Application of Voltage Control Area to Determine Reactive Power Requirements

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***Abstract*—On-line dynamic security assessment has grown in popularity in recent years due to the need to deal with the ever-increasing challenges of secured system operation. In on-line security assessment systems, a snapshot of the actual system condition is captured and analytical engines are used to assess security in near-real-time. This has greatly reduced the uncertainties previously introduced by forecasting required in conventional off-line operational studies. Basic on-line VSA systems are now quite mature (Phase 1), and new features and functions are in development including more comprehensive analyses and artificial intelligence that can be used to assist the operators in maintain secure systems (Phase 2). The paper presents a highly automated method identifying voltage control areas, areas prone to voltage instability, and reactive power reserves requirement ensuring voltage stability under all considered contingencies. During the completion of Phase 1 of the VCA project testing of the VCA software was limited to powerflow models of the Polish Power Grid Operator (PSE) System. A detailed description of the operational difficulties is provided. Conclusions, repairs and prevention undertaking are also described.**

Keywords- On-line DSA, voltage security assessment, VSA, voltage stability, intelligent systems.

I. The Meaning Of Reactive Power In Transmission Networks

Unavoidable consequence of loads operation is presence of reactive power, associated with phase shifting between voltage and current. Some portion of this power is compensated on customer side, while the rest is loading the network. The supply contracts do not require a cosφ equal to one. The reactive power is also used by the transmission lines owner for controlling the voltages. Reactive component of current adds to the loads current and increases the voltage drops across network impedances. Adjusting the reactive power flow the operator change voltage drops in lines and in this way the voltage at customer connection point. The voltage on customer side depends on everything what happens on the way from generator to customer loads. All nodes, connation points of other transmission lines, distribution station and other equipment contribute to reactive power flow. A transmission line itself is also a source of reactive power. A line that is open on the other end (without load) is like a capacitor and is a source of capacitive (leading) reactive power. The lengthwise inductances without current are not magnetized and do not introduce any reactive components. On the other hand, when a line is conducting high current, the contribution of the lengthwise inductances is prevalent and the line itself become a source of inductive (lagging) reactive power. For each line can be calculated a characteristic value of power flow Sk. If the transmitted power is above Sk, the line will introduce additionally inductive reactive power, and if it is below Sk, the line will introduce capacitive reactive power. The value of Sk depends on the voltage: for 400 kV line is about 32% of the nominal transmission power, for 220 kV line is about 28% and for 110 kV line is about 22%. The percentage will vary accordingly to construction parameters. The reactive power introduced by the lines themselves is really a nuisance for the transmission system operator. In the night, when the demand is low it is necessary to connect parallel reactors for consuming the additional capacitive reactive power of the lines (Fig. 1a). Sometimes it is necessary to switch off a low-loaded line (what definitely affect the system reliability). In peak hours not only the customer loads cause big voltage drops but also the inductive reactive power of the lines adds to the total power flow and causes further voltage drops (Fig. 1b).

The voltage and reactive power control has some limitations. A big part of reactive power is generated in power plant unites. The generators can deliver smoothly adjustable leading and lagging reactive power without any fuel costs. However, the reactive power occupies the generation capacity and reduces the active power production. Furthermore, it is not worth to transmit reactive power for long distance (because of active power losses). Control provided "on the way" in transmission line, connation nodes, distribution station and other points requires installation of capacitors or\and reactors. They are often used with transformer tap changing system. The range of voltage control depends on their size. The control may consist e.g. in setting the transformer voltage higher and then reducing it by reactive currents flow. If the transformer voltage reaches the highest value and all capacitors are in operation, the voltage on customer side can not be further increase. On the other hand when a reduction is required the limit is set by maximal reactive power of reactors and the lowest tap of transformer. In a power grid, the transmission system operator (TSO) is responsible for the maintenance of the system voltage within a given range at the various node points in his network. To this end, this operator must be responsible for reactive power management in the various parts of that network. Since reactive power transmission over long distances is not economical, the balance between reactive power generation and demand must be maintained on a regional basis within the area of operation concerned. This became impossible during the crisis. Reactive power transmission causes voltage drops and losses. It is therefore preferable that system operation should be optimised in such a way that the balance of reactive power will be maintained as effectively as possible on a local basis.

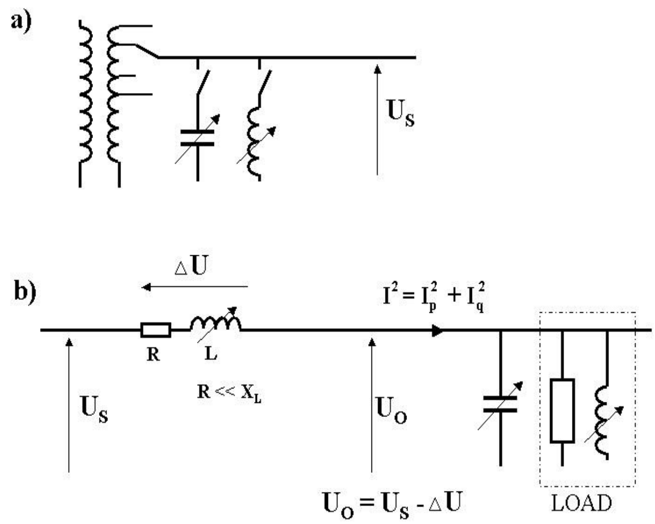


Figure 1. Idea of reactive power and voltage control in the networks.

In reactive power (and therefore voltage) control, a distinction is drawn between primary, secondary and tertiary voltage control. Primary control is implemented by the voltage regulators of generating units, which will initiate a rapid variation in the excitation of generators when they detect a variation in voltage across their terminals. Other controllable devices, such as static var compensators (SVCs) may also be involved in primary voltage control. Secondary control co-ordinates the action of voltage and reactive power control devices within a given zone of the network in order to maintain the requisite voltage level at a "key node point" in the system. Tertiary control involves a process of optimisation, using calculations based upon real time measurements, in order to adjust the settings of devices which influence the distribution of reactive power (generating unit controllers, tap transformer controllers and compensating devices, such as inductances and capacitors). Where the system load is high, the operator must be certain that, in case of a loss of generation, the remaining facilities will be able to deliver enough reactive power to keep the voltage within the required range. The same applies to the converse situation, where the system load is low and reactive power needs to be absorbed. Voltage profiles on either side of tie-lines must be harmonised by the operators of adjoining systems in order to allow the effective management of reactive power flows. This applies particularly to cross-border tie. Where voltage deviations lead to constraints on adjoining systems on a regular basis, compensating equipment must be installed in order to keep the system voltage within the normal range.

II. An Example Of Operational Difficulties In Transmission Networks Arose From Reactive Power

The difficulties showed up on June 26, 2006. The prediction for power consumption on this day was 18200 MW (in the morning peak) what was much higher compared with June in last year or previous years. This power was planed to be supplied from 75 generation units. Above these, there were a hot power reserve of 1350 MW (in this 237 MW second-reserve, 656 MW minute-reserve) and a cold reserve of about 2600 MW. In the north-east Poland there is not any grid-generation. The closest to this region is Ostroleka Power Plant, which in that time from three 200 MW units has two in operation and one set off for maintenance. In early morning of the 26th one unit in Power Plant Patnow had to be switched off and before noon four other units (two in Kozienice P. P. and two in Laziska P. P.) were switched off as well. All these unites were the main supplier to the north-east region of Poland. At 7 o'clock 570 MW of power was lost. At the same time the consumption prediction appeared to be wrong - the consumption was 600 MW higher and there was also much higher demand on reactive power. At 13 o'clock there was an unbalance of 1100 MW. In mean time one unit (in Dolna Odra P. P.) had been activated. However further activation from cold-reserve required more time (about 6 hours) because of technological reasons. Unusual heat wave spreading throughout the country caused deterioration of the operational conditions in power plants. Due to lack of sufficient amount of cooling water and exceeded water temperature levels the generating capacities of some power plants systematically decreased. That situation concerned mainly the power plants located in the central and northern part of Poland, the loadings of some transmission lines reached the acceptable limits what in turn cause the necessity of generation decrease in power plants located outside the mentioned region. The control of reactive power became critical. About noon the voltages were low, but still within limits. Rising demand and lack of additional reactive power sources brought further voltage decrease. The transformer voltage control had as a priority to keep constant the voltages in 110 kV networks. This in tern accelerated voltage decrease in 220 kV and 400 kV transmission networks. At 13 hours, most voltages in central and north Poland were below the limits. The generation units in Ostroleka P. P. worked with full power providing also about 100 MVA of reactive power each. They worked with automatic control of reactive power generation. Further increase on reactive power demand caused power oscillation between these two units, and as a consequence switching off one of them (due to large current) at 13:04. The voltage went down and in four minutes the second unit was also off because the voltage was too low. Lost of 400 MW and 200 MVA reactive in critical region affect dramatically all the system. The voltage became much below acceptable limits. All small, local power stations and heat-combine power stations were off immediately. A big unit in Kozienice P. P. was off at 13:08. A DC link to Sweden, that supplied the region with 300 MW was off, as well as its huge battery of capacitors.

To rescue the power grid additional power from neighbouring countries has been bought: 400 MW from Czech Rep., 100 MW from Slovak Rep. and 500 MW from Germany. In this time a sharp reduction of consumption was introduced. Switching off about 100 MW loads and a few lines allowed to stabilized the voltages in north of Poland and to put back in operation the units in Ostroleka and Kozienice P. P. About 16 hours the system operation returned to normal conditions.

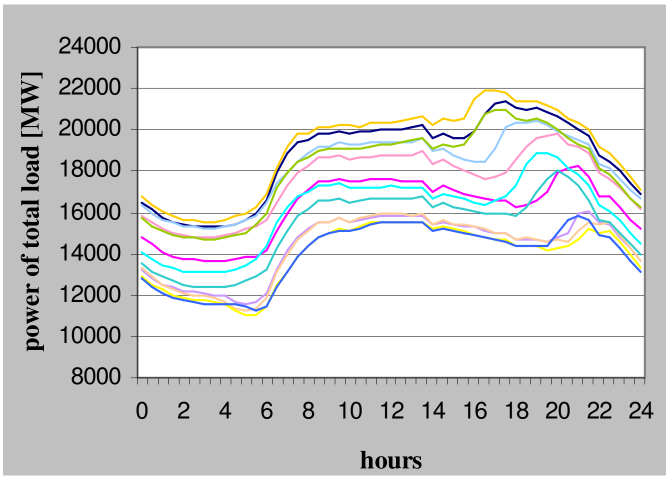


Figure 2. Daily power consumption in Poland average (2000-2005) for each month (top lines: winter months, bottom: summer months).

III. A Reactive Power Management In Transmission Networks

The crises situation described above shows a development of blackout without any unusual events like explosion, storm, hurricane, etc. The existing generation was sufficient to cover all the demand. The transmission capacity was much higher than necessary. The power grid is equip with automatic reactive power and voltage control system. This system also worked correctly. Despite the above a serious problem appeared. The reactive power compensation is a service that is location dependent. Transmission of reactive power over long distances is not only not economical but also ineffective from control point of view. Reactive power flow involves generation of additional reactive power. In normal operating conditions the control system manage to adjust generation of reactive power in power plants and to control the voltages. If the location of reactive power sources is inadequate, the control system may lead the power grid to a blackout. For ensuring appropriate reliability of supply in electrical energy are responsible network-companies which usually do not own any generation. Thus, they have to achieve their task by control of contracted reserves and generation-load balancing. Since customers are free to change their power demand at any time, the balancing consists in requesting a change in generation. In market economy all contracts are profit oriented. A term of the common good or wealth is not appealing to companies desperately needed income. The reliability of supply in market environment is on one hand more important due to customer expectation and on the other hand more difficult and more expensive to achieve.

The electrical energy is a very specific trade commodity, however it can be still, like other goods, characterized by quality parameters. Depending on the application, the customers may be interested in standard reliability of supply, cheap-price underrate reliability or require superior quality of supply irrespectively to the price. The reliability of delivered electrical energy may always be affected by major force and unpredictable circumstances. The level of acceptable risk depends on the desire of achieving high profit. A company responsible for delivery may not be able to keep promised standard or due to financial calculation may consciously choose to pay penalties. However, the task of the transmission system operator - TSO is different. The TSO is not profit orientated entity, its main aim is to ensure a reliable system operation. This approach proved to be correct, but the TSO needs more law based rules and regulations to enforce there measures. On the other hand the TSO should own some resources for providing at least a part of ancillary services.

IV. Identification of Voltage Control

Since it is well understood that voltage security is driven by the balance of reactive power in a system, it is of particular interest to find out what areas in a system may suffer from reactive power deficiencies under some conditions. If those areas prone to voltage security problems, often called critical Voltage Control Areas (VCA), can be identified, then the reactive power reserve requirements for them can also be established to ensure system secure operation under all conditions. To identify VCAs in a given power system, the considered system is stressed to its stability limit for various system conditions under all credible contingencies. At the point of instability (nose of the PV curve) modal analysis is performed to determine the critical mode of voltage instability for which a set of bus participation factors (PF) corresponding to the zero eigenvalue (bifurcation point) is calculated. Based on these PFs, sets of buses and generators that form the various VCAs in a given power system are identified. The identification procedure applies heuristic rules to (a) group contingencies that are related to the same VCA; and (b) identifies the specific buses and generators that form each VCA as described below. The identification program processes the sets of buses and generators corresponding to the PFs obtained from the modal analysis for each system condition and contingency case. Contingencies are clustered if their sets of bus PFs are *similar*. Finally, the program identifies the sets of buses and generators that are common to all contingencies of each cluster. Those sets of buses and generators form the VCAs of the power system. The VSAT program is used to simulate the scenarios and to compute PV curves for all transfers and contingencies. The objective is to stress the system in the manner specified by the given transfer and to perform modal analysis at the nose point of the PV curve. Modal analysis outputs include the critical mode eigenvalue (zero at the PV nose point), critical mode bus participation factors, and generators that are at their reactive power limit. All generated output files are collected for post-processing in order to generate the database (DB) records for the VCA identification engine. Each VCA identified is related to a cluster of contingencies; these cases are said to “support” that VCA. First, similar contingency cases are clustered and then second, the specific buses and generators that form the VCAs are identified. Before clustering contingency cases, however, a preliminary selection of buses and generators is done at an earlier stage of the VCA identification process as shown in Fig. 3.The VCA identification process consists of the following steps:

1) Selection of Buses for VCA Identification – From modal analysis results for each contingency, a subset of buses with high PF is selected for further analysis (SFAs): remaining buses are discarded. Several strategies to select such subset can be applied. Generator terminal buses appear in the PF only if the generator exhausts its reactive power reserves (marked as a Q-limited, QL bus).

2) Clustering of Contingency Cases based on SFAs – the identification program clusters contingency cases based on similarities. These clusters will be used to identify the VCAs in the power system, as described in Steps 6 and 7 below

3) Normalization of Generator Buses PFs - the generator buses PFs are normalized.

4) Selection of Generators in Cluster Ck - For each cluster $\mathbf{C}_k$, the frequency of generator bus participations in this Ck is calculated. The generator buses with the highest frequencies are selected to represent the cluster Ck reactive power reserves and are denoted as GENk.

5) Clustering of Ck based on GENs - In this step, a number of Ck are grouped together if their corresponding GEN sets are similar. Two GENs are considered similar if certain percentage of generator buses are matched. If GENi (from Ci) and GENj (from Cj) are similar, then Ci and Cj are grouped together into a preliminary VCAm. This VCAm is associated with a set of generator buses GENm that consists of the generator buses of the combined GENi and GENj. The first step in clustering Ck is to select the base set GENx to which other GEN's are compared. All Ck, which have GEN sets similar to GENx are clustered. Then a new base GENy is selected from the remaining ungrouped Ck and the process of clustering is repeated for the ungrouped Ck.

6) VCA identification part A: Selection of buses – For each preliminary VCAm, compute the frequency of each bus. Then select the buses with a frequency greater than a user defined threshold value These are the buses that form VCAm of the considered power system.

7) VCA identification part B: Selection of generators **-** For each GENm, get the frequency of each generator bus. Then select the generator buses with a frequency greater than a user defined threshold value The generators associated with these generator buses are the ones that form controlling generators associated with VCAm .

A. Heuristic Rules for Base Selection and Similarity Measurement

Selection of a base for clustering process - From the VCA identification process presented in the previous section we can observe that clustering is carried out twice:

- Clustering contingency cases as described in Step 2 and
- Clustering Ck based on GENs as described in Step 5.

Measure of similarity between buses/generators sets – The number of common elements C is counted and compared with a similarity of a user defined threshold T. If the number of common elements C is greater than the threshold T, then set-i and the base set are considered being similar. The similarity threshold T is set as a percentage of the number of elements in the largest set (set-i or the base set). If all elements of the smaller set (base or set-i) are included in the larger set then those sets are considered being similar. Once the VCAs are computed, the VCA identification software provides a report as shown in Figure 4. This display shows all the VCAs identified (two in the example shown), the contingencies that cause VAC instability, the buses in the VCA, the controlling generators and the required reactive reserves (see next section).

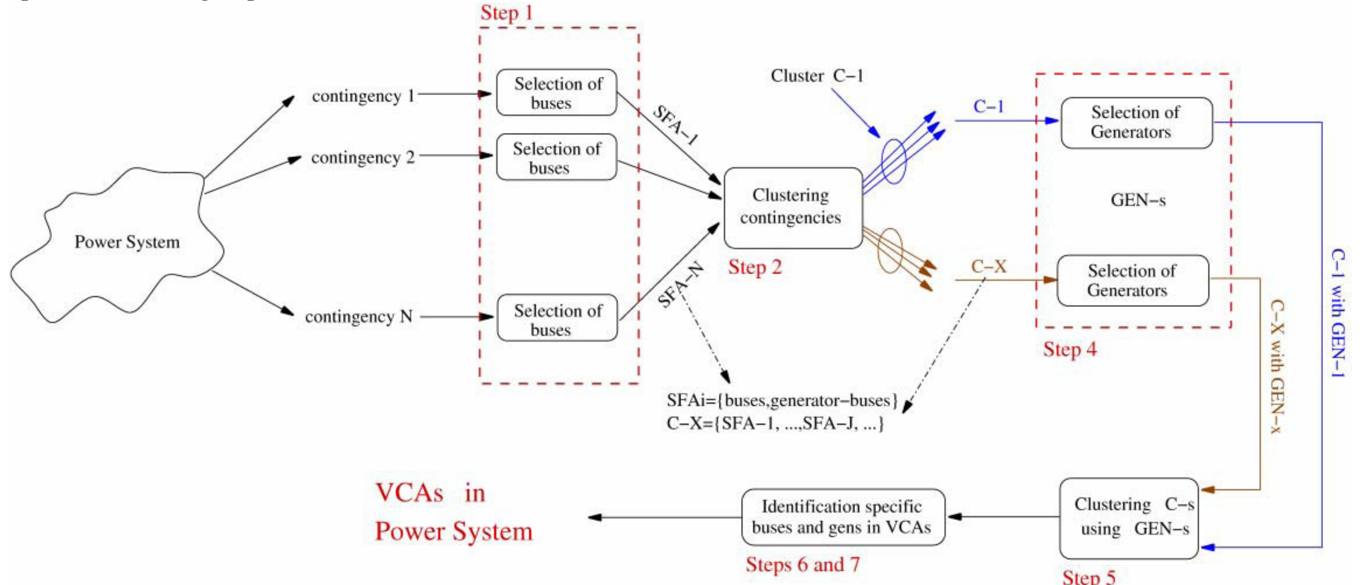
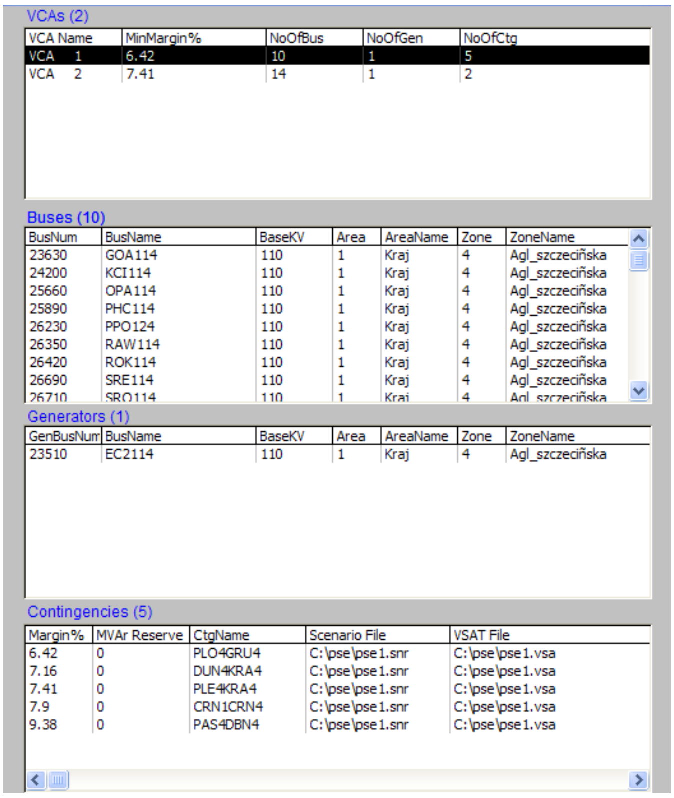


Figure 3. Steps in the VCA Identification Process

B. *Reactive Power Reserve Requirements*

After the VCAs have been identified, it is desirable to know what reactive power reserves are necessary to maintain in the system in order to ensure voltage stability under all conditions. In the section above describing VCA determination, the generators that control each VCA were identified. It is for these generators that reactive reserve requirement must be established for each VCA. For each scenario analyzed, the pre-contingency reactive output on each controlling generator is recorded at a "secure point" back from the nose of the PV curves as shown by Point "Post Contingency stability limit" in Figure 5. The "distance back from the nose" corresponding to Point "Post Contingency stability limit" is determined based on the required security margin criteria (such as 5% of the transfer load or generation). For each controlling generator the recorded reactive power output at Point "Precontingency stability limit" is subtracted from the post-contingency reactive power output of each generator at the nose point. For each generator, this difference represents the required reactive power reserves, for that specific generator, for the scenario under study. Once the required reactive power reserves have been computed for all generators and for all scenarios, the minimum reserve that needs to be held on each generator to ensure stable operation for all scenarios can be found using linear programming.



VCAs (2)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	6.42	10	1	5
VCA 2	7.41	14	1	2

Buses (10)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
23630	GOA114	110	1	Kraj	4	Agl_szczecińska
24200	KCI114	110	1	Kraj	4	Agl_szczecińska
25660	OPA114	110	1	Kraj	4	Agl_szczecińska
25890	PHC114	110	1	Kraj	4	Agl_szczecińska
26230	PPO124	110	1	Kraj	4	Agl_szczecińska
26350	RAW114	110	1	Kraj	4	Agl_szczecińska
26420	ROK114	110	1	Kraj	4	Agl_szczecińska
26690	SRE114	110	1	Kraj	4	Agl_szczecińska
26710	SRO114	110	1	Kraj	4	Agl_szczecińska

Generators (1)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
23510	EC2114	110	1	Kraj	4	Agl_szczecińska

Contingencies (5)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
6.42	0	PLO4GRU4	C:\pse\pse1.snr	C:\pse\pse1.vsa
7.16	0	DUN4KRA4	C:\pse\pse1.snr	C:\pse\pse1.vsa
7.41	0	PLE4KRA4	C:\pse\pse1.snr	C:\pse\pse1.vsa
7.9	0	CRN1CRN4	C:\pse\pse1.snr	C:\pse\pse1.vsa
9.38	0	PAS4DBN4	C:\pse\pse1.snr	C:\pse\pse1.vsa

Figure 4. Identification Program Output Display

C. *On-Line Computation of VCAs*

The approach described above can be applied to determine common critical VCAs in the on-line environment for all scenarios (described by all base cases, transfers, and contingencies) assessed in a VSA cycle; the results are simply obtained as a post processing effort following the deterministic analysis of voltage stability limits. However, in the on-line environment it is always desirable to provide information to the operator as quickly as possible (faster than the full deterministic analysis) and to endow the assessment tools will intelligence so as to help the operator garner as much insight into the system as possible, even if the existing scenario has not been observed before. Over time, a large database of analyzed scenarios can be developed by archiving key information and results from the on-line VSA system. This data can be used with an intelligent system framework, using techniques such as decision trees, to predict the VCAs and required reactive reserves from a given system condition without full computation. This is the justification for exploring the use of intelligent systems for use in on-line DSA systems.

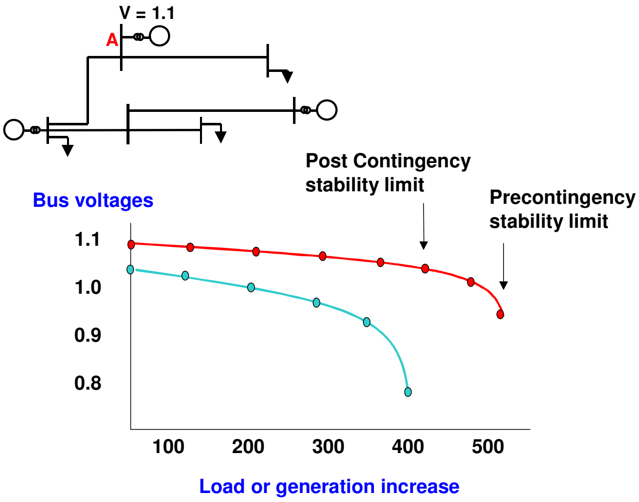


Figure 5. Voltage stability limit is reached when powerflow solution fails to converge

V. VCA TESTING FOR POLISH POWER GRID SYSTEM OPERATORS (PSE)

Institute of Electric Power Engineering completed the VCA testing for PSE. A three-day meeting was held at PSE office in Warsaw. The meeting included training on VSAT as well as VCA program. At the meetings a scenario was assembled and tested. The result of VCA testing was encouraging and well received. PSE is to setup additional scenarios for testing and Institute of Electric Power Engineering will assist PSE in analyzing the result of VCA. The detail of the testing in Warsaw is summarized below along with the result obtained. Comprehensive testing of the software requires several steps:

- Judicious selection of practical base cases, power transfers, and contingencies to be studied
- Tuning of the base cases to be suitable for transfer analysis
- Setup of all required data files
- Running VSAT to perform PV analysis and model analysis
- Analysis of the PV results and resolution of any problems such as local modes or criteria violations

- Running of the VCA program to generate the VCAs
- Analysis of the results of the VCA program including VCA, critical contingencies, controlling generators, and reactive reserve requirements

A. *Powerflow*

One powerflow basecase was examined and sanity checked. The recommendation of Powertech to PSE is to improve system model by considering the Generator Transformer explicitly in the Powerflow cases (Figire 6). The characteristics of the system is shown below:

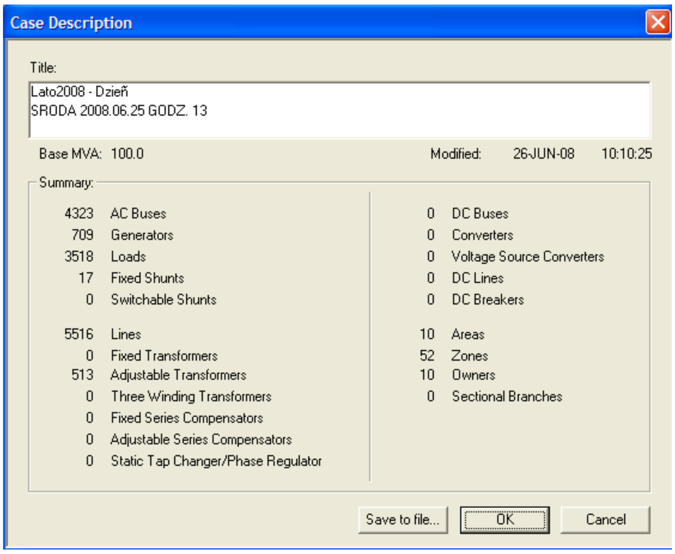


Figure 6. PSE System Characteristics

B. *Transfers*

Only 1 transfer was developed for stressing the PSE system. It was assumed that all loads in the Polish Power Grid will increase and generation in all PSE, with the exception of a few power plants, will also increase to match the load increase. 1 scenario corresponding to the above transfer was setup for VSAT run to compute PV curves and stability limit of each contingency defined below.

C. *Contingencies*

All N-1 contingencies for branches over 100 kV for the PSE system were analyzed (Table I). This resulted in 355 contingencies.

TABLE I. CONSIDERED N-1 CONTINGENCIES FOR PSE SYSTEM

Contingency ID	Contingency Description
ABR1ABR2	Brn: ABR122 - ABR212 (8510 - 520 '1')
ADA1ADA2	Brn: ADA124 - ADA214 (22780 - 1610 '1')
BLA2LAG2	Brn: BLA223 - LAG223 (950 - 1300 '1')
BOG1BOG2	Brn: BOG114 - BOG224 (22980 - 1640 '1')
…	…
BSP1BSP2	Brn: BSP114 - BSP214 (23030 - 1650 '1')

The result of VCA identification program revealed two VCAs (Figure 7). It should be noted that to arrive much more meaningful VCA analysis, PSE should assemble a larger number of scenarios and possibly include N-2 contingencies. The location of VCA 1 indentified by the VCA program and its supporting contingencies is shown on the geographical map of Polish Power System (Figure 8).

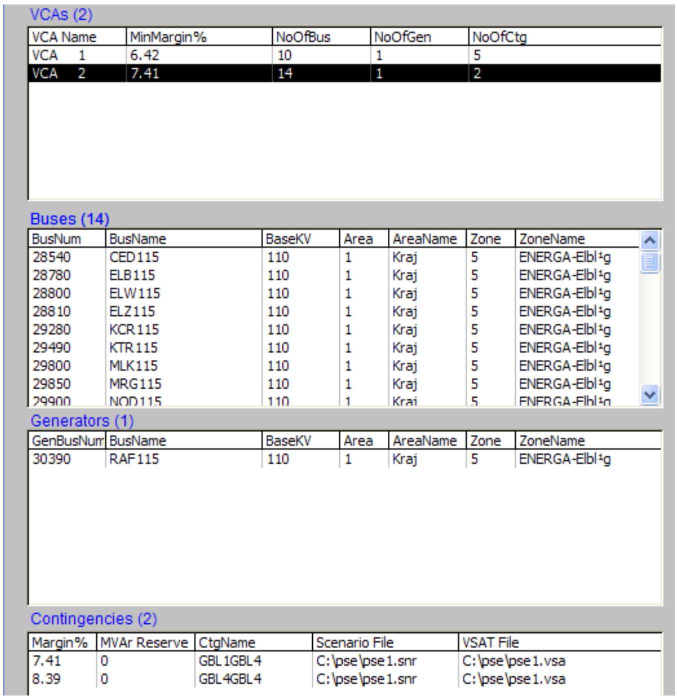


Figure 7. List ses, controlling generators and supporting contingencies for VCA 2

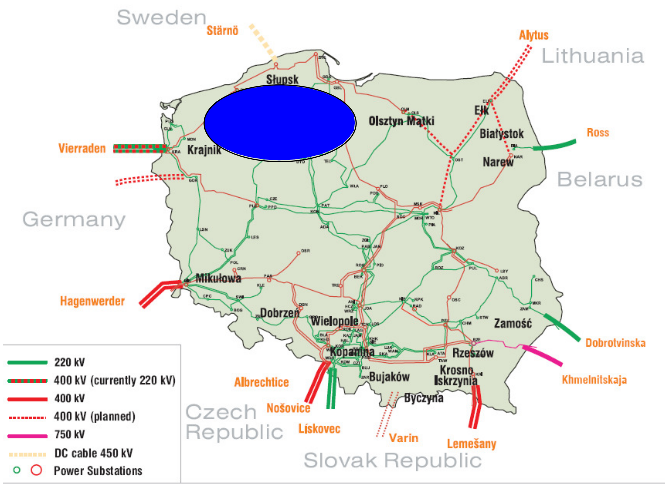


Figure 8. Location of VCA

VI. SUMMARY

An overview of the state-of-the-art of on-line VSA has been presented and a highly automated method for the identification of voltage control areas is described. Voltage control areas describe the regions in a power system that under specific conditions are prone to voltage instability. Intelligent systems hold promise to improve VSA speed, provide adaptive learning capabilities and offer the ability to identify key system parameters. An example of an intelligent system framework using decision trees has been described. Work in this area is continuing toward a pilot implementation at a host site.

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