Assessment and Enhancement of Small Signal Stability of a Renewable-Energy-Based Electricity Distribution System

Sudarshan Dahal, *Student Member, IEEE*, Nadarajah Mithulananthan, *Senior Member, IEEE*, and Tapan Kumar Saha, *Senior Member, IEEE*

***Abstract*—Market deregulation and environmental concerns of the power sector have encouraged renewable energy integration in the form of distributed generation, mainly in distribution systems. With integration of different generators and controllers, distribution systems are facing different types of stability issues which were not a concern in the past. This paper examines the small signal stability performance of a renewable-energy-based distribution system. The system, which consists of static and dynamic loads, is supplied by synchronous, induction, and static generators. The existence and nature of oscillatory modes are systematically investigated. A control methodology of using existing capacitor banks to support small signal stability of a distribution system is proposed. A controllability-based index is used to identify the controllable capacitor bank. An observability index has been used to design the additional controller for damping control. The effectiveness of capacitor controller is illustrated by using both eigenvalue and time-domain analyses.**

***Index Terms*—Capacitor, controllability, distributed generation, distribution system, observability, renewable energy, residues, small signal stability.**

I. Introduction

RECENT trends of legislative changes and environmental concerns around the globe are likely to increase penetration of renewable energy resources into power systems in the form of distributed generation (DG) units [1]. The integration and high penetration of renewable energy resources into a distribution system could introduce a number of key issues, including oscillatory stability which is also traditionally referred to as small signal stability [2]. Oscillatory instability may be caused by dynamic characteristics of distributed generators and improper tuning of the controllers [3]. It is one of the limiting criteria for synchronous operation of distributed generators [1], [4]. Also, dynamic loadability of a system is governed by small signal stability limit [5].

As of now, most of the works on small signal stability are on a transmission system which is characteristically different from a distribution system. For example, dynamics of a transmission network are governed by large synchronous generators while the dynamics of emerging distribution networks will be affected by different types of generators such as synchronous, induction, static generators and their controllers. In a large transmission system, generators are scheduled for reactive power support for voltage stability. On the other hand, DG units of small capacity are not required to support reactive power to the network, according to the interconnection guidelines for DG units set by utilities such as Australian Energy Market Operator (AEMO) [6]. Generators in a transmission system are usually equipped with power system stabilizers (PSS) for small signal stability while generators in emerging distribution systems (wind and solar generators) usually do not have such stabilizing functionality. Owing to the closeness of the generators and their controllers, dynamic interaction in a distribution system is a more complex issue. As a result, not only electromechanical modes but also some control modes become prominent issue for small signal stability. Hence assessment and enhancement of small signal stability becomes an important task for accommodating higher penetration of renewable-energy-based distributed generation for secure operation of the electricity distribution system.

In conventional power systems, damping of low frequency oscillations is supported by either power system stabilizers installed at synchronous generators or supplementary control loops of voltage control devices such as static var compensators (SVCs). With increased penetration of renewable energy resources, there are also efforts to utilize distributed generators (DG units) for oscillation damping. It has been reported that additional controllers at DFIG can also support damping of interarea oscillations [7]. Similarly, a PV generator may be controlled for stability enhancement [8]. Supporting stability of a distribution network from DG units is governed by the nature of the operational commitments they provide to the network. As of now, DG units of lower capacity do not have to meet any operational commitment to support stability of a network [6], [9], [10]. Hence in a distribution system with lower capacity of DG units, controllers are required at different points in the network to support small signal stability.

Distribution networks are usually compensated by mechanically switched capacitor banks to support node voltages. Such capacitor banks are incapable of handling the dynamics of a distribution network with distributed generators. Further, capacitor banks are reported to be detrimental to oscillation damping [11].

Manuscript received December 12, 2010; revised March 24, 2011; accepted June 26, 2011. Date of publication April 26, 2012; date of current version June 15, 2012. This work was supported by the University of Queensland through the APA award and by the CSIRO Australia under the Intelligent Grid Flagship Project.

The authors are with the School of Information Technology and Electrical Engineering, The University of Queensland, Brisbane, 4072, QLD, Australia (e-mail: sdahal@itee.uq.edu.au; mithulan@itee.uq.edu.au; saha@itee.uq.edu.au).

Digital Object Identifier 10.1109/TSTE.2012.2187079

On the other hand, capacitor banks can be dynamically controlled to enhance power quality of a distribution network [12]. However, the possibility of controlling shunt capacitor bank to support small signal stability of a distribution network is not well investigated. This paper proposes an approach to select the most suitable capacitor bank for installing such a controller. The contributions of the paper are: 1) assessment of small signal stability of a distribution network with different types of DG units; 2) a novel concept of controlling a shunt capacitor bank for small signal stability enhancement; and 3) simple mathematical expressions to identify the most effective capacitor bank and the most suitable feedback signal for installing a controller. The paper also presents a systematic approach to determine design parameters of such a controller.

The paper is organized as follows. Section II provides a description of different kinds of distributed generators, their operation, and modeling approaches. This section also explains modeling of distribution networks and loads.Section III presents the oscillatory modes of a distribution network with distributed generators. The dominant distributed generators for each oscillatory mode have also been identified in Section III. Section IV provides an analytical approach to determine the best location of a controller of shunt capacitor to provide oscillation damping as well as dynamic voltage support. Section V provides an approach to select feedback signals for additional controllers to adjust the damping of the modes. Finally, the conclusions drawn from the results and contributions of the work are summarized in Section VI.

II. System Modeling

In general, elements that should be considered in modeling of a power system for various stability studies are generators, generator controllers, transformers, transmission lines (including subtransmission lines), and loads. The modeling approach adopted in this paper is explained as follows.

A. Generator Modeling

A renewable-energy-based electricity distribution system may have different types of generators, i.e., synchronous generators, induction generators, and inverter-based or static generators [1]. An overview of the modeling approach of the generators is discussed.

1) *Synchronous Generators*: Conventional synchronous generators are popularly used in cogeneration, small hydro, and some wind power applications. Recently, permanent magnet synchronous generators (PMSGs) are also gaining popularity in various distributed generation applications, mainly in wind energy conversion (WEC). PMSGs are expected to offer many advantages to emerging distribution systems for reactive power management and efficient energy conversion from variable energy resources such as wind. As of now, the majority of synchronous generators used in distributed generation applications are of the conventional type. Hence, small signal stability issues with conventional synchronous generators are considered in this paper. The issues of rotor oscillations in a conventional synchronous machine are well known [2]. Since the generators connected to a distribution system do not take part in frequency regulation, mechanical torque of the generator is assumed to be constant. Usually synchronous generators are connected to distribution systems as constant active power sources operating at power factor control mode [1]. However, depending upon their capability, they may support the voltage by providing reactive power as well. In this paper, both operations of synchronous generator have been considered. For voltage control mode reactive power limit has been defined.

2) *Induction Generator*: The induction generators are popularly employed in wind power generation applications, small and micro hydro, and some thermal plants. With the increased penetration of induction machines in a power system, the induction machines' rotor oscillation is also an important issue [13]. The advancement of induction generator design has changed the way they impact on system stability. For example, the contributions of the squirrel cage induction generator (SCIG) and doubly fed induction generators (DFIG) on transient stability are different [14]. In this paper, induction generators are assumed to be consuming reactive power from the system. Hence, the squirrel cage induction generator (SCIG) model has been considered. Similar to synchronous generators, the mechanical torque is assumed to be constant. For dynamic analysis, SCIG has been modeled by the third-order induction machines model [15]. The reactive power support for the induction generator is partially supplied by a shunt capacitor, whose rating is equal to one third of the active power generated by the generator.

3) *Solar PV Generators*: The solar photovoltaic (PV) cells generate a dc current, which is converted into ac current by power electronics inverter control. The schematic diagram of a grid integrated solar PV system is shown in Fig. 1.
It is obvious from Fig. 1 that PV generators do not have any rotating mechanical parts as compared to the other two generation technologies and the dynamics of such systems are dominated by converter controllers [8]. The power is injected into the ac system by voltage source converter (VSC) operation. In this paper, the solar irradiation and temperature are assumed to be constant throughout the analysis. For a given solar irradiation and temperature, v_{dc} is determined by the maximum power point tracking (MPPT) scheme [16]. Hence, P_{pv} is constant as well. Also, v_t is the distribution network terminal voltage determined by network conditions whereas i is adjusted by VSC current control. Hence, the VSC current control strategy effectively decouples dynamics of i from dynamics of v_t. So, the PV system is decoupled from the distribution network and the loads, from the viewpoint of system dynamics. Grid connected PV systems have been reported to enhance small signal stability of a power system [17]. A simpler model has been suggested for stability analysis of a grid connected PV system [17], [4]. In this paper, the PV generator is considered as a static generator generating power at unity power factor.

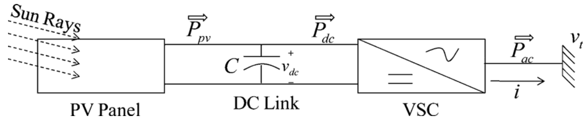

Fig. 1. Schematic diagram of grid integrated solar PV system.

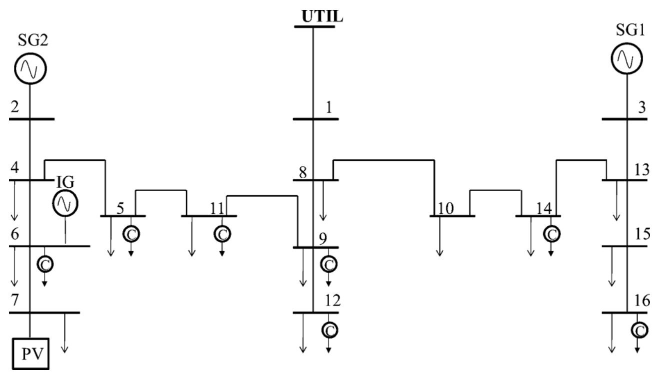

Fig. 2. Single line diagram of the test distribution system.

B. Load Modeling

In steady-state analysis, the loads are represented by constant power models. However, in dynamics analysis, there is no uniformity in choosing a load model. The IEEE task force [18] recommends that the active power loads be represented by constant current models and reactive power loads be represented by constant impedance models for dynamic simulation. On the other hand, induction motor dynamics is also popularly used to represent load dynamics. In recent years, the composite load models have been widely used where static parts are represented by ZIP and dynamic parts are represented by induction machines [19].

The selection of load model obviously affects the result of stability analysis [19]. In this study, dynamics imposed by DG units into the system is of importance. Hence, all the loads of the studied system are modeled by impedance loads [20].

C. Description of Distribution System

The configuration of a distribution system which is under study is shown in Fig. 2 [21].

In this system, three radial feeders are connected by tie lines. The motivation to choose this system is that it is convenient for studying the dynamic interaction of distant machines located on different feeders. The total load of the system is 28.7 MW and 17.3 MVAR. The distribution network is modeled by π-model similar to that of a transmission system model.

The distribution system is supplied by distributed generators located at different buses. Assuming that distributed generators are located based on location of renewable resources, selection of location is random in this case. The description of the generators is summarized in Table I. Here, synchronous generator SG2 has a reactive power limit of ± 3 MVAR. Capacitor banks are located at different buses to maintain voltage stability of the distribution system. Though a majority of DG units have reactive power capability, their reactive power contributions to distribution networks are governed by the nature of commitments to the system operators. As of now, most of the DG units are committed for the real power. Hence, network service providers must provide adequate reactive power support to ensure network stability.

TABLE I
SUMMARY OF GENERATORS OF THE SYSTEM

Gen	Power	Operation	Model	Bus
SG1	5 MW	Power factor control	Sixth order[2]	3
SG2	4 MW	Terminal voltage control	Sixth order[2]	2
IG	2 MW	Reactive power load	Third order[15]	6
PV	1 MW	Unity power factor	Static [1]	7

Section III discusses a linear analysis to assess small signal stability of the system.

III. OSCILLATIONS IN A DISTRIBUTION SYSTEM

A. Oscillatory Modes Observed in a Distribution System

For stability analysis, power systems are modeled using a set of differential equations and a set of algebraic equations as given in (1) [2]

$$\begin{cases} \dot{x} = f(x, y) \\ 0 = g(x, y) \end{cases} \tag{1}$$

where x is a vector of state variables and y is a vector of algebraic variables.

The differential and algebraic equations (DAEs) of (1) can be linearized at an operating point (x_o, y_o) and rearranged as

$$\begin{bmatrix} \Delta\dot{X} \\ 0 \end{bmatrix} = \begin{bmatrix} f_x & f_y \\ g_x & g_y \end{bmatrix} \begin{bmatrix} \Delta X \\ \Delta Y \end{bmatrix} \tag{2}$$

where $f_x = \partial f/\partial X|_o$, $f_y = \partial f/\partial Y|_o$, $g_x = \partial g/\partial X|_o$, and $g_y = \partial g/\partial Y|_o$. If g_y is a nonsingular matrix, (2) can be reduced as

$$\Delta\dot{X} = A\Delta X \tag{3}$$

where $A = (f_x - f_y g_y^{-1} g_x)$ represents the system state matrix of the distribution system with DG units. The eigenvalues of A provide the information of small signal stability. The system under study has 16 eigenvalues with all the DG units connected and the eigenvalues are shown in Fig. 3.

Since all the eigenvalues lie on the left side of the imaginary axis, the system is said to be asymptotically stable. Eigenvalue analysis may be used to determine acceptable renewable energy penetration before the system loses small signal stability. The limiting criteria for penetration could be either damping ratio or Hopf bifurcation condition [5].

In this system, four pairs of complex low frequency oscillatory modes were observed, which are summarized in Table II.

It can be observed that Modes 7,8 have the least damping ratio of nearly 2%, which is undesirable for a power system small signal stability. Hence, this mode has been considered as a critical mode in this paper. It is interesting to note that the oscillatory frequencies of all the modes are around 1.5 to 4 Hz, which is slightly higher than the frequency of electromechanical modes of large generators observed in a transmission system,

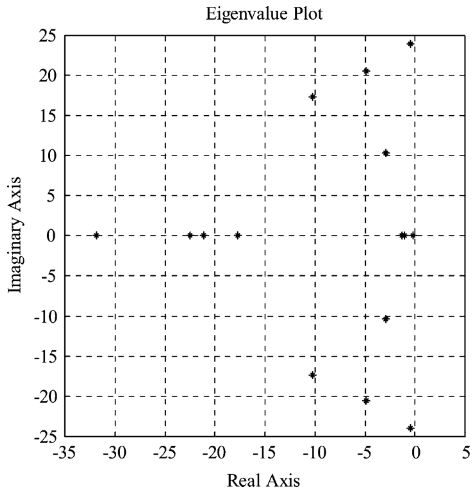

Fig. 3. Eigenvalues of the distribution system.

TABLE II
OSCILLATORY MODES EXISTING IN THE DISTRIBUTION SYSTEM

Modes	Real Part (1/s)	Imaginary Part (rad/sec)	Damping Ratio	Frequency (Hz)
1, 2	-4.85	20.50	0.23	3.26
3, 4	-2.90	10.40	0.23	1.66
5, 6	-10.30	17.40	0.50	2.77
7, 8	-0.44	24.00	0.02	3.82

which is typically in the range of 0.1 to 2 Hz. Some studies with induction generator applications also show a similar frequency of oscillations in a distribution system [22]. Further lower frequency modes are not observed.

The modes presented in this paper are local modes, which are very important for local stability of the generators. However, when a large number of generators are scattered in a large distribution system, this may form small groups of generators oscillating against each other creating a problem of interarea oscillations.

B. Participation Factor

The contributions of states on oscillation were calculated by evaluating the participation factors (PFs) of each state on a particular mode. Participation factor gives the relationship among the states and eigenmode in a dynamic system [2]. The participation of the kth state in the ith eigenmode may be given by

$$p_{ki} = \phi_{ki}\psi_{ik} \tag{4}$$

where

ϕ_{ki} kth entry of right eigenvector ϕ_i;

ψ_{ik} kth entry of left eigenvector ψ_i.

Participation factors are usually normalized to study the relative influence of different state variables on a particular mode

TABLE III
DOMINANT GENERATORS AND STATES FOR DIFFERENT MODES

Mode	Type	Dominant Generator	Dominant states (PF%)
1,2	Electromechanical	SG1	Rotor angle (28%)
			Speed Deviation (12%)
		SG2	Rotor angle (12%)
			Speed Deviation (28%)
3,4	Electromechanical	SG1	Rotor angle (11%)
			Speed Deviation (27%)
		SG2	Rotor angle (27%)
			Speed Deviation (11%)
5,6	Electromechanical	IG	Rotor speed (40%)
			q-axis rotor flux (42%)
7,8	Control	SG1	Rotor angle (21%)
			d-axis rotor flux (22%)
			Speed deviation (21%)
			Exciter (22%)

[19]. The normalized form of participation factor can be written as

$$\|p_{ki}\| = \frac{|\phi_{ki}|\,|\psi_{ik}|}{\sum_{1}^{n}|\phi_{ki}\psi_{ik}|} \tag{5}$$

where n is the number of state variables.

The dominant states and corresponding generators for different oscillatory modes were identified using participation factor. The results are shown in Table III.

It can be observed that the low frequency mode is coming from excitation and rotor inertia of SG1. It is not purely electromechanical mode, but a control mode. It has a unique frequency of 3.8 Hz, which is different from frequencies of purely electromechanical modes. Similar cases are expected in future distribution systems, which will have high penetration of DG units and controllers installed in a closer proximity.

Also, induction generators participate in system oscillatory modes along with synchronous generators. Two synchronous generators participate equally to Modes 1,2 and 3,4. Participation factors are indicative of the location of stabilizers to add damping on the weakest mode. Hence, it appears that a power system stabilizer (PSS) can be installed at SG1 to improve damping. However, installing a PSS at a generator depends on the nature of performance standard that the generator is committed to the distribution network. As of now, DG units of smaller capacity are usually not scheduled for supporting the small signal stability [9], [10]. Moreover, for a PSS to be effective, a faster exciter is needed at the synchronous machines. In such a case, a decentralized controller may be installed at a point in network (such as SVC or STATCOM) to support damping of low frequency oscillation [20]. In this paper, a shunt capacitor bank existing in the distribution network is selected

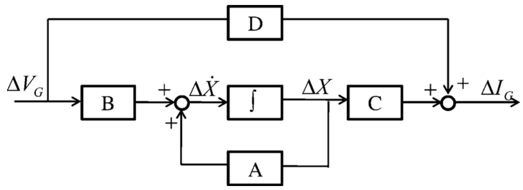

Fig. 4. State space representation of distribution system with DG units.

for installing such a controller. The controller can be designed in such a way to ensure that the critical mode has sufficient damping ratio by moving it to a safe location in a complex plane. In the following sections, the location and design of such a controller is discussed.

IV. Identification of Controller Location

A. State Space Representation of Distribution System

A distribution system with distributed generators may be represented by state space form as (6), where ΔV_G represent the voltages at generator terminals and ΔI_G represent the currents outputs of distributed generators

$$\begin{cases} \Delta \dot{X} = A\Delta X + B\Delta V_G \\ \Delta I_G = C\Delta X + D\Delta V_G. \end{cases} \tag{6}$$

The state space form of distributed generators may be in a form of block diagram as shown in Fig. 4.

The output currents of generators are related to network terminal voltages by

$$\Delta I_G = Y_{GG}\Delta V_G \tag{7}$$

where Y_{GG} is the generator admittance matrix. Now, using (6) and (7), the state space representation of a distribution network can be written as

$$\begin{bmatrix} \Delta \dot{X} \\ 0 \end{bmatrix} = \begin{bmatrix} A & B \\ C & Y_{GG} - D \end{bmatrix} \begin{bmatrix} \Delta X \\ \Delta V_G \end{bmatrix} \tag{8}$$

where V_G is the vector of real and imaginary components of generator terminal voltages. Using (8), relationships among terminal voltages and system oscillatory modes can be established.

The injection currents to the network are related to bus voltages by

$$\begin{bmatrix} \Delta I_G \\ \Delta I_R \end{bmatrix} = \begin{bmatrix} Y_{GG} & Y_{GR} \\ Y_{RG} & Y_{RR} \end{bmatrix} \begin{bmatrix} \Delta V_G \\ \Delta V_R \end{bmatrix} \tag{9}$$

where Y_{GG}, Y_{RR}, Y_{GR}, and Y_{RG} are the components of system admittance matrix. ΔV_R and ΔI_R are the voltages and current injections at network buses except generator buses. Now, if a controller is connected at a remote bus of the distribution system, state space representation of the distribution system with the control input Δu can be written as

$$\begin{cases} \begin{bmatrix} \Delta \dot{X} \\ 0 \\ 0 \end{bmatrix} = \begin{bmatrix} A & B & 0 \\ C & Y_{GG} - D & Y_{GR} \\ 0 & Y_{RG} & Y_{RR} \end{bmatrix} \begin{bmatrix} \Delta X \\ \Delta V_G \\ \Delta V_R \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ b \end{bmatrix} \Delta u \\ y = [0 \quad 0 \quad c] \begin{bmatrix} \Delta X \\ \Delta V_G \\ \Delta V_R \end{bmatrix} + d\Delta u. \end{cases} \tag{10}$$

Vectors b and c represent the controllability and observability vectors for inputs u and output y, respectively. The state-space formulation of (10) can be equivalently represented by transfer function as

$$G(s) = \frac{Y(s)}{U(s)}. \tag{11}$$

B. Selecting a Capacitor Bank for Controller

Using (10), the state space model of a distribution system with a shunt capacitor controller connected at a remote bus can be written as

$$\begin{bmatrix} \Delta \dot{X} \\ 0 \\ 0 \end{bmatrix} = \begin{bmatrix} A & B & 0 \\ -C & D - Y_{GG} & Y_{GR} \\ 0 & Y_{RG} & Y_{RR} \end{bmatrix} \begin{bmatrix} \Delta X \\ \Delta V_G \\ \Delta V_R \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ 1 \end{bmatrix} \Delta I_R \tag{12}$$

where ΔI_R is the vector of currents absorbed by a damping controller at the remote bus. Now, if β_R is shunt susceptance of a capacitor bank at bus r with voltage V_R, current injected to the bus by shunt capacitor can be written as

$$I_R = \beta_R V_R. \tag{13}$$

Linearizing (13) at an operating point of interest gives

$$\Delta I_R = \beta_{R0}\Delta V_R + V_{R0}\Delta\beta_R \tag{14}$$

where β_{R0} and V_{R0} are steady-state capacitive susceptance and bus voltage respectively. Now, (14) can be rewritten as

$$\Delta I_R = B_C \Delta V_R + b_{\Delta\beta,R}\Delta\beta_R \tag{15}$$

where B_C represents the steady-state susceptance of the controllable shunt capacitor and $b_{\Delta\beta,R}$ represents the steady-state voltage of shunt capacitor bus. Substituting (15) into (12)

$$\begin{bmatrix} \Delta \dot{X} \\ 0 \\ 0 \end{bmatrix} = \begin{bmatrix} A & B & 0 \\ -C & D - Y_{GG} & Y_{GR} \\ 0 & Y_{RG} & Y_{RR} + B_C \end{bmatrix} \times \begin{bmatrix} \Delta X \\ \Delta V_g \\ \Delta V_R \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ b_{\Delta\beta,R} \end{bmatrix} \Delta\beta_R. \tag{16}$$

Hence, $b_{\Delta\beta,R}$ represents the controllability vector of shunt capacitor control. Now, the controllability factor of mode i for

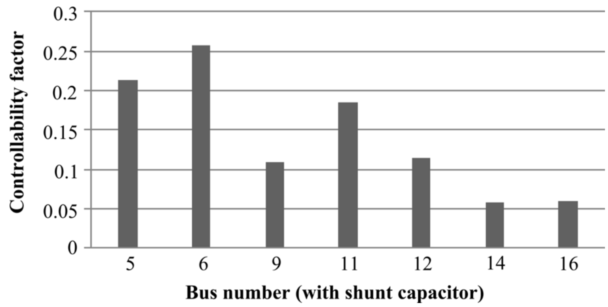

Fig. 5. Controllability factors of susceptance modulation of shunt capacitors of the test distribution system for the critical mode.

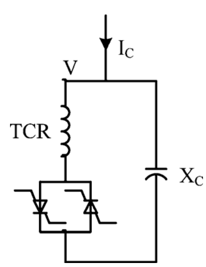

Fig. 6. Schematic diagram of thyristor controlled reactor for controlling the susceptance of a capacitor bank.

the shunt capacitor control at any arbitrary bus j can be written as

$$w_{ij} = b_{\Delta\beta,j}\psi_i \tag{17}$$

where ψ_i is the ith left eigenvector.

The controllability factors of critical modes for shunt susceptance modulations were evaluated for all the shunt capacitors of the test distribution network. The result is shown in Fig. 5.

It can be observed that the shunt capacitor at Bus 6 has the highest controllability factor for shunt susceptance modulation. Hence, controlling the susceptance of this capacitor is the most effective for damping control of the critical mode.

C. Application of Control

A power electronic reactance controller has a thyristor in series with an inductor, whose value can be adjusted by controlling the thyristor firing angle. Such a scheme is known as thyristor controlled reactor (TCR). The controller when connected in parallel with a capacitor bank is able to exchange capacitive or inductive current so as to maintain the bus voltage. In this paper, a scheme of controlling an appropriate shunt capacitor using a TCR is presented. A block diagram of such a scheme is shown in Fig. 6.

The transfer function of such a controller is given as

$$\Phi(s) = \frac{1}{1 + T_r s} \tag{18}$$

where T_r is the thyristor time constant. Usually, T_r is selected in the range of 0.02–0.05 s [2]. In this work, T_r is selected to be 0.02 s.

The system with a controller can be represented as Fig. 7.

Depending on the location of the controller, the influence may be either beneficial or detrimental to system modes [23]. In this case, the impact of the controller location on damping ratio of the critical mode was observed. The result is in Fig. 8.

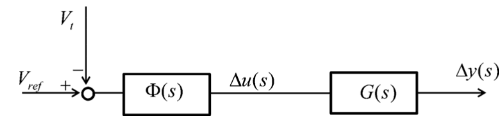

Fig. 7. Block diagram of the distribution system with converter control.

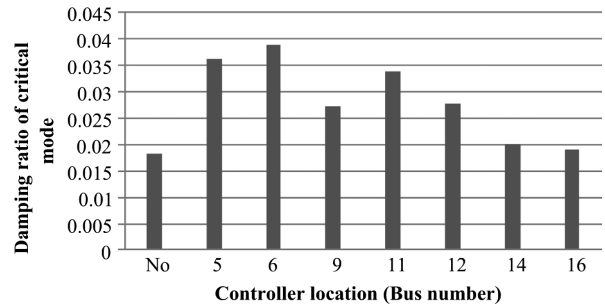

Fig. 8. Impact of controller location on damping ratio of the critical modes.

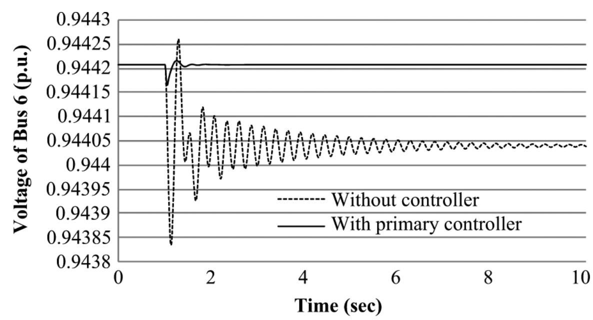

Fig. 9. Impact of controller on time domain response of the system.

It can be observed that the damping ratios of the critical modes with a controller installed at a bus are larger than the damping ratios with "no" controller. This shows that the controller has a positive impact on the damping of the critical mode. Also, the damping ratio is the highest for the controller installed at Bus 6. This confirms the ranking of the capacitors based on controllability factor, as shown in Fig. 5. However, the damping ratio after installation of a controller is still very low, i.e., less than 4%. This is regarded as a low damped case in a power system. Hence an additional controller should be designed to make the damping ratio at the desired value, i.e., 5% in this case. This will be discussed in Section V.

The effectiveness of the controller was also observed by time-domain simulation. A controller was installed at Bus 6. A step change in mechanical torque of wind generator by 10% was applied as a disturbance to the system. The response of voltage magnitude at Bus 6 was observed. The result is shown in Fig. 9. It can be observed that the controller effectively improves the transient and steady-state voltage profile of the system.

It should be noted that capacitor switching transient has been neglected in the simulation. The inclusion of switching transient shows an additional oscillatory mode $(-20.2 \pm j315.3)$, whose frequency of oscillation is close to power frequency, i.e., 50 Hz. In general, this frequency is out of frequency range of interest and not considered in instability study of low frequency oscillations.

V. Design of an Additional Controller

A. Selection of Feedback Signal

A suitable feedback signal should be selected as an input to an additional damping controller. The signal which is highly observable from the output of the system is selected as an appropriate signal to maximize the effect of the controller. In this paper, a comparison of two signals from the shunt capacitor, i.e., current and reactive power is done to select the best feedback signal.

1) *Current*: Comparison of (10) and (15) gives an observability vector of current through shunt capacitor as

$$c_{\Delta I_R} = \beta_{R0}. \tag{19}$$

2) *Reactive Power*: Expression for shunt capacitor reactive power is given by

$$Q_R = \beta_R V_R^2. \tag{20}$$

Linearization of (20) gives

$$\Delta Q_R = \Delta\beta_R V_{R0}^2 + 2V_{R0}\Delta V_R \beta_R. \tag{21}$$

Comparing (10) and (21), observability vector for shunt capacitor reactive power can be given as

$$c_{\Delta Q_R} = 2V_{R0}\beta_R. \tag{22}$$

Once, the observability vectors of the signals are determined, observability factor of mode i for the output k can be written as

$$v_{ik} = c_k \phi_i \tag{23}$$

where ϕ_i is the ith right eigenvector and c_k is observability vector for the kth output signal.

The product of modal controllability factor (w_{ij}) from (17) and observability factor (v_{ik}) gives residue associated with the mode. So, the residue R_{ijk} of mode i for input k and output j can be given as

$$R_{ijk} = w_{ij} v_{ik}. \tag{24}$$

Calculation of residue gives the valuable information on application of a controller to a system. The magnitude of residue gives the information on the best feedback signal for the controller [23]. The angle of residue gives the magnitude of phase compensation required at eigenvalue frequency to maximize the effect of the controller [2].

In this case, residues associated with critical modes for two different feedback signals, i.e., current and reactive power, were calculated. The results are given in Table IV. It can be observed that the residue is significantly higher for the reactive power signal as compared to the current signal. Hence, reactive power output of the shunt capacitor has been chosen as the feedback signal to the additional controller.

TABLE IV
Residues Associated With Different buses for Shunt Capacitance Modulation as Input and Current and Reactive Power as Output

Signal	Reactive power (ΔQ)	Current (ΔI)
Residue	1.55	0.82

B. Controller Gain

The residue associated to a mode λ_i of a system with a controller with feedback transfer function $\Psi(s,K)$ can be given as

$$\frac{\partial\lambda_i}{\partial K} = R_{ijk}\frac{\partial\Psi(s,K)}{\partial K} \tag{25}$$

where K is the constant gain of the controller.

Equation (25) gives the sensitivity of the mode with gain of the controller [23]. If K and $H(s)$ represent the gain and feedback transfer function part of $\Psi(s,K)$, then

$$\Psi(s,K) = K.H(s). \tag{26}$$

Assuming that gain K is small and substituting (26) into (25) gives

$$\frac{\Delta\lambda_i}{\Delta K} = R_{ijk}.H(s). \tag{27}$$

If $K = 0$ at initial operating point, ΔK equals K. Therefore, adding a feedback controller to the system changes mode λ_i as

$$\Delta\lambda_i = R_{ijk}KH(\lambda_i). \tag{28}$$

C. Phase Compensation

We can design a lead lag compensator to place a mode at a desired location at the negative half of the s-plane. The standard form of compensator design is given as [2]

$$KH(s) = K\frac{sT}{1+sT}\left[\frac{1+sT_1}{1+sT_2}\right]^m \tag{29}$$

where

$$\phi = 180^o - \arg(R_{ijk}) \tag{30}$$

$$\alpha = \frac{T_2}{T_1} = \frac{1-\sin\left(\frac{\phi}{m}\right)}{1-\sin\left(\frac{\phi}{m}\right)} \tag{31}$$

$$T_1 = \frac{1}{\omega_i\sqrt{\alpha}} \tag{32}$$

$$T_2 = \alpha T_1. \tag{33}$$

Here, T is the washout time constant, which is usually taken as 5–10 s, ω_i is the frequency of the mode in rad/s, K is the positive constant gain, and m is the number of compensation stages. The angle compensated by each block should not exceed 60°.

D. Performance of Controller

An additional controller was designed to enhance the damping of critical mode to a desired value. The block diagram

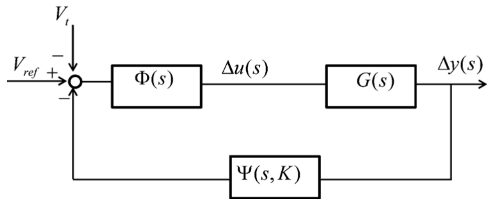

Fig. 10. Block diagram of the distribution system with converter control and additional controller.

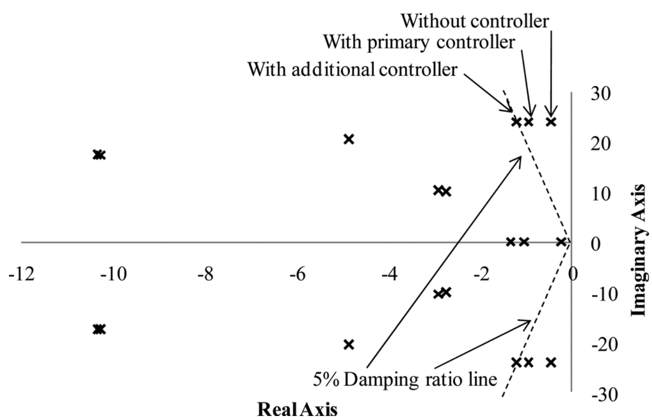

Fig. 11. Traces of system oscillatory modes with and without controller.

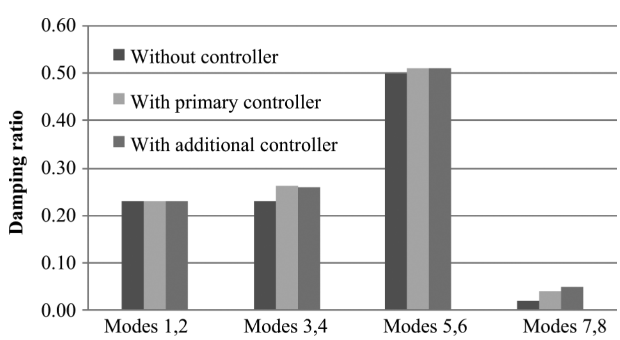

Fig. 12. Comparison of damping ratios of different modes with and without controllers.

representation of the additional controller in association with the primary controller of the system is shown in Fig. 10.

Using the procedure explained in Sections V-B and V-C, an additional controller was designed to achieve a desired damping ratio of the critical mode, i.e., 5%. The washout time constant was taken as 5 s.

The performance of the controller was observed by tracing the eigenvalues with and without controller. The result is shown in Fig. 11. The scales have been adjusted to observe only the complex eigenmodes. It can be observed that the controller effectively pushes the low frequency mode towards the desired damping ratio. There is no detrimental impact on damping of other modes.

The damping ratios of oscillatory modes with and without the controllers were also observed. The results are shown in Fig. 12.

It can be observed that an additional controller can effectively improve the damping of the critical mode to 5%. It is also observed that the primary controller has an impact on all the modes of the system, while the additional controller does not affect the damping of system modes, except the critical mode. Hence, additional damping controller design is useful for targeting the damping of a particular mode of interest without hampering the damping of other modes.

VI. Conclusions

This paper has presented a systematic approach for assessment and enhancement of small signal stability of a renewable-energy-based electricity distribution system. The modeling approaches of different types of distributed generators have been discussed. For a distribution network with distributed generators, different oscillatory modes and their dominant generators have been identified. A methodology for selecting an appropriate capacitor bank to provide dynamic control to enhance system small signal stability has been proposed.

Oscillatory modes with frequencies 1.5–4 Hz were observed for the distribution system with DG units. Some of them are low damped mode, which may be harmful to the stability of a system. The paper also demonstrates that the induction generator along with synchronous generators participates significantly on oscillatory modes.

It was shown that small signal stability of the distribution network can be ensured by installing a damping controller at a capacitor bank. The paper presented expressions of controllability and observability indices for designing a damping controller. Controllability index identified the best capacitor bank for installing such a controller. Observability index identified the best control signal for the controller. The steady-state deviation on bus voltage was eliminated by using the proposed controller. Next, the paper demonstrates that the proposed controller can improve the damping ratio of a low damped mode. The desired damping ratio can be achieved by selecting appropriate values of time constants and gain of the controller. In this case, the controller improved the damping ratio from 2% to the desired value, i.e., 5%. Hence, it can be concluded that regulating susceptance of a capacitor bank is an effective means of small signal stability enhancement of a renewable-energy-based distribution system.

References

[1] N. Jenkins, R. Allan, P. Crossley, D. S. Kirschen, and G. Strbac, *Embedded Generations*, 1st ed. London, U.K.: Inst. Elect. Eng., 2000.

[2] P. Kundur, Power System Stability and Control, Electric Power Research Institute.

[3] N. Mithulananthan, C. A. Canizares, and J. Reeve, "Tuning, performance and interactions of PSS and FACTS controllers," in *Proc. IEEE Power Engineering Society Summer Meeting*, 2002, vol. 2, pp. 981–987.

[4] L. Dong-Jing and W. Li, "Small-signal stability analysis of an autonomous hybrid renewable energy power generation/energy storage system Part I: Time-domain simulations," *IEEE Trans. Energy Convers.*, vol. 23, no. 1, pp. 311–320, Mar. 2008.

[5] E. Haesen, C. Bastiaensen, J. Driesen, and R. Belmans, "A probabilistic formulation of load margins in power systems with stochastic generation," *IEEE Trans. Power Syst.*, vol. 24, no. 2, pp. 951–958, May 2009.

[6] *National Electricity Amendment (Technical Standards for Wind Generation and other Generator Connections)*, Rule 2007, Australian Energy Market Operator (AEMO), 2007.

[7] G. Tsourakis, B. M. Nomikos, and C. D. Vournas, "Contribution of doubly fed wind generators to oscillation damping," *IEEE Trans. Energy Convers.*, vol. 24, no. 3, pp. 783–791, Sep. 2009.

[8] A. Yazdani and P. P. Dash, "A control methodology and characterization of dynamics for a photovoltaic (PV) system interfaced with a distribution network," *IEEE Trans. Power Del.*, vol. 24, no. 3, pp. 1538–1551, Jul. 2009.

[9] NEMMCO, An Introduction to Australia's National Electricity Market, National Electricity Market Management Company Limited, Australia, 2008.

[10] *Standards Coordinating Committee 21, IEEE Standard for Interconnecting Distributed Resources With Electric Power Systems*, IEEE Std 1547-2003, 2003.

[11] J. Hongjie, Y. Xiaodan, S. Xiaoyan, C. Jianhua, W. Wei, and Y. Yixin, "Relationship between shunt capacitor and small signal stability of power systems," in *Proc. Canadian Conf. Electrical and Computer Engineering*, 2005, pp. 1708–1713.

[12] A. Prasai, J. Sastry, and D. M. Divan, "Dynamic capacitor (D-CAP): An integrated approach to reactive and harmonic compensation," *IEEE Trans. Ind. Applicat.*, vol. 46, no. 6, pp. 2518–2525, Nov./Dec. 2010.

[13] B. M. Nomikos and C. D. Vournas, "Investigation of induction machine contribution to power system oscillations," *IEEE Trans. Power Syst.*, vol. 20, no. 2, pp. 916–925, May 2005.

[14] L. Holdsworth, X. G. Wu, J. B. Ekanayake, and N. Jenkins, "Comparison of fixed speed and doubly-fed induction wind turbines during power system disturbances," *Proc. Inst. Elect. Eng., Generation, Transmission and Distribution*, vol. 150, pp. 343–352, 2003.

[15] V. Akhmatov, *Induction Generators for Wind Power*. Brentwood, U.K.: Multi-Science Publishing Company Ltd., 2005.

[16] T. Y. Tiam, D. S. Kirschen, and N. Jenkins, "A model of PV generation suitable for stability analysis," *IEEE Trans. Energy Convers.*, vol. 19, no. 4, pp. 748–755, Dec. 2004.

[17] R. Shah, N. Mithulananthan, A. Sode-Yome, and K. Y. Lee, "Impact of large-scale PV penetration on power system oscillatory stability," in *Proc. IEEE Power and Energy Society General Meeting*, 2010, pp. 1–7.

[18] "IEEE task force on load representation for dynamic performance, load representation for dynamic performance analysis (of power systems)," *IEEE Trans. Power Syst.*, vol. 8, no. 2, pp. 472–482, May 1993.

[19] M. A. Pai and P. Sauer, *Power System Dynamics and Stability*. Champaign: Stipes Publishing L.L.C., 2006.

[20] N. Mithulananthan, C. A. Canizares, J. Reeve, and G. J. Rogers, "Comparison of PSS, SVC, and STATCOM controllers for damping power system oscillations," *IEEE Trans. Power Syst.*, vol. 18, no. 2, pp. 786–792, May 2003.

[21] S. Dahal, N. Mithulananthan, and T. Saha, "Investigation of small signal stability of a renewable energy based electricity distribution system," in *Proc. IEEE Power and Energy Society General Meeting*, 2010, pp. 1–8.

[22] F. Mei and B. Pal, "Modal analysis of grid-connected doubly fed induction generators," *IEEE Trans. Energy Convers.*, vol. 22, no. 3, pp. 728–736, Sep. 2007.

[23] G. J. Rogers, *Power System Oscillations*. Boston/London/Dordrecht: Kluwer, 2000.

Sudarshan Dahal (S'09) was born in Nepal. He received the Bachelor's degree in electrical engineering in 2003 from Tribhuvan University, Nepal, and the Masters degree in engineering in 2008 from Tokyo Institute of Technology, Japan. Currently, he is working toward the Ph.D. degree in the School of Information Technology and Electrical Engineering, The University of Queensland, Brisbane, Australia.

He has worked as an electrical engineer at Nepal Electricity Authority from 2004 to 2006. His research interests include dynamic stability and control, distributed generations, and load modeling.

Nadarajah Mithulananthan (M'02–SM'10) received the B.Sc. (Eng.) degree from the University of Peradeniya, Sri Lanka, in May 1993, the M.Eng. degree from the Asian Institute of Technology, Bangkok, Thailand, in August 1997, and the Ph.D. degree in electrical and computer engineering from the University of Waterloo, Canada, in 2002.

He has worked as an electrical engineer at the Generation Planning Branch of the Ceylon Electricity Board, and as a researcher at Chulalongkorn University, Bangkok, Thailand. He is currently a senior lecture at the University of Queensland (UQ), Brisbane, Australia. Prior to joining UQ, he was Associate Professor at the Asian Institute of Technology, Bangkok, Thailand. His research interests are integration of renewable energy in power systems and power system stability and dynamics.

Tapan Kumar Saha (M'93–SM'97) was born in Bangladesh in 1959 and immigrated to Australia in 1989. He received the B.Sc.Eng. degree in 1982 from Bangladesh University of Engineering and Technology, Dhaka, Bangladesh, the M.Tech. degree in 1985 from the Indian Institute of Technology, New Delhi, India, and the Ph.D. degree in 1994 from the University of Queensland, Brisbane, Australia.

He is currently a Professor in Electrical Engineering in the School of Information Technology and Electrical Engineering, University of Queensland. Previously he has had visiting appointments for a semester at both the Royal Institute of Technology (KTH), Stockholm, Sweden, and at the University of Newcastle, Australia. His research interests include condition monitoring of electrical plants, power systems, and power quality.

Dr. Saha is a Fellow of the Institution of Engineers, Australia.