

The EPNS shows the expected capacity shortfalls in the generation system within each time step in the given load curves. The EUE represents occasions, when the load demand exceeds available generation capacity. The LOLP is a measure for the probability of not being able to supply the load at a given point of time - thus it indicates the expected numbers of hours, on which a loss of load will occur. In NORDEL system an accepted value for LOLP is 0,001, which equals 9 hours per year [7].

The interdependency of these indices is shown in Figure A-18.

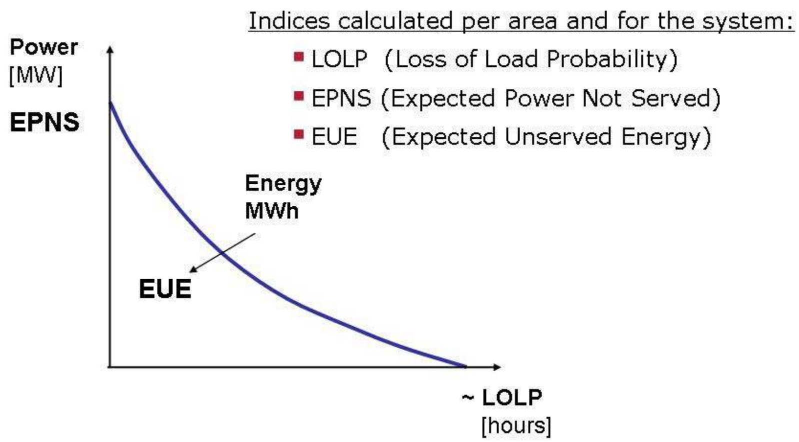


Figure A-18: Interdependency of Reliability Indices.

Necessary input values are:

- Load: The expected load and duration of peak period (stepwise duration curve consisting of 10 time sections).
- Generation: The generation capacity per unit which could be used in the specified peak period (incl. base and peak capacity), as well as the non availability for each unit (forced outage rate).
- Transmission: The transmission capacity between areas and its probability of being in operation, simple capacity model. The tool Assess offers the possibility of implementing load flow calculations instead.

MAPS generates tables for production capacity per area - i.e. the probability of production shortage for different power levels in the system. Then it generates tables for area loads and transmission links.

Depending on these tables it generates a network flow structure for the total system using a maximum flow algorithm. For each appearing shortage case the respective duration and consequently unserved energy is calculated. These values are finally summarized to the indices mentioned above.

As in general, also for the calculation of reliability indices it is evident, that the simulations depend on the quality of the input data.

Typically, the more classical approach of taking wind energy into account during adequacy investigations is setting the necessary generation input data for the wind contribution to zero due to its stochastic availability. This approach should be revised in future investigations. For CHP units the generation input data are set to a relatively small contribution with - compared to conventional units - a higher non-availability.

The system's utilization can be visualized in standardized diagrams, representing the most important input parameters: conventional production, load, wind power, CHP-production and electricity exchange, see Figure A-19. These parameters each have a minimum and a maximum value, indicated by dots, whereas up to now wind has been set to zero. The pictures below show two example situations indicating possible parameter combinations.

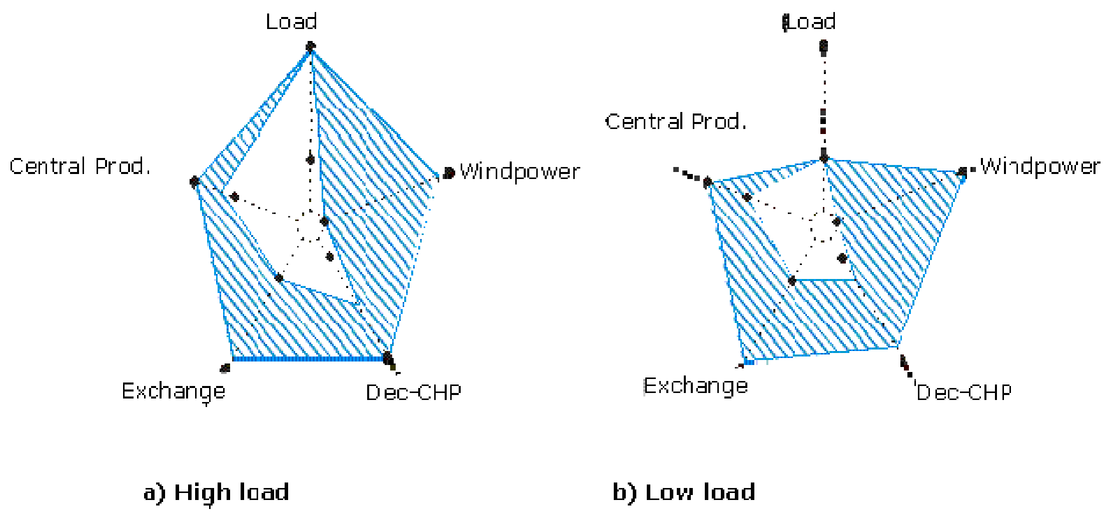


Figure A-19: Visualization of Load Situation indicating Different Parameters.

Critical situations are in practice typically found at high load / low wind power and/or low CHP production (a). Furthermore a situation with a maximum wind power and CHP production during low load will be a challenge for the system, but will not lead to a loss of load.

Considerations for Future Improvements

Considering the further growing share of wind power in the future power system it has to be discussed whether setting wind power to zero during adequacy investigation is a realistic way of modeling. The contribution of wind turbines cannot be neglected any longer, despite they are stochastic they have a certain capacity value for the power system.

Applying probabilistic analysis methods their contribution can be included calculating system adequacy, by using certain duration curves for offshore and onshore wind power availability, as have been shown above.

For the modeling of transmission lines and production units, valid input data, i.e. also representative statistical information about availability is important. This information should therefore be collected and managed by TSO's or other relevant parties. Usually they cannot directly be translated from one system to another, due to different framework conditions (salty air/ outages due to bush fires) and different maintenance strategies.

The improved implementation of power flow calculations instead of only taking transmission capacities into account would be profitable.

A satisfactory modeling of availability from CHP-units is essential in a system with high amount of production related to heat-demand. In today’s and even more tomorrow’s Danish system the CHP units behave according to market signals. It should be verified, if the modeling of this behavior is adequate.

In practice of probabilistic analysis today the incidents to transmission lines and production units are typically assumed to be uncorrelated and independent. However, in reality there are incidents which clearly are correlated, e.g. outage of lines due to weather incidents, or outage of power system devices due to a stressed operation situation as a consequence of an uncorrelated outage of some device or production unit.

Further investigations and statistical information are necessary in order to obtain an improved modeling of these correlated incidents.

References:

[1] Söder, L.; Hofmann, L.; Orths, A. et al.; Experience from Wind Integration in some High Penetration Areas, IEEE Transactions on Energy Conversion, vol 22 no. 1, March 2007.

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[5] Cherian, S.; Knazkins, V.: The Danish Cell Project - Part two - Verification of Control Approach via Modelling and Laboratory Tests, Proceedings of the IEEE Power Engineering Society General Meeting, 24-28 June 2007, Tampa, Florida, USA.

[6] Holttinen, H.; Meibom, P.; Orths, A.; et al: Design and Operation of Power Systems with large amounts of wind power - state-of-the-art report, IEA Annex 25, available at: http://www.ieawind.org/AnnexXXV.html

[7] Evaluation of MAPS, developed by Vattenfall. Date not available

[8] NORDEL: Methods for quantitative Assessment of Power Balances in the Nordic Power System. Final Report Phase 2.

Case 7 – Risk Analysis to Determine Operation Rules for Special Protection System in Hydro Québec

Country: Canada

Focus: Hydro-Québec TransÉnergie

Liberalization: Hydro-Québec unbundled its operations in 1997 and created Hydro-Québec TransÉnergie. Hydro-Québec TransÉnergie operates the transmission system. It manages power flows throughout Québec and markets system capacity, while maintaining the necessary standard of reliability. The division offers non-discriminatory access to Québec's transmission system to all customers on the wholesale market in northeastern North America.

Transmission expansion: In Québec, Hydro-Québec TransÉnergie ensures the long-term operability and growth of the transmission system with a view to sustainable development. The division's operation are regulated by the Régie de l'énergie (Energy Board), which sets the rates on the basis of cost of Service. The Régie also approves the division's capital investments and terms of service. Both its rates and its capital projects must be approved by the Régie.

Operation planning case: Some settings of a special protection systems was optimized by taking into account the occurrence degree of the network configuration and/or the fault to be considered and their impact on the security level.

Table A-4: Normal and extreme contingencies.

Normal Contingencies (Without SPS action and load loss)	Three phase fault with normal clearing
	Single line to ground fault with delayed clearing
	Breaker fault with normal clearing
	Loss of a bipolar dc line
	Loss of double-circuit line
	Loss of any element without fault
Extreme Contingencies (SPS and load loss allowed)	Single line to ground fault with loss of two series or parallel 735 kV line
	Loss of all 735 kV lines emanating from a substation
	Loss of all lines in a corridor
	Loss of two parallel 735 kV lines and bypass of all series capacitors on the remaining line in the same corridor

At Hydro-Québec, operation planning studies for maximum transmission capacities and automata settings (SPS) are currently accomplished with a deterministic approach. With this approach, to limit the study duration, the transmission capacities are assessed to cover only the worst possible contingency which is applied to a power system with a severe initial operating condition. So, this approach allows the coverage of a maximum of configurations but the automata settings are generally adjusted in a conservative way.

This conservative setting leads to oversized SPS action. So, during a real event, this action is often too powerful considering the event severity and affects service quality on customer side. Also, if a misoperation occurs and triggers an automat, there may be an unnecessary load shedding. Therefore, an equilibrium has to be kept between the magnitude of the SPS action needed to cover a maximum of operating possibilities, the quality of service for customer and the risks during untimely SPS operations.

To optimize these conservative settings, operation planning engineers have proceeded with a risk analysis method [1]. This statistical and probabilistic approach takes into account the occurrence degree of the configuration and/or the fault to be considered. The impact is assessed in time domain simulation. The automata operation rules and settings are assessed over a large number of real time snap shots coming from the control center data base. This approach has been used to optimize the special protection system – the RPTC system ("Rejet de Production et Télé délestage de Charge" in French) which activates the generator rejection and remote loading scheme.

Context

The operation criteria at Hydro-Québec require that the power system remains stable without any assistance of Special Protection Systems (SPS) following normal contingencies (Table A-4) [2]. These normal contingencies are hence used to determine the secure transfer limits for the various corridors of the system, in compliance with the Northeast Power Coordinating Council (NPCC) criteria.

In addition to these requirements, Hydro-Québec considers that it is also important for the system to remain stable after certain extreme contingencies (Table A-4) [3]. The system stability is maintained by Special Protection Systems. According to the event and the configuration of the power system, the special protection system – the RPTC system activates the generator rejection and remote load shedding scheme. Figure A-20 gives an overview of the basic structure and the general operation of the RPTC system. RPTC systems are installed in fifteen 735 kV substations of the Hydro-Québec system. The subsystems in a same corridor (or main axis) are combined into an independent group. There are a total of 4 groups of RPTC systems shown in dark shaded areas in Figure A-20. Each group of RPTC performs, associated with independent Special Protection Systems, the generation rejection scheme at one particular generation site while the remote load shedding function is centralized.

The operation rules of these protection systems are complex to establish because of the large number of network configurations to be covered, the dispatch of production for these configurations, as well as the great quantity of possible events. The proper level of generation rejection and remote load shedding must be programmed. Conventionally, the settings of these RPTC systems were defined using deterministic techniques, which focus on the worst-case scenarios. Therefore, it is difficult by the deterministic approach to find an optimal level of generator rejection and remote load shedding. The approach by the risk analysis is a more effective method for the design of these rules by ensuring a maximum degree of coverage while minimizing the level of action taken by RPTC automata and the consequences of an untimely automata action.

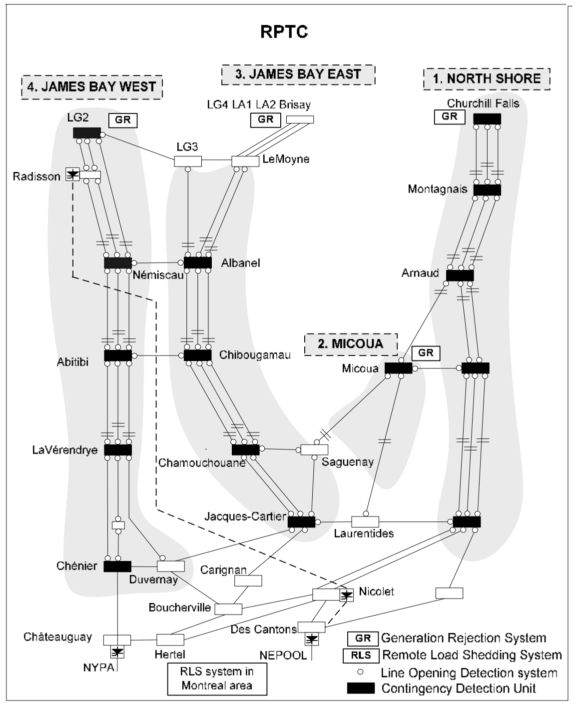

Figure A-20: RPTC system.

Methodology

The approach is developed to improve operational rules of special protection devices used to protect Hydro-Québec power system against extreme contingencies. Figure A-21 illustrates the flow chart of this approach designed to create and improve operational rules. There are mainly two modules in the approach: Database Generation (DG) and Rule Generation and Evaluation (RGE). The Database Generation takes advantage of in-house data retrieval program which gives the possibility to access a database of power system real time snapshots (power flow and dynamic data) collected periodically each five minutes over a long period of time. After choosing a large number of representative samples among these real cases, transient stability simulations are performed to evaluate the power system behavior under the extreme contingencies. Large amounts of results corresponding to these simulations are generated and stored for RGE module.

In RGE module, correlation analysis is initially performed to eliminate redundancy among the parameters and variables first selected as potentially relevant for specified study. An analysis is then performed with the remaining parameters and variables by using data mining tools [4] which builds regression trees using the control parameter of the special protection system as a goal attribute (for example: number of generator groups to be tripped, level of loads to be shed, etc.). In this way, the more relevant parameters and variables that can be used for the settings of the special protection system are identified and positioned at the top of the tree. New simplified regression trees are then built in the same way with a limited set of the most relevant parameters and variables chosen from the preceding set by the operation planning engineers. Many trees can be built by this process. These trees are translated into rules by adjusting thresholds and eliminating some tree nodes. Results of rules are compared and validated by their performance and degree of coverage for stability. The one rule which gives the best overall performance is chosen for the special protection system.

This last set of rules is reviewed by the operation planning engineers in charge of these devices and is used to elaborate the final set of rules to be implemented in the field. Some considerations (like reliability of the relevant parameters or variables inputs or like future addition of new equipment or removal of equipment for maintenance, not covered adequately by the data mining process) are then taken into account to make some final adjustments to the rules. This final set of rules is then validated with a large independent set of real case snapshots by simulation and compared with the rules used in the field. The risk level is also evaluated by degree of coverage for stability. If the results are satisfactory for the operation planning engineers, then the operation rules are programmed and updated in the control centre.

The construction of decision trees has been achieved by using data mining software [5].

Data base generation approach

The statistical approach used requires the processing of a very large quantity of results generated by numerous scenario simulations. Each scenario is composed of a power flow snapshot of the network with the disturbances. The simulations have typically a 10 second time frame and are performed on a PC network using a transient stability program. The approach has to generate pessimistic scenarios in order to cover adequately the critical situations where the RPTC automatic device operates with a good variance on the critical parameters and variables.

Two approaches have been initially envisioned:

- In the first approach, the generation of scenarios is done from a limited number of power flow base cases corresponding to real operating situations. These cases are then modified according to certain rules and the corresponding scenarios are simulated in order to create many critical situations for the RPTC system.

- In the second approach, the scenarios are generated from snapshots of real operating cases taken periodically over a long period of time (years) and disturbances critical for the RPTC system are simulated. These snapshots are stored in the control center database and are made available for planning and operation planning engineers through an in house data retrieval program.

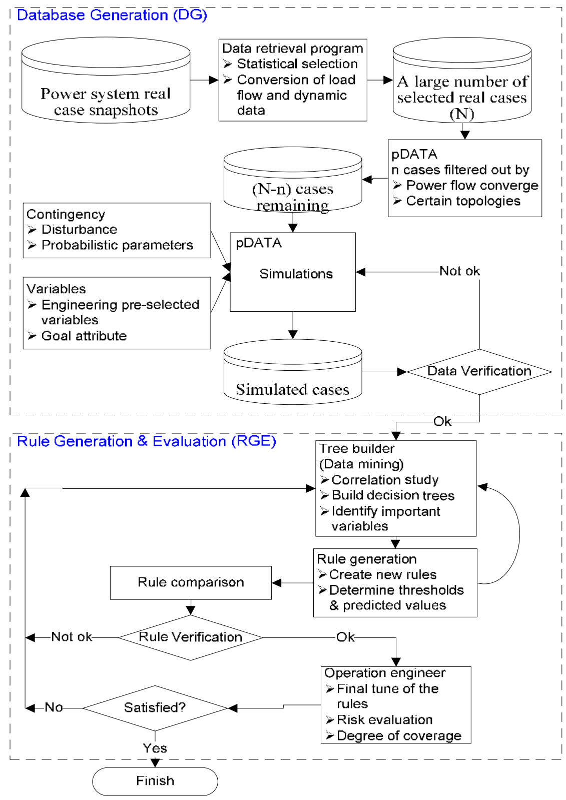

Figure A-21: Flow chart of rule generation for SPS.

Particular care has to be taken in the data generation process to avoid overrepresentation of non-relevant cases.

The results from the first approach are biased due to the overrepresentation of critical situations with in fact very low probability. This could be corrected only if probability data are available on disturbances and/or operating conditions. Therefore, the second approach, which has been retained, seems more appropriate due to the fact that all operating cases used are real and can be selected to cover adequately the envisioned power system conditions.

Control software (pData) was developed to filter snapshot cases in order to keep just the relevant ones (cleaning process). For each filtered case, pData software builds the disturbance to be simulated as a function of the peculiarities of the studied case.

From transient stability simulations, pData determines by an iterative procedure, for each case, the goal variable. The goal variable is depending on the type of studies, the consequence which could be the minimum number of units to be tripped, the amount of loads to be shed, or both.

Finally, pData extracts results and saves some engineering pre-selected relevant parameters and variables to simulated database which will be used for Rule Generation and Evaluation. It is important to validate the correctness and validity of the data. Any errors in the data will lead to wrong results. Quite often, results have to be re-simulated due to missing information or errors.

Rule generation and evaluation

Tree construction is based on data mining techniques [4]. Classification induction methods are used to construct decision trees [5]. Based on the information provided by decision trees, rules are generated.

Data mining refers to the extraction of high-level synthetic information (knowledge) from databases containing large amounts of low-level data.

Decision/regression trees

A decision tree (DT) is a map of the reasoning process. This data mining technique is able to produce classifiers about a given problem in order to deduce information for new, unobserved cases. The DT has the hierarchical form of a tree structured upside-down and is built on the basis of a Learning Set (LS). The LS comprises a number of cases (objects). Each case consists of pre-classified operating states (described by a certain number of parameters called candidate attributes), along with its correct classification (called the goal attribute). The candidate attributes characterize the pre-disturbance operating points in terms of parameters which can be used to make decisions. The tree building process seeks to build a set of rules relating these attributes to the goal attribute, so as to fit the learning set data well enough without over-fitting this data. The resulting tree is tested on a different data set (test set) where the prediction of the goal attribute by these rules is compared with the true class (determined by simulation) for each test case. The classification error rate for the test set measures if the method is successful or not.

There are many reasons to use decision trees. The first is their interpretability. A tree structure provides the information of how an output is arrived at. Another very important asset is the ability of the method to identify among the candidate attributes the most relevant parameters for each problem. A last characteristic of decision trees is its computational efficiency. The particular decision/regression tree induction method used for this task is described in details in [5].

Rule and risk evaluation

As mentioned earlier, decision trees can identify the most relevant parameters among the candidate attributes. Based on this information, many trees are constructed by selecting different set of relevant parameters. These trees are then translated into rules (if else) and put into excel sheets for tuning and comparing the performance. Performances of the rules are evaluated by their precision and risk level. The precision is measured differences between predicted variables and simulated variables. The risk level is the degree of coverage for stability.

Rules given directly by decision trees are unbiased estimates of the true value. Results could lead in unstable cases. Therefore, it is necessary to tune the rules in order to eliminate the unstable cases as many as possible while maintaining the precision. Tuning process is done by adjusting thresholds for each parameters and modifying values at terminal nodes of trees. Some weighting factors can be used to penalize the case where the predicted variables are far from simulated variables. If rules are not performed well, then the process has to go back to the tree builder to construct more trees.

The risk level is evaluated by the percentage of number of unstable cases given by the rule over total number of cases in the database containing simulation results. High level coverage for stability means high percentage of stable cases given by the rule.

The rate of acceptable coverage varies from event to event. It has to consider the consequences and the probability of occurrence of studied events. If the event leads to a loss of synchronism for the main grid, a high coverage rate will be required. Further more, if this event has already occurred in the past, an even higher coverage rate shall be required. On the other hand if the event does not lead to a loss of synchronism on the main grid, but to a frequency variation within acceptable limits, a lower coverage rate can be accepted. These considerations are qualitative and are based on the judgment and the experience of operation planning engineers. Generally, the coverage rate given by the new rule should be higher than the existing rule.

Table A-5: Generator Unit Tripping Scheme.

Modulation: 3 links at Churchill Falls	
Margin At Churchill Falls:	Units to be tripped
400 MW and less	8
401 to 700 MW	7
701 to 1000 MW	6
1001 to 1200 MW	5
1201 to 1400 MW	4
1401 to 1600 MW	3
1601 to 1800 MW	2
1801 to 2000 MW	1
2001 MW and more	0

Application example

The methodology described before was applied to find the settings for SPS of RPTC at the Churchill Falls substation.

To ensure network security and to avoid an unnecessary generation tripping, the number of generation units associated with the generation tripping scheme is adjusted to the loading and the configuration of the Churchill Falls – Arnaud corridor (North Shore indicated in Figure A-20). Table A-5 presents the rules determined by the conventional approach. The margin represents the difference between the maximum power transfer considering normal contingencies and the measured power transfer. The table gives the number of units to be tripped based on the margin.

A database was generated by using pData program described in the previous section. Using the generated database, correlation studies were performed. Table A-5 lists the statistics of the generated database. Among the 2130 cases for which the current rules tell us to trip 8 units, there are 1925 cases which need less than eight (down to zero) unit tripping. More synthetically, if we count among these 2130 cases the difference between the number of units required to trip by the current rules and the actual number of units necessary to be tripped according to the simulations, it is found that 33% of generator units (5643 units) are unnecessarily tripped with the currently used 8 units tripping rules.

The current rules are highly conservative and could possibly be improved by taking into account not only the margin but also the total power transfer through the Churchill Falls corridor in their formulation.

Constructions of regression trees were carried out on the generated database. Among 4560 objects (cases), 2000 objects were selected as a learning set and the remaining 2560 objects were comprised as a test set. The goal is to predict the minimum number of generator units to be tripped. Figure A-22 shows a constructed regression tree. The tree is to read top-down: each internal node corresponds to a test on one of the candidate attributes and the terminal nodes correspond to decisions about the number of units to be tripped.

Notice that among the 236 candidate attributes proposed to the tree building software, only 10 attributes were identified as important variables to decide on the number of units to be tripped.

By construction, the predictions of the regression tree are unbiased estimates of the true values; this means that their errors are both negative and positive. In practice, it may be preferable to have rules that have less negative errors (too few unit tripping – under-tripping) than positive ones (too many – over-tripping) because the cost of instability is much higher than the cost of unnecessarily tripping one or two more units. Such a bias can be introduced as a post-processing of the regression tree output, for example by adding some positive constant to its predictions before rounding up to the nearest integer.

Table A-6: Statistical data of unnecessary tripped units from the generated database.

# Of Units to Trip	Number Of Cases			Over-tripping		
	With Current Rules	Of Matched Tripping	With Over-tripping	# of Units	Average per case	Rate (%)
8	2130	205	1925	5643	2.65	33
7	647	93	554	1818	2.81	40
6	626	15	611	2288	3.65	61
5	135	0	135	625	4.62	93
4	278	0	278	1047	3.77	94
3	159	0	159	477	3	100
2	157	0	157	314	2	100
1	58	0	58	58	1	100
0	370	370	0	0	0	0
Total	4560	683	3877	12270	2.70	44

Although the regression tree gives much better results over the existing rules, the under-tripping rate is still too high and cannot be accepted by operation planning engineers. From the regression tree, it is observed that some important variables appear on the tree such as the transfer margin on the Churchill Falls corridor and the spinning reserve at Churchill Falls generation station. The new rules based on these two variables are established and shown in Table A-6. The new rules can also be illustrated in Figure A-23. The reason to choose the margin and spinning reserve is that the margin represents two variables: transfer and limit which implies the network topology, while the spinning reserve represents both the number of generators on line and the amount of power generated in the plant. It is also believed that rules expressed in terms of these two variables are more relevant for operation planning engineers since they should be more robust with respect to future addition of new equipments or removal of equipments for maintenance.

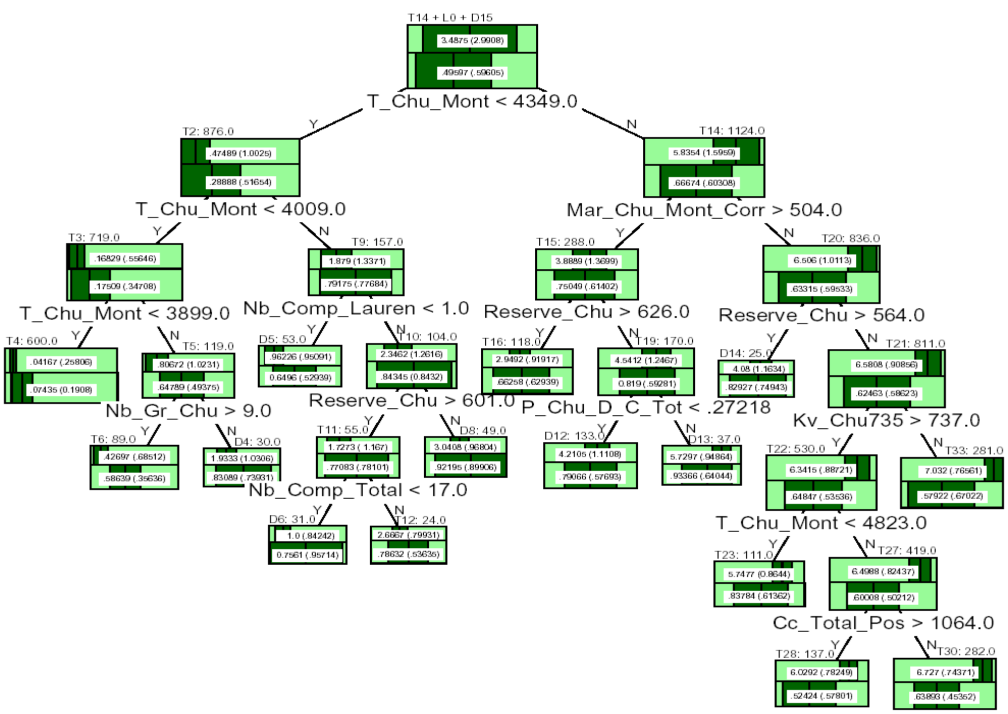

Figure A-22: Regression tree to predict number of generator unit tripping.

<u>Comparison of results</u>

Table A-7 lists the average of over-tripped units per case. Although this value may not have a direct physical meaning, it is used here as an indication of the improvement of the different methods tested. The first line of the table refers to the rules actually in use, and designed by the classical deterministic method. The second line gives the results obtained by rules of a post-processing of the regression tree of Figure A-22. Third line gives the performance of the new rules designed by hand from taking into account both margin and spinning reserve at the Churchill Falls power plant. The post-processing consists in adding a positive bias of 0.45 to the predictions of the tree and round up to the nearest integer (ceiling function). It can be seen that the regression tree has the least average value of over-tripped generator units per case. This means that if the regression tree rules are implemented, the number of generator unit tripping will be closest to their minimum among all other methods.

Figure A-24 shows the frequency diagram of mis-tripped generator units for different methods. The term of "mis-tripped" unit is defined as the difference between simulated optimal unit tripping and the number of units tripping prescribed by a rule. A positive value means generator units are over-tripped while negative value means under-tripped with respect to the value determined by simulations. From this diagram, one can observe that the distribution of mis-tripped units by the current rules is widely spread while that of the regression tree is concentrated. In most cases, the regression tree gives one generator unit over-tripping while the current rules sometimes gives 8 generator units over-tripping. The results from the regression tree are very promising, but more efforts have to be made to eliminate under-tripping cases.

Table A-7: Average of over-tripped units per case.

Methods Used	Average
Current Rules	2.70
Regression Tree with Post-processing	1.08
New Rules with two variables	1.62

The new rules combining two variables further eliminate the under-tripping cases. Despite it sacrifices the accuracy of generator tripping, the results are more reliable and acceptable by operation planning engineers. It also reduces the error of over-tripping cases. Furthermore, the new rules are quite simple and easy to be implemented.

Table A-8: The new rules combining two variables.

Rules for spinning reserve at Churchill		**Rules for transfer margin**		**New rules combining the two variables**
Values of reserve	**Number of gr. to trip (A)**	**Values of margin**	**Number of gr. to trip (B)**	
≤ 500	8	≤ 600	8	
501 to 600	7	601 to 800	7	
601 to 700	6	801 to 900	6	
701 to 900	5	901 to 1000	5	
901 to 1000	4	1001 to 1100	4	Min(A,B)
1001 to 1100	3	1101 to 1200	3	
1101 to 1200	2	1201 to 1300	2	
1201 to 1300	1	1301 to 1600	1	
≥ 1301	0	≥ 1601	0	

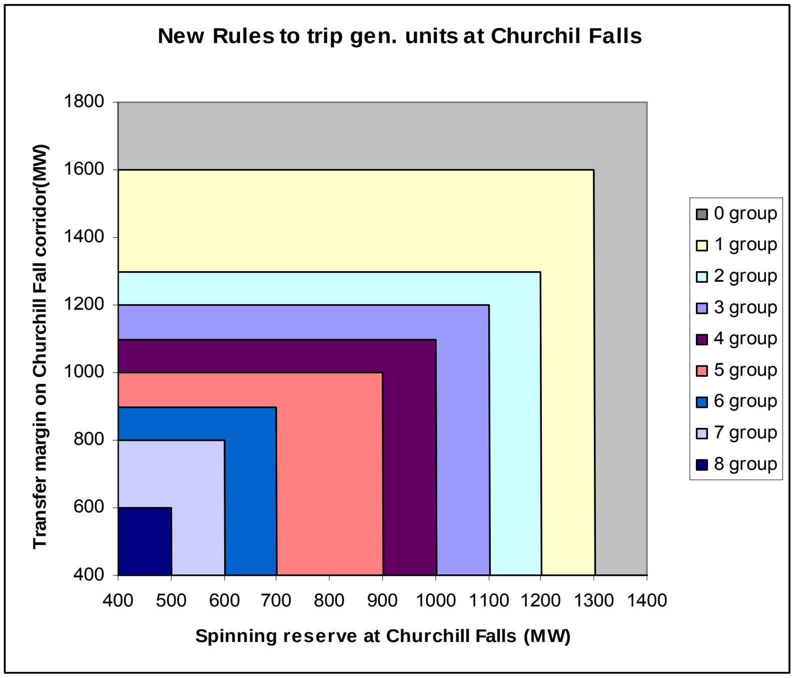

Figure A-23: New rules combining two variables.

Benefits

The application of this approach makes it possible, in particular, to minimize the number of generators tripped by the RPTC system for a large number of network conditions, while maintaining the same performance in terms of security coverage and impacts. New operations rules can thus be established and analyzed by operation planning engineers. This approach allows a larger view of the problem and has given interesting feedback on the deterministic result. It has confirmed sensitivities variables and has given access to relevant statistical analysis. Other applications of this approach are being considered at Hydro-Québec in the coming years for other automata settings validation and optimization and process optimization for dynamic security assessment.

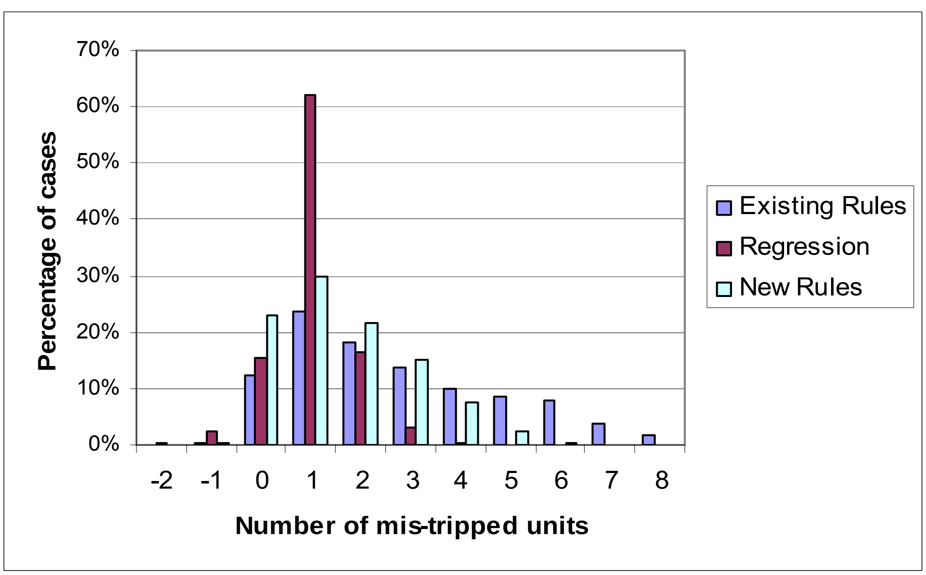

Figure A-24: Comparison of results of different methods.

Experience issues for TransÉnergie operation planning

Based on RPTC setting experience, some points are interesting to discuss:

- Generation of the database: Since a probability measure requires a set of value, the initial database is critical for the right attributions of probability. It has to be appropriate and representative of the phenomena. Data must be validated and checked in order to correct any errors or wrong results.
- Changing conditions: Our approach, based on historical conditions, gives a realistic picture but is difficult to predict the future. If there are new equipments or new operating strategies, it could affect the right adequacy of the database.
- Many iterations were required to determine which variables and parameters values are the most important
- Filtering and correlation necessity: Finding the right trees requires filtering and correlation, otherwise it is too complex to grasp.
- Tuning process: Rules given by one decision tree, were tuned by adjusting threshold for each parameters based on the problem and results.
- Extensive data manipulation: A friendly software environment is a must for easy extensive data manipulation.
- Expertise and know-how: A lot of expertise and know-how were needed in order to validate results, interpreted them correctly and evaluate their impact on the setting problematic

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APPENDIX B – LONG TERM OPTIMIZATION FOR RISK ORIENTED ASSET MANAGEMENT

B.1 Introduction

Realizing an efficient balance between reliability and economic benefits by maintaining and renewing power supply systems is the main goal of technical Asset Management techniques [1]. The network operator must obtain an appropriate-ate yield under observance of defined service and safety standards over the entire service lifetime [2]. One major question is the most efficient use of financial resources for maintenance and renewal of assets to reach a maximum quality standard. In this context, the risk-oriented Asset Management becomes more and more important. The main goal of this strategy is the monetary modeling of the asset importance and the quantitative modeling of the failure probability [3]. The combination of both parameters leads to the individual failure risk. The assessing of individual asset risks compared to others is the basis for an optimal assignment of maintenance and renewal measures [4].

The risk oriented maintenance is a derivative of the reliability centered maintenance (RCM, [5]-[7]), which has a large significance for the planning of maintenance and renewal measures in power systems [8]-[9]. Indeed, the calculation of individual cost-benefit relations is impossible, because the used parameters are modeled by normalized values in defined ranges. So, a monetary equivalent for the urgency of a measure cannot be estimated. Furthermore, it is impossible to quantify the benefits carrying out a maintenance or renewal measure. It is the goal of the approach presented in this paper to quantify the monetary risk value in dependency of maintenance activities on the one hand and individual cost-benefit relations on the other hand. This is the basis for the presented optimization model.

B.2 Risk Model

In this approach, the failure risk $\boldsymbol{R_n^t}$ of any asset $\boldsymbol{n}$ at the point in time $\boldsymbol{t}$ is calculated by (1).

$$\boldsymbol{R_n^t} = \boldsymbol{p_n^t} \cdot \boldsymbol{S_n} \qquad (1)$$

with:

$$0 \le \boldsymbol{p_n^t} \le 1, \ \boldsymbol{S_n}[€] \ge 0 \qquad (2)$$

The total risk $\boldsymbol{R_{tot}^t}$ of a group consisting of $\boldsymbol{N}$ assets is the sum of all individual risks according to (3).

$$\boldsymbol{R_{tot}^t} = \sum_{\boldsymbol{n}=1}^{\boldsymbol{N}} \boldsymbol{S_n} \cdot \boldsymbol{p_n^t} \qquad (3)$$

Both parameters are modeled by statistical approaches on the one hand and historical data analyses on the other hand [10]-[15]. The probability of failure depends on the time intervals since the last maintenance and renewal measures. The loss costs contain the expenses for repairing, monetary fines in the case of interruption, not supplied energy and image losses.

B.2.1 Risk map

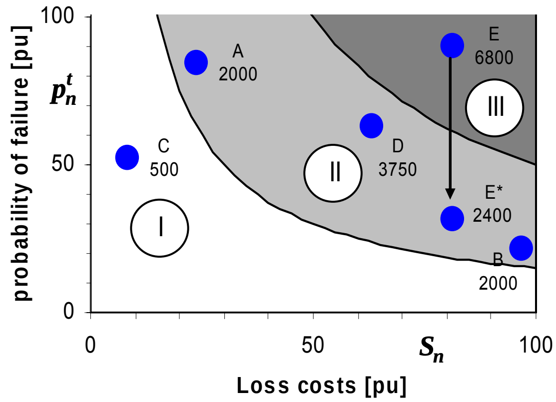

Figure B-1: Example risk map for HV assets.

The graphical illustration of the individual risks takes place in a risk map as shown in Figure B-1. Thus, a clear representation as a kind of screenshot of the actual risk situation is feasible. In this example, the single risks of five HV assets (A-E) are illustrated as dots. Furthermore, the respective risk values are displayed. The risks are affected by maintenance and renewal measures. In this case, the probability of failure decreases like it is illustrated for asset E exemplarily. This causes a suspension of the respective dot parallel to the ordinate. If no action is taken, the probability of failure will rise. The risk map is divided into three sectors (I-III), which indicate different risk grades. A quite common way for the as-assignment of individual measures is a categorization according to the area, in which the asset risk is situated.

Then, the measure that should be practiced at a single asset depends on the location of the risk dot and could be declared as follows:

Area I:	no measure
Area II:	maintenance
Area III:	renewal

This procedure allows a standardized method for the prioritization of a large number of Asset Management measures. However, it bears several drawbacks. The parting lines of the three areas cannot be defined but are depending on subjective experiences or further presetting. Indeed, a movement of these lines has a significant influence on the scheduled measures and the resulting total risk. Furthermore, the fact that maintenance and renewal measures at different assets lead to various resulting risks and costs is unconsidered. For example, according to the reliability model described above, a renewal of an elder circuit breaker is more effective than a renewal of a younger one. Another aspect is the difficulty of exhausting the budget in an optimal way because of different maintenance and investment costs.

To reach an optimal benefit under consideration of a fixed budget and further technical, economical and operational constraints, this model is formulated in terms of a mixed integer optimization problem.

B.3 Optimization Model

For a sustainable planning of Asset Management measures the holistic optimization for a long term period of time is necessary. By this means, future adaptations concerning budgets and further resources are regarded. Furthermore, this aspect is very important in view of inhomogeneous ageing structures. Assuming a rising demand of renewals in future it is important to unify the yearly

measures to redeem fixed resource limits. This can only be realized by regarding a long term optimization horizon of $\boldsymbol{T} > 1$ years.
Furthermore, it is important to consider different types of assets. For example, it is advantageously to optimize the schedules for the maintenance of whole substations. By this means, the costs for maintenance and renewal are reduced by realizing synergy effects.

Various technical, economical and operational boundary conditions have to be considered. They are modeled by linear constraints, so that the whole problem is based on mixed integer linear programming (MILP). As Asset Management measures are planned and performed once a year in general, discrete decision variables for a time period of one year are used. Again, the three alternatives mentioned in chapter 2 are considered.

B.3.1 Optimized schedules (fixed budget)

Assuming a fixed yearly budget $\boldsymbol{B^t}$ for maintenance and renewal, the following constraints are regarded:

- Total annual costs $\boldsymbol{K_s^t} \leq \boldsymbol{B^t}$
- Max./min. rates for maintenance and renewal
- Max./min. time intervals for maintenance and renewal
- Quality standards
- Max. failure risks

The objective of the optimization method is the minimization of the total failure risk over the whole optimization period. If it is assumed that the budget planning is carried out by a separate procedure so that the yearly monetary limits are well known for the whole period, the objective function is formulated according to (4).

$$\min \sum_{t=1}^{T} \sum_{n=1}^{N} (\boldsymbol{S_n} \cdot \boldsymbol{p_n^t}) = \min \sum_{t=1}^{T} \boldsymbol{R_{tot}^t} = \boldsymbol{R_{tot,T}} \qquad (4)$$

B.3.2 Budget optimization

In practice, the process of budget fixing is a complex procedure, which depends on various experiences and subjective recommendations. Hence, it is important to support the decision making in this context by systematic and objective methods. By means of quantifying the failure risk of a power supply system using the described risk model it is now possible to analyze the quantitative influence of budget variations. It can be determined, if a reduction or an increase is useful or not. As the failure rate of the whole asset group decreases, if the number of measures increases, the minimum total risk $\boldsymbol{R_{tot,T}}$ is obtained, if the yearly budgets are exhausted to a large extent. Hence, the yearly costs for Asset Management of a large group are nearly in accordance with the yearly budgets:

$$\boldsymbol{K_{tot}^t} \approx \boldsymbol{B^t} \qquad (5)$$

If the budget is increased, the failure risk decreases. Indeed, this dependency cannot be estimated without carrying out an optimization calculation for different budget values, so that it is impossible to model $\boldsymbol{R_{tot,T}}$ as a function of all $\boldsymbol{B^t}$ within the optimization horizon. The qualitative relationship is illustrated in Figure B-2 for an optimization horizon of $\boldsymbol{T} = 1$ year. It is assumed, that the failure risk should decrease stronger than the budget is increased. In other words, a profit in the sense of risk reduction is realized using the budget for maintenance and renewal. The green line in Figure B-2 represents the annual costs weighted with a profit expectation:

$$\boldsymbol{K_{tot,I}^t} = \boldsymbol{K_{tot}^t} \cdot (1 + \boldsymbol{I}) \qquad (6)$$

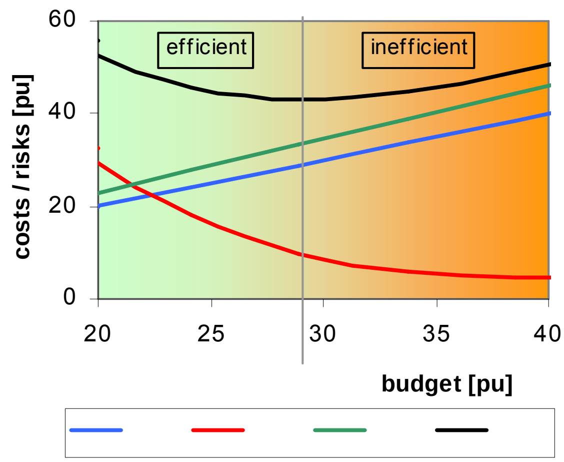

Figure B-2: Budget optimization (qualitative example).

The black line illustrates the sum of weighted costs and the corresponding budget (risk costs):

$$\boldsymbol{K}_{risk}^{t} = \boldsymbol{R}_{tot}^{t} + \boldsymbol{K}_{tot}^{t} \cdot (1 + \boldsymbol{I}) = \boldsymbol{R}_{tot}^{t} + \boldsymbol{K}_{tot,I}^{t} \qquad (7)$$

The minimum can be interpreted as the point of the optimal budget $\boldsymbol{B}_{opt}^{t}$. Here, the profit expectation is complied exactly and the risk is as low as possible. The area on the right hand side of this point leads to inefficient results. If the budget is increased, the risk is reduced at a lower level. Compared with this, the profit expectation is surpassed in the area of the left hand side. However, the risk is significantly higher.

According to the preliminary considerations, the objective function for the budget optimization is enhanced pursuant to (8).

$$\min \sum_{t=1}^{T} \boldsymbol{K}_{risk}^{t} = \boldsymbol{K}_{risk,T}^{t} \qquad (8)$$

B.4 Example Results

The developed methods are applied on a group of HV circuit breakers. For the further exemplary calculations, an optimization period of $\boldsymbol{T} = 5$ years is chosen (calendar years 2007-2011). Figure B-3 represents the optimization results of the first year within the planning horizon. It is assumed that a fixed yearly budget is known. The illustration complies with the risk map of Figure B-1. Moreover, the individual measures, which lead to the minimum total risk in terms of the objective function (9), are marked. The red dots represent renewals, whereas the maintenance measures are marked by blue dots. All further assets are marked green. The assignment of measures does not correlate strictly with the risk dot positions on the risk map. The parting lines as shown in Figure B-1 do not exist. This becomes obvious by means of the isorisks in Figure B-3, which represent points of constant risk values.

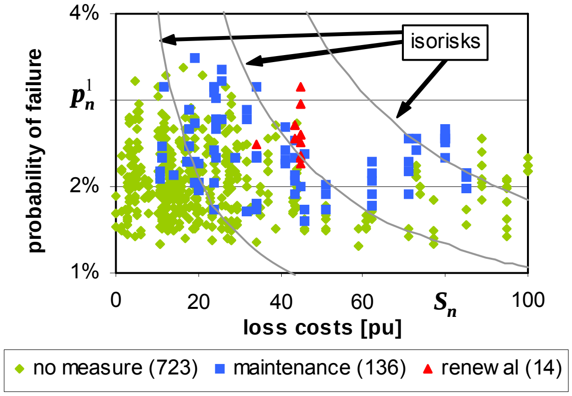

Figure B-3: Schedule for HV circuit breakers.

The benefits of a long term optimization compared to an assignment based on a yearly view are analyzed in the following. Therefore, the results are compared with those based on a yearly observation period, which is called the reference scenario. For this, every year of the observation period is optimized separately using the results of the previous years. If the budget is fixed, the objective functions are calculated step-by-step according to (8).

$$\min(\boldsymbol{S}_n \cdot \boldsymbol{p}_n^t) = \boldsymbol{R}_{ref,t} \quad \text{for} \quad 1 \le \boldsymbol{t} \le \boldsymbol{T} \qquad (9)$$

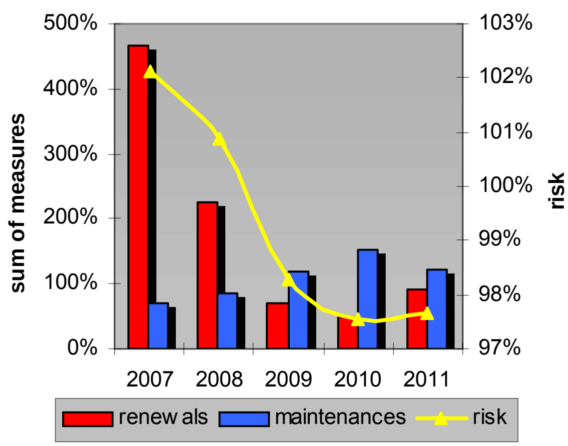

Figure B-4: Yearly results compared to reference scenario.

The results of the holistic optimization in relation to the reference scenario are illustrated in Figure B-4. It contains the numbers of yearly renewal and maintenance measures (left ordinate) as well as the resulting yearly risks (right ordinate).

The renewal rate (red) at the beginning of the optimization horizon is significantly higher than this of the reference scenario. In the first year, it is nearly five times higher. Compared with this, the maintenance rate (blue) is lower. By regarding a longer time period, the long term benefit of renewals is exploited. The higher renewal rate at the beginning has a positive impact on the long term risk situation. The medium risk is about 1% lower compared to the reference scenario. It becomes obvious that the long term optimization is much more efficient than the yearly one. The capital costs (CAPEX) are significantly higher and the operational expenditures (OPEX) lower, if the optimization horizon is analyzed as a whole.

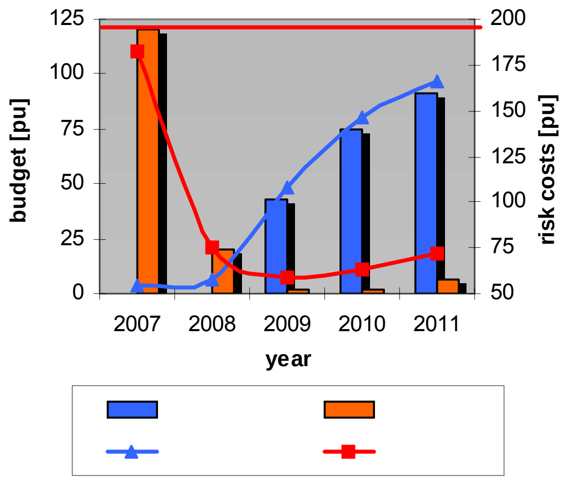

Figure B-5: Budget optimization.

Figure B-5 shows the results of the holistic budget optimization (red) and those of the corresponding reference scenario (blue). The bars represent the optimal yearly budgets $\boldsymbol{B}_{opt}^{t}$ (left abscissa) whereas the resulting risk costs $\boldsymbol{K}_{risk}^{t}$ are rep-resented by dots (right abscissa). The yearly budgets are bounded on a maximum value of 120 pu, which is a value 20% higher than this used at the optimization with fixed budget described above. For the profit expectation, the value $\boldsymbol{I} = 10\%$ is chosen. Both results deviate strongly from each other. The budget $\boldsymbol{B}_{opt}^{1}$ of the holistic optimization in the first year is the maximum budget value and decreases rapidly in the following years. Again, the positive impact of the longer time period up to the end of the optimization horizon is obvious. The medium budget as well as the medium risk costs of the reference scenario is significantly higher than this resulting from the holistic optimization.

The application proves that the holistic optimization approach leads to clearly more efficient results compared to the yearly scenario. In particular, the budget optimization is significantly more economic, if a long term period is regarded.

B.5 Conclusions

The risk oriented maintenance allows the quantification of asset importance on the one hand and asset condition on the other hand. By this means, a monetary value is calculated in every point in time regarding the individual benefits of maintenance and renewal measures, so that a cost-benefit analysis is possible. The proposed risk model is formulated within a mixed integer linear program regarding technical, economical and operational constraints. Thus, optimized schedules for a perennial time period are generated, which lead to the minimum overall failure risk and are based on objective approaches. Furthermore, the fixing of yearly budgets for maintenance and renewal is supported. Compared to results based on a yearly optimization horizon, a significantly more efficient planning is realized.

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<u>Further Reading:</u>

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APPENDIX C – FREQUENCY REGULATION

NERC Frequency Model:

Recently, NERC began investigating the need for standards to set minimum contributions to interconnection frequency response (Primary Frequency Control). Investigation of this problem required the development of a probabilistic model to explain expected frequency error for an interconnection. Initially a model was developed to consider two factors, normal frequency error and additional frequency error resulting from disturbance imbalance. This new model was necessitated by the need to estimate the reliability impact of frequency disturbance events that occur when frequency is not at its scheduled value. Older deterministic methods assumed that frequency was at schedule when a disturbance event occurs.

NERC is currently working on a new probabilistic frequency model to describe the balancing process. This model is currently expected to include a number of factors related to the balancing process and the resulting interconnection frequency that results. This frequency model currently includes consideration of the following balancing effects:

1. It includes the normally distributed frequency error that includes all of the normal errors resulting from the load and generation variability. This includes the effect of load and generation response to that variability through the governor response, load damping, through the reaction of Automatic Balancing Control Systems (formally AGC), and the manual dispatch actions taken to restore frequency to schedule.

2. It includes the additional large low probability events that result in large frequency disturbances caused by large generation plant trips, large load trips, and large imbalances resulting from transmission trips. These events have been effectively modeled using exponential distributions.

3. It includes the effects of changes in scheduled frequency implemented to facilitate time error corrections.

4. It includes the additional very low probability high frequency impact events that are not effectively modeled with the generation and load trips that are estimated using an exponential distribution.

5. NERC is investigating the possible addition of other factors that could be included in this frequency model. These other factors under consideration are:

    a. It could include the larger than normal frequency error tail probabilities that result from ramping limitations during the transition from off-peak to on-peak and on-peak to off-peak periods. These tail probabilities are being investigated using Kurtosis measurement methods among others.

    b. It could include the larger than normal frequency error tail probabilities that result from ramping limitations during re-dispatch actions taken to manage transmission constraints.

    c. It could include the larger than normal frequency error tail probabilities that result from uncoordinated dispatch actions taken to commit/de-commit generation and pumped storage facilities during transition periods.

The current vision of the NERC Frequency Model is limited to current operations experience. As system operations planning needs change, there will be additional changes required in the Frequency Model and frequency management methods.

The development direction of a probabilistic model of this nature shows that when considered as isolated services the measurement and evaluation of frequency control methods does not result in reasonable results. In the future, measurement and evaluation methods must, at a minimum, relate closely with each other for the different regions of frequency control (primary, secondary and tertiary control).

All of the above considerations become more important as the high variability of Wind and other renewable resources are considered as part of the planning problem.

FERC and DOE Investigations on Wind Integration:

Wind power is a valuable renewable but variable resource whose unpredictability tends to be larger over longer time periods. Integrating large quantities of this variable resource into the power system while maintaining reliable operations requires supporting resources to maintain a load and generation balance over all time periods. The nature, location and quantity of these supporting resources relative to the location and variability of the wind generation output, the transmission capability to access these supporting resources together with the characteristics of the load and other generation all impact the frequency response of the system. To maintain reliability, the imbalance between load and generation manifests itself as a frequency deviation from system nominal frequency. One proposal is to use frequency response as a metric for assessing the reliable integration of wind power into the power system.

Frequency Response is the lead measure for this because the balancing actions required to maintain a reliable interconnection are an ordered set. This ordered set includes the following:

1. It includes Unit Commitment and Dispatch Planning that manages the balance required for the daily (diurnal) variation in load;
2. It includes Manual Dispatch, either aided or supplemented by regulation, to manage the long ramping periods that typically occur during the morning pick-up and evening drop-off;
3. It includes Regulation (AGC) used to manage the shorter variations that occur from hourly to 15 minute dispatch or market schedules and 5 minute pricing intervals; and
4. It includes Frequency Response (both load and governor response) that manages load generation imbalances that are too fast or large for regulation to manage.

This is an ordered set because any imbalance not properly managed at the desired level, will fall through to the next level to be managed. For example:

- First, if there is an imbalance that is not properly managed by the unit commitment and scheduling process for the day, the unmanaged imbalance is passed on to the manual dispatch process.
- Second, if the imbalance cannot be managed by the manual dispatch process, the unmanaged imbalance gets passed on to the regulation process.
- Next, if the imbalance cannot be managed by the regulation process, the unmanaged imbalance gets passed on to the automatic frequency response process.
- Finally, when the imbalance passed on to the frequency response process exceeds the frequency response resources available, the system fails by either interrupting firm load to restore balance, breaking up to allow those islands that can rebalance do so, or by blacking out all or a portion of the grid.

In all cases, the final failure is the result of insufficient frequency response. In addition, any imbalance passed to the frequency response process results in a frequency error proportional to the imbalance managed by the frequency response process. Therefore, it is easy to measure and account for the amount of imbalance not managed by the longer term processes.

Existing Reserve definitions and Requirements:

Current reserve definitions and requirements for operations only look at reserves during two time intervals. They define reserves for activation intervals shorter than 10 to 15 minutes (Operating Reserves), and reserves for activation intervals longer than 10 to 15 minutes. As markets have developed, these reserve definitions have been modified to be a little more specific, but they still do not meet the requirements to insure reliability.

Current planning reserves are designed to be sufficient to manage all conditions that can result in inadequate capacity to serve firm load. These conditions include:

- Forced outages and de-ratings for generation
- Load forecast error
- Re-dispatch to manage transmission equipment outages and de-ratings
- Maintenance schedules
- Regional load diversity

Unfortunately, current operating reserve definitions do not include all of these factors. NERC is currently developing new definitions to address this issue among others.

In addition to the above conditions, Operating Reserves must also include any variability due to sub-hourly variations. These are primarily included in what would be considered the Regulating Reserve.

Future Reserve Definitions and Requirements:

It can be seen from the discussion of the additional variability in the previous subsection above, that the variable nature of renewables are expected to affect the power system, and that both system planning and operations planning must transition from consideration of adequacy during the peak period to both adequacy and variability over many intervals concurrently. Thus not only will maximum values be important, but rate of change variables and minimum values will become just as important.

One of the problems resulting from the adequacy planning is that only the error in under-generation direction is considered as part of the planning problem. This is acceptable when the system is unconstrained by any other conditions such as ramp-rate or back-down margin, but it can result in unreliable operations when other constraints arise. When imbalance can create reliability problems in both the over and under generation conditions, then the concept of “reserves” must be replaced with “margins”. This also requires that both the long-term and operations planning processes must include possible limitations on the ability of the system to manage variations in both load and generation.

When these two considerations are taken together, we find that the new planning environment must include definitions that include minimum manageable operating margins over multiple intervals. The rate-of-change, both up and down, and the available margin for that specific type of variation must be defined and confirmed as part of both the system planning and operations planning process. The expected margins and intervals must address the specific planning and operating needs of the system. For example:

- Frequency Response Margin will be defined as a specific margin adequate to manage sudden imbalances on the interconnection in both the low and high frequency direction within the time frame of a few seconds.
- Regulation Margin will be defined as a specific margin adequate to manage (restore frequency to schedule) the minute to minute variations in load and generation that occur over time intervals from 1 to 15 minutes.

- Contingency Margin will be defined as a specific margin adequate to manage the large infrequent imbalances that are too large to manage (restore frequency to schedule) with regulation or that are not economic to serve with regulation that occur over time intervals of 1 to 15 minutes.

- Replacement Margin will be defined as the specific margin adequate to manage (restore shorter margins to adequate levels) the longer load and generation variations associated with the diurnal cycle that occur over time intervals longer than 15 minutes.

System Planning and Operations Planning processes necessary to support interconnections with higher degrees of variability and uncertainty will require significantly different probabilistic planning processes than those currently in use.

<u>Observations and Conclusions:</u>

As the interconnections attempt to integrate newer technologies including renewables into the grid, all of the planning processes will need to be modified to include variations in both the over and under generation direction. This will be significantly different from the under generation only adequacy methods in use today. In addition, it should be expected that the timing considered in the planning processes must include shorter intervals than currently considered to manage the variability and uncertainty that is expected for the future operations.

APPENDIX D – THE REMARK TOOL

REMARK, [1, 2, 3], represents a new methodology proposed for the transmission planning process. REMARK stands for RELIABILITY and MARKET: in fact, the purpose of this tool is to conduct analyses of static reliability (or adequacy) of complex electric systems that operate in a liberalized market context and are divided into areas. In comparison to conventional planning tools, REMARK quantifies both indices generally used to assess reliability of electric systems and indices aimed at innovatively assessing from the economic point of view the effects and the eventual outcomes caused by the market structure on the transmission system evolution.

The main features of REMARK are:

- full network representation adopting a simplified direct current model;
- an Optimal Power Flow (OPF) algorithm;
- probabilistic simulation of one year of operation of the power system using a non-sequential Monte Carlo method;
- quantitative assessment of the reliability benefits;
- quantitative assessment of the "economic" benefits (both substitution and strategic effect).

The optimization aims to maximize the Social Welfare (SW), calculated as the sum of consumer surplus (CS) and producer surplus (PS). The optimization simulates the intersection of the supply and demand curves and the re-dispatching and load curtailment actions needed for the fulfillment of the network constraints. The model adopted to represent the transmission network is the simplified direct current model: however, all links (transformers and lines) are fully represented and all power transits are always subject to the imposed technical constraints. The OPF operates in a probabilistic environment in order to verify the system reliability taking into account also the probability of outages of each component and also to account for the different weather conditions. In fact, the OPF is framed into a non-sequential Monte Carlo Methodology that aims at accounting for the uncertainties of a significant sample of system configurations. Those configurations are described with combinations of load profiles and outages typical of a planned maintenance of different system components. The reference year is analyzed through a significant number (e.g. in the order of 1000-10000) of possible system configurations randomly extracted. Each configuration is randomly associated to a weekly load profile. Users can define the features of the selected load profile. For each selected profile a complete OPF is calculated.

The adopted OPF consists of four different stages. Each stage corresponds to a more detailed representation of the transmission system under study, in order to identify additional costs (for example, for re-dispatch or for load shedding) in presence of a zonal market and depending on the structure of the transmission grid.

1. During the first stage the optimal dispatch is calculated assuming a single-bus network model, i.e. a simplified model that does not account for network and market constraints. In this stage, REMARK identifies inadequacies, if present, of the existing generation system that is assessed using the EENS index (Expected Energy Not Supplied) that accounts for the load shedding caused by lack of power generation: the corresponding index is the Lack Of Power (LOP).

2. During the second stage, REMARK calculates the optimal dispatch taking into account only network constraints between market zones. Market operation is simulated matching curves of aggregated power supply bids and curves representing the aggregated demand in every market zone. In this process, the Net Transfer Capacity (NTC) between two zones is also considered. REMARK based on EENS index identifies the need to shed loads because of scarcity of NTC between two market areas: this is carried out by the calculation of the LOI index (Lack of

Interconnection). The difference between system costs calculated in stage 2 and stage 1 represents the "cost of the market".

3. During the third stage, the optimal dispatch is calculated, considering also network constraints of the interconnections between zones. The effects of these constraints are calculated using the LOI index. The difference between costs calculated in stage 3 and costs calculated in stage 2 are due to network constraints and represents the "cost of interconnections".

4. Finally, in the fourth stage the optimal dispatch is calculated taking into account power exchange constraints between market zones and constraints of all transmission elements, i.e. those interconnecting different zones and those within zones of the system. In this way, the optimal dispatch that complies with market outputs is calculated. In this stage, REMARK calculates the corresponding EENS index that accounts for the necessity to shed loads because of the physical constraints present on a multi-area transmission system. The difference between the costs calculated in stage 4 and the costs in stage 3 is due to the re-dispatch caused by constraints on the transmission corridors within market zones and represents the "cost of the network".

In stage 4, for each node of the grid, the values of Locational Marginal Prices (LMP) are calculated. These values represent the incremental costs of the load at each node: the geographical distribution of LMP is used to identify the critical zones in the system. Moreover, in stage 3 and 4 those corridors that operate close to their transmission limits, therefore representing the bottlenecks of the system, are identified. For each of them, REMARK calculates the duration of the operation of such corridors in those congestion conditions and the corresponding Lagrange Multipliers, representing the incremental cost of the transmission. Duration and cost allow the identification of the most critical network portions.

The tool can assess benefits of transmission expansions for each market zone, in addition to the overall social perspective (systemic approach), as well as separately for consumers, producers and TSOs.

In summary, the main results of REMARK are:

- Power exchanges between market zones;
- Duration and incremental cost of inter-zonal network congestions;
- Average power flows on all transmission links (interconnections, lines and transformers);
- Duration and incremental cost of all network congestions;
- LOLP (Loss Of Load Probability), LOLE (Loss Of Load Expectation) and EENS (Expected Energy Not Supplied) at each stage and for every weather condition;
- LMP (Locational Marginal Prices) for each node of the grid (average, minimum and maximum values and their variation);
- SW, CS, PS for each market zone and at each stage;
- SW, CS, PS for the overall system and at each stage;
- EENS for each node and at each stage;
- EENS for each zone and at each stage;
- EENS for the overall system and at each stage;
- Energy produced and the relevant generation cost (or price) of each generator at each stage;
- Energy produced and the relevant generation cost (or price) for each market zone at each stage, also divided and differentiated by type of generators;

- Energy produced and the relevant generation cost (or price) for the overall system at each stage, also divided and differentiated by type of generators.

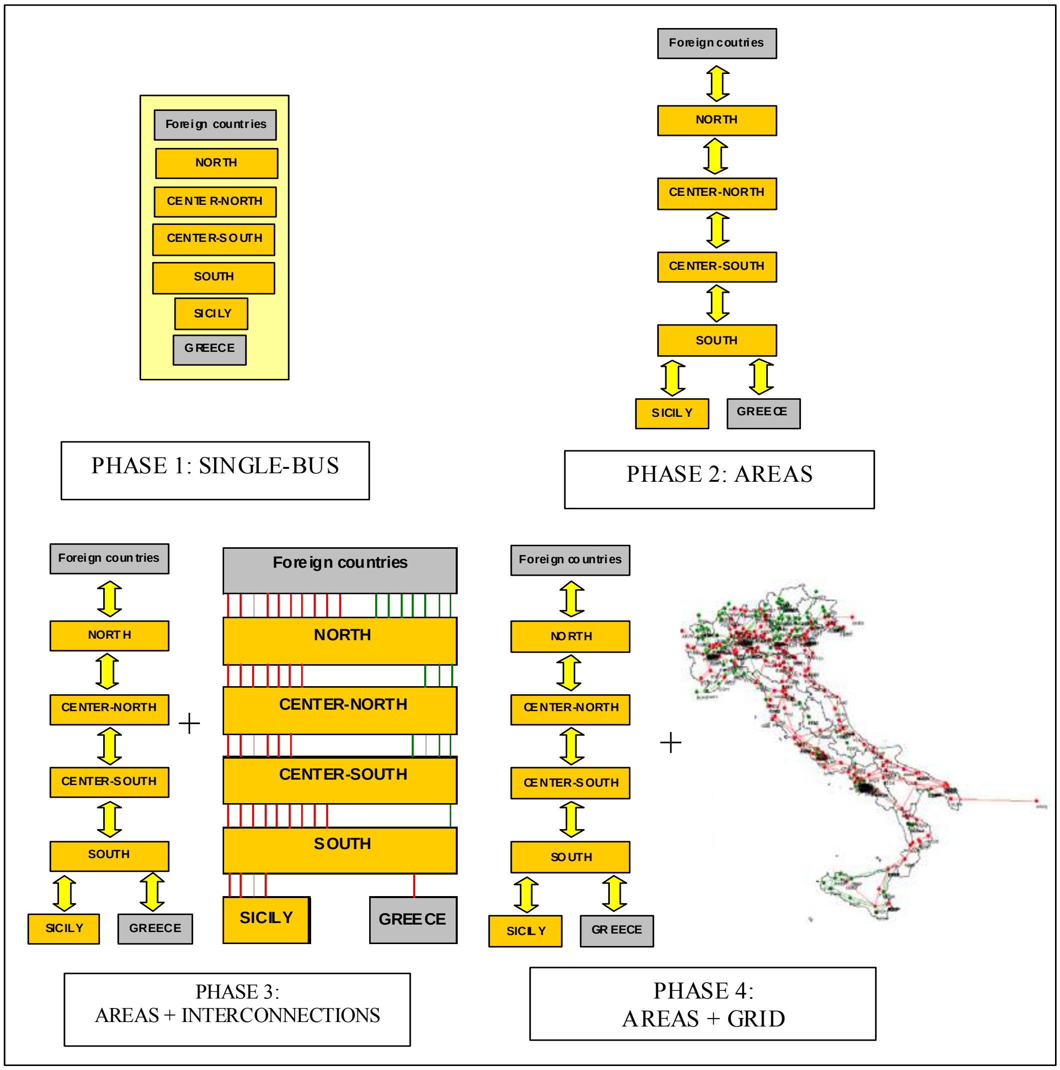

Figure D-1: Illustration of the four steps of the OPF system implemented in REMARK.

<u>The wind generation model in REMARK</u>

The wind generation model used in REMARK allows Wind Sites (i.e. Wind Power Plants) to be modeled, i.e. sets of wind turbines with a single point of common coupling thus injecting power into the grid through only one interconnection transformer. Further, Wind Zones are defined: neighboring sites, located in a geographical, also sufficiently extended, zone endowed with relatively homogeneous orographic and weather conditions, exhibit production patterns which are correlated with each other. Correlated[17] Wind Sites can thus be defined in the system under study.

The wind generation simulation model requires the following inputs:

- A number of Wind Sites, each characterized by the peak generated power by all the wind turbines (Pmax), by the HV point of common coupling and by the relevant Wind Zone

- A number of Wind Zones, each characterized by a generation profile

[17] i.e. statistically dependent according to the same production pattern distribution.

- A relevant number of production profiles, described by weekly diagrams (which can be distinguished into 52 different profiles and combined according to a specific calendar) in order to represent also possible season, monthly or weekly distinctions of the wind generation profile. The wind generation values in p.u. (P/Pmax) for a certain duration, still expressed in p.u. (t/T), are given for each typical week.

For each simulated hour REMARK determines the average wind generation of a Zone on the basis of the values stochastically extracted and referred to the typical distribution curve of the wind generation of that Zone.

Again, on the basis of the stochastically extracted values, the power production of each Wind Site of the same zone is moved (within +/- 5%) away from the average wind generation of the zone.

The wind generation profiles of the Wind Zones must not be confused with the wind profiles: the former represent the typical trend of the power provided by the wind turbines while the latter show the wind speed distribution identified through anemometric analyses. The wind speed values can be transformed into the produced power using the characteristic curves of the wind turbines. Within the same site, the power productions are not homogeneous among the individual wind turbines due to both the different location of the same turbines and mutual disturbance phenomena. Finally, the wind generation profiles of the wind sites must implicitly take into account the average unavailability of the individual turbines, i.e., the forced failure and the scheduled maintenance.

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