The Effects of Excitation Control Systems on Parallel Operation of DGs with the Main Grid

S. Kazemi, M. Parniani, M. Rasouli
Department of Electrical Engineering
Shrif University of Technology, Tehran, Iran
s_kazemi@ee.sharif.edu, mrasouli@ucalgary.ca, parniani@ee.sharif.edu

Abstract:

This paper presents actual cases of steady reactive power oscillation of Distributed Generations (DGs) during parallel operation with the main grid. The cause of the problem was found to be the adverse effects of excitation system voltage regulation. It is shown, through preliminary investigation and detailed simulation studies, that how the excitation control system can be modified to overcome this problem. On-site test results verify the analysis results and effectiveness of the remedial actions. Finally, general practical recommendations are offered for excitation control of synchronous generator-based DG, such that it performs properly, both in grid connected and islanding conditions.

Keywords--Distributed generation, excitation system control, parallel operation, reactive power oscillation.

1. Introduction

The benefits of Distributed Generation (DG) are well understood. However, parallel operation of DG units with the network results in some technical problems that should be resolved [1]. One of these issues is reactive power oscillation of the generator. This problem has been observed at Razi Petrochemical Company (RPC). The company, located at Mahshahr – Iran, has a non-utility generation plant with operational capacity of about 60 MW. This plant consists of five 14 MW, 11.5 kV gas turbo generators and one 15 MW, 11.5 kV steam turbo generator. Recently, the operators of this plant attempted to interconnect it with the local 132 kV transmission network (see Figure 1). Some potential benefits of this interconnection include:

- Reduce generation reserve requirements.
- Operate the turbo generators at base-load mode, and trade the supplement peak load demand and light load extra generation with the grid.
- Obtain backup power from the grid in the event of a DG system outage, and improve overall system reliability.

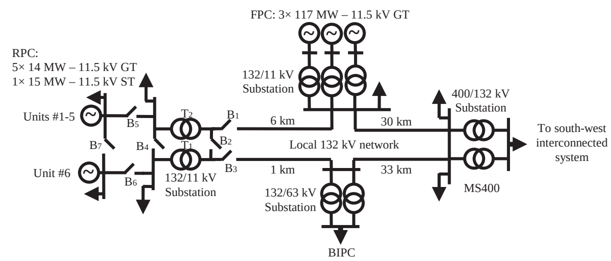

Fig. 1: Single line diagram of local 132 kV transmission network.

However, in several tries for performing this interconnection, steady oscillations in reactive power output of generators were observed, disabling them from parallel operation. A typical record of this problem for unit #6 of the plant is shown in Figure 2.

Fig. 2: An actual record of unit #6 of RPC plant during parallel operation with local 132 kV network. Steady oscillation in reactive power output of generator.

Study results and on-site tests show that similar problems may be encountered in other DG units connected to network, and the proposed corrective methods are applicable to those cases, too. A stringent requirement in this case and similar cases is that the unit performs properly both in grid connected and islanding conditions.

In the following sections, first, different types of excitation control systems are introduced. The study results – using both the preliminary and the detailed simulation – and site test measurements are presented next. Finally, general conclusions are made for proper operation of excitation control system of RPC generation units, as well as other synchronous generator-based DGs, when interconnected to the main grid.

2. Types of Excitation Control Systems

Since the beginning of ac power generation, several types of excitation control systems have been used to adjust the synchronous generator field. The objective is to ensure that the preferable generator output (voltage, VAR or PF) is regulated or controlled to the reference level set by the operator or plant controls [2-4]. Major types of excitation control systems are as follows.

2.1. Voltage Regulator

Traditionally, voltage regulator has been supplied with two modes of controls, automatic mode and manual mode. In automatic mode, excitation level is automatically adjusted to hold generator terminal voltage at reference level set by the operator or plant controls. In manual mode, excitation level is held constant and adjusted directly by the operator. Most voltage regulators also include a provision for reactive current compensation (line drop compensation), in which the voltage reference signal is modified so as to adjust the voltage of a point other than generator terminal, either inside or outside the terminal [7].

2.2. VAR/PF Regulators

VAR or Power Factor regulators are similar to voltage regulator, but they provide direct feed back of generator output VAR, PF or reactive current instead of voltage.

2.3. VAR/PF Controllers

When a voltage regulator is provided with a VAR or PF controller, the voltage reference of the voltage regulator will receive automatic raise and lower commands from the controller so as to maintain a constant steady state level of VAR or PF. Since the action of VAR/PF controller is slow, terminal voltage is regulated during transients. In some analog VAR controllers, the sensed quantity is actually the generator output reactive current [2-4].

3. Preliminary Investigation

Before detailed dynamic simulation of the system under study, it will be instructive to examine the effects of excitation control systems and their steady state (SS) parameters on steady reactive power oscillation of one generating unit of RPC plant (unit #6), when interconnected to the local 132kV transmission network.

In this investigation, simplified SS models are derived for electrical network, generator, excitation control system and other components. These models are then used to represent the basic phenomenon under investigation. The local 132 kV network is directly modeled, and the main 400 kV & 230 kV interconnected grid is represented by its thevenin equivalent. A hypothetical system disturbance is initiated by reducing the thevenin bus voltage from initial value of 1.0 pu to 0.95 pu. Such reduction in the remote system voltage may occur, for example, due to gradual increase in the system loading. Then, the generator #6 output terminal voltage vs. reactive power curves are calculated for each type of excitation control system and with different parameter settings. Some typical responses of unit #6 of the RPC plant during parallel operation with the local 132 kV network are shown in Figure 3. In the cases A and B, excitation control is on automatic voltage regulation (AVR) mode. In the case A, SS gain of the regulator (K) and reactive current compensation (X_C) are equal to 175 and 0, respectively. In this case, 5% voltage drop in the system characteristic renders the output MVAR of generator to increase by 8.48. In the case B, SS gain of the regulator and reactive current compensation are equal to 25 and 0.1, respectively. In this case, 5% voltage drop in the system characteristic renders the output MVAR of generator to increase by 3.02. In the case C, the excitation control is on VAR regulation mode and with SS gain of regulator equal to 50. In this case, 5% voltage drop in the system characteristic has no effect on the output MVAR of generator. Table 1 summarizes the SS response of unit #6 for different cases of excitation control. From this table following results can be concluded:

- If terminal voltage regulator is used for excitation control, large excursions of output MVAR will occur during parallel operation of this unit with the main grid. The excursions are larger with high AVR gain and low values of reactive current compensation.
- Proper selection of SS gain of voltage regulator and reactive current compensation values can be used to reduce MVAR fluctuations.
- Unlike automatic voltage regulator, use of excitation control systems that operate in manual control, VAR/PF or reactive current control or VAR/PF regulation lead to overcome this problem. However, under these conditions, generator terminal voltage will drop considerably with increased system loading.
- Steady state performance of VAR/PF regulation and VAR/PF control modes are very close.

4. Dynamic Simulation

In case of large disturbances like unintentional islanding, faults or sudden change of loads, dynamic response of the excitation system and generator outputs is also of concern. For this reason and also to validate the pervious results, detailed simulation studies were performed. PSCAD/EMTDC simulation package was used in the studies [5]. Unit #6 has brushless ac excitation system that is operated at automatic terminal voltage regulation. For representation of this excitation control system, manufacturer data was used in conjunction with typical data adopted from References [2, 5-9]. The speed governor - turbine system is similar to that described in Reference [10]. The synchronous generators are represented by sub-transient d-q model with two rotor circuits on each axis. The machine saturation is also modeled

Table 1: Steady State response of unit #6 of RPC plant to 5% drop in the system voltage, during parallel operation with local 132 kv network.

Type of Excitation Control System	SS Gain of Regulator K	Reactive Current Compensation X_C (pu)	ΔQ (MVAR)	ΔV (kV)
Automatic Voltage Regulation	175	0.0	8.480	0.077
		0.1	4.420	0.297
		0.2	3.020	0.374
	60	0.0	6.580	0.176
		0.1	3.870	0.330
		0.2	2.724	0.389
	25	0.0	4.420	0.297
		0.1	3.020	0.374
		0.2	2.281	0.414
Manual	-	-	0.280	0.528
VAR/PF Regulation	175	-	0.005	0.543
	60	-	0.014	0.543
	25	-	0.032	0.542
Reactive Current Regulation	175	-	0.094	0.549
	60	-	0.082	0.548
	25	-	0.057	0.547
VAR/PF Control	175 60 25	0 / 0.1 / 0.2	0.0	0.544
Reactive Current Control	175 60 25	0 / 0.1 / 0.2	0.10	0.550

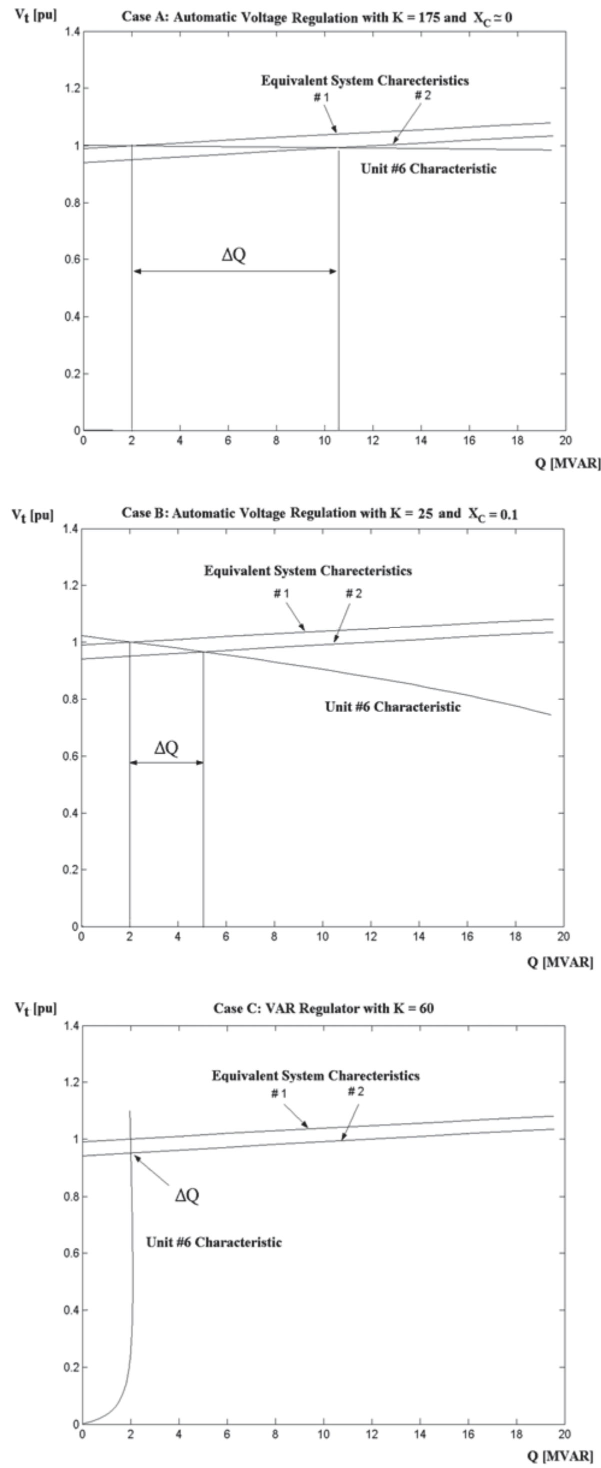

Fig. 3: Steady State responses of unit #6 of RPC plant to 5% system voltage disturbance, during parallel operation with local 132 kV network.

Synchronous generator parameters of RPC plant are given in the Appendix.

The network under study is that shown in Figure 1. The majority of RPC and local network loads are induction motors. Consequently, induction motor models, with typical data available in PSCAD software, were used for representation of these loads. Other network loads were represented by the polynomial load model [11].

4.1. First Scenario: Sudden Load Change

In order to examine the results obtained in preliminary investigation, the generation unit was considered to operate in parallel with the grid, and several sudden changes in the local network loading were applied during simulation period. Since in this case the SS response was of interest, the generator #6 terminal voltage – reactive power sensitivity was determined for each type of excitation control system and different settings of their SS parameters. Equal initial conditions were considered in all simulations. As an example, Figure 4 shows the case with AVR gain of 175 and reactive current compensation equal to 0.1 pu. Steady state responses of Unit #6 of RPC plant, for different cases of excitation control, are summarized in Table 2. Comparison of these results with those shown in Table 1, clearly confirms the conclusions made in the pervious section.

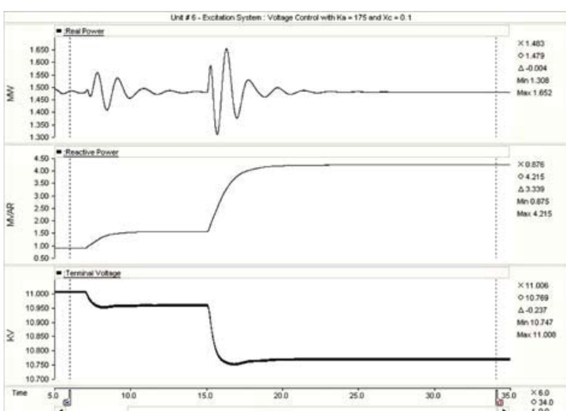

Fig. 4: Response of unit #6 of RPC plant during parallel operation with local 132 kV network to a sudden load change; excitation system on voltage regulation with AVR gain of 175 and reactive current compensation equal to 0.1 pu.

4.2. Second Scenario: Islanding

To assess the dynamic behavior of the generators under different excitation control modes, several types of disturbance were examined, including sudden load change, faults, loss of local generating units, and unintentional islanding. Among these cases, local system islanding gives notable results.

In this scenario, unit #6 of RPC plant is interconnected to the main grid through transformer T_1 and the local 132 kV lines between RPC - BIPC - MS400 substations. Switches B_1, B_3, B_5 and B_6 are closed and B_2, B_4 and B_7 are open (see Figure 1).

At t =10 s of simulation period, a fault was applied to the transmission line between RPC and BIPC. After 150 ms, the fault was cleared by tripping the faulted line. Afterwards, unit #6 together with the local RPC network operates as an island.

To assess the transient response of unit #6 to this disturbance, the following indices are used:

- Maximum deviation of output signals during and after the fault.
- Settling time, i.e. the time interval between the application of the fault and the moment after which the output signal stays within a sufficiently small band.

This scenario was repeated for each type of excitation control and with different settings for their SS parameters. As in the pervious scenario, equal initial conditions were considered in all simulations.

Table 2: Steady State response of unit #6 of RPC plant to sudden load change, during parallel operation with local 132 kv network.

Type of Excitation Control System	SS Gain of Regulator K	Reactive Current Compensation X_C (pu)	ΔQ (MVAR)	ΔV (kV)
Automatic Voltage Regulation	175	0.0	6.436	0.076
		0.1	3.339	0.237
		0.2	2.224	0.259
	60	0.0	4.758	0.164
		0.1	2.846	0.263
		0.2	2.020	0.306
	25	0.0	3.135	0.248
		0.1	2.197	0.297
		0.2	1.683	0.324
Manual	-	-	0.328	0.398
VAR/PF Regulation	175	-	0.004	0.414
	60	-	0.009	0.409
	25	-	0.035	0.408
Reactive Current Regulation	175	-	0.031	0.417
	60	-	0.020	0.416
	25	-	0.010	0.415
VAR/PF Control	175 60 25	0 / 0.1 / 0.2	0.0	0.415
Reactive Current Control	175 60 25	0 / 0.1 / 0.2	0.036	0.409

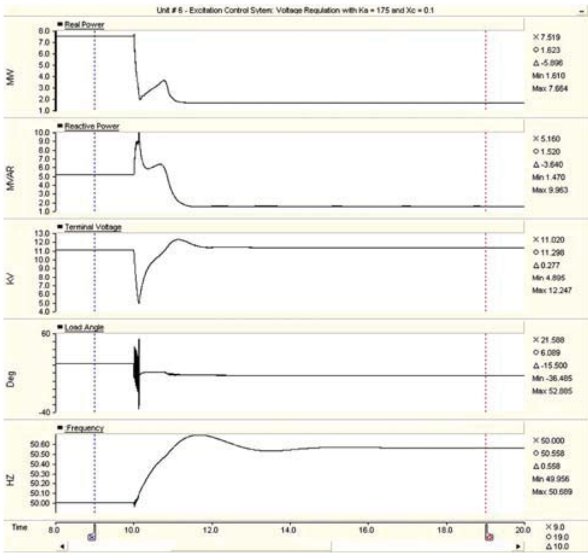

Fig. 5:. A sample response of unit #6 of RPC plant to a transmission line fault leading to islanding; excitation system on voltage regulation with AVR gain of 175 and reactive current compensation equal to 0.1 pu.

Generator active power, reactive power, terminal voltage, load angle and electrical frequency are the recorded output signals. A sample response of unit #6 is shown in Figure 5. In this case, unit #6 excitation system is on voltage regulation mode with SS regulator gain and reactive current compensation equal to 175 and 0.1 pu, respectively.

Table 3 shows some of the SS and transient response indices of unit #6 for various settings of its excitation system voltage regulation. Form this scenario, following results are obtained:

• Increasing the SS regulator gain and reducing the value of reactive current compensation render higher damping of the generator active power response. They also cause increasing in maximum deviation observed in the generator reactive power response. As of the settling time, increasing the values of SS regulator gain and reactive current compensation cause decrease in the settling time observed in the generator reactive power response. Consequently, it can be concluded that, increasing in the value of reactive current compensation causes increased damping of the generator reactive power response.

• During short circuit period, effects of SS gain of AVR and reactive current compensation on maximum deviation observed in the generator terminal voltage are negligible. But after fault clearing (islanding condition), large values of SS gain of AVR and small values for reactive current compensation cause reduction in maximum deviation observed in the generator terminal voltage.

• The behavior of unit #6 load angle and frequency responses are similar to active power in all cases.

• Investigation of SS behavior of the generator terminal voltage shows that, selection of very small values for SS gain of AVR or very large values for reactive current compensation can cause insufficient voltage regulation in the RPC owned network, after islanding. In contrast, such settings are advantageous during parallel operation and reduce MVAR variations. Proper selection of SS gain of voltage regulator and reactive current compensation values is possible to achieve desired performance in both conditions. In this selection, the role of over and under excitation limiters and protections should be considered [12-14]. These equipments should be tuned with due consideration of different operating modes of the generator and local network.

• Investigation of the SS behavior of unit #6 frequency shows that, due to the unbalance in active power demand and generation after islanding condition, the final value of the generator frequency may exceed the permissible range (49.5 Hz – 50.5 Hz). Consequently, when the islanding condition occurs, the load-frequency control system should be automatically switched to frequency control mode. During parallel operation with the main grid, this system should be operated in load control mode. Also, close examination of frequency and voltage deviations in this scenario reveals a potential need for consideration of Volt/Hz limiter for the excitation system.

The abovementioned scenario was repeated for other types of excitation control system, and the following results were obtained:

• With excitation system operating in VAR/PF or reactive current control modes, during transient period the excitation system responds similar to voltage regulator. However, a few seconds after islanding, prolonged over- or under-voltages may occur in RPC owned network. This is due to the unbalance between VAR/PF or reactive current demand after islanding and controller action so as to maintain a constant SS level of generator output VAR/PF or reactive current. To avoid such problem, after occurrence and detection of islanding condition, excitation control should be changed to automatic voltage regulation mode.

• An excitation control system operating in VAR/PF or reactive current regulation modes will not provide either momentary or SS adjustment of excitation current in response to voltage disturbances and reactive power unbalance. Similar results are also found when using the excitation control system in manual control mode. Consequently, applications of these modes are not recommended for excitation control of DG units which are expected to continue operation after islanding.

Table 3: Response of unit #6 of RPC plant to a transmission line fault leading to islanding;excitation system on voltage regulation and with reactive current compensation

Terminal Voltage Transient Response		Reactive Power Transient Response		Active Power Transient Response		Final Steady State Operating Condition				Initial Steady State Operating Condition				Reactive Current Compensation X_C (pu)	SS Gain of Regulator K
Setling Time [s]	Maximum Deviation [kV]	Setling Time [s]	Maximum Deviation [MVAR]	Setling Time [s]	Maximum Deviation [MW]	Frequency [HZ]	Voltage [kV]	Reactive Power [MVAR]	Active Power [MW]	Frequency [HZ]	Voltage [kV]	Reactive Power [MVAR]	Active Power [MW]		
2.86	1.261	1.94	4.86	1.22	5.83	50.56	11.07	1.48	1.63	50	11.00	4.97	7.52	0.0	175
2.83	1.227	1.68	4.80	1.24	5.85	50.56	11.30	1.52	1.63	50	11.02	5.16	7.52	0.1	
2.85	1.287	1.49	4.74	1.27	5.92	50.55	11.55	1.55	1.63	50	11.02	5.24	7.52	0.2	
3.74	1.517	2.39	4.81	1.24	5.85	50.55	11.19	1.49	1.64	50	11.02	5.09	7.42	0.0	60
3.67	1.535	2.37	4.76	1.25	5.87	50.55	11.42	1.53	1.63	50	11.02	5.21	7.42	0.1	
3.59	1.584	2.35	4.73	1.27	5.94	50.55	11.66	1.58	1.63	50	11.03	5.26	7.42	0.2	
4.87	1.674	3.04	4.77	1.28	5.88	50.55	11.43	1.53	1.63	50	11.02	5.18	7.42	0.0	25
3.83	1.705	2.98	4.74	1.29	5.91	50.55	11.65	1.57	1.63	50	11.02	5.25	7.42	0.1	
3.80	1.762	2.22	4.72	1.31	5.95	50.55	11.87	1.62	1.63	50	11.03	5.28	7.42	0.2	

5. On-site Tests

To verify the effects of excitation system voltage regulation on parallel operation of generation units of RPC plant with the local 132 kV network, on-site tests were conducted on unit #6 of this plant. Two digital, fast and slow recorders were used to capture the generator active and reactive powers, terminal voltage and stator current. All of the quantities were recorded for different values of SS gain of voltage regulator and the degree of reactive current compensation. After applying each new setting, sufficient time interval was provided. Then, an intentional disturbance of changing the transformer T_1 tap position was applied, and the data were recorded by the fast recorder. Figure 6 shows an actual response of unit #6 when transformer T_1 tap position was moved one step down and returned. For assessment of long term performance of the generator during parallel operation with the local 132 kV network, generator signals were also recorded with a slow recorder, similar to that shown in Figure 2. Table 4 summarizes the results obtained from on-site tests. Comparison of these results with those shown in Tables 1&2 clearly verifies the conclusions already made. A high gain voltage regulator will provide fast transient response to improve voltage regulation and help transient stability. Thus, in order to avoid large excursions in steady reactive power of the generator during parallel operation with the main grid, and also to provide proper long-term and transient response in all probable operating conditions, selection of medium values for SS gain of voltage regulator and relatively large values for reactive current compensation is recommended. To comply with this recommendation, SS gain of voltage regulator and reactive current compensation of unit #6 of RPC plant were set to 50 and 0.15 pu, respectively. Figure 7 shows the actual system response with these settings. One should compare this result with Figure 2, where these parameters were equal to 175 and 0.05 pu, respectively.

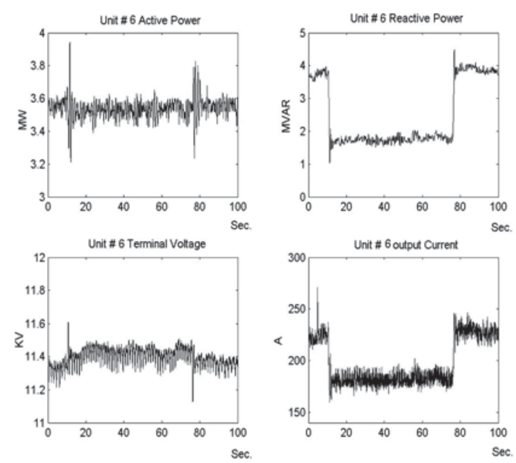

Fig. 6: An actual response of unit #6 of RPC plant to an intentional disturbance; excitation system on voltage regulation with AVR gain of 175 and reactive current compensation equal to 0.05 pu.

Table 4: response of unit #6 of RPC plant to intentional disturbances; excitation system on voltage regulation.

SS Gain of Regulator - K	Reactive Current Compensation X_C (pu)	ΔQ (MVAR)	ΔV (kV)
175	0.05	2.3	0.07
175	0.15	1.3	0.18
50	0.05	2.0	0.09
50	0.15	1.0	0.25

6. Conclusions

In this paper an actual case of reactive power oscillation of synchronous generator-based DG, during parallel operation with main grid was presented. By using simplified and detailed studies, and also on site testes, the adverse effects of excitation system voltage regulation on parallel operation of a typical DG with the main grid were investigated. The cause of the problem was identified, and general remedial actions through excitation control system were proposed, such that the system has satisfactory performance both in parallel and islanding states.

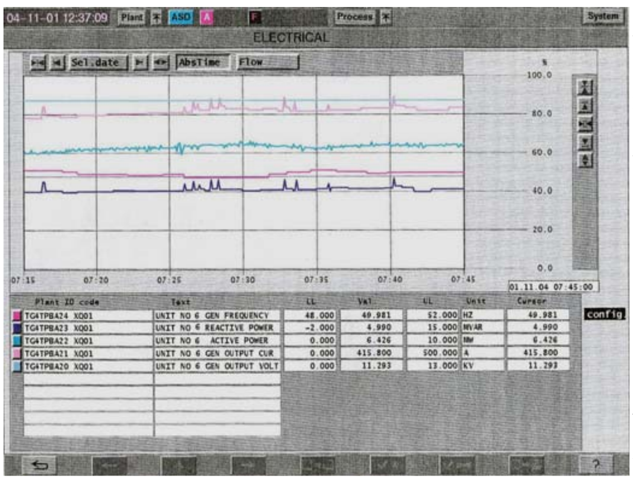

Fig. 7: An actual record of unit #6 of RPC plant during parallel operation with local 132 kV network – New settings.

Based on the study and test results, the following general conclusions are made:

- If terminal voltage regulator is used in a synchronous generator-based DG, undesirable conditions may exist for parallel operation of DG with the main grid. These conditions occur when the transmission or distribution voltages are sensitive to local load fluctuations. Here, forcing constant terminal voltage by AVR results in large excursions of reactive power.
- Proper selection of SS gain of voltage regulator and reactive current compensation values is an effective measure to overcome this problem.
- Manual excitation control reduces the change in the magnitude of generator output reactive power in response to disturbances. However, under this condition, generator voltage will drop with the application of load, especially in islanding conditions. This mode of operation is not recommended for long-term operation.
- Use of excitation control system that operates in VAR/PF control mode is also recommended. During transient period the excitation system responds as a voltage regulator. That is, if a transmission line fault or other momentary disturbance causes a sudden change in generator terminal voltage, the voltage regulator will provide the desired transient forcing beneficial for recovering voltage from such an occurrence in a fraction of second. However, if the disturbance is sustained or occurs relatively slowly over time, then the controller will adjust excitation according to the variation in generator VAR, PF or reactive current, rather than voltage. To avoid prolonged over or under voltages that may occur after islanding condition, excitation control should be changed to voltage regulation mode, after occurrence and detection of islanding condition.

- Use of excitation control system that operates in VAR/PF regulation mode can also resolve this problem. However, during transient voltage disturbances, VAR/PF regulators will not provide any boosting of excitation system output in response to a reduction in voltage. Thus, this mode of operation is not recommended for excitation control of DG units that are expected to continue operation after islanding.

- When the voltage regulator is equipped with reactive current compensation circuit for VAR sharing, conditions could exist where the voltage regulator causes insufficient synchronizing torque of the generator, or conversely, causes excessive over current in the generator field winding. These conditions are most probable during parallel operation of DGs with the main grid. To avoid such problems, under excitation and over excitation limiters and protections should be provided in the excitation system. Settings of these equipments should be tuned with due consideration of different operation modes. Volt/Hz excitation limiter may also be needed, especially on occurrence of islanding conditions.

- To avoid undesirable frequency change or instability due to active power unbalance after islanding, the load-frequency control should be automatically switched to frequency control upon detection of islanding.

APPENDIX

Generator data (all reactances in pu on machine MVA):

T'_{do} = 5.516 s H = 1.29 s D = 0.00 pu

X_P = 0.1 pu X_d = 2.351 pu X'_d = 0.426 pu X''_d = 0.292 pu T''_{do} = 0.10 s

X_q = 1.35 pu X'_q = 0.63 pu T'_{qo}= 0.80 s

X''_q = 0.171 pu T''_{qo} = 0.10 s S (1.0) = 0.176 S (1.2) = 0.490

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