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GCC Power 2009

THE 5TH GCC CIGRE INTERNATIONAL CONFERENCE
AND 14TH EXHIBITION FOR ELECTRICAL EQUIPMENTS

19 - 21 OCTOBER

RIYADH - KINGDOM OF SAUDI ARABIA

CONFERENCE PROCEEDINGS

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SESSION 2

الخليج سيجري
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GCCIA SYSTEM FREQUENCY CONTROL PHILOSOPHY

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GCCIA System Frequency Control Philosophy
فلسفة التحكم في نظام الذبذبة لشبكة الربط الكهربائي الخليجي

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SUMMARY

Through GCCIA (Gulf Cooperation Council Interconnection Authority) grid, the Gulf Cooperation Council (GCC) countries namely the United Arab Emirates, Bahrain, Saudi Arabia, Oman, Qatar, Oman and Kuwait are in the process of interconnecting their national grids to a common backbone. Bahrain, Saudi Arabia, Oman, Qatar, and Kuwait are already interconnected through GCCIA project Phase-I and United Arab Emirates and Oman which is covered under Phase-III of GCCIA project will be connected to GCCIA grid by 2010. This interconnection project will have various important benefits for each of the member States and for the region as a whole, such as increased security through mutual support, reduction of investments through reserve sharing and, in future, the potential capability of connecting and trading with other power pools.

One of the objectives of the new Interconnection Control Center (ICC) is to ensure that frequency and interchanges follow agreed schedules provided by member States and validated by ICC. In order to meet this objective, a hierarchical AGC system is implemented, with an ICC AGC Monitoring Model at to top level and AGC functions in member States at the second level.

GCCIA will be dealing with two control blocks namely the 60 Hz control block which involve the Saudi system only and the 50 Hz control block which involve all other member states. The Frequency control on the 50 Hz System will be coordinated by ICC while on the 60 Hz System it will be managed by the Saudi-Arabian TSO SEC. To ensure that each TSO carries its share of frequency regulation duties, and to ensure that all TSOs work together in the coordination of frequency, ICC will monitor the overall system frequency and compute Area Control Error (ACE) using an AGC Monitoring Model which will produce ACE signal for each TSO Control Area.

The AGC function at ICC computes a global Area Control Error (ACE) and distributes it among the member States using agreed distribution factors. Each member State's AGC includes its share of global ACE as an additional correction signal to it local ACE calculation.

In future, other configurations can be considered such as a control block structure (also called pluralistic AGC, in UCTE terms). In this mode, one of the block members takes the responsibility of ensuring that total net interchange of the block with respect to external partners follows total net agreed scheduled interchanges with those external partners, whereas the remaining block members maintain frequency and their respective interchanges in the usual manner.

The paper discusses AGC principles and implementation details to support current and future GCCIA operation. It highlights existing member States frequency control methodology and gives recommendations for the interconnection.

ملخص

يمتد مشروع الربط الكهربائي الخليجي عبر دول مجلس التعاون لدول الخليج العربية وينفرد باستخدام رابط كهربائي مستقل لربط شبكاتها الكهربائية دون استخدام الشبكات الداخلية للدول للتمرير الطاقة الكهربائية من خلالها وتشمل المرحلة الاولى من المشروع ربط كل من السعودية والكويت وقطر والبحرين حيث تم اكتمال هذه المرحلة في الربع الاول من عام ٢٠٠٩ وتم التشغيل التجريبي للمشروع وسيتم ربط كل من الامارات وعمان في عام ٢٠١٠ حيث يتم حاليا تنفيذ ربط شبة الامارات بالشبكة الرئيسية للهيئة
هذه الورقة تستعرض فلسفة التحكم في نظام الذبذبة لشبكة الربط الكهربائي الخليجي حيث ستقوم الهيئة من خلال مركز التحكم والذي يحتوى على انظمة المراقبة الالية بقياس و مراقبة مستوى الذبذبة للنظام الكهربائي الذي يعمل بنظام ٥٠ هيرتز ومن ثم يتم احتساب مستوى التصحيح المطلوب من كل دول ويتم ارسال مستوى التصحيح المطلوب الى كل دولة بشكل دوري والي .ينم التحكم بمستوى الذبذبة على جانب ال٦٠ هيرتز من خلال مركز التحكم التابع للشركة السعودية للكهرباء وذلك لانفرادها بظام الذبذبة الذي يعمل على تردد ٦٠ هيرتز وبالتالي يسهل عملية التحكم والتنسيق.

KEYWORDS

GCC - GCCIA – Frequency Control

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1. INTRODUCTION

Phase I of the GCC interconnection project consists on the interconnection of Bahrain, Kuwait, Saudi Arabia and Qatar by means of a double-circuit 400 kV line and associated substations. In addition, a back-to-back HVDC connection allows interconnecting Saudi Arabia network (60 Hz nominal frequency) to the other countries (50 Hz nominal frequency). Commissioning of phase I was achieved in June 2009.

Phase-III will allow further extending of the interconnected network to UAE and Oman.

Major benefits can be obtained from interconnecting electric networks, such as robustness of operation through mutual support in case of incident and postponement of investments through reserve sharing. Energy exchanges can also favour more efficient operation: more economic energy can be imported from neighbouring utilities, depending on fuel prices and power generation technology. In future, the interconnection opens the potential capability of connecting and trading with other power pools.

Interconnected operation requires, on the other hand, close coordination among member TSOs and changes in their business processes. For example:

- Import/export contracts should be agreed among members, including energy and reserve;
- Planning of day-ahead or longer-term future operation most take agreed import/export schedules into account;
- Maintenance activities should be coordinated to ensure that reserve levels are adequate at all times;
- Total generation by each member TSO should be such that import/export flows are kept at the agreed scheduled levels;
- Frequency should be kept at its reference value in each network;
- Import/export energy deviations with respect to schedules should be accounted for and compensated.

Frequency control on the 50 Hz System will be coordinated by ICC. This paper focuses on Automatic Generation Control implementation requirements for interconnected operation and analyzes possible future configurations.

2. The frequency control question

Frequency control in isolated networks

In an isolated network, generation and demand must match at all times. Any mismatch provokes frequency deviations that must be compensated by sending correction controls to selected generators in the system. The measure of error, in MW, is called Area Control Error, or ACE, and is calculated as:

$$ACE = B \cdot \Delta f = B \cdot (f - f_S) \qquad \ldots\ldots (1)$$

where f is the instantaneous measured frequency and f_S is the scheduled frequency (usually nominal, i.e. 50 Hz or 60 Hz).

B is the system *frequency bias*, in MW/Hz, also called *power system frequency characteristic*.

ACE is filtered to obtain the necessary generation correction, or regulation component, **R**. A proportional and integral (PI) filter is typically used:

$$\mathbf{ACE} \longrightarrow \boxed{\mathbf{PI}} \longrightarrow \boxed{\mathbf{-1}} \longrightarrow \mathbf{R}$$

$$R = -K_P \cdot ACE - \frac{1}{T}\int ACE \cdot dt$$

Finally, the regulation component R is distributed among selected power plants/units to increase or decrease generation in order to reduce ACE. Distribution is based on different criteria defined by each utility, such as unit response capabilities (ramp rate) and/or economics.

Frequency control in interconnected networks

In interconnected networks, MW flows through the tie-lines must also be taken into account when supervising the equilibrium between generation and demand. In other words, the following equilibrium equation must hold at all times:

generation + load + interchanges = 0

To control interchanges in addition to frequency, ACE calculation now becomes:

$$ACE = B \cdot \Delta f + P - P_S \qquad \ldots\ldots (2)$$

where P is the instantaneous **net tie-line flow** (sum of measured MW over all the tie-lines) and P_S is the **scheduled net interchange** (sum of agreed interchange transactions with all neighbours).

Under certain conditions such as a relatively small network connected to a much larger network, the smaller network has little influence on the global frequency and can limit itself to keeping net interchange at its scheduled value. In this case, ACE calculation reduces to:

$$ACE = P - P_S \qquad \ldots\ldots (3)$$

Control modes defined by equations (1), (2) and (3) are called, respectively:

(1) CFC – Constant Frequency Control

(2) TLBC – Tie-line Bias Control

(3) CNIC – Constant Net Interchange Control

Time error correction

Since system frequency is always fluctuating due to random demand variations, it is likely that at the end of the day the integral of the frequency error will not be zero. Consequently, electrical clocks will show an error with respect to true time.

In isolated networks, the TSO can choose to correct or not this error by temporarily introducing a correction term to (1) or by temporarily changing the scheduled frequency (for instance, setting f_S = 50.02 during one hour).

In interconnected operation, if it is agreed to perform time error correction, a coordinating entity such as GCCIA keeps track of global time error and issues correction schedules (f_S) to all concerned members, typically for the following day. For time correction to be effective, it must be simultaneously implemented by all the TSOs in the same synchronous zone.

Inadvertent interchange correction

Due to natural variations of the demand, net tie-line interchange cannot be kept at exactly its target (scheduled) value, and at the end of the day some countries would have exported more energy (MWh) that committed while others would have imported more MWh than initially planned. These differences are called *Inadvertent Interchanges*.

Since energy has a cost, Inadvertent Interchanges must be corrected (compensated). There are two main ways of doing so:

- Via commercial settlement
- Via Inadvertent Energy Payback

Only the second option is discussed here.

Inadvertent Energy Payback is implemented as follows: the coordinating entity for the interconnected system keeps track of all inadvertent energy exchanges over a period. It then generates balanced correction schedules for each member, typically on a daily basis.

ACE calculation by each member becomes:

$$ACE = B \cdot \Delta f + P - P_S + \Delta P_S^{INADV}$$

where ΔP_S^{INADV} is the Inadvertent Interchange Correction schedule.

To account for the fact that energy generation does not have a flat cost (base energy is cheaper than peak energy, for instance), it is possible to group the hours of the week in different tariff periods. One example of such tariffs is Peak hours versus Off-peak hours. Inadvertent Interchange is then separately accounted for each tariff type, and payback is made at hours corresponding to the same tariff. In other words, inadvertent energy consumed on a peak hour must be paid-back also at a peak hour.

3. Frequency control schemas

Different possible LFC implementations have been experienced in large interconnected systems. Among these the most important ones are centralised, hierarchical and pluralistic.

Centralised load-frequency control

In this control structure, each individual TSO controls both its frequency and its net interchange. This mode is described by previous equation (2).

Block control

In other control structures, a group of TSOs get together to form a *control block*. A block example with three members is illustrated in Figure 1 below.

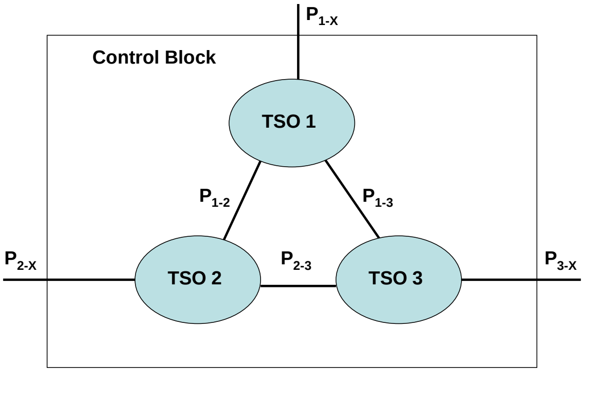

Fig. 1- LFC control block

Figure 1 depicts a control block composed of three TSO members. Each solid line represents tie-lines (one or many) between TSOs. P_{1-2} represents the instantaneous MW power that flows between TSO 1 and TSO 2 through the set of tie-lines connecting them. Similar definitions apply for P_{1-3} and P_{2-3}. In addition, P_{1-X} represents the interchange of TSO 1 with other TSOs outside the control block. MW flows P_{2-X} and P_{3-X} are defined likewise.

The main objective of the control block structure is to ensure that net MW interchange of the block is properly kept. For this purpose, a Block Control Error is defined as:

$$BCE = P_{Block} - P_{Block}^{Sched} \quad \ldots\ldots (4)$$

where the net block interchange is:

$$P_{Block} = P_{1-X} + P_{2-X} + P_{3-X}$$

and the net block scheduled interchange is the total interchange scheduled by all members of the block with all other TSOs outside the block:

$$P_{Block}^{Sched} = P_{1-X}^{Sched} + P_{2-X}^{Sched} + P_{3-X}^{Sched}$$

Similar to ACE, a PI filter is implemented to compute the required regulation:

$$\Delta P_{BCE} = -K_P \cdot BCE - \frac{1}{T}\int BCE \cdot dt \quad \ldots\ldots (5)$$

Maintaining net block interchange can be achieved by using either hierarchical or pluralistic control. These two control block modes are described below.

Hierarchical load-frequency control

In hierarchical control, one of the TSO in the control block will be assigned the role of “block leader” while the others will be “block sub-ordinates”. Notice that the roles of leader/sub-ordinate are not fixed and can be changed at any time by common agreement among block members.

In this mode, the block leader computes the Block Control Error (BCE) and its corresponding regulation correction ΔP_{BCE}. Then, through a set of agreed participation factors, the block leader distributes the required MW regulation correction among all members in the block:

$$\text{Correction for TSO j} = \alpha_j \cdot \Delta P_{BCE} \quad \ldots\ldots (6)$$

Clearly, the sum of participation factors **α** must add to 1, to ensure 100% distribution of BCE correction:

$$\sum_j \alpha_j = 1$$

Finally, each member in the control block takes its share of BCE by adding it to the standard ACE calculation given by equation (2). Thus, For the j^{th} TSO, ACE is calculated as:

$$ACE_j = B_j \cdot \Delta f_j + P_j - P_{S,j} + \alpha_j \cdot \Delta P_{BCE} \quad \ldots\ldots (7)$$

Notice that calculation of BCE in (4) implies that:

a) The block leader gets real-time measurements of all tie-lines connecting the control block to TSOs outside the block. These measurements are usually telemetered by each block member and then transmitted to the block leader through an inter-center communications protocol such as ICCP TASE.2 or ELCOM.

b) The block leader knows the scheduled interchanges of all block members with TSOs outside the block. These schedules are usually centralised by an interconnection authority and communicated to the block leader or, as in the case of GCCIA, the interconnection authority can take the role of block leader.

In addition, the block leader must be able to communicate, to each block member, the member’s share of BCE given by equation (6). Again, TASE.2 or ELCOM links will be used for this purpose.

Figure 2 illustrates inter-center communication needs for hierarchical control implementation, assuming TSO 1 is the block control leader. Dotted lines represent the information flow.

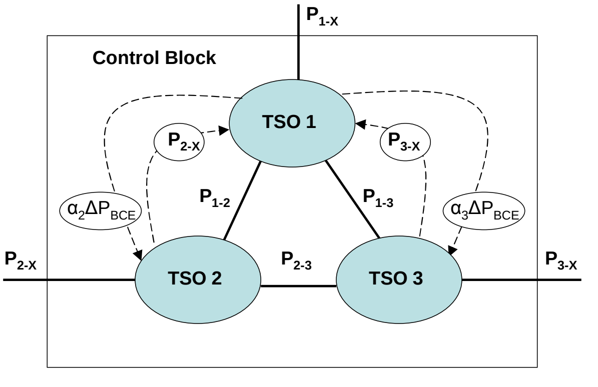

Fig. 2- Hierarchical control communication needs

Pluralistic load-frequency control

Different than hierarchical control, in pluralist control the block leader takes the full burden of compensating block control error. This arrangement can prove useful for interconnecting a system with relatively low secondary reserve: by constituting a block with a stronger system capable of delivering the required reserve, the smaller system can operate in the interconnected grid and still maintain the scheduled interchanges.

In pluralistic control, sub-ordinate TSOs compute ACE in the standard manner given by equation (2). From the stand-point of sub-ordinate block members, pluralistic control and centralised load-frequency control are equivalent.

The block leader, on the other hand, compensates the full BCE as:

$$ACE_L = B_L \cdot \Delta f_L + P_L - P_{S,L} + \Delta P_{BCE} \text{ ...... (8)}$$

(subscript L stands for "Leader")

Comparison with the hierarchical control formulation (7) shows that pluralistic control is a particular case of hierarchical control, if the participation factor **α** of the block leader is set to 1 while all others are set to zero. BCE is compensated by the pluralistic block leader by using generators in its own area only.

As for hierarchical control, pluralistic control requires for the block leader to get telemetry and schedules from other block members, as previously discussed. On the other hand, the requirement for communicating a correction term from the leader to the sub-ordinate members of the block disappears. This is illustrated in Figure 3, assuming again that TSO 1 is the block leader.

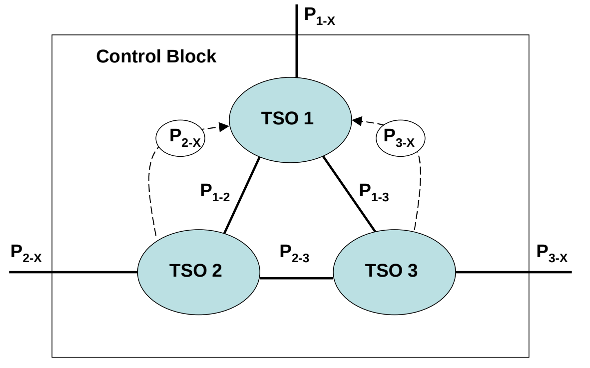

Fig. 3- Pluralistic control communication needs

4. GCCIA system frequency control

Figure 4 shows the interconnected system of GCC. It works in a hub configuration, with Member States connecting to a central back-bone and coordinated by ICC, the Interconnection Control Center.

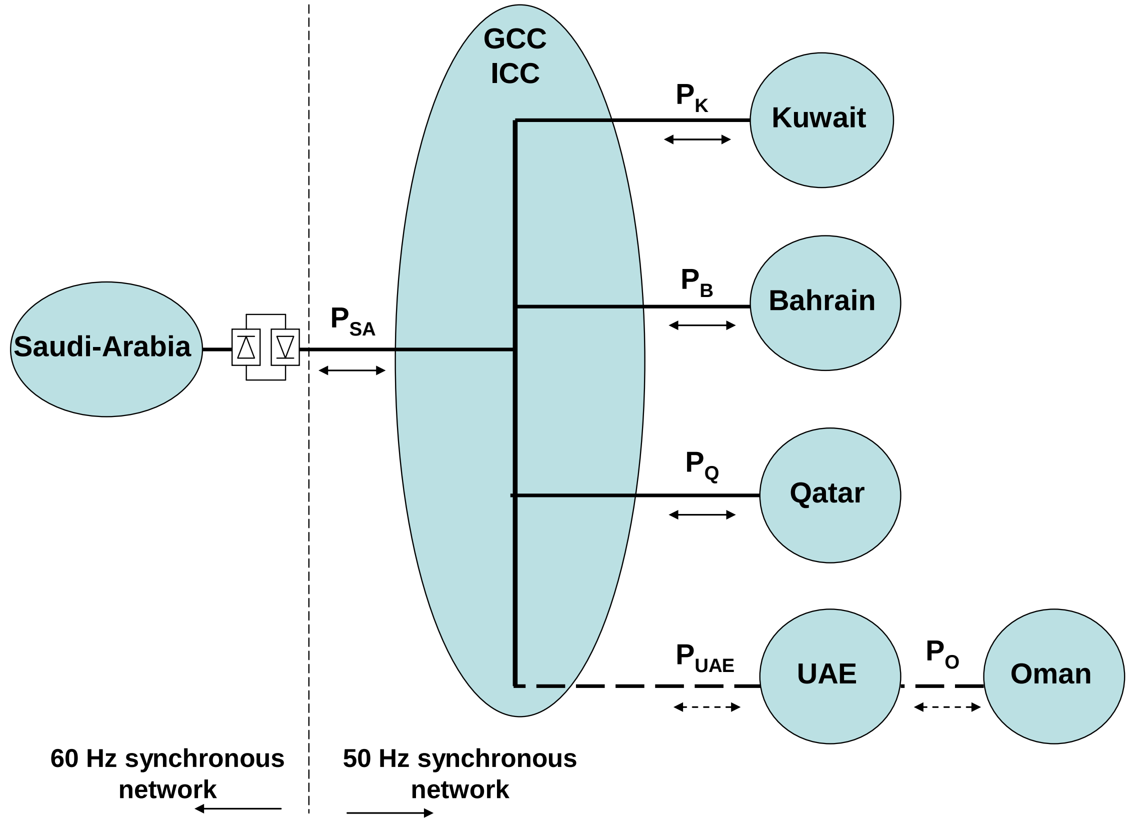

Fig. 4- GCC Interconnected System

Currently, the majority of GCCIA Member States perform centralized load-frequency control in CFC mode (Constant Frequency Control) – equation (1).

As countries interconnect, GCCIA members will initially move to TLBC mode (Tie-line Bias Control) – equation (2).

When full interconnection is completed, hierarchical control becomes possible, with ICC acting as block leader.

It must be noted, however, that ICC has no generation means of it own, so a particular variation of hierarchical control is initially implemented.

GCCIA hierarchical load frequency control is done by computing a Block Control **F**requency Error (or GCCIA ACE) as:

$$BCFE = ACE_{GCCIA} = B_{GCCIA} \cdot \Delta f$$

and distributing it to all GCCIA Member States through participation coefficients α_j.

The system power frequency characteristic is:

$$B_{GCCIA} = \sum B_k$$

where $\mathbf{B_k}$ are the system frequency bias coefficients (MW/Hz) of each Member State in the synchronous zone, that is, excepting Saudi Arabia, which is decoupled (from the frequency point of view) due to the HVDC back-to-back link.

Participation coefficients are obtained by normalizing the $\mathbf{B_k}$ coefficients:

$$\alpha_j = \frac{B_j}{\sum_k B_k} = \frac{B_j}{B_{GCCIA}}$$

In other words, total GCCIA ACE is distributed proportionally to the frequency bias (power system frequency characteristic) of each Member State.

In future, it is foreseen that GCCIA could be interconnected to other power pools and it would then be necessary to keep GCCIA exchanges with external pools according to schedules. The present hierarchical implementation can then be extended to include the external tie-line errors as in equation (4). A GCCIA Block Control **P**ower Error could then be computed and distributed to all members, including Saudi Arabia:

$$BCPE = P_{GCCIA} - P_{GCCIA}^{Sched}$$

where P_{GCCIA} is the interchange of GCCIA block with other power pools.

Distribution of BCPE necessitates a different set of coefficients to include Saudi Arabia’s contribution, if desired.

5. CONCLUSIONS

The interconnection of electrical networks brings many benefits and creates new operational challenges, in particular for the control of frequency and interchange flows. This paper reviewed the main concepts involved in load-frequency control of interconnected systems. The current hierarchical system frequency control mechanism implemented in GCCIA has been described, and options for extending it to support potential future interconnection with other power pools have been discussed.

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APPLICATIONS OF SYNCHRONIZED PHASOR MEASUREMENTS FOR SECURE POWER TRANSFER BETWEEN CONTROL AREAS

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Applications of Synchronized Phasor Measurements for Secure Power Transfer between Control Areas

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ABSTRACT

Most power systems today are operated close to their steady-state stability limits as demonstrated by several voltage collapse incidents throughout the world. There is significant impact resulting from transferring electrical power from the generating plant to the load centers without considering the safe limits of power transfer under different load conditions.

This paper presents the technical studies for computing transfer limits in Saudi Electricity Company (SEC) - Western Operating Area (WOA) and the guidelines for System Operations.

The paper also bring out the proposal for the use of Wide Area Monitoring (WAM) functions to identify the safe transfer limits on the main transmission lines.

KEY WORDS

Collapse — Dynamic Behavior – PMU – Stability – Transfer Limit.

1-INTRODUCTION

The SEC-WOA bulk power system consists of 380 kV transmission network with local area transmission at 110kV and the major load centers are located in Jeddah, Makkah and Madinah while the generation plants are in Jeddah, Makkah, Shoaiba, Rabigh, Madinah and Yanbu. With the knowledge of maximum power transfers, it helps to allocate the proper spinning reserves or plan maintenance of generating units. It therefore becomes necessary to determine in advance, the practical limits of active power (MW) transfer between different areas, under a variety of system conditions in order to maintain a continuous and reliable operation. In SEC-WOA, the load centers are in Jeddah, Makkah and Madinah. Though there are generating plants in each of these three areas (PP3 and PP2 in Jeddah , MPS in Makkah, TPS in Taif, Airport Plant and B. Ali in Madinah), these by themselves are insufficient to cater to the respective area loads especially during peak season and therefore need to import power from outside areas (Rabigh, Yanbu or Shoaiba). Rabigh consists of steam and gas turbine generation as well as combined cycle units with a total generation capability of approximately 2600 MW while Shoaiba has a total generation capacity of about 4300 MW. These two plants are connected to rest of WOA (Shoaiba to Makkah and Jeddah, Rabigh to Jeddah, Makkah and Madinah). This study performed by consultant to compute the maximum MW transfer capability out of these two (Rabigh and Shoaiba) plants to rest of WOA and MW transfer limits into Jeddah, Makkah and Madinah considering normal operation as well as operation under contingencies based on the reliability and operating criteria for various load levels in the system.

The paper also bring out the proposal for the use of Wide Area Monitoring (WAM) functions that uses high-resolution measurements synchronized by Global Positioning System (GPS) through reliable telecommunication channels, these measurements create a comprehensive system overview to identify the safe transfer limits on the main transmission lines based on the phase voltages, currents and angle measurements at both sides for maximizing the utilization of the lines capacities within stability margin. The use of WAM measurements enables system dynamics behavior to be monitored continuously and provides early warning against dangerous system operation.

2- SYSTEM DESCRIPTION

2.1 SEC-WOA 380KV Network

The SEC-WOA bulk power system consists of 380 kV transmission network with local area transmission at 110kV. The major load centers are located in Jeddah, Makkah and Madinah while the generation plants are in Jeddah, Makkah, Taif, Shoaibah, Rabigh, Madinah and Yanbu.

Though there are generating plants in each of these three areas (PP3 and PP2 in Jeddah, MPS in Makkah, TPS in Taif, Airport Plant and Bir Ali in Madinah), these by themselves are insufficient to cater to the respective area loads especially during peak season and therefore need to import power from outside areas (Rabigh and Shoaiba).

Rabigh consists of steam and gas turbine generation as well as combined cycle units with a total generation capability of approximately 2,600 MW while Shoaiba has a total generation capacity of about 4300 MW. These two plants are connected to rest of WR network (Shoaibah to Makkah and Jeddah, Rabigh to Jeddah, Makkah, Madinah and Yanbu). There are also Desalination plants (SWCC) owned generation in Jeddah, Yanbu and Shoaibah.

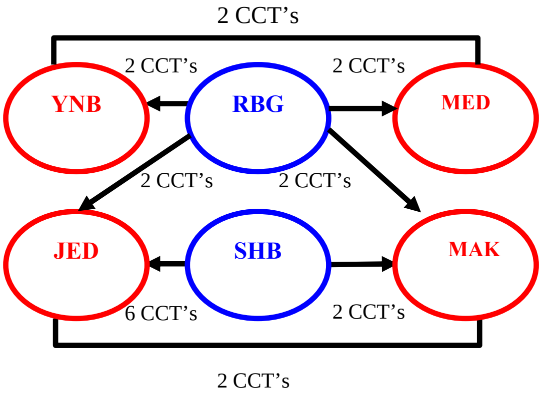

Fig. (1) 380 KV Network for SEC-WOA Peak 2008G

2.2 Generation Capabilities

The recorded peak load of SEC-WOA for year 2008 G was 10735 MW with average annual growth rate between 6-7%. The generation capabilities include steam, gas turbine and combined cycle units in addition to the export from the desalination plants in Jeddah, Shoaiba and Yanbu as well as Marafiq as listed in table (I):

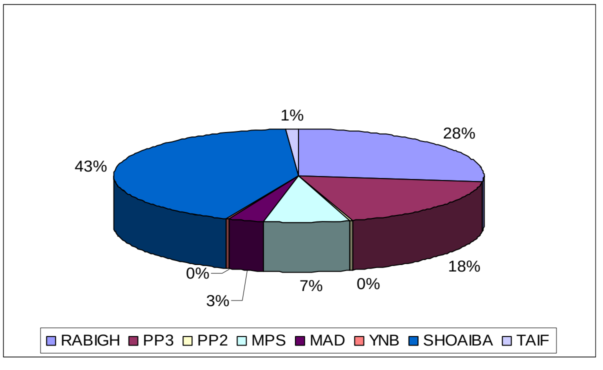

Fig. (2) SEC-WR Power Plant Capabilities

Table (I) SEC-WOA Gen. at Peak 2008G

POWER PLANT	*STEAM*	*C.C*	*GT*	*PEAK 2008G MW*	*AVAIL. MW at PEAK*
RABIGH	6	3	12	2548	2548
SEC-SHB	11	-	-	4372	4372
PP3-JED	-	-	35	1660	1660
PP2-JED	-	-	4	50	50
MAKKAH	-	-	17	683	683
MADINAH	-	-	9	282	282
TAIF	-	-	5	97	97
YANBU-E	-	-	3	45	45
SUB-TOTAL	17	3	85	9737	9737

POWER EXPORT FROM SWCC , MARAFIQ & ARAMCO TO SEC - WOA					
MARAFIQ	4	-	7	141	141
SWCC-JED	5	-	-	289	289
SWCC-SHB	9	-	-	391	391
SWCC-YNB	5	-	-	118	118
ARAMCO	-	-	-	59	59
G-TOTAL	39	3	86	10735	10735

In 2008, load demand increased 9.5% compared to previous recorded peak at 2007G (9802 MW).

3- TRANSFER LIMITS IN SEC WOA SYSTEM

The loadability of high voltage transmission lines is limited by its thermal rating as well as angle, voltage or transient/dynamic stability. For the actual operation point , local indicators can be calculated to determine the stability limit. The physically most reasonable approach for the calculation of steady state limits is the calculation of the maximum loadability point on the base of actual measurements at both ends of the line.
This leads to a more accurate value compared to off-line determined values with high uncertainties.

3.1 Thermal Transfer Limit

The thermal loading on facilities due to an increase in the interface power transfer under system intact and (N-1) contingencies should be monitored to determine the thermal constraints that are directly attributable to the power transfer between areas.
Such determination is made by computing the distribution factor (i.e. sensitivity) associated with the assumed transfer.
The power transfer analysis included system intact as well as single branch contingency evaluation. The facility loadings were compared against the respective rate values for system intact as well as contingencies.
A transfer distribution factor of 5% was used as a screening threshold for relevant facilities to be flagged as limiting elements, following the industry practice [1].

3.2 Voltage Based Transfer Limit

3.2.1 Voltage Limits

The first part of the analysis included the determination of voltage performance in terms of acceptable voltages for steady state operation (for e.g. 0.95 – 1.05 p.u. for system intact and 0.9-1.10 p.u. for contingencies).

3.2.2 Slow Voltage Collapse

It is not sufficient to determine the steady state voltage at buses and compare it against the applicable criteria. It is critical to determine whether the state of the system is such that there is no potential voltage collapse situation for a small increase in the transfer level. There are two approaches to the determination of potential voltage collapse condition. In the first approach, the voltage at the subject bus is plotted against the power transfer being studied. Such a curve is called (PV) curve and is illustrated in Fig. 3

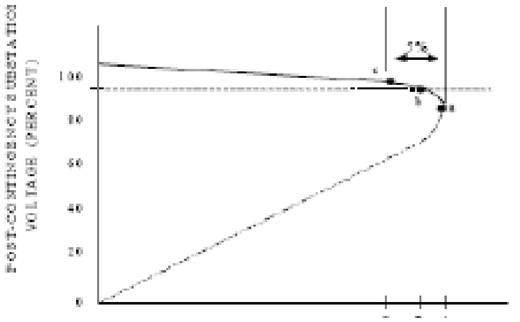

Fig. (3) Typical PV Characteristic

Referring to the above curve, point “a” is the “knee point” beyond which a voltage collapse is certain. Point “b” is where the curve crosses the post-contingency low voltage limit (for e.g. 90%) and point “c” is the point where the power transfer has some margin to the collapse point (point “a”). Another approach to determine the potential voltage collapse issue is to determine the reactive power margin at a given bus for a given power transfer. This approach is called (QV) approach and involves plotting bus voltage against reactive power. From the (QV) curves, the reactive power margins at the test bus can be computed. The reactive power margin is computed as the distance between the knee of the (QV) curve and the zero reactive power line.

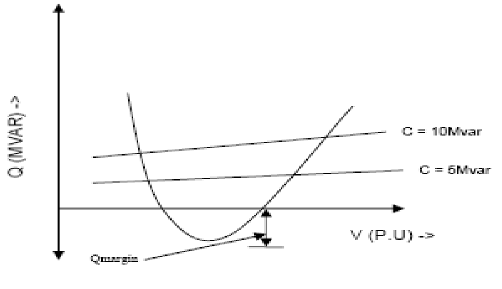

Fig. (4) Typical QV Characteristic

If the knee of the QV curve is below the x-axis (zero reactive power line), it indicates a positive reactive power margin at that location (Fig.4), whereas if the knee of the QV curve is above the x-axis, it shows a reactive deficiency instead. For this study, either of the above approaches (i.e. PV or QV) was used as deemed necessary by the situation.

3.3 Stability Based Transfer Limit

The stability based transfer limit is usually determined by applying a margin (e.g. 10%) to the thermal or voltage limits, whichever is lower. However, if the thermal and/or voltage transfer limit corresponds to the maximum net export out of a generating plant, then the stability testing is performed at that transfer value. A power flow case was developed by simulating power transfers reflecting such values. Dynamic analyses were then performed by applying 3-phase faults (with the subsequent outage of a single facility on fault clearing) as well as single-line-to-ground faults on double circuits (leading to the outage of two circuits post fault clearing) to verify stable and acceptable system operation.

4- INTERFACES AND LOAD LEVELS

4.1 Interfaces

The maximum power flows on the following interfaces were determined:

Rabigh – South (Interface #1)
Rabigh – Jeddah (Interface #1A)
Rabigh – Makkah (Interface #1B)

Madinah Import (Interface #2)

Shoaiba Export (Interface #3)
Shoaiba – North Jeddah (Interface #3A)
Shoaiba – South Jeddah (Interface #3B)
Shoaiba – Makkah (Interface #3C)

Makkah – Taif (Interface #4)

4.2 Load Levels

The flow limits for the above mentioned interfaces were calculated for the following system conditions:
• Peak load expected for year 2008.
• Average day summer season load level (85% of the summer peak load).
• Load level corresponding to 65% of the summer peak (Min. load for summer).
• Load level corresponding to 40% of the summer peak (average day winter season).
• Minimum load level expected for the year 2009.

With the present generation levels (SEC owned) in Rabigh and Shoaiba, the net output from these plants are approximately 2,300 MW and 4,300 MW respectively.

5- APPLICATIONS OF PMU BASED WAMS FOR SECURE POWER TRANSFER

5.1 Corridor Monitoring

The technical and economic constraints play significant role in the installations of wide area measurements to all network buses. The requirements to support synchronized phasor data stream and processing are demanding beside an efficient telecommunication infrastructure, complex information management systems are needed. The best locations for PMU placement have then to be carefully defined in the planning stage in order to maximize the added value for operation. The buses selected for PMU installation are closely dependent on the desired monitoring applications. To get a throughout picture of the system state , the rate of buses needing direct measurements proves to be in between 20-25% which may still be too high for a preliminary WAMS project [2]. As far as voltage monitoring is concerned in this paper , the most critical load areas are to be monitored. Based on operational experience and simulation results of critical scenarios, the nodes presenting lower loadability margins should be chosen. All sites of specific interest to the System Operators (cross-border flow monitoring, critical interfaces, main generation plant and load areas, nodes equipped with SVC's) can be included.

In real power systems the main limitations are typically caused by transmission corridors between generation and load areas. If these transmission corridors extend a certain length, voltage stability is the limiting factor, which needs to be carefully supervised to utilize the corridor to a maximum extent. The main principle of the corridor voltage stability monitoring is to use the measurements from both ends of the transmission corridor, reduce them to lump currents and voltages and to compute a reduced equivalent model of the transmission corridor [3].

The measurements from both of the transmission line enabling splitting of the respective part into T-equivalent of transmission corridor and Thevenin equivalent of the generators.

For the measured phasors $\overline{v}_1, \overline{i}_1$ and $\overline{v}_2, \overline{i}_2$ where the impedances $\overline{Z}_T, \overline{Z}_{sh}$ and $\overline{Z}_L$ are given by:

$$\overline{Z}_T = 2\frac{\overline{v}_1 - \overline{v}_2}{\overline{i}_1 - \overline{i}_2} \quad (1)$$

$$\overline{Z}_{sh} = \frac{\overline{v}_2\overline{i}_1 - \overline{v}_1\overline{i}_2}{\overline{i}_1^{\,2} - \overline{i}_2^{\,2}} \quad (2)$$

$$\overline{Z}_L = \frac{\overline{v}_2}{-\overline{i}_2} \quad (3)$$

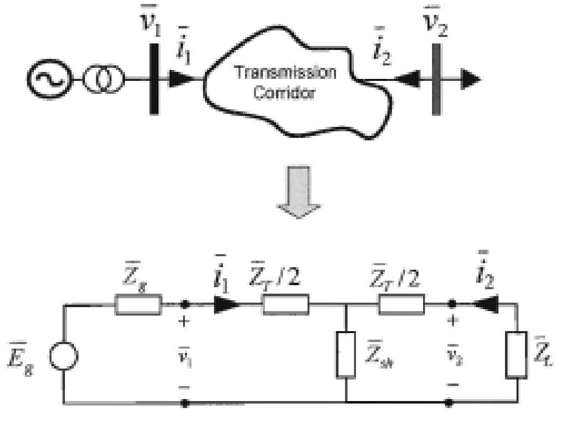

Fig. (5) T- and Thevenin – equivelents of transmission corridor fed by generation area

5.2 Thermal Monitoring

The line parameters based on phasor information can be determined from the phasor measurements of voltage and currents at both ends of the line. If the actual value of R is determined, the actual line temperature can be calculated according to the following:

$$\frac{R_1}{R_2} = \frac{T_1 + T_0}{T_2 + T_0} \quad (4)$$

R_1 is the determined values of R. R_2 and T_2 are a pair of given values from the original design of the line. T_0 is a material constant for the line wires. This temperature is the average temperature of the entire line between two measurement points and includes the actual situation of ambient conditions like wind speed, and line current.

6-PROPSED PMU INSTALLATIONS IN SEC-WOA TRANSMISSION SYSTEM

The monitoring system should do what an system operator would so, if he would have sufficient time to analyze the situation and take the proper action. All actions need to be simple as much as possible.

6.1 PMU Locations

Most of the installations of WAMA are operated mainly as independent systems and cover only minor parts of transmission systems. There are two types of concepts:

- PMUs sparsely spread throughout the transmission system.
- PMUs only fully observing a small dedicated portion of the transmission system.

Based on the previous results of transfer limits within SEC WOA transmission network, the installation of PMUs is highly recommended in the following interfaces:

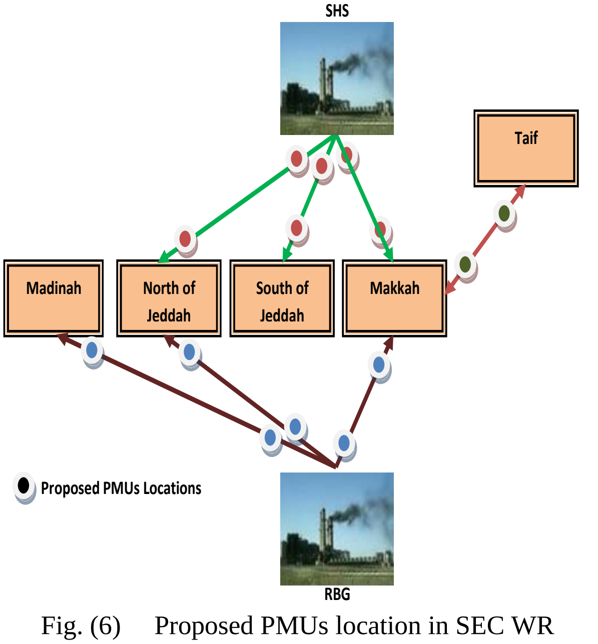

Fig. (6) Proposed PMUs location in SEC WR

6.2 Integration of WAMS into SCADA/EMS Systems

Replacements of all RTU in the transmission network of SEC-WOA are not a realistic expectation. The integration of WAMS can be done by using PMU measurements in the state estimation to improve its accuracy.

Other practicable approach is to have separate WAMS and show the results on an integrated human machine interface (HMI) to the operator. The fully synchronized system can stay separate from the SCADA system, which make it much easier to expand the SCADA system in a modularized way.

6.3 Communication Requirements

The communication system is the backbone of WAMS. It is presently the limitation in terms of cost, reliability and speed. It is very critical to have deterministic behavior and reliable operation specially for control applications. All kind of communications channels can be used for WAMS but for wide area control a high-speed communication is required. The critical issue is not so much the bandwidth, but the time-delay of the communication [4]. Communication channels are expected to be redundant and dedicated for wide area applications. High speed communication systems will make the installation of wide area system much easier.

6.4 GPS Requirements

The whole system depends also on the availability of global positioning satellite (GPS) signals. The losses of GPS-antenna signal due to bad weather conditions should be considered and the monitoring system must be designed in a way that it provides information for a specified time period without receiving a GPS signal. The placement of antenna is a critical issue as well. Separate antenna can be used for each PMU but if not placed properly to avoid electromagnetic incompatibilities with other substation equipment. One well placed antenna providing a signal to all PMUs is preferred.

7- WAMS IN SEC INTERCONNECTIONS

SEC operates an Interconnected Transmission System consisting of an Eastern Operating Area (EOA) and Central Operating Area (COA). Presently, the interconnection between the two regions comprises of two 380kV double circuit overhead lines (series compensated) and one 230kV double circuit overhead line.
Two additional 380kV double circuit lines (Fadhili-Sudair and Ghunan-Khurais-PP9) are being planned to be constructed. The expected transfer limit (stability limited) between EOA-COA would be about 4500 MW after the commissioning of the two additional 380 kV lines.
A new 400km long 380kV interconnection between COA (Qasim) and WOA (Madinah-East) is being planned and the main purpose of the interconnection will be the transferring of power from the COA - EOA part of the system towards the WOA around 500-1000MW.
Besides this Interconnection, SEC will operate another transmission system in Western Operating Area (WOA) with a 380kV interconnection (Shoaiba – Namerah) to Southern Operating area (SOA).
The transmission system across the Kingdom will become one synchronous operating system spanning from Jubail (in EOA) to Abha (in SOA) – a distance of more than 2000km.

The installation of WAM in this interconnected system will be of great help to transfer the power between different regions to the maximum safe limit and it will provides early warning for system operators in case of sever situations.

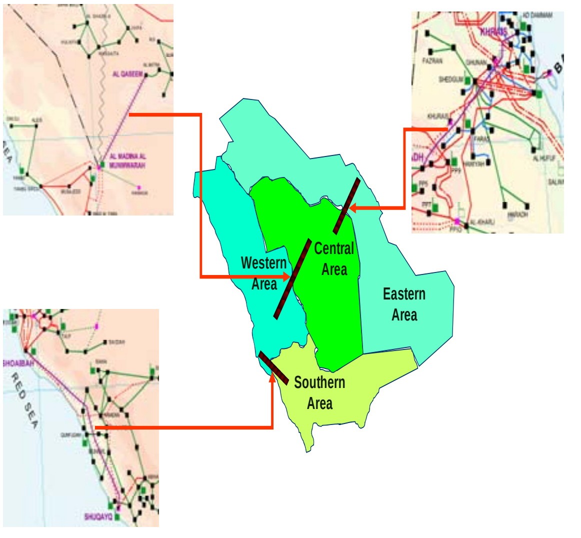

Fig. (7) SEC Internal Interconnections

8- WAMS IN GCC INTERCONNECTIONS

The main purpose of GCC interconnections was the reserve sharing between GCC states which will reduce the amount of the required reserve in each country significantly by providing the chance of power transfer within the interconnected networks. The additional spare transmission capacity allows the power trading as a great chance to use the interconnectors to its maximum margin considering the safe and secure transfer limits.
Installation of WAMS within GCC transmission corridors provides reliable power transfer taking into account the thermal and stability limits.

9- OTHER APPLICATIONS OF WAMS SYSTEM

Phase voltages, currents and phase angle will be continuously measured at specific locations in the power system with high sampling rate to be used as an input to the voltage stability software to evaluate the stability conditions of the power system in real-time and take the proper action to avoid system instability or voltage collapse in the steady state as well as in case of system disturbance.
The voltage stability software monitor the flow in MW through the main interconnecting lines and cables and evaluate the maximum possible power transfer on each of them and give warning to dispatchers and actions to overcome such problems can be done either manually by the dispatchers or automatically through SCADA and EMS using protection devices [5].
The voltage stability calculations give the chance to system operators to utilize the transmission lines up to the stability limits, which can save the need for implementing some new lines unless it is necessary.

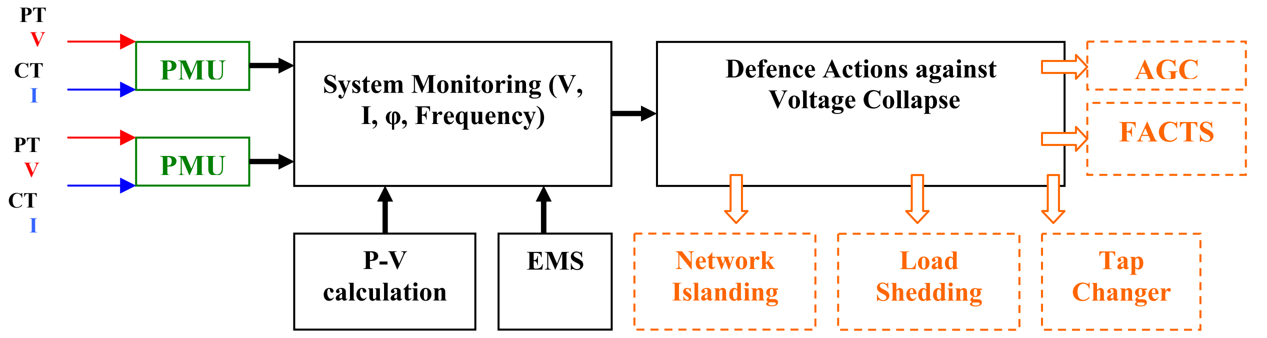

Fig. (8) Overview of Wide Area Monitoring applications

9.1 Event Detection

Within control room monitoring in SEC WR control centers, the knowledge of events occurring in the system helps to understand the causes of system disturbances.

Such information provides a clear picture of the overall situation. Currently, the available information regarding events is limited and transmitted with the usual SCADA delays.

On the other hand, complete system observability provides accurate event detection using system synchronized measures sampled at high sampling rate (i.e. one sample per cycle), both the nature and location of the events can be determined by compared analysis of bus voltage magnitude and phase variations between sampling steps.

Largest variations are associated to the event location. When all bus voltages magnitudes and phases are monitored, results will be very accurate while performance will be less accurate under partial observability conditions but it will be of great help for operators to better realize the occurrence of high impact events close to the monitored nodes.

9.2 Islanding Detection

Frequency is a good indicator of system integrity. Within SEC WOA, steady state frequency is identical at all buses. In case of severe disturbances, the power system may split into islands due to cascade line tripping or special protection scheme intervention. A faster identification of system separation might help system operators to follow promptly the evaluation of events.

The application can be based on the analysis of phase angle trends. Different islands present different frequencies, the relevant bus voltage absolute phase angles experience increasing displacement [6].

Even if the online system identification is more accurate than today, the implementation of an automatically acting scheme for emergency situations is an extremely difficult task when it is to be deployed as an online adaptable system instead of a fixed rule based one.

WAMS as SPS will only be considered in practice if it does not contain too much intelligence and if the rules for the actions are very transparent and are as simple as possible [7]. The information collected from WAMS can be used for alarm messages in case of the infringement of a threshold value for a certain stability value. The usability of such information is crucial for system operators if integrated into SCADA/EMS operation scheme. Because of the speed of WAMS systems the operator is more and more the bottleneck for taking quick actions.

9.3 Impact on Operation and Planning

The operation of the power system is mainly based on deterministic offline planning studies and most of the limits are determined by planning studies and set in conservative way to lower the risk of system instabilities. In normal operation, this limits the use of the existing networks capability. While in emergency situations, it may be possible that based on that limits that are too conservative, operational actions are over reacting. On the other hand, if WAMS detailed information is available to the operator about system status, it will lead to operate the system based on actual situation and the alarm system suppose to pre-warn of imminence of critical situations and will help to avoid over or under reactions of the operators.

The impact of WAMS as intelligent alarm system will be a shift closer to real-time operational limits and can increase the transmission capability [8].

From the planning point of view, WAMS information can be used to generate or verify accurate system models through using WAMS as disturbance recorder. WAMS can provide information to have proper models via integrating the data into SCADA/EMS instead of offline evaluation to support the operational planning.

The information benefits of the monitoring system can be used for higher system security or for higher network utilization. The latter includes the risk that operating closer to network stability limits might lower the system security drastically. The balance between these two benefits has to be considered carefully when specifying and designing the monitoring system.

10- CONCLUSIONS & RECOMMENDATIONS

- Installation of PMUs at the critical locations and the additional information from PMU gives system operators higher confidence in the system status and voltage stability information is very valuable for network situations.
- The measurement records provided by WAMS support the network planning as well as operational planning for better dynamic modeling of power systems.
- WAMS and control applications depend on the available communication channels and high speed communication systems will make the installation of wide area system much easier.

11-ACKNOWLEDGMENT

The authors would like to express their gratitude to the support and encouragement received during the course of this paper from Eng. Abdullah Aljuhani, Manager Coordination &Technical Services and Eng.Abdulaziz Ma'atoq Executive Director –Developing Transmission Area – Saudi Electricity Company –K.S.A.

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VOLTAGE INSTABILITY AND VOLTAGE COLLAPSE

Mohamed Nagib Omara, Thani Mohamed Al Khusaibi
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Voltage Instability and Voltage Collapse

Mohamed Nagib Omara [1], Thani Mohamed Salim Al Khusaibi [2]

***Abstract*— With the advent of deregulated energy markets and the growing desire to fully utilize existing transmission equipment and infrastructure, voltage stability issues are becoming increasingly critical. Based on actual incidents, short-term voltage instability is increasing, especially on heavily loaded and stressed system. The main symptoms of voltage collapse are – low voltage profiles, heavy reactive power flows, inadequate reactive support, and heavily loaded systems. The collapse is often precipitated by low-probability single or multiple contingencies.

A common scenario is a large disturbance such as a multi-phase fault near a load center that decelerates motor loads. Following fault clearing with transmission outages, motors draw very high current while simultaneously attempting to reaccelerate, and may stall if the power system is weak. Massive loss of load and possibly area instability and voltage collapse may follow. Fast-acting generator excitation controls, fast-acting reactive power support devices (SVC, STATCOM, SMES), or fast load shedding can prevent voltage collapse.

The paper presents an actual voltage collapse case study in the Sultanate of Oman Main Interconnected System (MIS).

***Index Terms*— Voltage collapse, voltage instability, reactive power, VAR compensation.**

I. INTRODUCTION

The main symptoms of voltage collapse are low voltage profiles, heavy reactive power flows, inadequate reactive support, and heavily loaded systems. The consequences of collapse often require long system restoration. Schemes which mitigate against collapse need to use the symptoms to diagnose the approach of the collapse in time to initiate corrective action.

Voltage Instability problems are likely to increase in the future because of:

1. Growing use of low inertia compressor motors for air conditioning, heat pumps, and refrigeration;
2. Possible global warming, causing increased use of air conditioning with higher load factor;
3. Increasing amounts of voltage-insensitive loads with electronic power supplies;
4. More intensive use of transmission systems;
5. Increasing use of capacitor banks for heavily loaded, constant torque type mechanical loads are the most onerous ,these loads (i.e., air conditioner compressor motors) may comprise up to 50% of summer peak load (Oman system) The potential for voltage stability problems is highlighted because both shunt capacitor bank reactive power, and induction motor electrical torque decrease with the square of the voltage.

Generators, if nearby, may ensure voltage recovery. The time-overload capability of generator field and armature circuits may be Load characteristics, and the possibility of fast voltage collapse, affect the type of reactive power compensation required. For fast-acting loads, reactive power compensation (SVC, STATCOM) tend to be required rather than the common mechanically switched compensation.

A related longer-term scenario involving motor loads assumes a power system survives the first few seconds following a severe disturbance, with motors re-accelerating to normal speed [1]. Under the situation where no adequate reactive power supports may cause field current overload of generators. After tens of seconds of time delay, over-excitation limiters reduce field current to continuous capability; alternatively, power plant operator intervention or protective tripping may occur. The field current and reactive power reduction can result in cascading field current limiting, armature current overloads, and also in generator and transmission line tripping by backup relays. With Heavy loads, and inadequate reactive power compensation a fast collapse follows.

II. TIME FRAME OF VOLTAGE COLLAPSE

Voltage collapse can occur over a wide variety of time frames. Figure I show some of the time frames of the various phenomena involved in loss of voltage stability. It can be seen that several orders of magnitude of times are involved.

Advances in numerical algorithms and computer power have made it possible to simulate systems of very large size and with many types of equipment. Several software tools are now available to perform simulation of power system responses over a long period of time. Examples are the EPRI's ETMSP .EUROSTAG, and PSS/E. The time frame of the voltage instability phenomenon is an important factor in application of mitigation measures.

Voltage collapses in the transient time frame are most often caused by slowly cleared faults, followed by the significant voltage depression.

Collapses in the longer term time frame may result from loss of significant sources of local generation such as 3rd June 2008 in Oman or reactive support, or from loss of heavily loaded transmission capability. In such cases,

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transient overload capability may allow nearby generators to maintain voltages for a short time, until maximum excitation limiters come into effect and local Var support is severely curtailed. However, loss of significant reactive power support can also lead to loss of angular stability and voltage collapse in the transient time frame as was the case in the 13 March 1989 collapse of the Hydro Quebec system due to loss of several critical SVCs that were supporting the transmission system voltages.

Collapses in the long term time frame may also be caused by unusually fast load build up (such as the Tokyo 23 July, 1987, incident). They may also be caused by changing over time, of the characteristic of the load sensitivity to voltage .Thus a loss of a significant source of local generation or reactive support can precipitate a voltage collapse in the transient or long term time frame.

The compressor torque–speed characteristic, low inertia and high load factor. Slow tripping of stalled residential air conditioners makes short term voltage instability a serious concern. The overloads and voltage depression caused by stalled motors can cause cascading tripping of lines and generators, leading to area collapse within a few seconds.

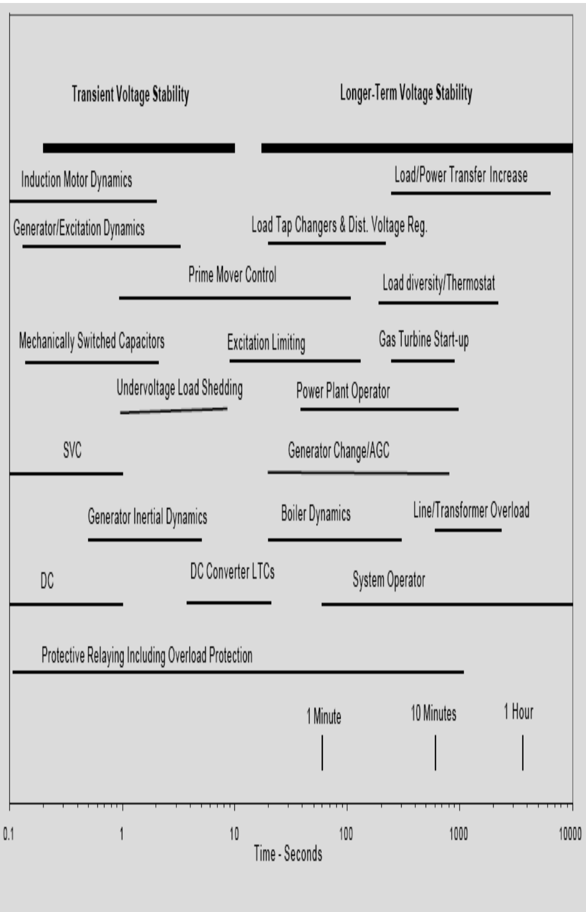

Figure 1 time frames of voltage instability

III. The Fundamental Principles of Mitigation Actions

a- ANTICIPATE THE PROBLEM by using load flow and stability studies to identify system conditions that may lead to voltage instability. Conditions that lead to voltage collapse may be caused or aggravated by heavy power transfer between regions; so coordination among the affected regions is essential to develop the appropriate mitigate action. Results of these studies can be used to develop special operating procedures to minimize the probability of collapse. Where studies show that operating procedures alone are not sufficient to ensure voltage stability, special control and protection schemes can be applied to mitigate the conditions leading to collapse.

b- USE APPROPRIATE DIAGNOSTIC techniques to provide early warning of the voltage stability problems. Since voltage collapse is a wide area problem, these techniques often need communications assistance. The communications are not necessarily high speed, but must be reliable. The techniques involve measurement of relevant factors such as voltage magnitude, status and output of sources of reactive power, rate of change of reactive power generation with respect to load, and magnitudes of real and reactive power flows.

c- PROVIDE TEMPORARY REACTIVE support until operator action can stabilize system. This may require taking advantage of temporary overload capabilities of generators and synchronous condensers (if any) in the affected area. To ensure full capability of all sources are available, they should be operated from time to time at maximum and minimum reactive outputs to ensure all protective devices coordinate properly with control devices.

d- PROVIDE PERMANENT REACTIVE SUPPORT. Since it is the deficiency of reactive power sources that causes voltage to drop, provision of these sources are an effective means of maintaining voltages. Switched capacitors are a popular means of providing such support, but care must be taken to avoid depending entirely on fixed support such as is provided by capacitors. Fixed sources do not provide the control of system voltage which is critical in near collapse situations.

e- PROVIDE AN APPROPRIATE mix of static and dynamic sources of reactive support.

Although dynamic sources of reactive power are much more expensive than fixed sources, they do have the advantage of being able to control voltages. Manual or automatic switching of static sources of reactive power is a better means of keeping dynamic sources near the middle of their operating range than adjusting their reference voltage.

f- TEMPORARY LOAD RELIEF by blocking tap changers or reducing distribution supply voltage. The amount of load relief provided by these means is determined entirely by the static and dynamic characteristics of the real and reactive components of the load with respect to voltage level. These characteristics vary widely, and may need to be determined by test. The reduction in reactive power demand with voltage is often larger than the reduction in real power demand. It must be ensured that voltage quality is not degraded so much.

g- SHED LOAD. THIS ALTERNATIVE is the ultimate short term mitigation action. Since the cause of voltage collapse is an excess of load for the given transmission system, load shedding is a clearly effective action (Oman case).

h-CHOICE OF ACTION(S) depends to a large extent on dynamics. The speed of collapse can vary widely from a few seconds to tens of minutes. Since many of the mitigation actions offer temporary benefits, their effectiveness will vary widely with the dynamic characteristics of the collapse. Therefore, there are no actions that are generally preferable for all types of power systems.

Protection and control actions must be coordinated with each other. As it becomes more difficult to provide new transmission and generation, utilities rely more on complex, and diverse protection and control systems. To ensure coordination is achieved, three items become important, communications, test and integrations

Communications are required to ensure coordination between different geographic locations. Test of coordination by regular exercising of control actions while the power

system is not stressed is the best way to ensure they will operate properly and coordinate with each other and with protection systems under stressed conditions.

System dynamics in the voltage collapse time frames depend on three factors, temporary overload capability of dynamic sources of reactive power, timing of control devices such as transformer load tap changers, and dynamic response of loads to voltage changes. Of these factors, it is usually the load characteristics that are most difficult to determine. Even if load characteristics are determined by test, mitigation actions based on these characteristics should be initiated in the region where the characteristics are valid..

Operator training and response is very important. Operators must be able to recognize voltage instability conditions and must be able to act promptly and effectively to arrest collapse. The time frame of collapse is often longer than operator response time. All automatic actions which are intended to provide temporary relief must be accompanied by clear indication of their action; so that operators can recognize the conditions. Further, operator training must include clear direction as to actions they are required to take when voltage collapse is imminent. Protection engineers can help in ensuring reliability of mitigation actions by proper design, and by coordination with other protection and control actions affecting system stability.

I- SVC VERSUS VOLTAGE-SOURCED CONVERTER DEVICES

Power system SVCs and voltage-sourced converter devices (STATCOM) regulate a bus voltage via the reactive current/power output. Over the control range, a droop characteristic of a few percent is used to avoid excessive control action and to coordinate with other voltage control equipment. The main difference between SVCs and voltage-sourced converter devices is clear when the control limits are reached which occurs for a few percent drop or rise of system voltage. SVCs at their boost limit become very expensive ac capacitor banks. Voltage-sourced converter devices, however, inherently provides constant current output down to low voltage (Figure 2). At 70% voltage, for example, SVC output is 70% current or 49% reactive power, while STATCOM output is 100% current or 70% reactive power. This difference can be crucial in supporting reacceleration of motors following a short circuit [2]. Voltage sourced converter devices provide better performance for equal reactive power ratings; alternatively, a smaller STATCOM will equal the performance of a larger SVC.

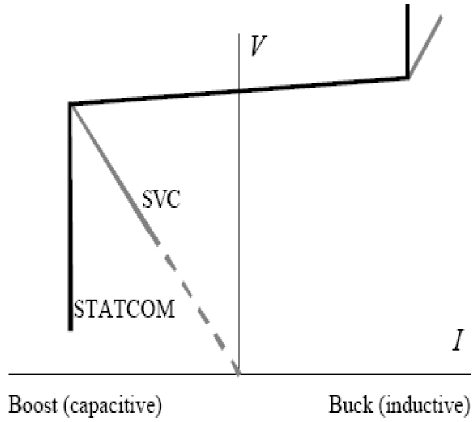

Figure 2. STATCOM and SVC characteristics.

Voltage-sourced converter devices have other advantages such as smaller size and higher speed. Voltage-sourced converter devices have symmetrical boost and buck reactive power ranges, SMES with its energy storage and discharge capability adds additional flexibility for stability and power quality support.

J- TRANSCO VERSUS DISCO'S VOLTAGE SUPPORT

Conventional shunt capacitor banks are most commonly at distribution level. Power Company SVCs or STATCOMs most commonly regulate transmission voltage

Larger, transmission level devices achieve economies of scale and provide support for several nearby substations. On the other Reactive power must be transmitted through the coupling transformer, through transmission lines, and then through bulk power delivery transformers and feeders to the load areas requiring high current during motor reacceleration. An alternative is several small built devices connected at distribution level and distributed at major bulk power delivery substations. Smaller size allows more options in the design, and reduces problems such as connection of thyristors or power transistors in series.

IV- CASE STUDY

1. OETC MAIN INTERCONNECTED SYSTEM (MIS) OVERVIEW

The OETC MIS is interconnected by 220 kV and 132 kV transmission lines. This network is supplied by 8 gas based power stations. It extends across the whole of northern Oman and interconnects bulk consumers and generators of electricity located in the Governorate of Muscat and in the regions of Batinah, Dakhliyah and Sharquiya. OETC MIS has no Var compensation devices. Capacitor banks are available only on the 33 KV and 11 KV networks in some primary substations. The Main Interconnected System is operating in an isolated mode connected to some industrial customers and some local networks.

2- THE INCIDENT

OETC MIS experienced a severe voltage deterioration specially in the eastern part of the system ,the voltage deteriote from 132 KV to 74 KV due to the opening of the main 132 KV ring and the tripping of Al Kamil Power station with 274 MW.

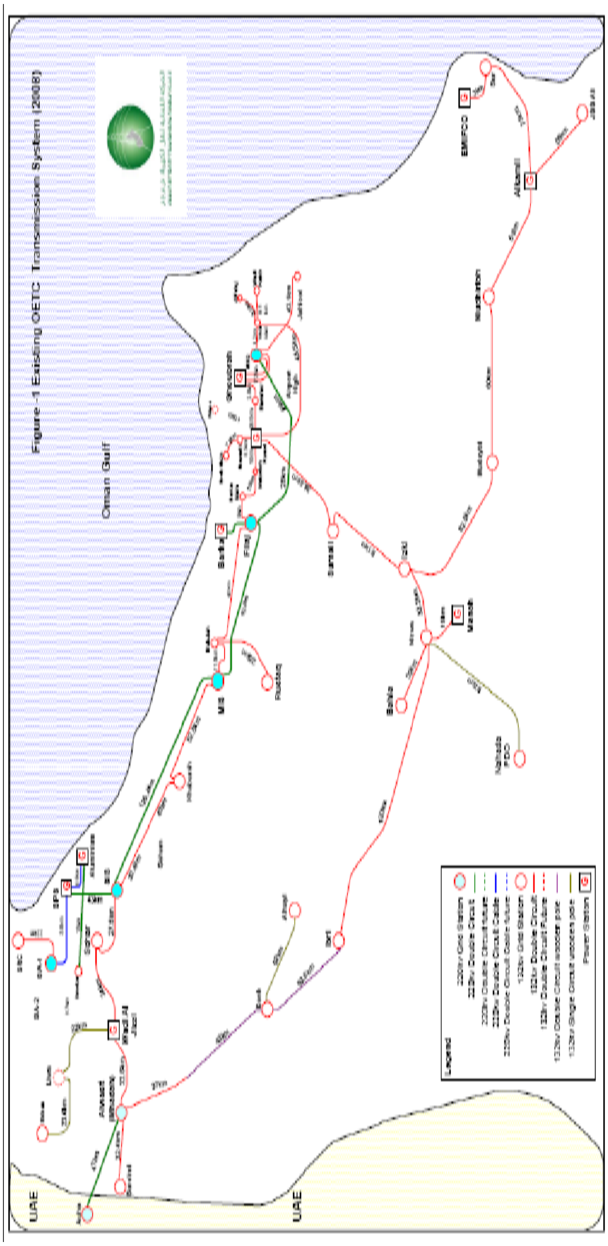

Figure 3 MIS interconnected System

3. SEQUENCE OF EVENTS

At 14:11:07.774 Al Wasit - Wadi Jizzi ckt2 trip on backup E/F protection

• The first serious impact was at Ibri (from 122. kV to 77kV) and Mudaibi (from 124 kV to 100kV).

After this system trip, load picked up by Wadi Jizzi – Al Wasit ckt-1 (148 MW)
After trip of ckt-2, causing opening of the system main 132 KV ring. the system voltage was almost as before the trip, except at Dank.
At 14:11:35.970 Al Kamel PS GT-1 tripped on stator overcurrent
At 11:36.262 Al Kamel PS GT-3 tripped on stator overcurrent
At 14:11:38.032 Al Kamel PS GT-2 tripped on stator overcurrent

- Sudden and severe voltage deterioration at Al Kamil power station 132 kV Busbar (from 132 kV to 114.1 kV)
- Accompanied with reduction of Al Kamil generation output and severe voltage reduction at Mudairib(125.4 kV to 120.8 kV). The rest of the system voltage profile was almost same as before.
- The voltage deterioration at Al Kamil PS and the adjacent Mudhirib station pulled the system voltage further down.
  Izki(126.9 kV to 105.7 kV) Still Al Wasit-Wadi Jizzi ckt-1 was in service.
- Rest of system voltage reduced around 1 kV average.
- Voltage at Dank deteriorated very fast to 86 kV
- Wadi Jizzi – Al Wasit ckt-1 tripped due to massive flow of power following Al Kamel voltage deteriorated to 104 kV.
- AL Kamil started importing power from the system (units tripped). Voltage deteriorated from 104.4 kV to 74 kV.

Load Dispatch Centre (LDC) interfered with severe manual load shedding in the most affected area. The rate of fall of voltage was very fast. It fell down to below 65 kV in some locations of the system, especially at Dank substation.

33 kV Feeders of at least 100 MW tripped at this stage, on indications such as distance protection, apparently due to low voltage conditions simulating distance protection fault. Some more loads (Approx another 200MW) must have been thrown off the system (due to Air-conditioners tripping

4. System Configuration, Demand and Generation

Table 1 Generation condition before and after the incident

GENERATION	% of the available capacity	Generation Availability	Before trip	After trip			
Time-->	1400		14:00	14:12		15:00	16:00
Rusail	102%	586 MW	596	547	381	489	517
Ghubrah	90%	503 MW	453	400	461	467	450
Manah	67%	269 MW	180	158	146	138	155
Wadi Jizzi	82%	272 MW	230	250	129	123	138
Al Kamil	91%	282 MW	247	0(trip)	30	121	147
Barka-1	100%	456 MW	454	462	327	431	436
Barka-2	On test	100 MW	100	100	100	120	110
Sohar	100%	629 MW	593	600	601	529	530
Soh.Alumin		115 MW	114	113	114	114	115
OMCO		20 MW	20	20	20	17	17
PDO		5 to 10 MW	2	Trip	Trip	14	-28
TOTAL GEN		3237 MW	**2989**	**2650**	**2309**	**2563**	**2587**
Load Shed							
Muscat			0	0	246.3	180.4	8.3
Majan			0	9.1	132.7	93.9	0
Mazoon			0	91.4	285.4	136.7	60.7
TOTAL L/S			**0**	**100.5**	**664.4**	**411**	**69**

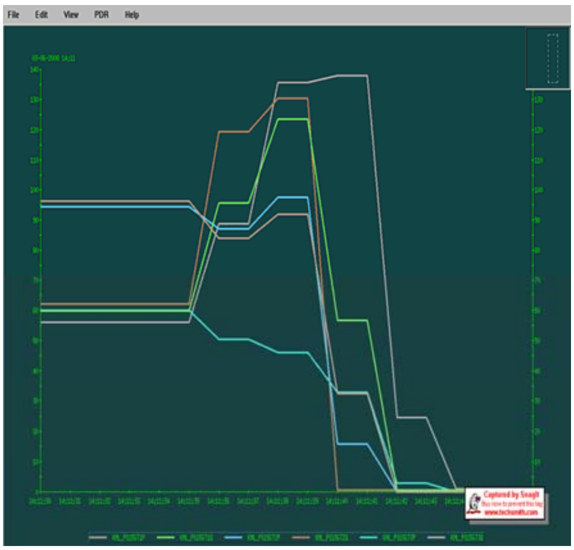

Figure 4 Al Kamil Generations MW, MVAr

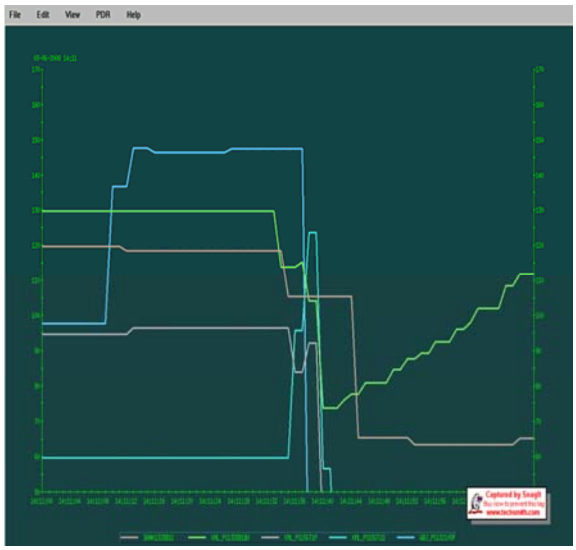

Figure 5 Wadi Jizzi-Al Wasit flow, Dank Voltage, Al Kamil Voltageand Al Kamil GT-1 MW, MVAR

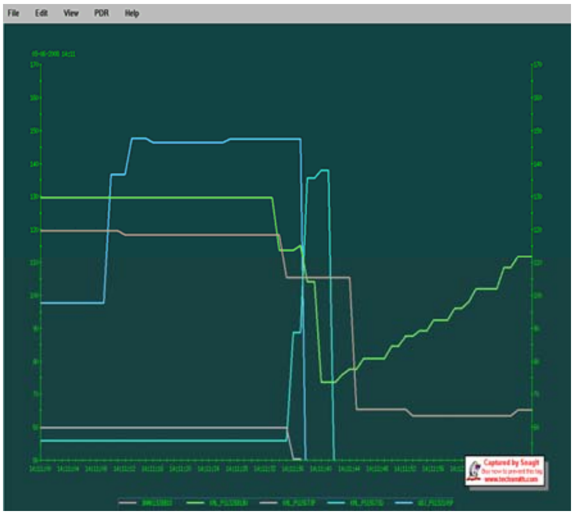

Figure 6 Wadi Jizzi-Al Wasit flow, Dank Voltage, Al Kamil Voltageand Al Kamil GT-3 MW, MVAR

Figure7 Voltages at various points – Manah, Nizwa, Izki, Mudaibi, Mudhirib, Al Kamel and Sur

Al Kamel power plant has three frame 9 open cycle gas turbines, connected to the eastern sub network of the system. Two more open cycle power plants having 10 units frame 9 open cycle gas turbines are electrically closer to the source of the disturbance than Al Kamel power plant. The only difference is that the other 10 units frame 9 gas turbines were marginally loaded less than Al Kamel generating units before the incident. Only Al Kamel three generating units tripped on stator overcurrent.

According to:

A- ANSI C50.13-1989 (for generator overcurrent and over load protections).

Overcurrent relay consists of an instantaneous overcurrent unit and a time over current having extremely inverse characteristics. The overcurrent unit is set to pick up at 70-100 % of full load current and a time setting is chosen so that the relay operating time is 7 seconds at 226% of the full load current.

For generator overload protection, under emergency condition it is permissible to exceed the continuous out put capacity for a short time. The armature winding short time thermal capability is shown in table 2.

Table 2 ANSI C50.13-1989 over current protection

Time in seconds	10	30	60	120
Armature current %	226 %	154 %	130 %	116%

B- As per IEC 60255 the protection settings of the Al Kamil and Manah generators have been modeled as shown on the graph below together with the full armature current thermal capability as in figure 8

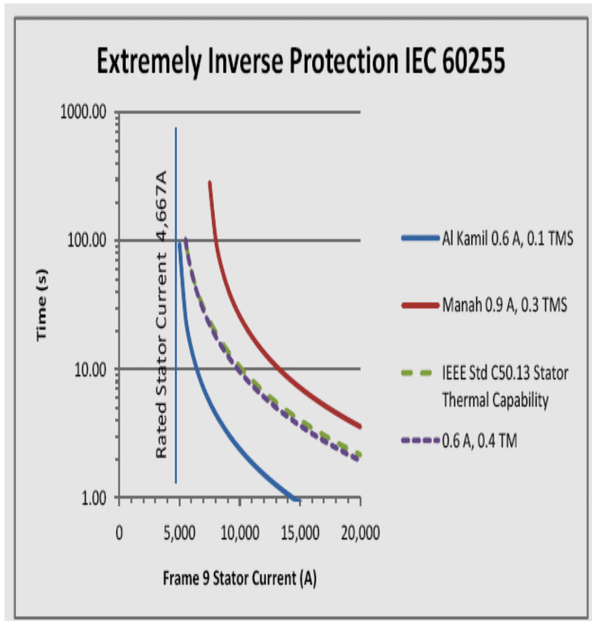

Figure 8 IEC 60255 Inverse protections

It is concluded that the Al Kamel generators are over-protected and the Manah generators Under-protected. The required protection setting lies about mid-way between with the protection set at 0.6A and 0.4TMS

V. PROPOSED OETC UNDER VOLTAGE LOAD SHEDDING

DESCRIPTION OF OETC UVLS SCHEME

The automatic under voltage load shedding scheme monitors a selected list of dynamic system conditions and will shed load until proper system voltages and var reserves are restored. The scheme consists of three independent subsystems, one Muscat system, one at Majan system and one at Mazoon which can shed load in their respective areas, or jointly for more severe system problems.

Each subsystem monitors the key station bus voltages and a designated group of units for its var reserve, which is the remaining var boost capacity of the group. If the bus voltage drops below a set level or if the var reserve drops below a set level, its sensor will key a continuous signal to all distribution control centers. After time delay (Ts2) ,

load shedding will start and continue in incremental blocks until the initiating conditions have reset.
A reduced time delay (Ts1) should be used if any two or more subsystems have simultaneously initiated load shedding.

UVLS AND PLANNING STANDARDS AND RELIABILITY CRITERIA

OETC is proposing and planning to implement the use of load shedding to meet the Performance Levels for the purposes of meeting the Planning Standards and Reliability Criteria. The standards do allow planned loss of load in a system where the disturbance originated, but not in the neighboring systems. For planned loss of firm load can occur on all systems, however cascading cannot occur. If standards and criteria are not met, then UVLS may be a useful tool.
The following points illustrate how UVLS can be used to meet Planning Standards and Reliability Criteria:

1. IF UVLS IS TO BE EVALUATED as an option to meet the planning standards and reliability criteria, load shedding studies should be performed as described in this document. Note that UVLS is not effective for those systems or contingencies where voltage collapse occurs in less than one second, or where overloads occur without sufficient voltage drop.
2 THE VOLTAGE PICK-UP and time delay settings of the automatic UVLS must be properly coordinated with the manual scheme.
3. SYSTEMS WHERE VOLTAGE COLLAPSE is not likely to cascade into neighboring areas can still benefit from a cost-effective UVLS; a) to avoid local voltage collapse, b) to control loss of load, and c) to facilitate load restoration.
4. SYSTEMS WHERE THE NEEDED generation and /or transmission projects have been delayed, and the resulting lack of voltage support is likely to put the system at a risk of voltage collapse, could employ UVLS until those projects are operational.
5. IF UVLS IS USED TO MEET planning standards and reliability criteria, then it must be highly reliable. UVLS is usually applied with local relays tripping local loads, in which case a failure to trip does not mean the failure of all UVLS, but only one portion of the UVLS.
6.IF THE DESIRED PLANNING STANDARDS and reliability criteria are not met with failure to trip the most effective load, sufficient additional load can be armed to shed so that the criteria would be met. Where a central UVLS or a direct trip control is used, redundancy may be necessary so that failure is not credible.
7. UVLS SHOULD BE DESIGNED in a way to recover adequate real and reactive power reserve margins in the system following contingencies. These margins should be equal to or greater than those defined under the Voltage Stability criteria.
8. SOME INDIVIDUAL SYSTEMS OR "POCKETS" within these systems may use UVLS to mitigate low voltage conditions caused by extreme weather conditions or unanticipated load growth, even without any disturbances. Such systems would need to drop even more load under contingencies. A multi-stage load-dropping scheme may be suitable for such systems.
9. UVLS CAN BE ARMED TO OPERATE during limited times or seasons of the year, for specific load levels, and /or during specific disturbances such as loss of a certain transmission path. This is in contrast to UVLS applied as a Safety Net where it is usually more appropriate to arm the scheme all the time.

RELAY TRIP SETTINGS

The UVLS relay trip voltages and time delays to trip must be appropriate for the system they are being applied to. The appropriateness depends on the structure of the transmission and generation network, the contingencies being planned for, the actual load response, and control actions of devices like transformer LTC's, generators, switched capacitors, SVC's, other relays, etc. This can be tested by dynamic simulations.
The voltage trip thresholds can be determined from the results of steady state simulations of worst contingencies using voltage sensitive load models.

The steps selected are:

- Trip 5% of load when monitored bus voltages fall to 90% or lower of normal for a minimum of 3.5 seconds.(the figures can be changed)
- Trip 5% additional load when bus voltages fall to 92% or lower for 5.0 seconds. .(the figures can be changed)
- Trip 5% additional load when bus voltages fall to 92% or lower for 8.0 seconds. .(the figures can be changed)

ONE STEP OR MULTI-STEP

UVLS is inherently "multi-step" in the sense that buses will experience differing voltages and voltage drops. This is unlike under-frequency sensing where all the buses in a local area have the same frequency.

1- Plans to shed load automatically should be examined to determine if unacceptable over- voltage, over-frequency, or transmission violations might result. Potential unacceptable conditions should be mitigated.
2- If over-voltage, or over-frequency is likely by a single large load shedding stage, the amount of automatic load shed should be reduced, and multi-stage load shedding be adopted.
3- If N-2 events include EHV (220kV) and 132 kV combinations, a single stage of load tripping may not be adequate to provide predictable, accurate and desirable results. Using different trip delays, and/or trip set points may help.
4- Dynamic studies should verify the UVLS voltage trip settings and trip time delays. If no studies then monitoring of the system performance is used

RELAY SETTINGS

On applying under-voltage relays to automatically trip loads, choices must be made on the time versus voltage response of the system and its loads. They are:

1- Relay voltage trip levels for different load blocks, time delays to trip, time to reset, and failure time.
2- The selection of the load blocks to trip, their sizes, locations, and load composition.

3- Relay automatic load restoration voltage levels, timing, and the choice of loads to be automatically restored to control over-voltage. Automatic restoration can be dangerous in UVLS and needs a lot of thought.

4- Coordination with transformer load-tap changing, reactor and capacitor switching, and generator VAR controls, and the total system response.

Manual load shedding may be required to backup the automatic scheme. The LDC Dispatcher will monitor the key var reserve and substation voltages in the area and initiate manual load shedding if these monitored quantities remain above or below their settings described under settings.

ARMING CONDITIONS

The automatic under voltage load shedding scheme will be armed and disarmed by Distribution control centers under direction from LDC. The scheme is not required and should not be armed at times during light load condition.

SETTING

Table 3 UVLS Voltage Settings

Area	Muscat Area	Sharqiyah Area	Al Bathena Area	Very Weak Areas
Minimum 132 KV Voltage	Less than 118KV	117KV	118KV	115KV
VAR Reserve				
Minimum 220 KV Voltage	200KV	200KV	200KV	198 KV

VIII. Recommendations

1. Stator over current protection of the generating units to match ANSI C50.13
2. Changing the control logic of some of the shunt capacitor banks in the 11 KV and 33 KV levels from power factor logic to voltage logic to match the control logic of AVR of the transformers
3. Sufficient static and dynamic voltage support are needed to maintain voltage levels within an acceptable range.
4. Sufficient reactive power reserves must be available to regulate voltage at all times.
5. Metering must be in place and maintained to capture actual reactive consumption at various points.
6. Transmission and Distribution planners must determine in advance the required type and location of reactive correction.
7. Distribution reactive loads/demand must be fully compensated before transmission reactive compensation is considered.
8. The reactive capability of the generators should be largely reserved for contingencies on the EHV system or to support voltages during extreme system operating conditions.
9. Load shedding schemes must be implemented if a desired voltage is unattainable thru reactive power reserves.
10. Distributed Shunt Capacitor Banks along Long Distribution line
11. Reactive power supply should be located in close proximity to its consumption.
12. OETC to disable sensitive backup E/F protection and replace it with normal E/F protection.
13. OETC Directional Over current protection to be set to the fault level and install over load protection.

VII. Conclusion

1. The reactive capability of the generators should be largely reserved for contingencies on the EHV system or to support voltages during extreme system operating conditions.
2. Transco to install dynamic sources of reactive support, (SVCs and voltage-sourced converter devices (STATCOM)
3. Proper training for the load dispatch centre system operators.
4. Install proper wide area monitoring schemes.
5. Install automatic under voltage load shedding scheme to quickly arrest fast voltage drop.
6. 6-Distribution reactive loads/demand must be fully compensated before transmission reactive compensation is considered.
7. Coordinating LTC blocking scheme can be utilized in area where voltage instability is imminent.

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DISPATCH APPLICATION SYSTEM (DAS) FOR NETWORK PERFORMANCE MONITORING

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Dispatch Application System (DAS) for Network Performance Monitoring

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***Abstract*—** This paper presents the Dispatch Application System (DAS) as a powerful tool for representing the physical elements of the electric transmission system. This tool provides an electronic communication to record and approve the schedule outages activities which forward with recommendation to the dispatchers. The tool supports the Load Dispatch Center (LDC) staff to observe and monitor all activities and the status of the network. The DAS system is developed with approach to automatically determine the Key Performance Indicator (KPI) in the form of daily to annual basis. The database structure allows a power system analyst to mathematically model the electrical characteristics or the network in different simulation platforms.

***Index Terms*—** DAS, KPI, Anomalous Losses, Availability and Energy Loss Incentive.

I. INTRODUCTION

The DAS is in house developed application tool to facilitate the dispatch activities of the transmission network named Dispatch Application System

(DAS). It is used to support operational planning, real time, dispatcher and performance engineers. It is developed using a well defined functional description that suits the need of the Transmission System Operator (TSO). The DAS is structured based on easily updated database combined with state of art web application techniques. The database contains each TRANSCO asset with unique ID subdivided in different classifications. The system is updated immediately for the foreseen upcoming equipment with all its relevant data. This tool provides a proper technique for recording and approving the scheduled outage activities assigned for the field engineers. The DAS enables the real time engineers to review the requested applications and forward their decision and recommendation to the dispatchers. Consequently, the dispatcher proceeds for the approved work applications with capability to record any incident occurred in the network. Therefore, the performance group has excellent opportunity to observe all the activities and incidents in the transmission system. The tracking of the application activities is implemented in the DAS system for ensuring network security in response to individual system updates. The DAS demonstrates superior performance for automatically calculating the Key Performance Indicator (KPI) of the network and activities reports in a variable time span from daily to annual bases. The DAS gives flexibility of recording and retrieving data with capability of classification and different combination of reports that required for asset management group achieving the performance standards and analysis for the Transmission System Operator (TSO).

The DAS system is used to facilitate the activates that impacts the Abu Dhabi Water and Electricity (ADWEA) privatization model. Fig.1 demonstrates the top level model of all participant companies from Generation, Transmission and Distribution. These companies are operated on the following regulation basis:

- Transmission code
- Interconnection codes
- Metering code
- International standards for power quality, delivery and system security.

Transco network is operated based on the above regulatory codes to ensure the security of the network and the availability of the service. The interconnections with other network are managed based on the interface agreements that should enable higher reliability and support from other neighbors networks in case of emergency. The RSB is observing the performance of the network to meet the standards and the power quality requirements.

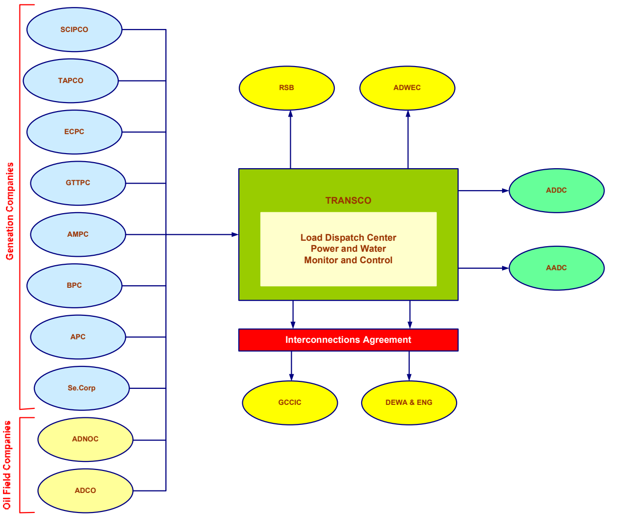


Fig.1. Abu Dhabi Water and Electricity privatization Model.

II. STRUCTUR OF DATABASE

The DAS database is developed based on the available data from the network manager, Unit commitment, contractors, tests, study and planning department. The criterion to structure and develop the database for the assets of TRANSCO network follows the following guidelines:

- Identification of known equipments parameters.
- Identification of data sources
- Definition of database tool and translators to be applicable for different simulation tools.
- Definition of the process of the database maintenance
- Definition of parameters interface for the simulation platforms
- Define the conversion of the network parameters to be consistent with the platforms parameters list.

The database is reviewed and validated with respect to the manufacture data for the electrical equipments and other accurate sources of data. The daily data related to activities, reports, plans; schedules are prepared by the department's staff and forward to the head of department and LDC manager for approval.

III. SYSTEM DESCRIPTION

The DAS implements many applications that facilitate the daily work and the data flow to the LDC staff. It allows observing the network performance, namely the Key Performance Indicator (KPI) in a daily to annual basis. Figure 2 shows a portion of the DAS applications,

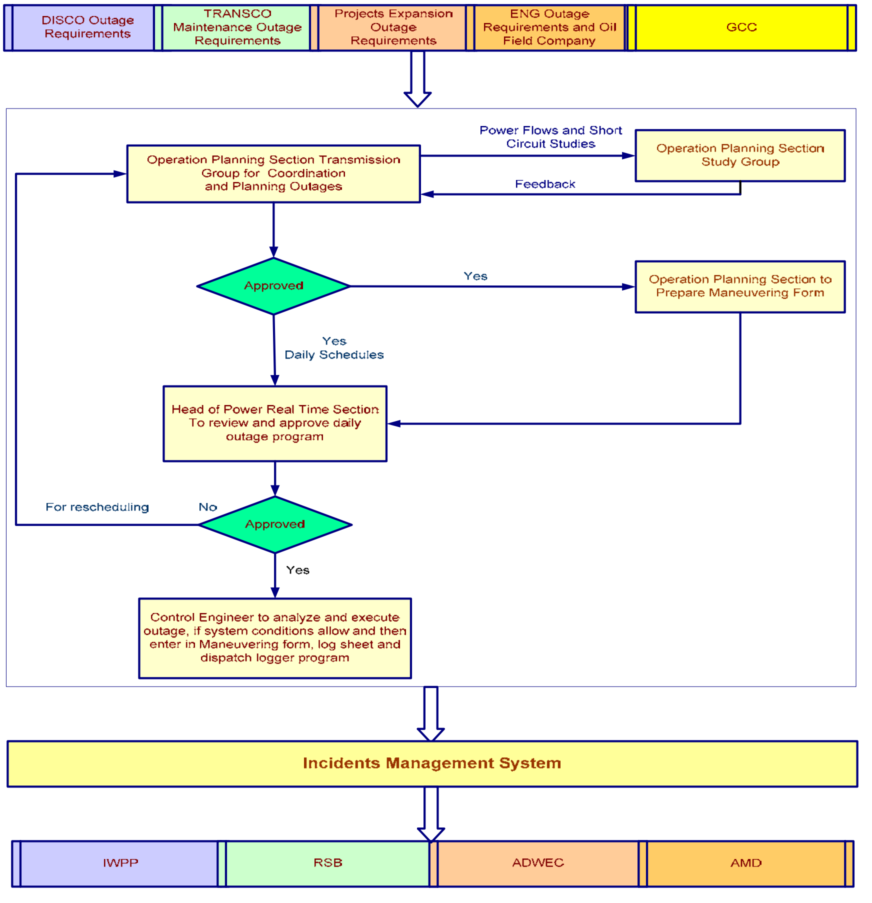


Fig.2. The flow chart of the power transmission outage planning activity using DAS system.

which describes the process for the planning of power transmission outage associated with the process in the DAS system. The criterion of outage incident is developed based on the following requirements:

1. Distribution companies outages
2. TRANSCO maintenance outage
3. Project expansion outage
4. Other users outages requirements

The transmission group at the operational planning section receives the outage request and forwards it to the operational study group to conduct the required analysis. Therein, the concept studies for the transmission system operation such as power flow, contingency analysis, short circuit analysis and other conceptual studies are mandatory to approve or decline the outage request. The study group carried out the required network analysis and investigates the impact of the outage on the performance and the security of the network achieving N-1 criteria.

Consequently, provides the recommendation for achieving such outage. The study report includes the recommendation that forwards to the planning transmission group in order to take the final decision to approve or decline the outage request. In case of approval, the operational planning group prepares the maneuvering form that should be accepted by the real time head of section. Thereafter, the control engineer executes the outage restricted to the logging system database that details the steps of the maneuver for achieving the application.

IV. SYSTEM APPLICATIONS

This section briefly presents implementation issues associated with the DAS applications. These applications are developed to facilitate the operational activities and the observation of TRANSCO network. The main features and applications are summarized as follows:

1. Task work management
2. Power dispatch,
3. Power facility
4. Electronic logger

This section demonstrates the main applications and their influence on the daily work, acceleration, coordination and the quality of deliveries.

1) Task Management

This application addresses all tasks assigned for the LDC departments and the available resources. The interface panel illustrates the pending, done and future tasks based on the marked option with description of the achievement, loading of work and the future tasks as illustrated in Fig. 3. Therefore, it supports the LDC staff with updated information and feedback that helps for scheduling their work and deliveries.

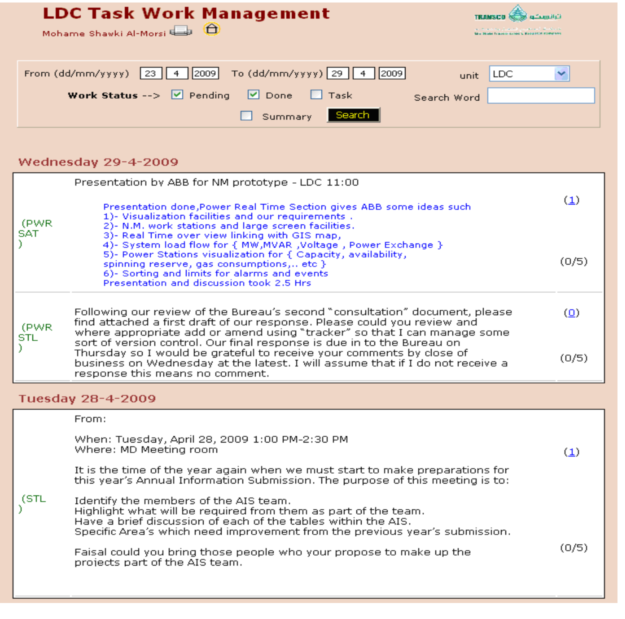
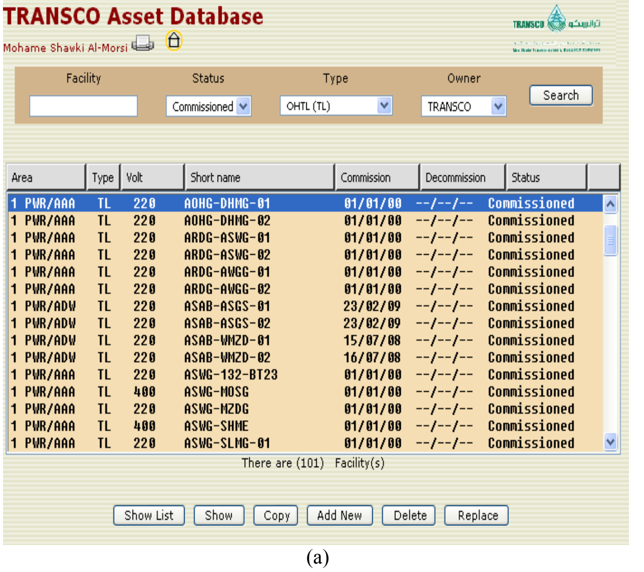


Fig.3. The task management control panel.

2) Power Facility

The power facility panel provides a detailed database for the network equipments including Generators, GT &ST, Power Plants, Distillers, OHL, Transformers, Cables, Bus Bars, Bus Coupler, and Bus Sections, Machines, Auxiliary Transformers, Spare Bay, SVC and Shunt Reactors. The database classified into project items, commissioned and decommissioned items to know history of the network elements. The assets also classified based on the ownership of TRANSCO or others. The parameters list is maintained by the senior real time engineer. Figure 4 illustrates the overview of the power facility and the detailed parameter list of the selected transmission line.



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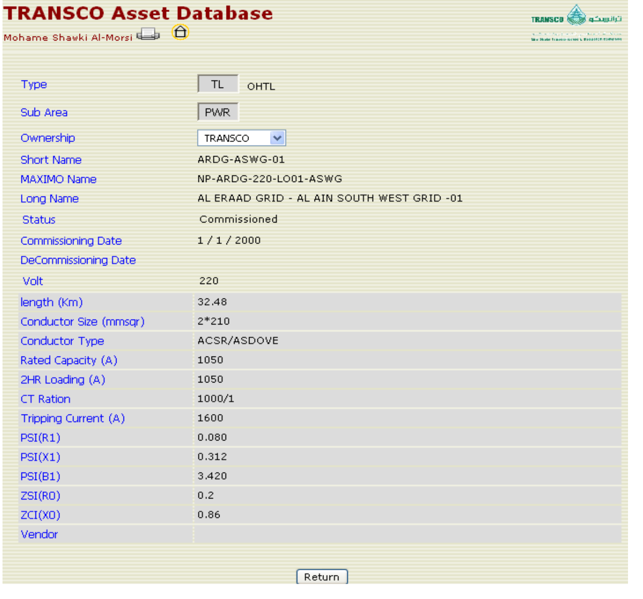


(b)

Fig.4. Overview of the power facility.

3) Power Dispatch

This panel is used for several applications related to the availability of generation and transmission services. Fig.5 illustrates the console of the power dispatch panel that comprises number of applications for recording all generation and transmission incidents such as tripping, outages, commissioning and service. The incident is recorded with considering the equipment ID, starting and normalized times, reasons, facility, management approval and comments from the dispatcher.

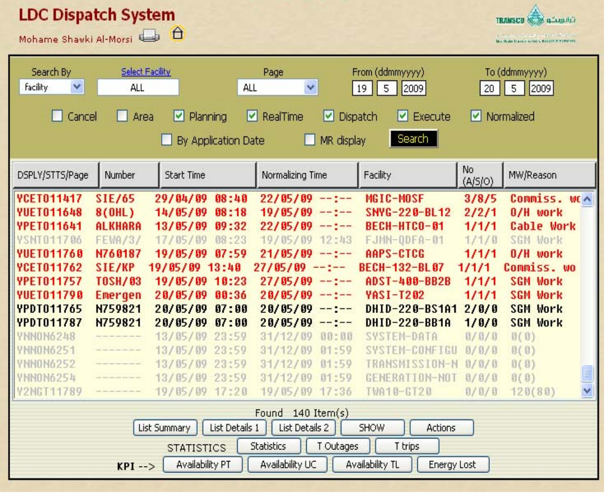


Fig.5. The console of the power dispatch panel.

The overview of the operation dispatch can be categorized by facilities or incidents in a specified time interval. The incidents are recorded based on the TRANSCO security procedures as follows:

1. Filed Engineer notifying the generation and transmission planning group for new application through DAS.
2. Planning group receives the applications and ranking them based on the applications priorities.
3. Outage applications should be forwarded to the study group for conducting the required system studies and analysis in order to provide the recommendation and precaution for achieving the application.
4. The planning group receives the approved study report and schedules all applications with maneuver forms and forwards them to the real time head of section.
5. The real time head of section reviews the network work conditions, application request and approve the conclusion of the study report based on the current topology of the TRANSCO network.
6. The shift control engineers receive the schedules planning sheets for achieving the application based on the defined maneuvering steps.

The tripping and outages incidents are follow the following processes as described in Figs. 6 and 7.

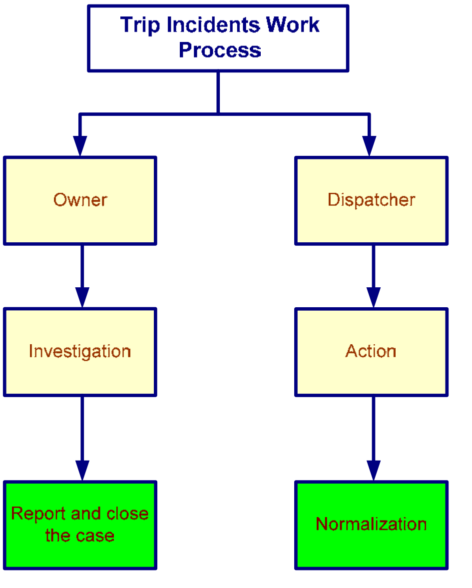


Fig.6. The tripping incidents process.

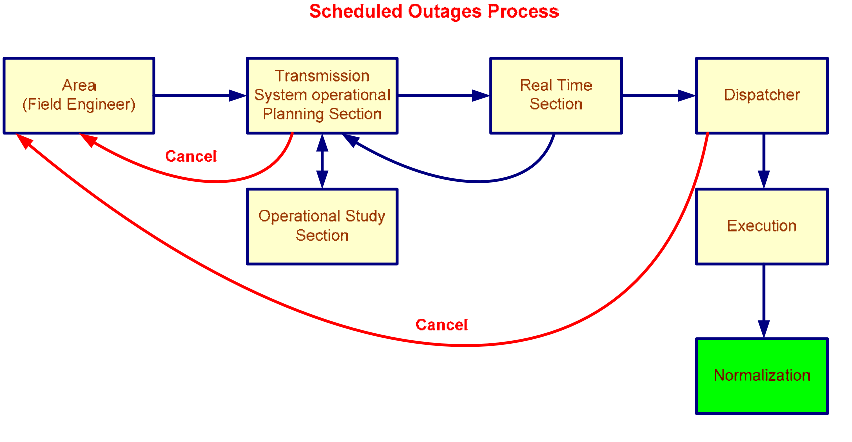


Fig.7. The scheduled outages process.

The safety document should be issued for each incident to meet the TRANSCO standard safety rules. Fig. 4 demonstrates the incidents in respect to work status in black, red and grey colors that represent under dispatcher, execution and normalization respectively. The data of the tripping incidents in terms of tripping time, reasons, normalization and safety documents is available in the power dispatch panel as shown in Fig.8.

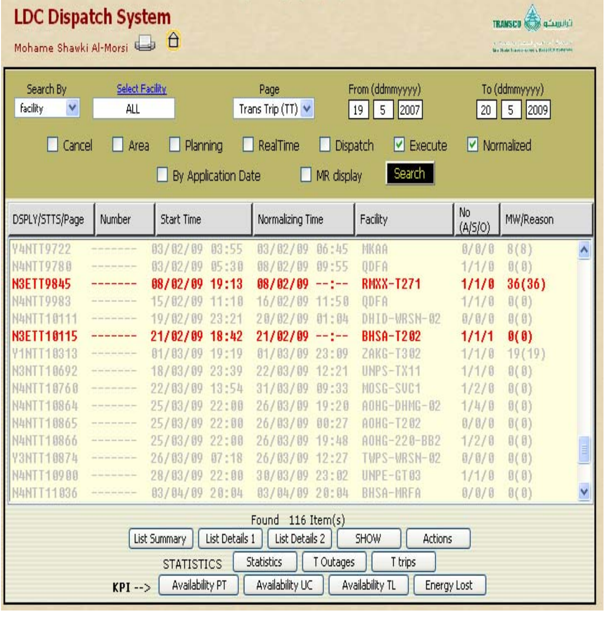


Fig.8. The recorded incidents in the DAS.

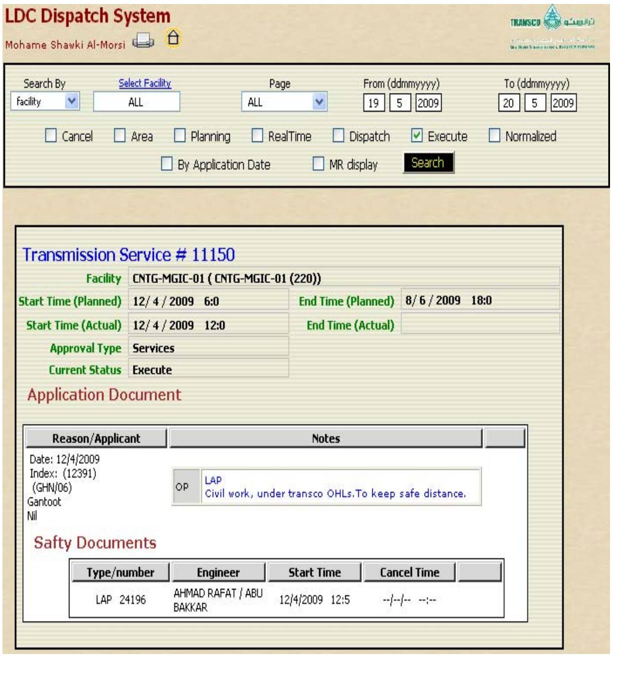


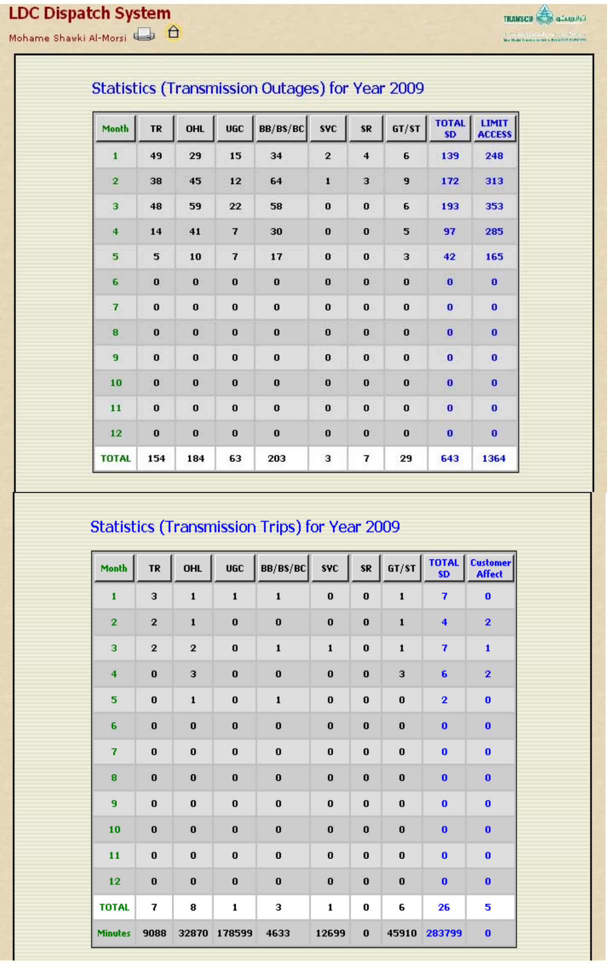
Fig.9. The recorded incidents of all facilities.

This overview enables to analyze the network performance in order to provide the proper recommendation for system reliability enhancement. Figure 9 shows one of the recorded incidents of the transmission line due to civil work under TRANSCO OHLs as safety regulation to keep safe distance. This incident is recorded and associated with safety documents and approved as service outage.

Figure 10 shows one of the recorded incidents of the transmission line due to civil work under TRANSCO OHLs as safety regulation to keep safe distance. This incident is recorded and associated with safety documents and approved as service outage. There are many reasons for transmission and generation outages, thus the classification of the outages is important for determining the KPI for TRANSCO assets. The database enables to perform important statistics in terms of tripping and outages as shown in Fig. 11 in order to demonstrate the network performance.

Fig.10. Tripping and outages statistics of the generation and transmission system.

All incidents are classified in DAS system in order to perform the required statistics for the transmission outages and tripping individually as shown in Fig. 11.



LDC Dispatch System

Mohame Shawki Al-Morsi

Statistics (Transmission Outages) for Year 2009

Month	TR	OHL	UGC	BB/BS/BC	SVC	SR	GT/ST	TOTAL SD	LIMIT ACCESS
1	49	29	15	34	2	4	6	139	248
2	38	45	12	64	1	3	9	172	313
3	48	59	22	58	0	0	6	193	353
4	14	41	7	30	0	0	5	97	285
5	5	10	7	17	0	0	3	42	165
6	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0
TOTAL	154	184	63	203	3	7	29	643	1364

Statistics (Transmission Trips) for Year 2009

Month	TR	OHL	UGC	BB/BS/BC	SVC	SR	GT/ST	TOTAL SD	Customer Affect
1	3	1	1	1	0	0	1	7	0
2	2	1	0	0	0	0	1	4	2
3	2	2	0	1	1	0	1	7	1
4	0	3	0	0	0	0	3	6	2
5	0	1	0	1	0	0	0	2	0
6	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0
TOTAL	7	8	1	3	1	0	6	26	5
Minutes	9088	32870	178599	4633	12699	0	45910	283799	0

Fig.11. Statistics of the classified outages and tripping transmission system.

V. ELECTRONIC LOGGING

The electronic logging is important panel for the real time and shift engineers who are responsible for achieving the approved applications. All approved applications are recorded in the DAS system and the defined procedures for achieving such applications should be presented in the electronic logging for carrying out all incidents as straight forward. The electronic logging includes the approved procedure and steps for each maneuver that reviewed by the real time head of section to confirm the validity of the steps based on the current network condition. Therefore, the steps are described in details and recorded in the electronic logging which acting as check list for shift engineer as shown in Fig.12.

LDC Dispatcher Logger

Mohame Shawki Al-Morsi

Dispatcher Disk: GEN, TRANS

Date (dd-mm-yyyy): 20 5 2009

Search

Transmission Network Dispatch Log Sheet (20/5/2009)

Time	Station-CCT	Equip	Operation Time: Inst. Time	Execution: ON	Execution: OFF	Description	NCC Eng.	Field Eng.	
01:25	YASI-T202		00:36		00:36	S/D,ISOLATED OM EMERGENCY BASIS DUE TO "SF6 GAS LOW "ALARM ON 132 CB (Q0).	Faris Omar	SAAD AL GHARHY	(1)
08:32	DHID-220-BB1A		08:13		08:13	S/D & ISOLATED AS PER OP. SHEET NO 34,MAY,2009	Majdi Harbieh	ABDULLAH	(1)
13:51	AAPS-CTCG		13:38	13:38		NORMALIZED & LOADED AS PER OP. SHEET NO. 33,MAY,2009 AARCC INFORMED.	Khaled Barakat	MOHSEN & EMAD	(1)
14:06	UNPS-TX03		12:44	12:44		NORMALIZED AS PER OP. SHEET NO. 26,MAR,2009	Khaled Barakat	JAMEEL & MAGDI	(1)
14:48	DHID-220-BB1A			14:36		NORMALIZED & LOADED THE B.B AS PER OPER. SHEET#034,MAY,09	Abdul Rashid	ABDULLAH	(1)

Fig.12. The electronic logging console of the DAS system.

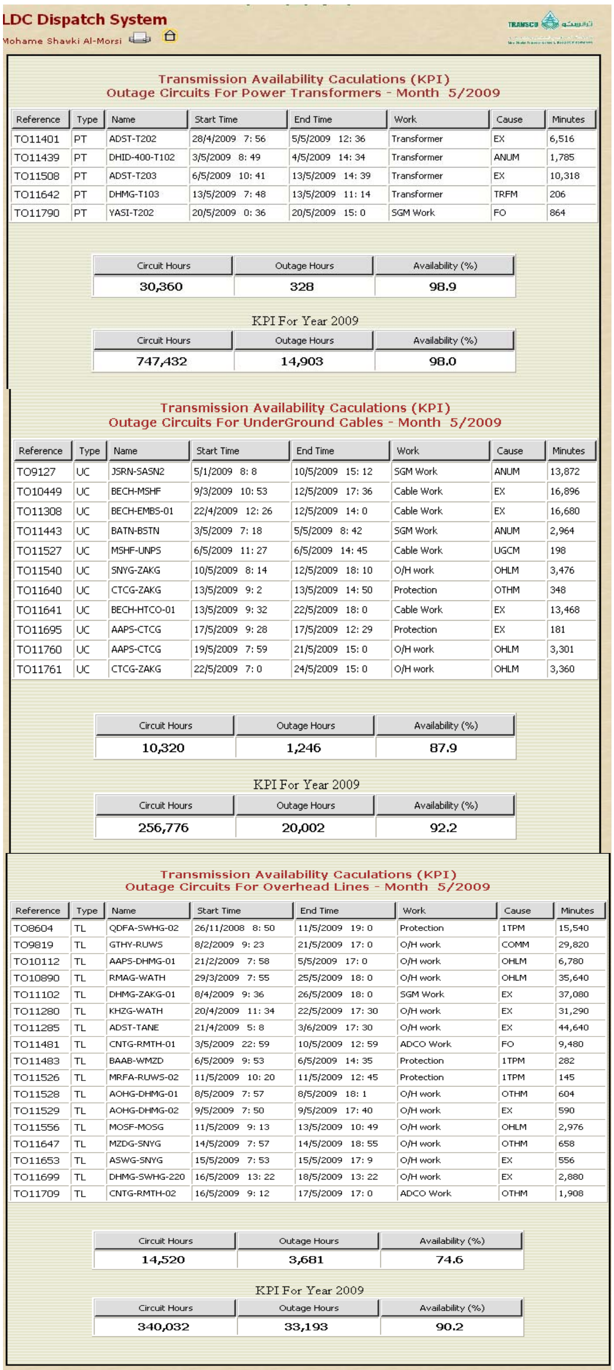
VI. CLASSIFIED REPORTS

The DAS system supports the ability to create variety of daily to annual reports and carrying out important statistics. This unique ability allows the LDC staff to generate database reports that specify the network conditions such as generations, transmission, status of the network equipments, reserve, incidents applications, maneuver steps, KPI for network facilities……etc. The DAS system allows the LDC staff easily updates the database based on the daily activities on the TRANSCO network. For most of the reports you can view the executive summary-including graphs, tables, definitions of terms used, and explanation of all network activities. All of the reports are available for printing for the LDC based on the authority access.

VII. KPI DETERMINATION

The term KPI becomes one of the most important term in business development and management. In theory it provides a series of measures against which internal managers and external investors can judge the business and how it performs over the short and long term. The KPI when it developed should provide all the staff with clear goals and objectives, coupled with full understanding of how they relate to the overall success of the organization.

Therefore, the achievement of the TRANSCO target is measured through the use of qualitative assessments and through the quantities indicators, namely key performance indicator. KPI is used as the primary measures of whether the LDC is achieving their objectives.



LDC Dispatch System

Mohame Shawki Al-Morsi

TRANSCO

Transmission Availability Caculations (KPI)
Outage Circuits For Power Transformers - Month 5/2009

Reference	Type	Name	Start Time	End Time	Work	Cause	Minutes
TO11401	PT	ADST-T202	28/4/2009 7: 56	5/5/2009 12: 36	Transformer	EX	6,516
TO11439	PT	DHID-400-T102	3/5/2009 8: 49	4/5/2009 14: 34	Transformer	ANUM	1,785
TO11508	PT	ADST-T203	6/5/2009 10: 41	13/5/2009 14: 39	Transformer	EX	10,318
TO11642	PT	DHMG-T103	13/5/2009 7: 48	13/5/2009 11: 14	Transformer	TRFM	206
TO11790	PT	YASI-T202	20/5/2009 0: 36	20/5/2009 15: 0	SGM Work	FO	864

Circuit Hours	Outage Hours	Availability (%)
30,360	328	98.9

KPI For Year 2009

Circuit Hours	Outage Hours	Availability (%)
747,432	14,903	98.0

Transmission Availability Caculations (KPI)
Outage Circuits For UnderGround Cables - Month 5/2009

Reference	Type	Name	Start Time	End Time	Work	Cause	Minutes
TO9127	UC	JSRN-SASN2	5/1/2009 8: 8	10/5/2009 15: 12	SGM Work	ANUM	13,872
TO10449	UC	BECH-MSHF	9/3/2009 10: 53	12/5/2009 17: 36	Cable Work	EX	16,896
TO11308	UC	BECH-EMBS-01	22/4/2009 12: 26	12/5/2009 14: 0	Cable Work	EX	16,680
TO11443	UC	BATN-BSTN	3/5/2009 7: 18	5/5/2009 8: 42	SGM Work	ANUM	2,964
TO11527	UC	MSHF-UNPS	6/5/2009 11: 27	6/5/2009 14: 45	Cable Work	UGCM	198
TO11540	UC	SNYG-ZAKG	10/5/2009 8: 14	12/5/2009 18: 10	O/H work	OHLM	3,476
TO11640	UC	CTCG-ZAKG	13/5/2009 9: 2	13/5/2009 14: 50	Protection	OTHM	348
TO11641	UC	BECH-HTCO-01	13/5/2009 9: 32	22/5/2009 18: 0	Cable Work	EX	13,468
TO11695	UC	AAPS-CTCG	17/5/2009 9: 28	17/5/2009 12: 29	Protection	EX	181
TO11760	UC	AAPS-CTCG	19/5/2009 7: 59	21/5/2009 15: 0	O/H work	OHLM	3,301
TO11761	UC	CTCG-ZAKG	22/5/2009 7: 0	24/5/2009 15: 0	O/H work	OHLM	3,360

Circuit Hours	Outage Hours	Availability (%)
10,320	1,246	87.9

KPI For Year 2009

Circuit Hours	Outage Hours	Availability (%)
256,776	20,002	92.2

Transmission Availability Caculations (KPI)
Outage Circuits For Overhead Lines - Month 5/2009

Reference	Type	Name	Start Time	End Time	Work	Cause	Minutes
TO8604	TL	QDFA-SWHG-02	26/11/2008 8: 50	11/5/2009 19: 0	Protection	1TPM	15,540
TO9819	TL	GTHY-RUWS	8/2/2009 9: 23	21/5/2009 17: 0	O/H work	COMM	29,820
TO10112	TL	AAPS-DHMG-01	21/2/2009 7: 58	5/5/2009 17: 0	O/H work	OHLM	6,780
TO10890	TL	RMAG-WATH	29/3/2009 7: 55	25/5/2009 18: 0	O/H work	OHLM	35,640
TO11102	TL	DHMG-ZAKG-01	8/4/2009 9: 36	26/5/2009 18: 0	SGM Work	EX	37,080
TO11280	TL	KHZG-WATH	20/4/2009 11: 34	22/5/2009 17: 30	O/H work	EX	31,290
TO11285	TL	ADST-TANE	21/4/2009 5: 8	3/6/2009 17: 30	O/H work	EX	44,640
TO11481	TL	CNTG-RMTH-01	3/5/2009 22: 59	10/5/2009 12: 59	ADCO Work	FO	9,480
TO11483	TL	BAAB-WMZD	6/5/2009 9: 53	6/5/2009 14: 35	Protection	1TPM	282
TO11526	TL	MRFA-RUWS-02	11/5/2009 10: 20	11/5/2009 12: 45	Protection	1TPM	145
TO11528	TL	AOHG-DHMG-01	8/5/2009 7: 57	8/5/2009 18: 1	O/H work	OTHM	604
TO11529	TL	AOHG-DHMG-02	9/5/2009 7: 50	9/5/2009 17: 40	O/H work	EX	590
TO11556	TL	MOSF-MOSG	11/5/2009 9: 13	13/5/2009 10: 49	O/H work	OHLM	2,976
TO11647	TL	MZDG-SNYG	14/5/2009 7: 57	14/5/2009 18: 55	O/H work	OTHM	658
TO11653	TL	ASWG-SNYG	15/5/2009 7: 53	15/5/2009 17: 9	O/H work	EX	556
TO11699	TL	DHMG-SWHG-220	16/5/2009 13: 22	18/5/2009 13: 22	O/H work	EX	2,880
TO11709	TL	CNTG-RMTH-02	16/5/2009 9: 12	17/5/2009 17: 0	ADCO Work	OTHM	1,908

Circuit Hours	Outage Hours	Availability (%)
14,520	3,681	74.6

KPI For Year 2009

Circuit Hours	Outage Hours	Availability (%)
340,032	33,193	90.2

Fig.13. The calculations of the transmission system availability.

The calculation of the transmission circuit service availability is mandatory based on the service quality standards. The transmission circuit services availability is the capability of a transmission entity's transmission network to provide transmission services to exit points to the level agreed in its connection agreements with distributors, transmission customers. Therefore, the transmission system availability is determined as in eq. (1) [1]-[4],

$$KPI = 1 - \frac{\sum \text{Number of interrupted circuit hours}}{\text{Total number of circuits} \times 8760 \text{ hours}} \tag{1}$$

Where the number of the interrupted circuit hours is defined in relation to each circuit in a transmission entity's, the number of hours during each reporting period in relation to which that circuit is unavailable to provide transmission services to exit points to the level agreed in connection agreements with distributors, transmission customers and generators and that unavailability interrupts the provision of transmission services to exit points required by distributors, transmission customers or generators at that time.

Figure 13 illustrates the KPI calculation for the transmission availability. All the outages circuits of the power transformers, underground cables and the overhead transmission lines are recorded in order to determine the availability factor based on the defined eq. (1). Therefore, it provides information to analyze the network performance and the system availability and reliability.

VIII. CONCLUSION

This paper presents a powerful application tool that used to facilitate the dispatch activities of the transmission network named Dispatch Application System (DAS). The DAS is used for recording and approving the scheduled outage activities assigned for the field engineers. The DAS enables the real time engineers to review the requested applications and forward their decision and recommendation to the dispatchers. This tool comprises number of applications significantly impact the performance of all activities associated with accurate database for TRANSO network. There are many applications are implemented to cover the daily activities of the LDC employees respecting TRANSCO policies and company structure. The electronic communication of all activities enhances the employee's performance and the acceleration of the work based on easily updated database. The network performance in terms of transmission system, generation and network facilities is obtained using the DAS system in a daily to annual basis. Furthermore, it enables for achieving important statistics that required for evaluating the system reliability and the quality of service. This tool enriches with valuable reports that summarizes the daily activities and system performance. Thus, it provides overview about the LDC achievements in a friendly interface environment. Thus, the management activities are easily conducted based on the available database such as planes, project progress and achievements.

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IMPROVING TRANSMISSION LINE PERFORMANCE USING TRANSIENT BASED ADAPTIVE SPAR

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Improving Transmission Line Performance using Transient Based Adaptive SPAR

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Abstract:

Adaptive SPAR offers many advantages over conventional techniques. In the case of transient faults, the arcing extinction time can be accurately determined and in the case of a permanent fault, breaker reclosure can be avoided. This paper describes, in some detail, the design of a new Adaptive SPAR technique that extracts high frequencies transients, from the CVT. The main case of study in this paper is the High Dam / Nagh Hamady, Nagh Hamady /Assuit 500 kV double circuit transmission system in the Egyptian network Fault scenario cases representing different fault locations, inception angles, actual representation to secondary arc characteristics, and with/without shunt reactor existence were extracted from simulation work, and then verified through real field records in that system. The outcome of this study indicates that the proposed technique can be used as an effective means of achieving an adaptive single pole auto reclosure scheme.

Keywords:

Transmission lines, Single Pole Auto Reclosure, Adaptive, Dead Time, Transient Fault, Permanent Fault.

I. Introduction:

Operation of transmission networks faces a lot of obstacles regarding the trip/close decision on each line and its consequences on the stability of the network [1, 2]. A successful Automatic close back-in decision (Auto Reclose) to a line can maintain the reliability of the network by restoring power supply and obtain a secure decision by avoiding the attempt to close onto fault. Also, Auto Reclosing (AR) Dead Time affects the stability of the transmission line and therefore the whole network.

According to statistics shown in [3] Arcing faults represents 90 % of the transmission faults. Most of these faults are transient faults that may extinguish by tripping the line. These faults may occur due to moisture in the early morning or polluted insulators, which are common conditions in the Egyptian environment [4]. Therefore, AR is supposed to be a necessary application in order to improve reliability to important transmission lines. Single pole Auto Reclosing (SPAR) algorithms can be programmed either in an individual device or implemented as a function in a numerical relay. Traditional SPAR Algorithms perform their main function successfully; which is to reclose the faulty phase after specific predefine dead time, regardless the fault situation (extinguished or not) [5, 6].

Usually, this dead time is a fixed interval [7], and it can reflect the time margin for a phase to separate from the three phase line without losing stability in the system. It's obvious, that stability margin can be increased as much as the dead time reduced. The optimum solution to this problem is to adapt the dead time according to the information captured from the voltage and current signals associated with the faulty phase after tripping. Adaptive dead time schemes were developed in literature in order to reduce the dead time using different techniques involving neural network [8, 9], fuzzy logic [10], zero sequence voltage [11], and power of high frequency components in current signal 2]. In this paper, a new SPAR algorithms is developed, where dead time is adapted according to the fault extinguishing information. The proposed SPAR performs several functions, first it can discriminate between natures of faults, and secondly it can detect the instant of fault extinguished. Discrimination between faults nature is

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important to decide closing or blocking decisions, while fault extinguishing detection is essential to ensure the instant of reclosing decision. Hence, the faulty phase will stay out of service for the least essential time required and then reclosed back-in to service without unsuccessful AR attempt (i.e. close onto fault). If permanent fault is detected, the other healthy phases will be tripped and the proposed SPAR will be blocked for further later closing attempts.

Algorithms used in this SPAR depend on the harmonic distortion analysis of the voltage waveform at the faulty line end terminal in order to perform the first function. The second function is accomplished using transient waveforms based fault detection / location technique. The algorithms are discussed in details and the Egyptian 500 kV network is used for testing of the algorithms. Different fault scenarios where subjected to the algorithms , in which different fault locations, inception angles, actual representation to secondary arc characteristics and with/without shunt reactor existence were extracted from simulation work, and then verified through real field records in that system.

II. Transient Based SPAR Algorithms:

After the fault been detected, classified, and located through protection devices, a single phase tripping order is issued to circuit breaker. In this instant, three scenarios can be expected regarding fault existence after breaker tripping action. The first scenario is the extinguishing of the fault instantaneously by the trip decision, and no secondary arc exists but the oscillation due to shunt reactor starts, if any. The first scenario represents the transient fault type. The second scenario is the existences of fault after tripping decision, which extinguishing instant appears within specific time period (i.e. fixed dead time). The second scenario represents the long duration transient fault type. The third scenario, is the existence of secondary arc for specific time period (i.e. fixed dead time), without the extinguishing instant occurrence. The third scenario represents the permanent fault type and any closing attempt to it will be unsuccessful.

The new SPAR algorithms have to perform two sub-routines in order to reach successful reclose attempt. The first sub-routine is to distinguish between existence and absence of secondary arc. The second sub routine is to search for arc extinguish in case of secondary arc existence. The flow chart shown in Fig. 1 describes the proposed SPAR algorithms with details about its inputs, expected functions, and implemented routines.

First: The analog inputs to the algorithms, will be the secondary voltage from the instrument transformers installed on the line under study and the transient voltage signals from the communication tap of the coupling capacitive voltage transformer (CCVT) [13]. The transmission protection devices should supply the algorithms with information, which is phase selection. The digital inputs to the algorithms will be provided from the circuit breaker regarding trip decision

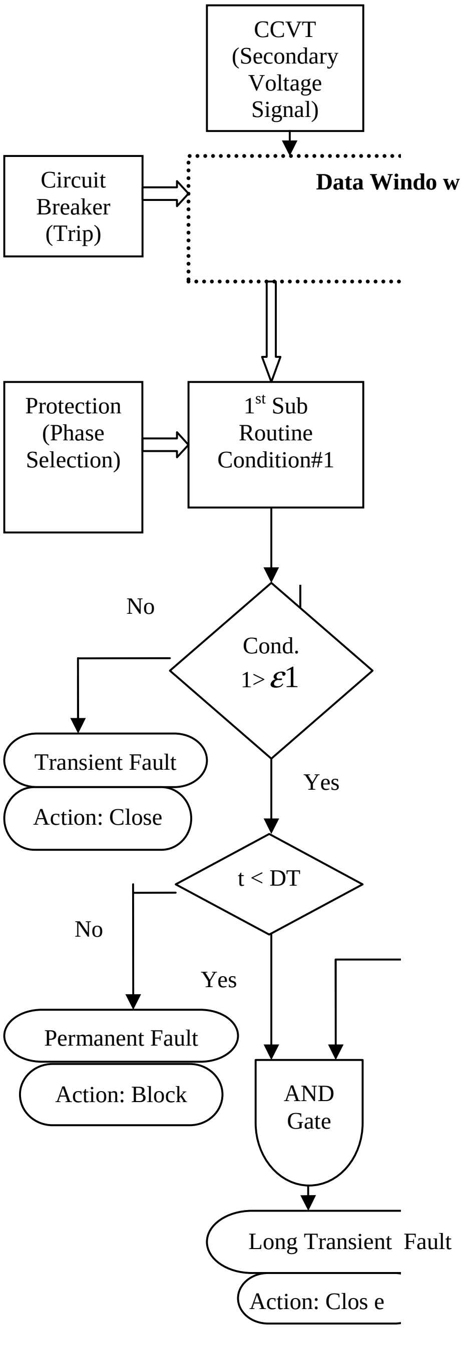

Figure (1): Proposed SPAR algorithms flow chart.

Second: the inputs will be in processing success of data. The information regarding the protection data, the secondary voltage from one end terminal first sub routine in order to differentiate between existence and non existence of secondary arc. This sub routine will accomplish "Condition#1" status. In this sub routine voltage inputs from both line ends processed using Discreet Fourier Transform (DFT) in order to comp and odd harmonic components. The computed frequency components of voltage from one line end will be used to calculate a discrimination quantity.

Since, it's well known that arcing faults voltages has a high percentage of harmonics, and after studying the voltage signal of several fault scenarios, it was found that the percentage of odd harmonics in ranges of (3, 5, 7, 9) are more obvious. Therefore, a good method of measuring the harmonics of secondary arc and separate it from the shunt reactor oscillation will be through using Total Harmonic Distortion Percentage "THD %" [14].

$$THD\% = \frac{\sqrt{\sum_{n=3,5,7,9}\left(V_F^{(n)}\right)^2}}{V_F^{(1)}} \times 100 \qquad \textbf{Equation (1)}$$

Where;

$V_F^{(n)}$: Amplitude of (n) harmonic component of faulted line sending end voltage.

$V_F^{(1)}$: Amplitude of fundamental frequency component of faulted line sending end voltage.

The calculated THD % amplitude, from the faulty phase sending end voltage (Shunt reactor location); can be used to determine the secondary arc existence when exceeding specific threshold. But due to the existence of different threshold with the variation of system conditions related to shunt reactors existence/ non existence, another expression will be derived from the first, which is difference of THD between faulty phase and other two healthy phases.

$$THD\_diff = |(THD\_p1) - (((THD\_p2) + (THD\_p3))/2)| \qquad \textbf{Equation (2)}$$

Where;

THD_p1, THD_p2 THD_p3 : It is the Total Harmonic Distortion percentage for the faulty phase and the other two healthy phases, respectively.

THD_diff : It is absolute difference in Total Harmonic Distortion percentage between he faulty phase and the other two healthy phases.

If "THD_diff" didn't exceed specific threshold ($\varepsilon 1$) then "Condition#1" not specified, and fault is transient, and no arcing exist. Therefore, Closing Decision can be accomplished instantaneously. If "THD_diff" increases than specific threshold ($\varepsilon 1$) then "Condition#1" is satisfied, and secondary arcing exist. Therefore, another subroutine will work in parallel with the 1st subroutine to search for the arc extinguishing instant. The transient input signal will fed to the 2nd subroutine, in order to search for arc extinguishing moment. The transient signal can detect any transient disturbance within the line length and locate its position according to the following equation [15].

$$x = \frac{L-(t_b - t_a)v}{2} \qquad \textbf{Equation (3)}$$

Where;

x : It is the distance to fault from the sending end of the line.

L : It is the line length.

t_b, t_a : It is the time detected where the transient signals at terminal b and a respectively, exceeds specific threshold.

v : It is the wave propagation velocity of the line.

If the signal exceeds specific threshold ($\varepsilon 2$), while the location 'x' exist within the line length, therefore, transient disturbance occurs and arc is extinguished. At this result, "Condition#2" is satisfied.

Hence, significance of secondary arc existence and long duration transient fault extinguishing is presented. Closing decision may be issued afterwards instantaneously.

If "Condition#1" exist for specific time period which represents allowed dead time, and "Condition#2" not satisfied, therefore, permanent fault exists. Permanent fault status requires tripping the other healthy phases, and blocking decision to any further closing attempts to the SPAR.

The maximum allowed dead time is related to a stability study regarding the line and determining the maximum time period that the line may operate with two healthy phases only without loosing system stability. Setting the thresholds ($\varepsilon 1$), ($\varepsilon 2$), and maximum allowed dead time must be done according to each study separately. It may differ between simulated cases and recorded fault scenarios due to load conditions or environmental effects.

III. SPAR Testing Realistic Network:

For the purpose of testing the new SPAR algorithms, a simulation case study is represented using Egyptian 500 kV transmission network data. The line under study lies between High Dam Substation and Nag Hamady substation. The line is double circuit configuration with 146 miles in length. The line has a shunt reactor permanently installed to it from the High Dam Busbar direction only. Schematic diagram for the system under study is shown in figure (2).

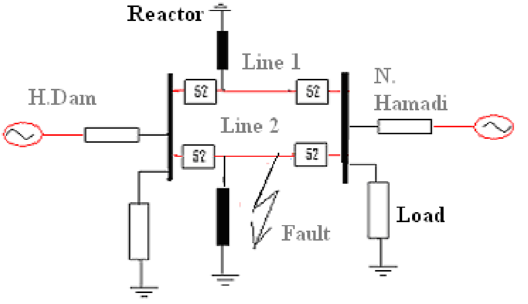

Figure (2): Egyptian 500 kV network.

Table (I) Fault Scenarios used for testing the SPAR.

Case	D	Ph	Rec	In feed	Type	Ex Instant (msec)
1	10 %	A	Yes	Normal	1	0 – 100
2	90 %	A	No	Normal	1	0 – 100
3	10 %	B	No	Normal	1	0 – 100
4	90 %	B	Yes	Normal	1	0 – 100
5	10 %	A	No	Normal	2	670
6	50 %	B	Yes	Weak	2	644
7	90 %	C	No	Weak	2	670
8	90 %	A	Yes	Normal	3	-
9	50 %	B	No	Normal	3	-
10	10 %	C	Yes	Weak	3	-

Where;

D: Refers to the distance in length percentage between the sending end and the fault point on the line.
Ph: Refers to the Faulty phase.
Rec: Refers to the Existence status of reactor.
Type (1, 2, 3): Refers to the type of fault (Transient, Long duration Transient, and permanent respectively).
Ex. Instant: Refers to the fault extinguishing instant in seconds, if fault recorded starts at the trip time.

Arcing faults in this study is represented with primary and secondary arc algorithms programmed to the ATP software through the ATP models language [16]. The primary and secondary arcing models are extracted from an experimental study done in [17]. Although both arcs are simulated in fault representation, but in this study, which occur after the breaker tripping action, secondary arc will be our main concern. In order to show the importance of the study, comprehensive fault scenarios will be represented to test the SPAR. The fault scenarios will include different fault types (i.e. transient, long duration transient, permanent), existence of reactor status, different fault locations (i.e. 10-50-90 %) of the line length and different (extinction times of long duration transient fault). Finally, a validation process is presented in this study, where the SPAR is tested against real fault record on the same line.

IV. Using Adaptive SPAR Algorithms

In order to reach valid thresholds for all fault scenarios discussed above, a comprehensive study for voltage and transient signals corresponding to different fault types and system conditions is done. Figures (3, 6) shows the sending end voltage signal for cases 1 and 3 respectively, while figures (4, 5) shows the sending end transient voltage signals for cases 1 and 3 respectively. Cases 1 and 3, represent transient fault, where only two disturbances occurs on transient signals, the first occurs at 0.1 seconds, which represent the primary arc initiation time, and protection devices should deal with this type of fault to trigger the breaker control circuit to produce trip decision, which appears at the instant 0.2 seconds as the 2nd disturbance. It's obvious from the transient signals that no transient signals appear afterwards, and also the shunt reactor oscillation is shown after tripping instantaneously. That's all is a significance of the fault final extinguishing and the system is balanced.

SPAR close decision must not be issued after the trip time instant instantaneously, in order to leave some delay time before closing , in order to let the severe discharge due to breaker tripping period to end first. Close Action will depend on circuit breaker characteristics, and system conditions, which are in our case, the close will happen after 0.1 seconds (5 cycles).

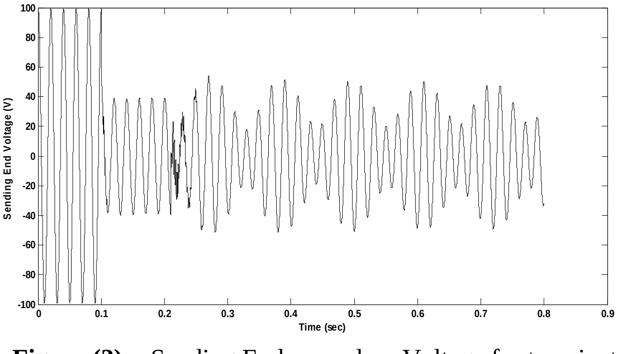

Figure (3): Sending End secondary Voltage for transient fault on Phase "A", located at 10% apart from line sending end, with reactor existence.

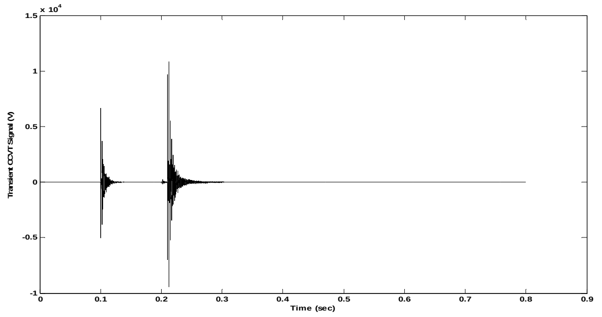

Figure (4): Transient Voltage signal for transient fault on Phase "A", located at 10% apart from line sending end, with reactor existence.

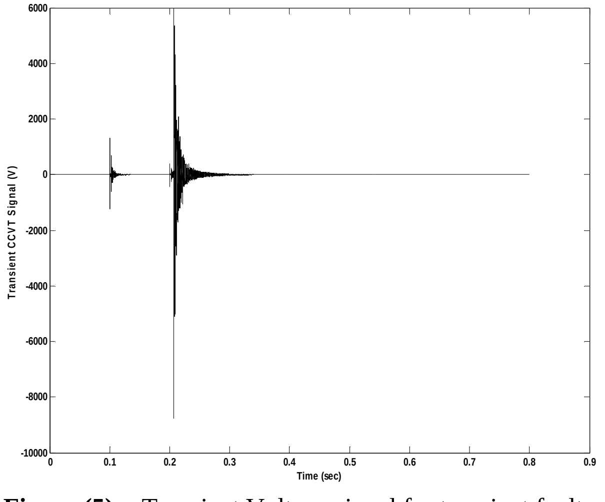

Figure (5): Transient Voltage signal for transient fault on Phase "B", located at 10% apart from line sending end, with reactor absence.

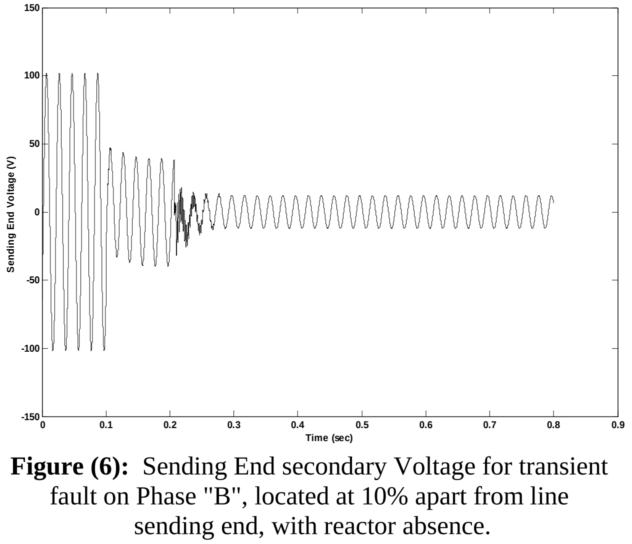

Figure (6): Sending End secondary Voltage for transient fault on Phase "B", located at 10% apart from line sending end, with reactor absence.

Case 7 show a long duration transient fault type, where the transient signal, and the sending end secondary voltage signal are shown in figures (7, 8), respectively. As shown in figure (7), the signal starts at 0.25 seconds (i.e. after the breaker trip action by 50 msec), and a third disturbance appears with high magnitude at 0.67 seconds from the start of the simulation time. Hence, long duration transient fault occurs, where secondary arc exist and extinguished at the 3rd disturbance time.

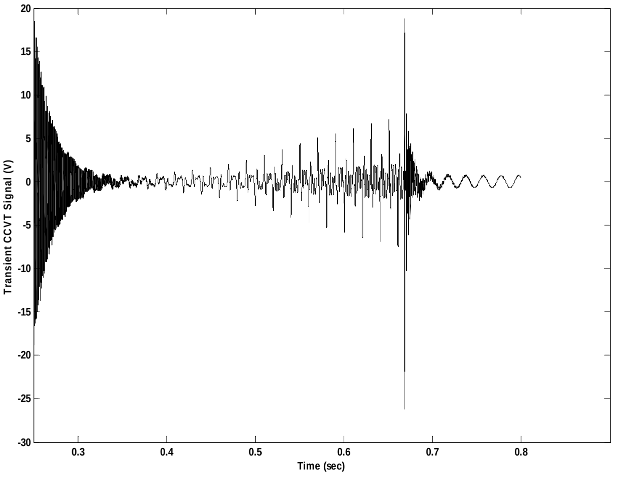

Figure (7): Transient Voltage signal for long duration transient fault on Phase "C", located at 90% apart from line sending end, with reactor absence.

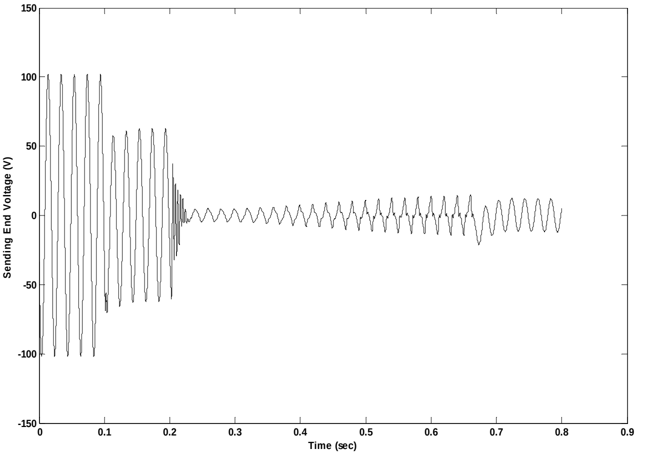

Figure (8): Sending End sending Voltage for long duration transient fault on Phase "C", located at 90% apart from line sending end, with reactor absence.

Figures (9, 10) show the transient signals and sending end secondary voltage for case 10, which represent permanent fault (i.e. extinguishing moment will occur after the maximum allowed dead time). This fault type need a SPAR block action after the maximum allowed dead time ending in order to maintain stability for the line. In the 500 kV Egyptian network, the maximum allowed dead time for SPAR is 900 milliseconds (45 cycles) but in the simulation cases a smaller time period is used (370 msec or 19 cycles) in order to give a clear representation to the test results.

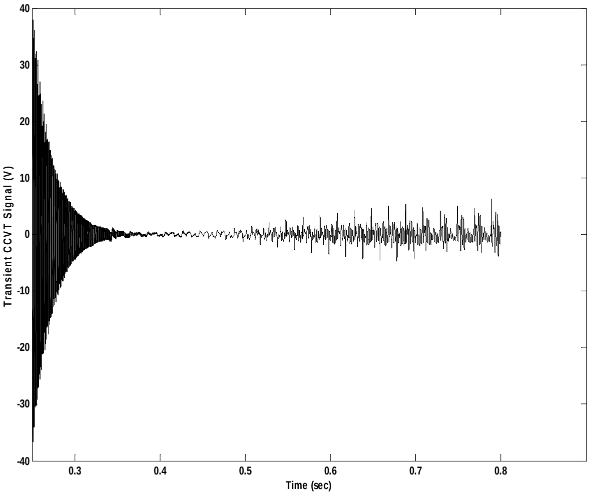

Figure (9): Transient Voltage signal for Permanent fault on Phase "C", located at10% apart from line sending end, with reactor existence.

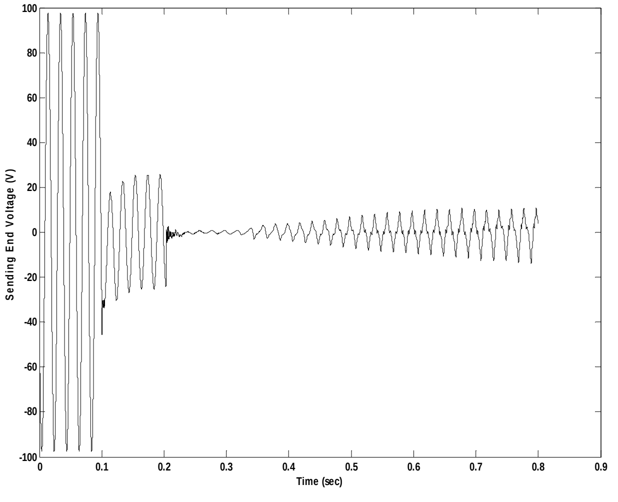

Figure (10) Sending End secondary Voltage for Permanent fault on Phase "C", located at10% apart from line sending end, with reactor existence.

The MATLAB [18] is used to program the proposed SPAR algorithms and testing the cases. Figures (11), shows the Total Harmonic Distortion percentage (THD %) for all the cases 1,3,7,9, and 10. THD results didn't exceed 11 % for transient faults while it increases in secondary arc gradually till extinguish instant reaching 46% then it falls again to the transient fault values. It's obvious that the first condition threshold will be 11%.

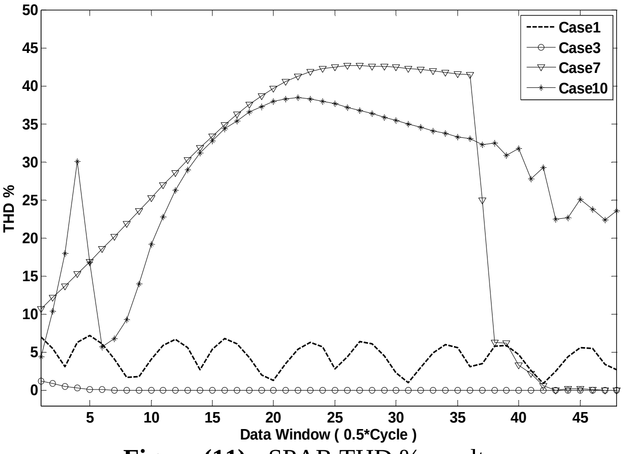

Figure (11): SPAR THD % results.

Figure (14) shows condition 1 for cases 1, 3, and 7. Condition 1 satisfied only for case 7, in the existence of secondary arc duration. Figure (15) shows condition 1 for cases 9 and 10. Condition 1 satisfied in case 9 and 10 for the whole duration.

Table (II): SPAR Condition 1 and 2 results for all simulation cases.

Case	Condition # 1 Occurrence time (MDW)		Condition # 2 Occurrence time (MDW)	
	Start	End	Start	End
1	-	-	1	4
2	-	-	1	14
3	-	-	1	5
4	-	-	1	7
5	1	37	36	38
6	5	36	34	36
7	1	39	36	38
8	3	(48) End	-	-
9	1	(48) End	-	-
10	8	(48) End	-	-

Table (II) shows conditions 1 and 2 for all the 10 simulated cases described in table (I). Each condition is specified by its start time and end time of the condition by the moving data window number, which is illustrated in figure (11).

Table (III): SPAR Functions results for all simulation cases.

Case	SPAR Action		Fault Type	Adaptive DT duration (msec)
	Type	Time (msec)		
1	1	460	1	260
2	1	460	1	260
3	1	460	1	260
4	1	460	1	260
5	1	660	2	460
6	1	640	2	440
7	1	660	2	460
8	2	680	3	480
9	2	670	3	470
10	2	740	3	540

Table (III) show the results for the fault type, SPAR action, and SPAR action time, respectively, for all the 10 simulated cases described in table (I). Action 1, 2 is presenting close and block respectively. Fault type 1, 2, and 3 is representing transient, long duration transient and permanent fault respectively. As shown in figures the cases are well identified to their fault types and correct SPAR actions and the time where the action is taken is recognized in milliseconds.

Table (III), shows the SPAR action type and proposed time in milliseconds, which starting from the simulation start time. The breaker trip at 200 milliseconds after the simulation start time, and the SPAR algorithms starts after 100 milliseconds from the trip order, So, if the transient fault conditions is specified, therefore, the SPAR will give a close within 160 milliseconds and the total adaptive dead time as shown in table will be 260 milliseconds from the trip order. Long duration transient faults, will have a close when it reaches it's extinguish condition as shown in cases 5, 6, and 7. Permanent faults will give a block decision after the corresponding fault type conditions satisfied and passed the maximum allowed dead time of the system, which is this simulation cases is 370 milliseconds from the start of algorithms work or 470 milliseconds from the trip order.

V. Algorithms Testing on Real Field Records

Validation through the field record is required in order to check the feasibility of the new SPAR algorithms with the main problem. Fault occurred at phase "B", at the middle of the line, when the reactor is existed and the in feed is in its normal conditions. Figures (12, 13) shows the transient signal and the secondary voltage signal for a real fault record occurred on the same line under study. Due to the absence of the CVT communication transient waveforms in this fault record, the transient voltage signal is captured from filtering the sending end secondary voltage signal using Butterworth high pass filter with a cut-off frequency of 500Hz. It's obvious from the record that the fault type is transient, and a perfect action after the breaker tripping, will be a SPAR close decision. As shown in figure (14), the total harmonic distortion percentage didn't exceed 18 %, and both conditions (1 and 2) didn't exist. The proposed SPAR decision was a close decision, and the fault type was transient as shown in figure. As shown in table (IV) detects the time for the close action which is 390 milliseconds after the record start time. The breaker trip at 130 milliseconds after the record start time, and the SPAR algorithms starts after 100 milliseconds from the trip order, So, if the transient fault conditions is specified, therefore, the SPAR will give a close within 60 milliseconds and the total adaptive dead time as shown in table will be 260 milliseconds from the trip order.

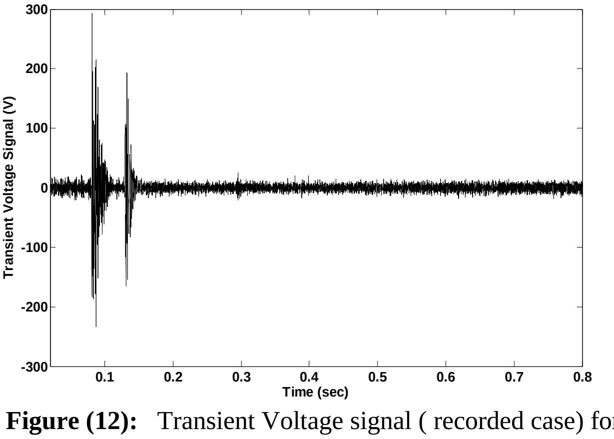

Figure (12): Transient Voltage signal (recorded case) for Transient fault on Phase "B", located at 50% apart from line sending end, with reactor existence.

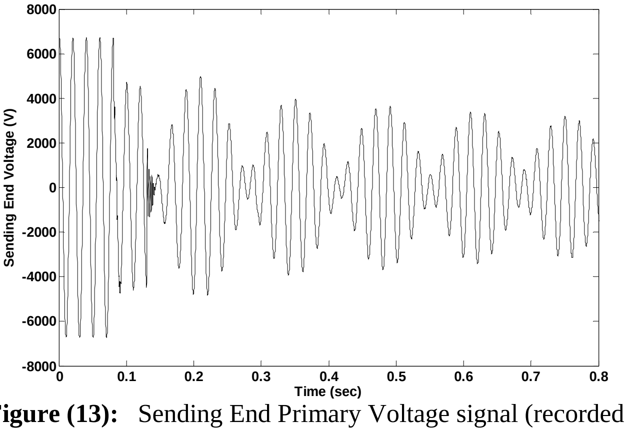

Figure (13): Sending End Primary Voltage signal (recorded case) for Transient fault on Phase "B", located at 50% apart from line sending end, with reactor existence.

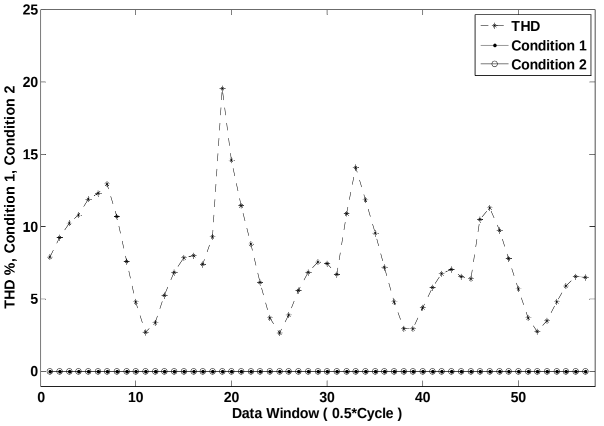

Figure (14): SPAR THD%, Condition 1, and Condition 2 results.

Table (IV) Recorded Fault Case SPAR Function "Fault Type", "Action", "Action Time" results.

SPAR Action		Fault Type	Adaptive DT duration (msec)
Type	Time (msec)		
1	390	1	260

The agreement between the tasks goals and the algorithms results, prove the feasibility of the proposed SPAR to be used in any fault case or system condition. Thresholds and dead time must be provided after a load flow, short circuit and transient stability studies to the line under study before SPAR installation. It's preferred to monitor and capture data through high resolution and using higher sampling rate devices (i.e. fault recorders, PMU's) in order to reach the specific goals accurately.

VI. Conclusions:

This paper proposes new algorithms for Adaptive SPAR technique that extracts high frequencies transients, and secondary voltage waveform from the CVT. The new Adaptive SPAR can differentiate between permanent and transient faults during the dead time period. The system can then, adapt itself to reduce the dead time and reclose in case of transient faults, or trip the other two phases and blocking the circuit breaker in case of permanent faults, respectively.

The used transient signals from CVT proves the fault extinguishing detection process, since its well known by the high accuracy and speed in detection and location of transient disturbance within the line, without been affected with the common instrument transformer problems (i.e. Saturation, and Ferro Resonance).
The use of THD as a discriminator between the existence and non existence of the arcing phenomena helps to improve the SPAR decision by differentiating between fault arcing phenomena and other harmonics oscillation due to shunt reactor existence within the line under study.

While traditional protection relays may easily mal-operate due to the oscillations resulted from reactor existence, the proposed adaptive SPAR succeeded to overcome this phenomena and successful achieve its main tasks. The new SPAR algorithms presented in this paper reduces the dead time according to each fault case, and differentiate between fault types in order to reach successful SPAR decisions, in order to improve transmission system stability during operation process

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