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A METHODOLOGY FOR DYNAMIC UTILITY INTERACTIVE OPERATION OF DISPERSED STORAGE AND GENERATION DEVICES

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Abstract - This paper is introducing a new methodology for the dynamic integration of dispersed storage and generation devices into the electric utility distribution network operations. The dispersed source is viewed as an active device contributing towards the regulation of real and reactive power flows while improving the stability of the power system. Conceptual means are developed for an effective DSG-utility grid interface. Computer models of appropriate interconnection and control equipment are used in simulation studies to test the effectiveness of control strategies and optimize design parameters. Simulation results indicate that load frequency control and voltage regulation may be effectively accomplished with dispersed generators within a fraction of the time required for conventional regulating units. Appropriate modulation and conditioning of the DSG-output power can assist in damping out undesirable power oscillations. Implementation of the proposed policies may result in reduced load following requirements for conventional power generating units, increase the value and acceptability of new energy technologies, and improve power quality and stability of the interconnected system.

INTRODUCTION

In recent years there has been growing interest in utilizing Dispersed Storage and Generation (DSG) devices to provide some of the electricity demand on a large scale [1-3]. Such systems are usually interfaced with an existing power grid for fuel displacement purposes, as well as for earning some capacity credit. Interest in the use of DSGs in electric distribution systems results from a number of technical, economic, and institutional factors. The Public Utility Regulatory Policies Act (PURPA) of 1978 [4] has cleared the way for the guaranteed interconnection of customer-owned generation to electric utility systems. Recent advances in DSG technologies combined with electric energy cost trends make the small production of electric power more economically attractive. PURPA regulations require utilities to provide the necessary specifications for the sizing, maintenance, safety, and reliability needs for the effective intertie of all customer-owned generated power. Moreover, the utilities must offer to purchase all power production from DSG facilities at just and reasonable rates, as well as supply electricity to these small power producers when needed. Furthermore, small power production represents a potential alternative to central station production for the electric utility industry since small DSG devices have a reduced environmental impact, may be constructed and become operational in a relatively short time and produce electricity from available domestic and renewable fuels while located close to load centers. Utility-owned DSGs would present technical intertie problems similar to those of customer-owned equipment.

The interconnection and operation of dispersed storage and generation devices at the electric distribution level raise numerous planning and operational concerns [5-9]. Electric utilities usually specify DSG interface requirements and protection schemes that are capable of responding to all "abnormal" system conditions by disconnecting the dispersed source from their system. This utility philosophy--requiring extensive protection hardware and viewing the dispersed source as a nuisance--results in increased costs associated with the interconnection hardware and an inefficient utilization of available generated power. Moreover, the value of New Energy Technologies (NET) is further decreased, with a corresponding increase in power production from conventional sources, since this operating philosophy allows for stochastic output power variations from dispersed generators causing excessive ramping of the utilities' regulation units and increasing load-following, spinning reserve, and unloadable generation requirements. Recently, it has been suggested that if NETs are to contribute significantly to the electric energy supply, then methods must be developed for operating these new sources in harmony with the conventional power system [1,10,11].

This paper is introducing a new philosophy for the effective integration of NET devices into the utility grid. The dispersed generator is viewed as an active device contributing towards the regulation of real and reactive power flows while improving overall system stability. Conceptual means are developed for the dynamic integration of DSG devices such as solar, wind, fuel cells, batteries, cogenerators, etc., into the power utility system. Appropriate interface equipment and control strategies result in reduced load-following requirements for conventional power generating units while improving power quality and stability of the interconnected system.

THE INTERFACE PROBLEM

A methodology is presented in this paper for the operation and control of DSG devices so that they contribute towards the regulation of real and reactive power flows while providing a stabilizing effect to system disturbances. Figure 1 shows a block diagram of the proposed system configuration. The primary energy source (wind, solar, biomass, hydrogen, etc.) is converted to electrical form.

The Power Conditioning Subsystem is central to the proposed control and stabilization philosophy. It consists of a dc to ac inverter with a capability of delivering both real and reactive power to the grid. Reverse flow of power (from the utility lines to the storage device) is also possible and may be desirable under appropriate supply/load management policies. A

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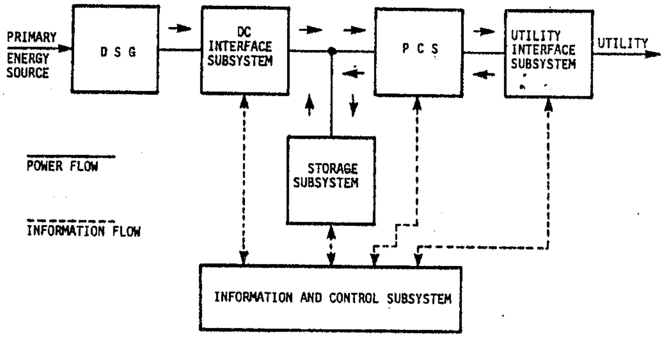


Figure 1. Block Diagram of the DSG-Utility Interface.

possible inverter design for control purposes is based upon the principle of self-commutation. Voltage-fed, self-commutated inverters have been developed using techniques of square wave generation with harmonic neutralization, various PWM methods, and high frequency linking of the input to output power flow [10,12-15].

For our purposes, the inverter may be represented as an ac source connected to the utility grid through an impedance buffer (Figure 2). System frequency variations, Δf, are continuously monitored at the grid bus and a control signal proportional to Δf is used to vary the phase difference Φ between the inverter and grid buses, thus transferring more or less real power to the utility. Control of the amplitude of the inverter voltage E in relation to the line voltage V regulates reactive power flow. Under four quadrant P-Q operation, the inverter is absorbing real and reactive power from the grid making them available for storage.

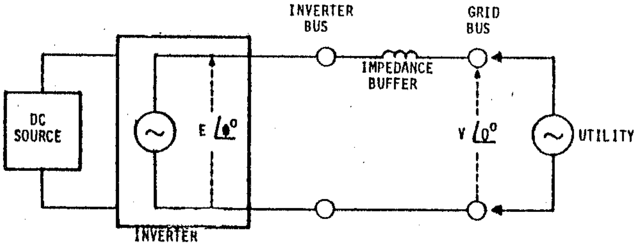


Figure 2. Equivalent Representation of Inverter-Grid System.

The system configuration is complemented, as shown in Figure 1, with suitable information retrieval/processing and control instrumentation.

SYSTEM REGULATION AND STABILITY

A generic voltage-fed, self-commutated inverter is assumed at the output stage of the PCS. It is further assumed that the inverter is designed to handle efficiently all required power swings. A sufficient supply of dc power is available either directly from the dispersed generator or from storage.

Normally, a conventional storage facility associated with solar and wind generators is designed to accommodate energy requirements for an extended period of time, typically 4-5 days, during which the primary dispersed source is unavailable. In the control configuration examined in this paper, the storage facility serves primarily the purpose of providing suitable amounts of energy, over brief periods of time, required to cover the difference between supply and demand. In one possible operating mode, the output power of the conventional unit may be regulated in a stepwise manner. The task of the storage unit is to provide, under worst-case conditions, the maximum difference between the load demand and the conventional power in the time interval from one generation step transition to the next. Thus, the load demand may be fully satisfied from storage in the event of primary source unavailability. For a small autonomous power system, the maximum daily difference between load demand and conventional power production may be taken to be 100 kW. If the maximum duration between step changes in conventional power production is 3 hours, the storage capacity required to fulfill the control objectives is estimated to be of the order of 150 kWh.

The first part of the analysis involves the inverter real and reactive power control dynamics, while the second combines the PCS representation with the swing equation of a conventional rotating generator and appropriate network load-flow models to predict the dynamic behavior of the interconnected system.

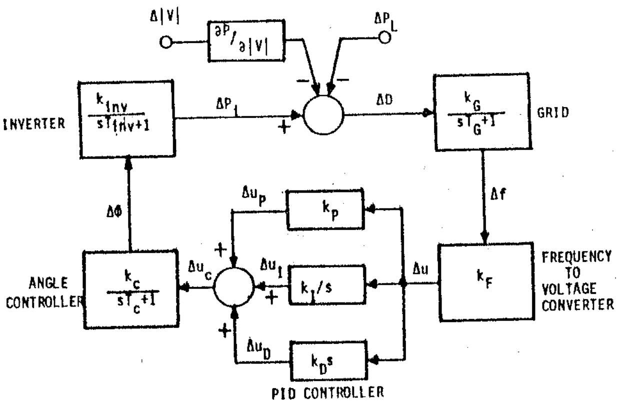
A. Real and Reactive Power Control

For purposes of analysis, it is assumed that one or more DSGs of the type specified previously, are operating in a coherent power system consisting of diesel-powered generating units, power transmission and distribution facilities, and typical loads. Situations of this category are already in existence in several small islands or isolated communities with WECS clusters and PV arrays operating in parallel with the local power system [16].

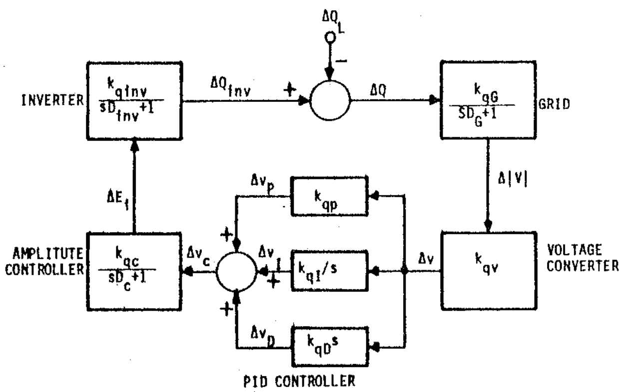
Figures 3(a) and (b) are transfer function representations of the real and reactive power control mechanisms of a single PCS operating in parallel with a conventional diesel-powered system. Similar representations are valid for all other dispersed generators connected to the grid. The amount of generated power that each unit contributes to a particular load demand is a function of its rated capacity and is determined by a static frequency-load characteristic of the unit. The slope of this characteristic is fixed numerically by the overall feedback loop gain.

The system of Figure 3 is configured on the basis of the following assumptions:

1. The linear models of (a) and (b) are valid for small load disturbances corresponding to linear changes in system frequency.
2. All system machine inertias (generating and load units included) are assumed to be represented by a single time constant, T_G.
3. The real and reactive power output of the inverter are represented by a first-order transfer function, assuming that both the angular displacement, $\Delta\phi$, and the voltage amplitude variations are kept small. Similar representations using first and second-order dynamics have been suggested by other investigators [17,18]. The inverter time constants, T_{inv} and D_{inv}, are due to time delays that the real and reactive power are subjected, as they are transferred from the inverter output to the utility grid.
4. The feedback loop branches into two paths: an angle controller and an amplitude controller. The angle controller consists of a frequency to voltage converter, a PID compensator, and a first-order transfer function representing the time delay introduced by the controller. Similarly, the amplitude controller consists of a voltage converter, a PID regulator, and an analogous transfer function, representing time delays.



(a)



(b)

Figure 3. Transfer Function Representation of (a) Real Power Control and (b) Reactive Power Control Schemes.

5. In the voltage control loop, the power grid is again represented with a first-order transfer function under the assumption that small changes in ΔQ produce proportional changes in the amplitude of the utility voltage $\Delta|V|$. The transfer function time constant, in this case, is, of course, relatively small. An exact ΔQ vs. $\Delta|V|$ relationship would involve solution of the system load flow equations. Accounting for overall problem accuracies, such a step is not presently warranted.

In state-variable form, the dynamic system model of the coupled real and reactive power control mechanisms (Figures 3(a) and (b)) is expressed with the following equations:

$$
\begin{aligned}
\dot{x}_1 &= x_2\\
\dot{x}_2 &= x_3\\
\dot{x}_3 &= x_4\\
\dot{x}_4 &= -a_3x_4-a_2x_3-a_1x_2-a_0x_1 + \Delta P_L + \alpha\Delta|V|\\
\dot{x}_5 &= x_6\\
\dot{x}_6 &= x_7\\
\dot{x}_7 &= x_8\\
\dot{x}_8 &= -a_{q3}x_8-a_{q2}x_7-a_{q1}x_6-a_{q0}x_5 + \Delta Q_L
\end{aligned} \tag{1}
$$

where:

$$K = k_{inv}k_ck_fk_G \qquad a_3 = \frac{T_{inv}T_c+T_{inv}T_G+T_cT_G}{T}$$

$$T = T_cT_{inv}T_G \qquad a_2 = \frac{T_{inv}+T_c+T_G-Kk_D}{T}$$

$$a = \frac{\partial P}{\partial|V|} \qquad a_1 = \frac{1-Kk_P}{T}$$

$$a_0 = -\frac{Kk_I}{T}$$

$$b_2 = T_{inv}T_ck_G \qquad K_q = k_{qinv}k_{qc}k_{qv}k_{qG}$$

$$b_1 = (T_{inv}+T_c)k_G \qquad D = D_cD_{inv}D_G$$

$$b_0 = k_G$$

$$a_{q3} = \frac{D_{inv}D_c+D_{inv}D_G+D_cD_G}{D} \qquad b_{q2} = D_{inv}D_ck_{qG}$$

$$a_{q2} = \frac{D_{inv}+D_c+D_G-K_qk_{qD}}{D} \qquad b_{q1} = (D_{inv}+D_c)k_{qG}$$

$$a_{q1} = \frac{1-K_qk_{qP}}{D} \qquad b_{q0} = k_{qG}$$

$$a_{q0} = -\frac{K_qk_{qI}}{D}$$

For a step change in real and reactive load power, ΔP_L and ΔQ_L, the corresponding changes in system frequency and line voltage are written as:

$$
\begin{aligned}
\Delta f &= -\frac{1}{T}\,(b_2x_4+b_1x_3+b_0x_2)\\
\Delta V &= -\frac{1}{D}\,(b_{q2}x_8+b_{q1}x_7+b_{q0}x_6)
\end{aligned} \tag{2}
$$

Numerical values for design parameters and system constants are specified on the basis of available data from existing facilities, systems, and components. The power grid is representative of a small autonomous system providing electrical power to consumers of an isolated community. The methodology is applicable to any control area which supports both conventional and dispersed sources.

With a step load disturbance of ΔP_L = 80 kW and ΔQ_L = 60 kVAR, two cases are examined and results are presented in Figures 4(a) and (b), respectively. The response of Figure 4(a) is arrived at with zero integral control ($k_I = k_{qI} = 0$). As it is anticipated, a permanent frequency and voltage deviation from their normal values results, following the load disturbance. It is observed that the percent Δf and ΔV errors are within the maximum permissible tolerances (± 0.5 Hz and ± 5% voltage deviation). The nominal line voltage is considered to be 220 V in this example. The time response in this situation is determined primarily by the power system time constant rather than the inverter and controller time constants.

In the second case, large values for the integral controller gains are used while a substantial differential gain is maintained for the voltage control loop, i.e., k_I = 10, k_{qI} = 10, and k_{qD} = 0.1. The system response is clearly underdamped exhibiting small oscillations and reaching zero steady-state condition in a relatively short time.

B. Combined Dynamics

The differential equations describing the rotating generator swing dynamics are combined next with

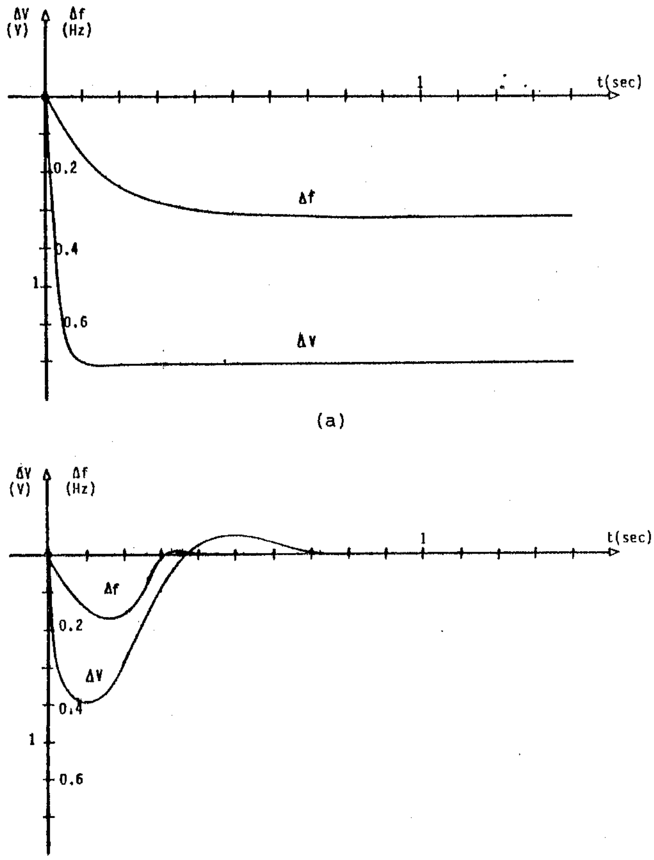


Figure 4. Frequency and Voltage Variation vs. Time With (a) Zero Integral Control and (b) Strong Integral Control Gain.

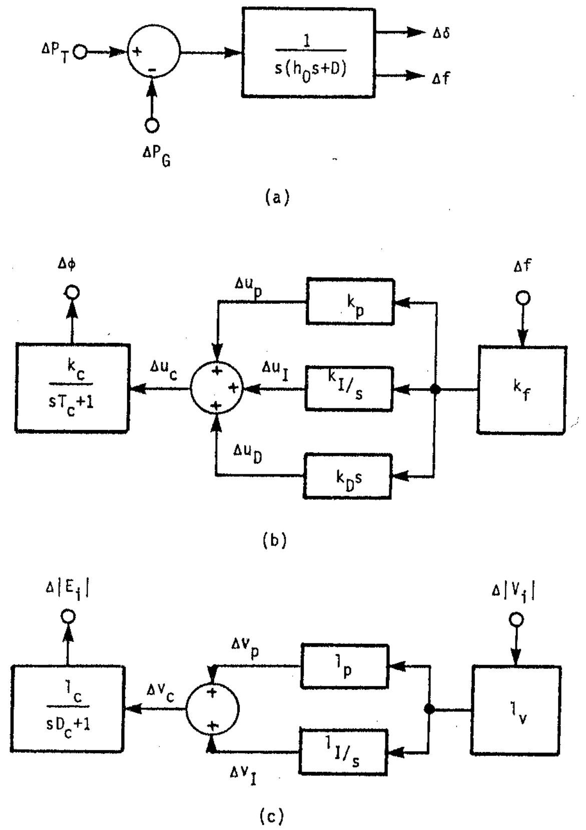


Figure 5. Block Diagram Representation of the Generator Swing, Pf and QV Feedback Control Dynamics.

load flow representations of real and reactive power transfer and the interface control dynamics of the previous section in order to determine the dynamic stability of the interconnected system. A block diagram representation of the rotating generator dynamics is shown in Figure 5(a), while Figures 5(b) and 5(c) depict the real and reactive power control dynamics of the inverter, respectively.

The generator swing equation may be written as

$$\Delta P_T - \Delta P_G = h_o \ddot{\Delta\delta} + D\dot{\Delta\delta} \quad (3)$$

where

$h_o = \frac{H}{\Pi f^o}$ and D is the damping factor due to the machine damper windings.

With $x_1 = \Delta\delta$ and $x_2 = 2\Pi\Delta f$, a state variable formulation of the swing dynamics is expressed as

$$\dot{x}_1 = x_2$$
$$\dot{x}_2 = h_o(\Delta P_T - \Delta P_G + Dx_2) \quad (4)$$

The angle and amplitude feedback dynamics of each one of the inverters (Figures 5(b) and 5(c)) can be written in the following form

$$\dot{x}_3 = \frac{k_I k_f}{2\pi} x_2 \qquad x_{3\,min} < x_3 < x_{3\,max}$$

$$\dot{x}_4 = \frac{1}{T_c}\left[k_c\left[\frac{k_p k_f}{2\pi} x_2 + x_3 - \frac{k_D k_f}{2\pi h_0}(\Delta P_G + Dx_2)\right] - x_4\right]$$

$$x_{4\,min} < x_4 < x_{4\,max}$$

$$\dot{x}_5 = \ell_I \ell_v \Delta|V_i| \qquad x_{5\,min} < x_5 < x_{5\,max}$$

$$\dot{x}_6 = \frac{1}{D_c}\left[\ell_c(\ell_p \ell_v \Delta|V_i| + x_5) - x_6\right] \qquad x_{6\,min} < x_6 < x_{6\,max}$$

where

$$x_1 = \Delta\delta$$
$$x_2 = 2\pi f$$
$$x_3 = \Delta u_I$$
$$x_4 = \Delta\phi \quad (6)$$
$$x_5 = \Delta v_I$$
$$x_6 = \Delta|E_i|$$

The control angle ϕ is the angle between the inverter bus voltage E_i and the grid bus voltage V_i.Eg is the emf behind the generator transient reactance and it is assumed to remain constant during the transient state. The input turbine power, P_T, is also taken to be constant; therefore, $\Delta P_T = 0$. Under the assumption that the system frequency f remains fairly constant, the interconnected network is considered to be in the sinusoidal steady-state. Load-flow analysis may, therefore, be used to calculate changes in the grid bus voltage and the power supplied by the generator due to changes in the control variables $\Delta|E_i|$ and $\Delta\phi$. Figure 6 shows a block diagram of the overall simulation program. Steady-state operating conditions are established using the Load Flow algorithm. The transmission line is assumed to be lossy and a sudden

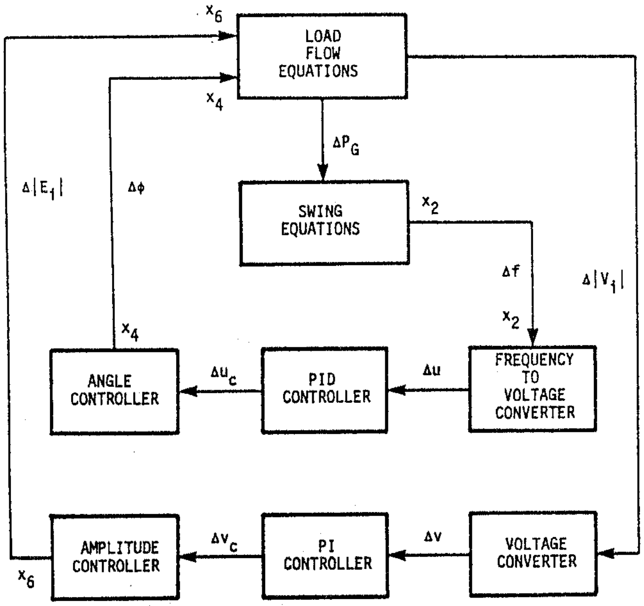


Figure 6. Block Diagram of the Combined Generator-Inverter-Grid Simulation Algorithm.

change in load demand initiates the post-fault condition. The change in load demand establishes a new initial condition for the load flow equations. The Load Flow algorithm is used to calculate the changes in the grid bus voltage and the electrical power supplied by the conventional generator. The generator swing dynamics are accessed next producing an output change of frequency Δf. Changes in grid voltage $\Delta|V_i|$ and frequency Δf are inputted to the amplitude and inverter angle controller algorithms, respectively. The outputs from these two programs are deviations in the inverter voltage $\Delta|E_i|$ and phase angle $\Delta\phi$. These last two quantities are the inputs to the Load Flow algorithm for the next program iteration.

Figure 7 depicts a single-line diagram of a small autonomous power system consisting of one conventional power generator without any frequency and voltage control capabilities and a rated capacity of 500 kVA, transmission lines, and two identical inverters of the type suggested in the paper, with a rating each of 100 kVA. The system nominal voltage is considered to be 200 V. Simulation studies were conducted on the basis of the flow diagram shown in Figure 6. With representative system parameters chosen to reflect actual field conditions, several test runs were executed with various step load changes. Typical simulation results are shown in Figures 8(a), (b), and (c).

Figure 8(a) shows deviations of the system frequency, bus voltages where the inverters are connected, real power provided by the conventional unit, and real power produced by each inverter, for a 20% step load increase. Since the conventional unit supplies a fixed amount of real power, the increase in load is taken up eventually by the inverters, as it is illustrated in the figure. The inverter parameters have been adjusted for optimum response conditions. Indeed, the system reaches steady state in a very

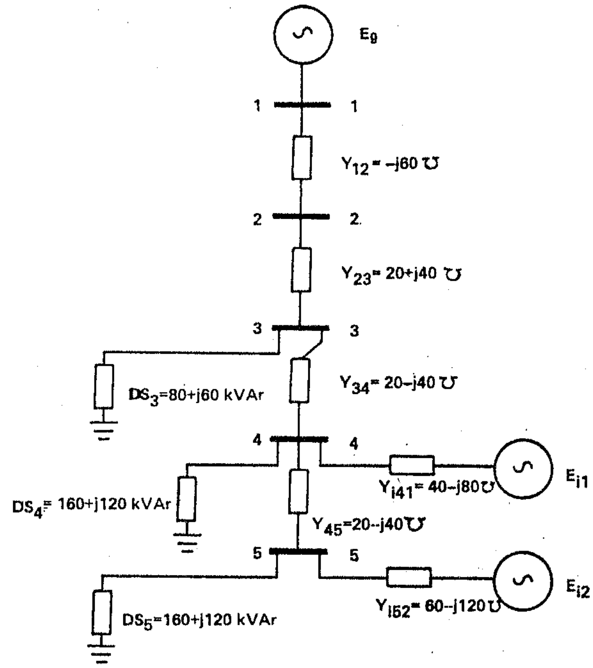


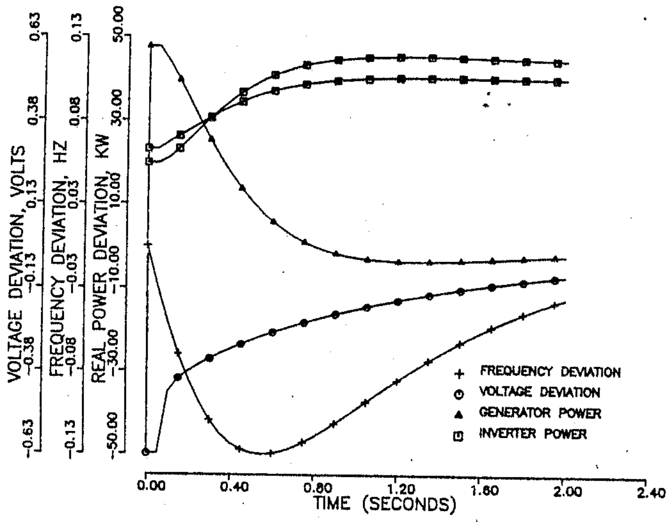
Figure 7. A Single-Line Diagram of the Power System Used in the Example.

short period of time, which is one of the attractive features of the proposed configuration.

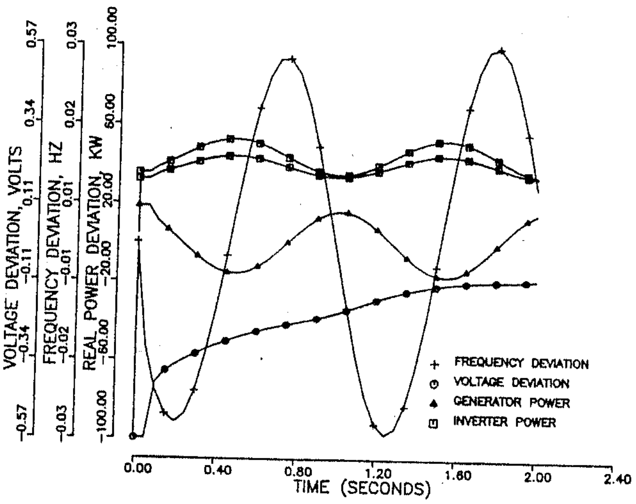
Figure 8(b) depicts the response of the same quantities to a similar load disturbance. In this case though, the inverter parameters are purposely assigned values away from the optimum settings. The figure clearly illustrates the sensitivity of the response to the inverter parameters as evidenced by the resulting instability.

A different philosophy of approach is suggested for DSG devices connected to a large electric power system. Since in this situation DSG penetrations are small, frequency control is, for all practical purposes, impossible. DSG devices though, may be effectively utilized for local voltage regulation. One such possible configuration is shown in Figure 6, where the branch: swing equations-f to v converter-PID-angle controller is omitted. Moreover, the conventional generating unit is topologically substituted with an infinite bus (Figure 7). Thus, this network may represent a specific distribution feeder of a large power system. An 20% load change now results in the responses of Figure 8(c). The inverter parameters have again being set to their optimum settings. The system behavior is relatively stable and it returns to a steady state condition in a very short period of time. The real power provided by the inverters remains almost constant while the power system undertakes to supply the increased load demand. The figure shows the deviation of reactive power introduced by the inverters which is necessary for voltage regulation purposes. It is theoretically conceivable that future large DSG penetrations will affect both frequency and voltage control loops if the proposed philosophy is adopted.

Simulation results indicate that implementation of the control and stabilizing strategies involves the utilization of a frequency vs. power "drooping"



(a)



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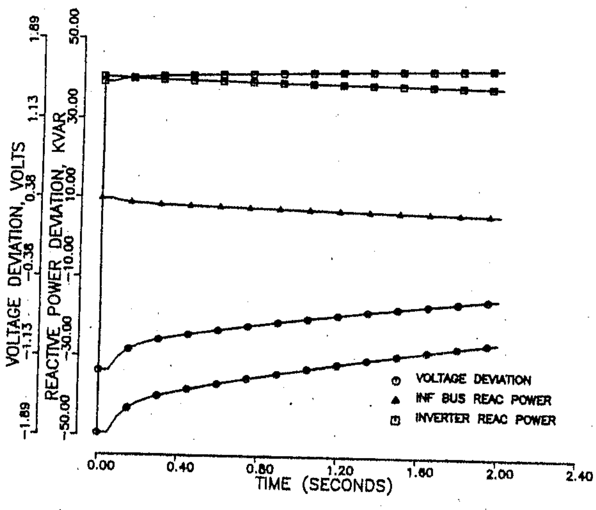

(c)

Figures 8(a), (b), and (c). Response of System Variables to a Load Disturbance.

characteristic for each inverter. A permanent load disturbance is shared by the operating power conditioning units according to their capacity. The proposed scheme thus "simulates" the control characteristics of a conventional unit.

The dispersed generator may be used to improve system stability by appropriately modulating the inverter output power. Disturbances on the utility system usually result in power oscillations along the T/D lines. These oscillations can be damped out by injecting real power from the inverter into the grid in such a way so that the net effect is a cancellation of any undesirable occurrences. The approach is implemented by monitoring the frequency and amplitude of the oscillating power and generating control signals which shape accordingly the inverter output power. For a particular disturbance, effective stabilizing action depends not only upon the magnitude of the disturbance, but also on available reserve power in storage and the reaction time of the inverter circuitry. Successful implementation of this scheme relies heavily on the speed and flexibility with which the electronic inverter moves power from the primary source/storage facility to the utility lines.

CONCLUSIONS

The proposed control and stabilization methodology constitutes a significant departure from accepted utility practices in the interconnection of dispersed storage and generation devices with the utility grid. The requirement for extensive protection hardware and the view of the DSG as a parasitic source are substituted with a positive approach where the dispersed generator is contributing beneficially to the operation of the power system.

Simulation results indicate that the response time of the control elements is extremely short with the overall DSG--utility grid--generator systems exhibiting stable transient behavior.

Immediate benefits in improved voltage regulation will be realized via implementation of the proposed control strategies even at small DSG penetration levels. Future increased penetrations are bound to bring about positive results as far as frequency control and stability improvement are concerned.

Equipment costs may be kept to an acceptable level while the operation of the devices may be fully automated.

Probably, the most significant limitation, from an economic standpoint, of the scheme refers to the utilization of an energy storage facility. Careful sizing of this device to maintain an acceptable reliability threshold will ensure optimum technical and economic results.

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