UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER10-1706-000

REQUEST FOR REHEARING OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

The California Independent System Operator Corporation (the ISO) requests rehearing of the Federal Energy Regulatory Commission's August 31, 2010 order on tariff revisions rejecting certain interconnection requirements for asynchronous generating facilities proposed by the ISO in its tariff amendment filed in this docket on July 2, 2010.[1] The Commission's order arbitrarily discriminates against synchronous generating facilities and exposes the grid to negative consequences. The order also ignores record evidence and does not articulate a sufficient rationale for rejecting the ISO's proposed tariff revisions. Finally, the order is inconsistent with another Commission order approving the North American Electric Reliability Corporation's interpretation of a reliability standard that applies voltage control requirements to all generating facilities.

The ISO will face increasing operational and reliability challenges resulting from thousands of megawatts of wind and solar photovoltaic facilities seeking to interconnect to the ISO's transmission system over the next several years in

[1] *Cal. Indep. Sys. Operator Corp*., 132 FERC ¶ 61,196 (2010). The ISO files this request for rehearing pursuant to Section 313 of the Federal Power Act, 16 U.S.C. § 825l, and Rule 713 of the rules and regulations of the Commission, 18 C.F.R. § 385.713 (2010).

response to California's ambitious renewable portfolio requirements. The technical criteria that the ISO proposed in its tariff amendment will significantly enhance the ISO's ability to meet these challenges with success and, as the ISO explained at length in its filing, are reasonably applied to asynchronous generating facilities. The Commission's order, however, rejects the ISO's proposal with little to no explanation as to why the ISO's proposal fails to meet the "just and reasonable" standard and, in doing so, undermines the ISO's efforts to continue to ensure that it has the best tools to operate the electrical grid in a reliable manner. This decision is particularly troubling given the Commission's increased focus on system reliability in light of the Energy Policy Act of 2005. The Commission should reverse its decision to reject the ISO's proposed interconnection requirements for asynchronous generating facilities and make them effective as of July 3, 2010.

II. Background

A. Increased penetration of wind and solar photovoltaic resources underscores the importance of voltage control for power systems

As the ISO explained in its July 2, 2010 filing, the expectation that all generators connected to the transmission grid will provide reactive power and voltage control is fundamental to maintaining reliable electric service. The absence of this capability subjects the operation of the power system to significant difficulties and reliability concerns. The ability to control voltage across the large footprint of a power network is one of the most important and complex functions performed by system operators. Voltage problems that impact the reliability and the quality of supply arise from a number of reasons, including transmission line loading/charging; reactive power losses produced to serve the load; electric proximity of the voltage sources to load centers; coordination of voltage control and reactive power sources on various levels, i.e. the generator unit, plant, system levels; the robustness of voltage sources; the level of reactive load compensation; and the frequency of changes in power output from internal generation.

Grid operators maintain voltage control of large power systems through a combination of mechanisms, including Automatic Voltage Regulation (AVR) at generator locations, regulated shunt compensation or Static VAR Compensation devices, shunt static compensation, under-load tap changing transformers as well as the voltage characteristics of load. Among these, AVR is the most critical source of voltage control because it is an active mechanism for voltage control. Other mechanisms, while also necessary, are passive and are limited by their ratings. As a result, grid operators cannot operate power systems by relying only on the passive elements of the network. Indeed, voltage collapse cases documented in the electric industry have occurred in part because of the limitation of such controls.

Reactive power problems are mostly local in nature and it is therefore crucial to provide a necessary level of reactive power support and voltage control in a distributed manner on all network levels and especially at the sending and receiving ends of transmission lines. Voltage and reactive power problems cannot be resolved centrally. For these reasons, it has become standard industry practice for transmission operators to require generating facilities to provide a level of reactive power support and to maintain voltage schedules. This is especially important for large generating facilities (20 megawatts and above) that generally supply power at a significant distance from load centers. NERC has established a requirement for generators to operate in automatic voltage control mode and to maintain generator voltage or provide reactive output as directed by the transmission operator.[2] The Commission approved this reliability standard under the Energy Policy Act of 2005.[3]

The need for active voltage control should not depend on the results of interconnection system impact studies for individual generating facilities, but rather derives from engineering fundamentals of power systems to ensure the reliable operation of the grid, both now and in the future. As the Commission is aware, there are literally thousands of text books, technical papers, and journal article available that discuss this concept. For convenience, the ISO is attaching sample references to such materials, including portions of the Electric Power Research Institute's textbook on *Power System Stability and Control* and *The Electric Power Engineering Handbook*. These materials are attached hereto as Exhibit A.[4]

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[2] VAR-002-1.b Generator Operation for Maintaining Network Voltage Schedules at http://www.nerc.com/files/VAR-002-1_1b.pdf

See also, VAR-001-2 Voltage and Reactive Control at http://www.nerc.com/files/VAR-001-2.pdf

[3] *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1881-1885.

[4] *Power System Stability and Control*, Prabha Kundur, EPRI Engineering Series, Chapter 14.1 1994. *See also, the Electric Power Engineering Handbook*, L.L Grisby, CRC Press, IEEE

It is not surprising that renewable resources, particularly wind and solar photovoltaic facilities, have not matured to provide this capability until the last few years. Early installation of wind generation technologies lacked the capability to produce reactive power at the generator. To remedy this issue, these facilities depended on capacitor banks to offset the reactive load placed on the network by the induction machine employed by wind generators. As a result, wind generation would generally provide excessive reactive power at low production levels and consume substantial quantities of reactive power at high production levels. This characteristic created high voltages during periods of low wind production and high conventional production and low voltages during periods of high wind production and low conventional generation, thereby aggravating the transmission system voltage profile.

Grid operators could tolerate this situation when wind and solar photovoltaic capacity did not reflect a significant percentage of nameplate capacity when compared to total system capacity, and most of these facilities were connected at the distribution rather than transmission level. This situation is rapidly changing, particularly in California, which is facing a significant penetration of wind and solar photovoltaic capacity (up to 30 percent in the near term and over 50 percent in the midterm) to meet the state's renewables portfolio standard targets of 20 percent and 33 percent, respectively. This penetration reflects a nameplate capacity over 25,000 megawatts in the ISO system. Under low load conditions, this capacity could represent the vast majority of operating

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Press, Chapter 11.4, 2001. The ISO provides these sources as supplemental material to its July 2, 2010 transmittal letter and supporting documents. 18 C.F.R. § 385.713 (c)(3).

resources in the ISO, together with must run facilities like nuclear and hydro-electric. Fortunately, as documented by the ISO in its July 2, 2010 filing, the capability of wind and solar photovoltaic resources to provide reactive power and voltage control is now available.[5] A decision that fails to equip this massive level of capacity with the modest level of controls proposed by the ISO defies sound engineering. The alternative of operating the remainder of the thermal generation fleet at no load or low load just for voltage stability is technically problematic and would create serious negative environmental and economic impacts.

Another consideration with regard to voltage control when dealing with high penetration of wind and solar photovoltaic resources, is the change in reactive losses on the transmission network during swings between imports and exports of power. Typically, when the generation fleet is operating at minimum levels, the transmission system must import power to support internal load. These imports cause reactive losses on the network that will offset the charging of transmission lines. Typically, the transmission system is designed to maintain voltage stability when such a condition occurs. As wind and solar photovoltaic production increases to a level that offsets real power imports, transmission lines become unloaded and voltages on the network can become excessive. During high levels of internal wind and solar photovoltaic production, the transmission system may need to export real power resulting in excessive reactive power

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[5] Prepared testimony of Reigh Walling, Attachment D to ISO July 2, 2010 transmittal letter, at 20-34 and Appendix C thereto. *See also*, Sections 1 and 2 of GE Energy paper regarding Interconnection Standards Review Initiative dated April 28, 2010, submitted as part of Attachment F to the ISO's July 2, 2010 transmittal letter.

losses on the network and low voltages. While there are techniques and reactive power control tools to manage this situation, the challenge arises from the frequency at which the power output from these resources changes. Large and frequent changes can result in severe voltage fluctuations that may lead to voltage instability.

Optimizing the voltage profile of a power grid also minimizes system power losses. An optimal voltage profile will decrease voltage stability risks and increase the capacity of transmission lines by eliminating excessive reactive power flows. Grid operators achieve this optimization through the coordinated control of generator AVR, other voltage control mechanisms, power dispatch, and load characteristics.[6] Exempting a significant portion of the generation fleet from voltage control requirements eliminates a critical tool to achieve the optimization.

Finally, grid operators also benefit from the experience of other power system operators. The ISO has given significant attention to the experience of the Spanish power system operator, which already operates a large system with a significant presence of wind generation. Spain has recently implemented similar requirements to those proposed by the ISO for reactive support and voltage control, and applied these requirements to all facilities existing and new

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[6] The ISO provides an excerpt from *the Electric Power Engineering Handbook* as well as a portion of an IEEE tutorial course on application of optimization methods for economy/security functions in power system operations as Exhibit B hereto to describe the reduction of losses in a power system through optimizing voltage controls. *See*, t*he Electric Power Engineering Handbook*, L.L Grisby, CRC Press, IEEE Press, Chapter 4:11 at 4:169-170, 2001; Walter L. Snyder, Jr. Linear Programming Adapted for Optimal Power Flow," IEEE Tutorial # 90EH0328-5-PWR, at 32-35, 1990. The ISO provides these sources as supplemental material to its July 2, 2010 transmittal letter and supporting documents. 18 C.F.R. § 385.713 (c)(3).

after recognizing that the historical approach of exempting wind and solar photovoltaic is not workable. Attached hereto as Exhibit C is a white paper prepared by EPRI summarizing the lessons learned in the Spanish system from a recent fact finding visit that included the ISO and senior members of the Commission staff.[7] The white paper identifies that wind and solar photovoltaic resources should provide voltage control when large volumes of those facilities seek to interconnect to a power system.[8]

Continuing to require conventional synchronous generating facilities to carry the burden of supporting the transmission system is neither practical nor just given the certainty of having less synchronous generation available as a result of the high penetration of renewable resources. It is also not appropriate to defer this burden to future generating facilities seeking to interconnect to the ISO. Asynchronous generating facilities currently have access to cost-effective technology and face no competitive disadvantage in providing a fair share of their reactive support to the electricity grid. The ISO believes that increasing the number of market participants that have the capability to supply and consume reactive power will expand the topology of resources supporting the grid.

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7 The Interconnection of Large-Scale Renewable Resources into the Spanish Power System, EPRI, July 2010. http://my.epri.com/portal/server.pt?Abstract_id=000000000001021538 The ISO provides this white paper as supplemental material to its July 2, 2010 transmittal letter and supporting documents. 18 C.F.R. § 385.713 (c)(3).

8 *Id.* at 7-8 and 10.

B. Procedural History

On July 2, 2010, the ISO submitted proposed tariff revisions to the Commission to apply certain requirements to asynchronous generating facilities seeking to interconnection to the ISO grid. These requirements included, among others, power factor design and reactive power capability, voltage regulation and generator power management requirements. The ISO developed these requirements largely to ensure the continued reliability and security of the transmission system in light of the significant increase in wind and solar photovoltaic generating facilities seeking to interconnect to the ISO's grid. As the ISO explained, the first group of projects under consideration in the ISO's new interconnection procedures contains over 8,200 megawatts of capacity from renewable resources.[9] The amount of energy provided by asynchronous generating facilities will continue to increase under the California's renewables portfolio standard and other environmental policies and will displace a large amount of conventional generation.[10]

The ISO's proposed tariff revisions establish an equitable set of interconnection requirements for asynchronous generating facilities. Among others, these requirements seek to ensure that asynchronous generating facilities contribute reactive power to the electricity grid, maintain voltage schedules and have the capability to manage active power. These requirements are critically important to maintain voltage levels across the transmission system

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9 ISO July 2, 2010 transmittal letter at 2.

10 *Id*. at 2-3.

as well as maintain the reliable operation of generating units following a disturbance.[11]

Of particular importance, these requirements will support the voltage control of its power system. The ISO presented significant record evidence and a detailed justification for establishing these requirements, including expert prepared testimony and an analytical study addressing integration of wind projects in the Tehachapi area of California.[12] The ISO's proposed requirements will ensure that new asynchronous generating facilities that replace conventional generation provide a minimum level of support to the reliable operation of the grid.[13] The ISO described how these requirements are technically feasible and commercially reasonable.[14]

In its August 31, 2010 order, the Commission rejected without prejudice these proposed requirements. With respect to reactive power, the Commission determined that the ISO did not explain adequately why system impact studies are not the proper venue for identifying power actor requirements for asynchronous generating facilities.[15] The Commission also asserted that an ISO study reflects that the ISO can preserve system performance if new wind

[11] ISO July 2, 2010 transmittal letter at 8, 15-16 and 23-25. *See also*, prepared testimony of Nisar Shah Attachment E to ISO July 2, 2010 transmittal letter at 2-6.

[12] ISO July 2, 2010 transmittal letter at 6-29 and Attachments D and E thereto.

[13] ISO July 2, 2010 transmittal letter at 4-6.

[14] Prepared testimony of Reigh Walling, Attachment D to ISO July 2, 2010 transmittal letter.

[15] August 31, 2010 order at P 46.

generation includes turbines that cannot provide reactive power.[16] Without any discussion of the ISO's showing, the Commission also determined that the ISO did not support its voltage regulation requirements and that requirements for generator power management are premature absent rules for operational and market protocols governing the circumstances in which the ISO will utilize these capabilities.[17]

Separately, the Commission issued an order on September 16, 2010 approving a NERC interpretation of reliability standard VAR-002-1.1b.[18] This standard requires among other things that "[u]nless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power (within applicable Facility Ratings) as directed by the Transmission Operator."[19] NERC interpreted the requirements of this standard to apply to *all* generating operators whether equipped with an automatic voltage regulator or not. And NERC did not exempt asynchronous generating facilities from these requirements. The ISO's proposed tariff requirements would facilitate the ability of asynchronous generating facilities to comply with NERC's interpretation of reliability standard VAR-002-1.1b as approved by the Commission.

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16 *Id.* at n. 45.

17 *Id.* at PP 54-55 and 87-89.

18 *North American Electric Reliability Corp.* 132 FERC ¶ 61,220 at PP 2 (2010).

19 See, R2 of VAR-002-1.b Generator Operation for Maintaining Network Voltage Schedules at http://www.nerc.com/files/VAR-002-1_1b.pdf

III. Statement of Issues

The ISO identifies the following statement of issues and specifications of error concerning the Commission's order.

1. The order arbitrarily discriminates against synchronous generating facilities by shifting the burden to provide reactive power, maintain voltage schedules and manage generator output to these resources. This discrimination ultimately harms the ISO by narrowing the percentage of the generation fleet that can provide reactive support and other important capabilities to the electricity grid. As a result, the ISO may not have access to sufficient resources that provide reactive power and ratepayers will face higher costs to obtain this necessary capability. In addition, the inability of asynchronous generating facilities to manage active power output will undermine their ability to operate reliably after a disturbance and thereby increase reliability concerns. The order reflects arbitrary decision-making under the Administrative Procedure Act because it provides no facts that support exempting the large volume of asynchronous generating facilities currently seeking to interconnect to the ISO grid from the proposed interconnection requirements. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). The August 31, 2010 order is accordingly in error and the ISO respectfully requests that the Commission modify this order on rehearing.

2. The order ignores record evidence supporting the ISO's proposed interconnection requirements and misreads an analytical study that supports the adoption of the ISO's proposed power factor requirements for asynchronous

generating facilities. By failing to address the record evidence presented by the ISO, the Commission has failed to engage in reasoned decision-making. *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998). Moreover, the ISO has a statutory right under Section 205 of the Federal Power Act to implement tariff modifications so long as they are just and reasonable. The ISO presented more than adequate evidence to support such a finding. By failing to explain how the ISO's proposal was unjust and unreasonable, the Commission's order is contrary to Section 205 of the Federal Power Act. The August 31, 2010 order is accordingly in error and the ISO respectfully requests that the Commission modify this order on rehearing.

3. The order is inconsistent with another Commission order issued on September 16, 2010 that approves a NERC interpretation of reliability standard VAR-002-1.1b. This standard includes the requirement that a generator operator maintain the generator voltage or reactive power output, within applicable facility ratings, as directed by the transmission operator. NERC interprets the requirements of this standard to apply to all generators and the Commission's September 16, 2010 order approves this interpretation. The ISO's proposed requirements for asynchronous generating facilities will allow these facilities to adhere to NERC's interpretation of reliability standard VAR-002-1.1b. In light of these facts, the ISO respectfully requests that the Commission modify its August 31, 2010 order and approve the ISO's proposed interconnection requirements. Absent a rehearing that reconciles these orders, the Commission's August 31, 2010 order reflects arbitrary decision-making under the Administrative Procedure Act.

IV. Request for Rehearing

A. The Commission's order arbitrarily discriminates against existing conventional generators and asynchronous generating facilities that will seek to interconnect to the ISO in the future.

By rejecting the ISO's attempt to implement reasonable technical criteria relating to the interconnection of asynchronous resources, the Commission's order arbitrarily discriminates against synchronous generating facilities. The ISO developed its proposed interconnection requirements related to reactive support, voltage regulation and active power management to ensure that asynchronous generating facilities will provide a level of support to the electric grid that is roughly comparable with the support that synchronous generators are currently required to provide to the electricity grid. Reactive power is necessary to energize and transmit power in an alternating current system. Without this feature, the ISO cannot maintain system voltage. Synchronous generators represent the most controllable and robust source of reactive power.[20] The large number of wind and solar photovoltaic generators interconnecting to the ISO will displace output from these conventional generators and may create a deficiency of reactive power resources that could decrease the voltage stability of the ISO system.

[20] ISO July 2, 2010 transmittal letter at 8 and Attached E thereto, Memorandum from Keith Casey to ISO Board of Governors dated May 10, 2010 at 4-5.

Given these circumstances, and the fact that all generating facilities will derive the same benefits from access to the ISO's transmission system, it is unreasonable and discriminatory not to require asynchronous generating facilities to provide reactive support, voltage regulation and power management capabilities on a general basis. The Commission's order provides no analysis or factual evidence to support why asynchronous generating facilities seeking to interconnect to the ISO grid should not have these capabilities or why only conventional generators should shoulder the burden to maintain these capabilities.

The only explanation provided by the Commission is reference to its determination in Order Nos. 661 and 661-A that reactive power and voltage support can be required from wind generators only after findings that such support is necessary in a system impact study. The Commission made this determination because of a concern that a general requirement might discriminate against wind generators because of the relatively higher cost of installing the necessary equipment for a wind generator as compared to conventional generators. However, in the July 2, 2010 filing, the ISO explained at length that compliance with its proposed requirements would not raise such concerns, because compliance with those requirements would add very little in the way of additional costs to asynchronous generating facilities – in the range of .25 to 1 percent of overall facility costs. The ISO supported this explanation with prepared testimony and references to analytical studies. The Commission did not address this evidence.

By requiring the ISO to make reliability determinations on a case-by-case basis, there is a significant possibility that studies of asynchronous generating facilities connecting in the near term will, in many cases, find no immediate need for reactive power and voltage support from those facilities given the existing state of the system. However, as the percentage of asynchronous resources on the system rises in relation to conventional generators, the need for reactive and voltage support from generators will increase in order to avoid serious reliability issues. This means that the ISO would either need to obtain the necessary support through one of two options: (1) requiring a higher proportion of asynchronous resources interconnecting in the future to provide necessary support, which would mean that such future resources would be subsidizing resources that interconnected earlier and were not required to provide support; or (2) mandating costly retrofits of existing resources in order to install, after the fact, the equipment necessary to provide the required support. Neither of these options is as fair or reasonable as the ISO's proposed general requirements. Again, however, the Commission did not address these arguments in the order.

By failing to adopt the ISO's technical requirements, the Commission's order arbitrarily establishes a framework that discriminates against conventional generators. The order provides no rationale for this discriminatory treatment except for the reference to Orders No. 661 and 661-A, which the ISO specifically addressed in the July 2, 2010 filing. To withstand review under the arbitrary and capricious standard, the Commission must have "examine[d] the relevant data and articulate[d] a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made."' *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). The order fails this standard because the Commission did not articulate any satisfactory explanation for discriminating against conventional generators and failed to respond to the ISO's specific arguments as to why its proposed technical requirements were fair and non-discriminatory.

B. The Commission's order fails to engage the arguments presented by the ISO and does not reflect reasoned decision-making.

The order ignores record evidence supporting the ISO's proposed interconnection requirements and misreads an analytical study that supports the adoption of power factor, voltage regulation and generator management requirements for asynchronous generating facilities. By failing to address the arguments and record evidence presented by the ISO, the order does not reflect reasoned decision-making.[21]

Throughout the order, the Commission summarily concludes that based on the record, the ISO "has not supported the proposal as just and reasonable."[22] Without a discussion of why the ISO's showing is insufficient, however, the order is not sustainable. In the case of generator management capabilities, the Commission fails to even consider the proposed requirements but instead rejects

[21] "[i]t most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it – that it conduct a process of reasoned decision making." *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) (internal citations omitted).

[22] August 31, 2010 order at P 47, 54.

them because the ISO has yet to articulate the operational and market circumstances in it will utilize these requirements.   But the ISO did provide an explanation of the operational circumstances in which these capabilities would assist grid operators. Specifically, the ISO identified system wide over-frequency and local transmission congestion as operational situations in which it may be necessary to reduce output from asynchronous generating facilities.[23] The Commission order simply does not examine the relevant data presented and does not articulate a satisfactory explanation for why it is reasonable to expect that resources – other than the current tide of asynchronous generating facilities seeking to interconnect to the ISO – must shoulder the burden of these requirements.

The Commission's order selectively references the ISO's 2007 renewable integration study that examined the integration of 4200 megawatts of wind power. The Commission's order suggests some of these resources need not provide reactive power to preserve system stability.[24]   As the ISO has made clear, it is now facing a much greater volume of wind and solar photovoltaic resources seeking to interconnect to the grid. In addition, the order ignores or dismisses the core findings of the 2007 renewable integration study.   The first conclusion of the ISO's 2007 renewable integration study is that "all new wind generation units must have the capability to meet the WECC requirements of ±0.95 power factor.

[23] ISO July 2, 2010 transmittal letter at 23-24.

[24] August 31, 2010 order at n 45.

This reactive capability is essential for adequate voltage control."[25] The ISO also described and referenced a recent study that recommends exploring generator power management capabilities for wind and solar to address significant ramping issues under a 33 percent renewable portfolio standard.[26] The order ignores these and other analyses that support the ISO's proposed interconnection requirements.

The ISO bears the burden of demonstrating that its proposed technical criteria are just and reasonable. The ISO met this burden by showing, through the presentation of substantial evidence, that its proposed criteria would significantly facilitate the ISO's ability to ensure grid reliability and would avoid discriminatory treatment vis-à-vis other generators. Moreover, the ISO demonstrated that requiring asynchronous resources to adhere to its proposed technical criteria would not place an unreasonable burden on those resources. Given the evidence presented by the ISO, the Commission has the obligation, under Section 205 of the Federal Power Act and the Administrative Procedures Act, to either approve the ISO's proposal or explain why the ISO's proposal fails to meet the just and reasonable standard. The order does neither, and therefore, is not legally sustainable. The Commission should grant rehearing.

C. The ISO's proposed requirements are consistent with the Commission's recent approval of NERC's interpretation of applicable voltage and reactive power requirements.

[25] ISO July 2, 2010 transmittal letter at 11 and fn 18.

[26] ISO July 2, 2010 transmittal letter at 24 and fn 53.

The Commission's order rejecting the ISO's proposed interconnection requirements for reactive power and voltage regulation stands in contrast to a separate order the Commission issued on September 16, 2010 addressing NERC's interpretation of an existing voltage and reactive reliability standard – VAR-002.1.1b. In that order, the Commission approved NERC's interpretation that the requirements of VAR-002.1.1b apply to all generators. NERC's standard requires generator operators maintain generator voltage or reactive power as directed by the transmission operator. Under NERC's interpretation, approved by the Commission, this requirement applies whether or not a generator is equipped with an automatic voltage regulator.[27]

The ISO recognizes that the Commission has already identified a specific mechanism for transmission operators to require individual wind and solar photovoltaic generating facilities to provide reactive power and voltage control through interconnection system impact studies. In its transmittal letter and supporting testimony, the ISO explained why this mechanism is insufficient in view of the large number of asynchronous generating facilities seeking to interconnect and relatively short-time horizon for current interconnection system impact studies.[28]

The Commission's September 16, 2010 order, however, clarifies that all generators must control voltage or reactive power output under the NERC reliability standard unless exempted by the transmission operator. The ISO's

[27] September 16, 2010 order P 11.

[28] ISO July 2, 2010 transmittal letter at 11-12 and Attachment E thereto, Prepared Testimony of Nisar Shah at 7-9.

proposed interconnection requirements are consistent with this requirement and would allow asynchronous generating facilities interconnecting to the ISO to adhere to NERC's interpretation because they would have the capability to provide reactive power and voltage regulation. The concentration of asynchronous generating facilities in centralized locations in California such as Tehachapi, Carrizo Plain and other areas underscores the importance of facilitating generator compliance with NERC's standard. The ISO urges the Commission to grant rehearing of its August 31, 2010 order and approve the ISO's proposed technical requirements in order to reconcile the conflict between the Commission's orders.

V. Conclusion

The Commission should reverse its order rejecting the ISO proposed tariff requirements for power factor design, voltage regulation and generator power management. By exempting asynchronous generators from these requirements, the Commission is arbitrarily shifting a considerable burden to conventional synchronous generators and potentially imposing this burden on future asynchronous generating facilities that seek to interconnect to the ISO. The Commission's order also ignores the technical evidence supporting the need for reactive power from asynchronous generating facilities and conflicts with a recent Commission order approving NERC's interpretation that voltage regulation requirements set forth in reliability standard VAR-002-1.1b apply to all generators. The ISO's efforts to interconnect a significant amount of wind and solar photovoltaic resources over the next decade will displace conventional resources that provide reactive support, voltage regulation and power management capabilities. These capabilities support the reliable operation of the transmission grid. The Commission should grant rehearing and authorize the ISO to apply its proposed requirements to asynchronous generating facilities effective July 3, 2010.

Respectfully submitted,

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EXHIBIT A

POWER SYSTEM STABILITY AND CONTROL

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Chapter 14

Voltage Stability

Voltage control and stability problems are not new to the electric utility industry but are now receiving special attention in many systems. Once associated primarily with weak systems and long lines, voltage problems are now also a source of concern in highly developed networks as a result of heavier loadings. In recent years, voltage instability has been responsible for several major network collapses. The following are some examples [1,2]:

- New York Power Pool disturbances of September 22, 1970
- Florida system disturbance of December 28, 1982
- French system disturbances of December 19, 1978, and January 12, 1987
- Northern Belgium system disturbance of August 4, 1982
- Swedish system disturbance of December 27, 1983
- Japanese system disturbance of July 23, 1987

As a consequence, the terms "voltage instability" and "voltage collapse" are appearing more frequently in the literature and in discussions of system planning and operation.

Although low voltages can be associated with the process of rotor angles going out of step, the type of voltage collapse related to voltage instability can occur where "angle stability" is not an issue. The gradual pulling out of step of machines, as rotor angles between two groups of machines approach or exceed 180°, results in very low voltages at intermediate points in the network (see Chapter 13, Section 13.5.3). However, in such cases the low voltage is a result of the rotors falling out of step rather than a cause of it.

Voltage stability, as described in Chapter 2, is concerned with the ability of a power system to maintain acceptable voltages at all buses in the system under normal conditions and after being subjected to a disturbance. A system enters a state of voltage instability when a disturbance, increase in load demand, or change in system condition causes a progressive and uncontrollable decline in voltage. The main factor causing instability is the inability of the power system to meet the demand for reactive power.

This chapter will review basic concepts related to voltage stability and characterize the "voltage avalanche" phenomenon. The dynamic and static approaches to voltage stability analysis will be described, and methods identified for preventing voltage instability.

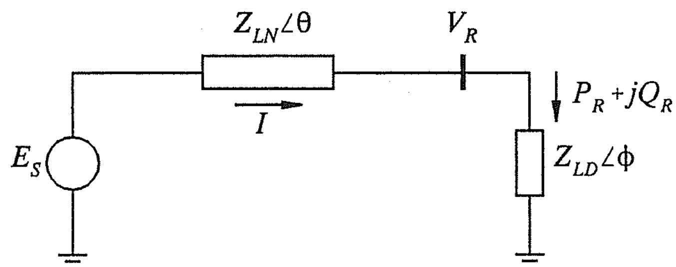
14.1 BASIC CONCEPTS RELATED TO VOLTAGE STABILITY

Voltage stability problems normally occur in heavily stressed systems. While the disturbance leading to voltage collapse may be initiated by a variety of causes, the underlying problem is an inherent weakness in the power system. In addition to the strength of transmission network and power transfer levels, the principal factors contributing to voltage collapse are the generator reactive power/voltage control limits, load characteristics, characteristics of reactive compensation devices, and the action of voltage control devices such as transformer under-load tap changers (ULTCs).

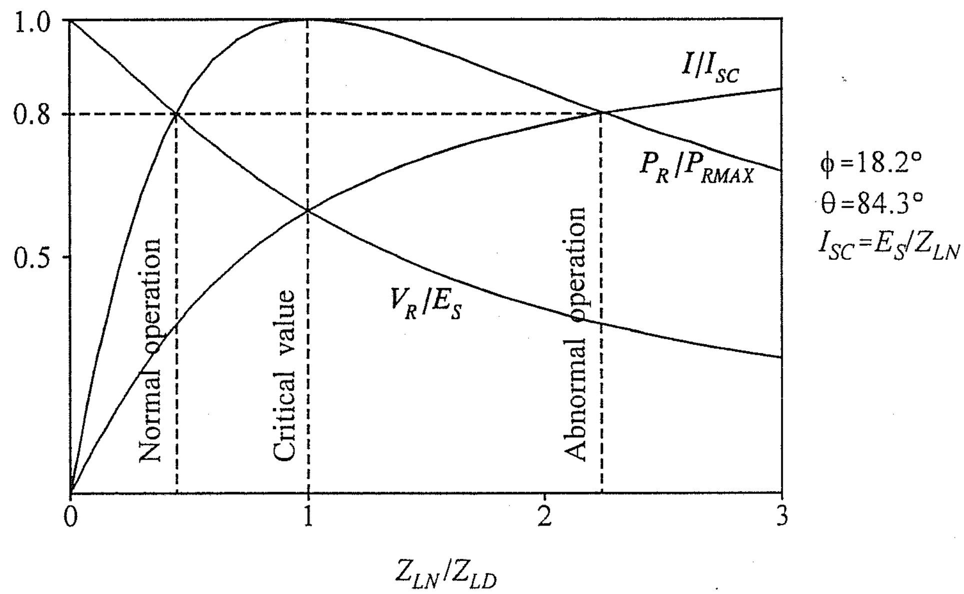
This section illustrates the basic concepts related to voltage instability by firstly considering the characteristics of transmission systems and then examining how the phenomenon is influenced by the characteristics of generators, loads, and reactive power compensation devices.

14.1.1 Transmission System Characteristics

The characteristics of interest are the relationships between the transmitted power (P_R), receiving end voltage (V_R), and the reactive power injection (Q_i). Such characteristics were discussed for a simple radial system in Chapter 2 (Section 2.1) and for transmission lines of varying lengths in Chapter 6 (Section 6.1). For complex systems with a large number of voltage sources and load buses, similar characteristics can be determined by using power-flow analysis (see Chapter 6).



(a) Schematic diagram



(b) Receiving end voltage, current and power as a function of load demand

Figure 14.1 Characteristics of a simple radial system

Let us briefly review the characteristics of the simple radial system considered in Chapter 2 (Figure 2.4). For reference the schematic diagram of the system is reproduced in Figure 14.1(a). As shown in Section 2.1.2, the current I and receiving end voltage V_R and power P_R are given by the following equations:

$$I = \frac{1}{\sqrt{F}}\frac{E_S}{Z_{LN}} \tag{14.1}$$

$$V_R = \frac{1}{\sqrt{F}}\frac{Z_{LD}}{Z_{LN}}E_S \tag{14.2}$$

$$P_R = \frac{Z_{LD}}{F}\left(\frac{E_S}{Z_{LN}}\right)^2 \cos\phi \tag{14.3}$$

where

$$F = 1+\left(\frac{Z_{LD}}{Z_{LN}}\right)^2 + 2\left(\frac{Z_{LD}}{Z_{LN}}\right)\cos(\theta-\phi)$$

Plots of I, V_R, and P_R are shown in Figure 14.1(b) as a function of load demand (Z_{LN}/Z_{LD}), for the case with $\tan\theta=10.0$ and $\cos\phi=0.95$. To make the results applicable to any value of Z_{LN}, the values of I, V_R and P_R are appropriately normalized.

As load demand increases (Z_{LD} decreases), P_R increases rapidly at first and then slowly before reaching a maximum, and finally decreases. There is thus a maximum value of active power that can be transmitted through an impedance from a constant voltage source. The power transmitted is maximum when the voltage drop in the line is equal in magnitude to V_R, i.e., when $Z_{LD}/Z_{LN}=1$. The conditions corresponding to maximum power represent the limits of satisfactory operation. The values of V_R and I corresponding to maximum power are referred to as *critical values.*

For a given value of power P_R delivered ($P_R<P_{RMAX}$), two operating points may be found corresponding to two different values of Z_{LD}. This is shown in Figure 14.1(b) for $P_R=0.8$. The point to the left corresponds to normal operation. At the operating point to the right, I is much larger and V_R much lower than for the point to the left.

For a load demand higher than the maximum power, control of power by varying the load would be unstable, i.e., an increase in load admittance would reduce power. In this region, the load voltage may or may not progressively decrease depending on the load-voltage characteristic. With a constant-admittance load characteristic, the system condition stabilizes at a voltage level that is lower than normal. On the other hand, if the load is supplied by a transformer with ULTC, the tap-changer action will try to raise the load voltage, which has the effect of reducing effective Z_{LD}. This lowers V_R still further and leads to a progressive reduction of voltage. This is the phenomenon of *voltage instability.*

From Equation 14.3, we see that the maximum value of P_R can be increased by increasing the source voltage E_S and/or decreasing ϕ.

A more traditional method of illustrating the phenomenon is to plot the relationship between V_R and P_R, for different values of load power factor with E_S constant as shown in Figure 14.2. The locus of critical operating points is shown by dashed lines in the figure. Only the operating points above the critical points represent satisfactory operating conditions.

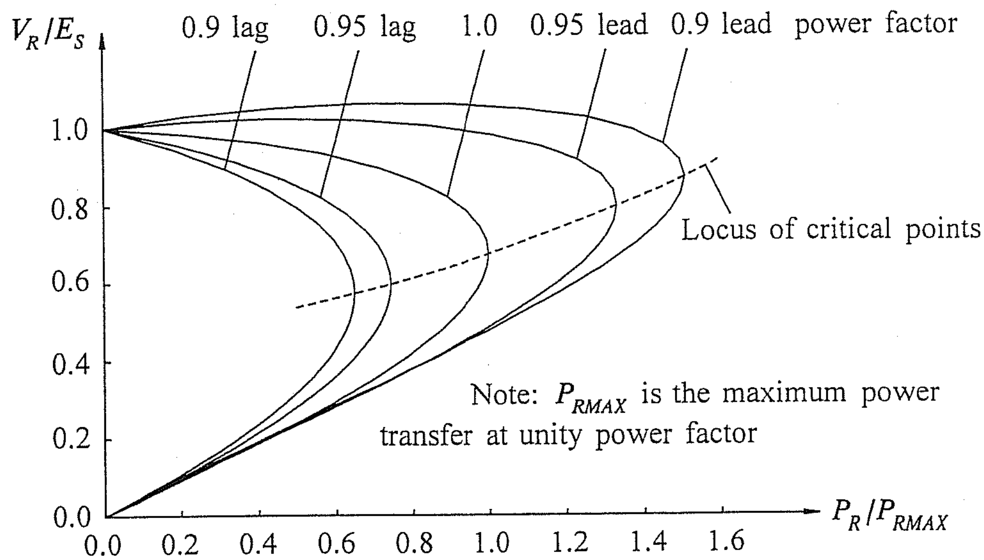


Figure 14.2 The V_R-P_R characteristics of the system of Figure 14.1

In Chapter 6 (Section 6.1), we developed similar *V-P* characteristics for transmission lines of different lengths. Practical power systems consisting of many voltage sources and load buses also exhibit similar relationships between active power transfer and load bus voltages. We will illustrate this for the system shown in Figure 14.3, consisting of 39 buses with nine generators and one synchronous condenser. Figure 14.4 shows the *V-P* curve for the system; it represents the variation in voltage at bus 530, a critical bus in the load area prone to voltage instability, as a function of total active power load in the shaded area. This curve has been produced by using a series of power-flow solutions for different load levels. The loads in area 1 (shaded) are uniformly scaled up while the power factor is kept constant. The active power outputs of generators are correspondingly increased in proportion to the size of generator. The P and Q components of each load are assumed to be independent of the bus voltage. At the "knee" of the *V-P* curve, the voltage drops rapidly with an increase in load demand (or nominal voltage load). Power-flow solution fails to converge beyond this limit, which is indicative of instability. Operation at or near the stability limit is impractical and a satisfactory operating condition is ensured by allowing sufficient "power margin."

We see that complex systems have *V-P* characteristics similar to those of the simple radial system of Figure 14.1. Such characteristics represent the basic property of networks with predominantly inductive elements.

We have so far considered the *V-P* characteristics with constant load power factor. Voltage stability, in fact, depends on how variations in Q as well as P in the load area affect the voltages at the load buses. Often, a more useful characteristic for certain aspects of voltage stability analysis is the *Q-V* relationship, which shows the

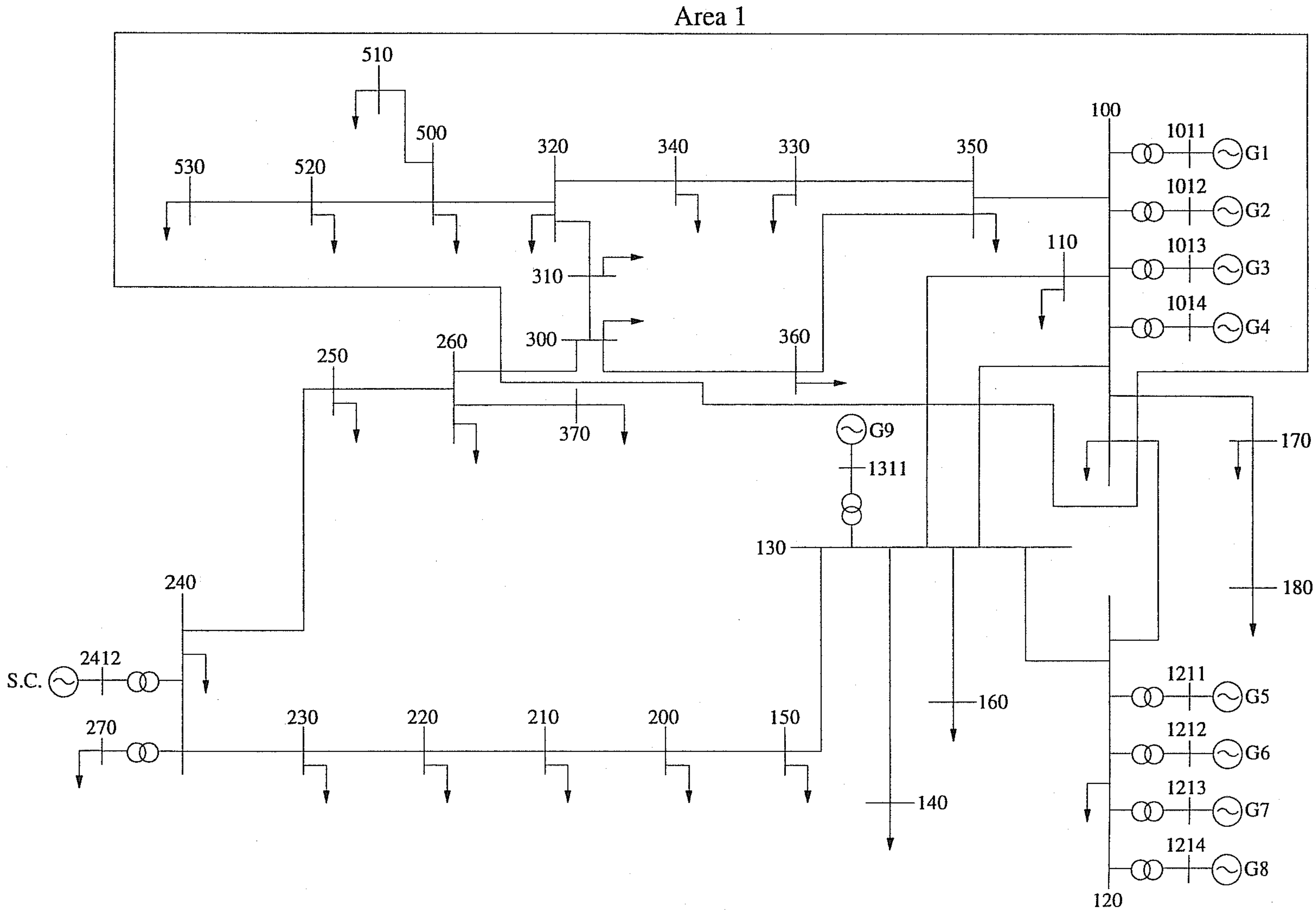


Figure 14.3 A 39-bus, 10-machine test system

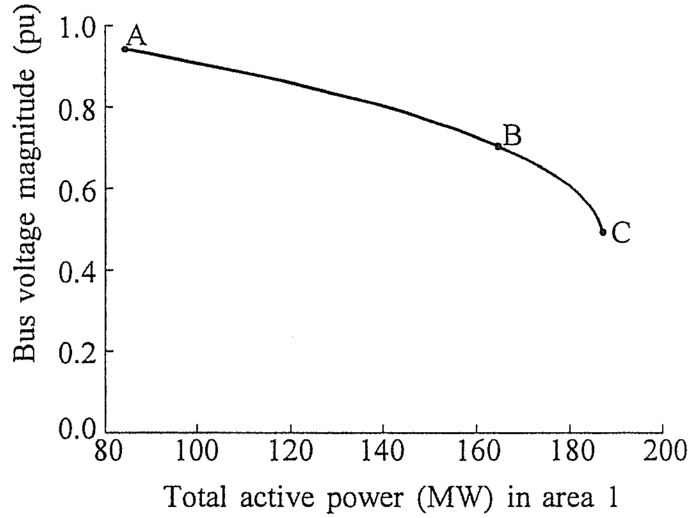


Figure 14.4 The *V-P* curve at bus 530 of the system shown in Figure 14.3

sensitivity and variation of bus voltages with respect to reactive power injections or absorptions. For the simple radial system of Figure 14.1, such characteristics for different values of load power are shown in Figure 2.8 of Chapter 2. These characteristics can be derived more readily than the *V-P* characteristics for systems with a non-radial type structure and are better suited for examining the requirements for reactive power compensation.

Figure 14.5 shows the *Q-V* curves computed at buses 160, 200, 510, and 530 for the three operating conditions represented by points A, B, and C on the *V-P* curve of Figure 14.4. Point A represents the base case, point B a condition near the critical operating point, and point C a condition at the critical operating point. Each of these *Q-V* curves has been produced by successive power-flow calculations with a variable reactive power source at the selected bus and recording its values required to hold different scheduled bus voltages. The bottom of the *Q-V* curve, where the derivative dQ/dV is equal to zero, represents the voltage stability limit. Since all reactive power control devices are designed to operate satisfactorily when an increase in Q is accompanied by an increase in V, operation on the right side of the *Q-V* curve is stable and on the left side is unstable. Also, voltage on the left side may be so low that protective devices may be activated. The bottom of the *Q-V* curve, in addition to identifying the stability limit, defines the minimum reactive power requirement for stable operation [3].

In this section we have examined the characteristics of transmission systems as impacted by the flow of active and reactive power through highly inductive elements. It is evident from the analysis presented here that the following are the principal causes of voltage instability:

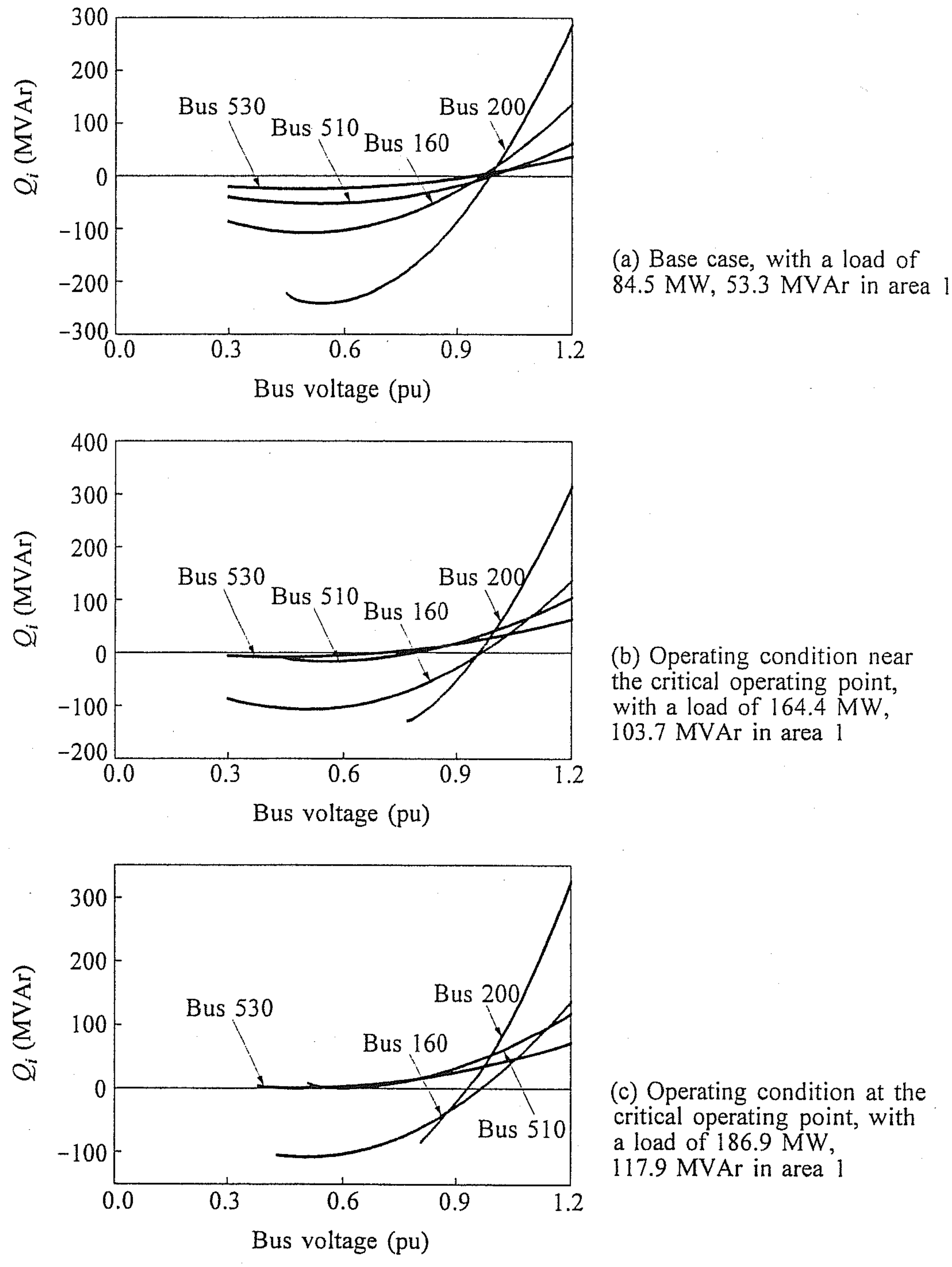


Figure 14.5 The Q-V curves for system shown in Figure 14.3

- The load on the transmission lines is too high.
- The voltage sources are too far from the load centres.
- The source voltages are too low.
- There is insufficient load reactive compensation.

The transmission system *V-P* and *Q-V* characteristics have been introduced here primarily to illustrate the basic phenomenon associated with voltage instability. The approach presented for deriving the characteristics by using conventional power-flow programs is, however, not necessarily the most efficient way of studying the voltage stability problem. Methods of analyzing voltage stability are discussed in Section 14.3.

14.1.2 Generator Characteristics

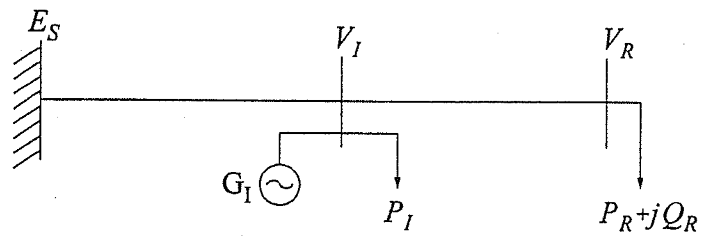
Generator AVRs are the most important means of voltage control in a power system. Under normal conditions the terminal voltages of generators are maintained constant. During conditions of low-system voltages, the reactive power demand on generators may exceed their field current and/or armature current limits (see Chapter 5, Section 5.4). When the reactive power output is limited, the terminal voltage is no longer maintained constant.

The generator field current is automatically limited by an *overexcitation limiter* (OXL). The function and modelling of such limiters are described in Chapter 8 (Sections 8.5 and 8.6). With constant field current, the point of constant voltage is behind the synchronous reactance (see Chapter 3, Figure 3.22). This effectively increases the network reactance significantly, further aggravating the voltage collapse condition.

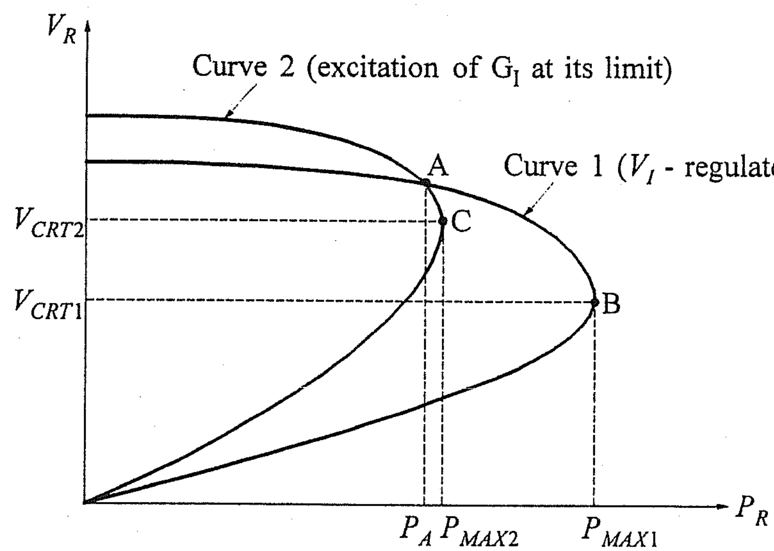
On most generators, the armature current limit is realized manually by operators responding to alarms. The operator reduces reactive and/or active power output to bring the armature current within safe limits. On some generators, automatic armature current limiters with time delay are used to limit reactive power output through the AVR [2].

To illustrate the impact of loss of generator voltage control capability, consider the system shown in Figure 14.6(a). It consists of a large load supplied radially from an infinite bus, with intermediate generation supplying part of the load and regulating voltage (V_I).

With voltage at the intermediate bus maintained, the *V-P* characteristic is shown by curve 1 in Figure 14.6(b). When the generating unit at the intermediate point hits its field current limit, the bus voltage (V_I) is no longer maintained and the *V-P* characteristic is shown by curve 2. An operating condition such as that represented by point A is considerably more stable when on curve 1 than when it is on curve 2. These results demonstrate the importance of maintaining the voltage control capability of generators. In addition, they show that the degree of voltage stability cannot be judged based only on how close the bus voltage is to the normal voltage level.



(a) Schematic diagram



(b) The V_R-P_R characteristics

Figure 14.6 Impact of loss of regulation of intermediate bus voltage

This situation is similar to that which led to voltage collapse in the Brittany region of the French system in December 1965 and in November 1975 [4].

14.1.3 Load Characteristics [1,5]

Load characteristics and distribution system voltage control devices are among the key factors influencing system voltage stability.

The characteristics and modelling of different types of loads are discussed in Chapter 7. Loads whose active and reactive components vary with voltage interact with the transmission characteristics by changing the power flow through the system. The system voltages settle at values determined by the composite characteristic of the transmission system and loads.

Shunt capacitors, however, have a number of inherent limitations from the viewpoint of voltage stability and control:

- In heavily shunt capacitor compensated systems, the voltage regulation tends to be poor.

- Beyond a certain level of compensation, stable operation is unattainable with shunt capacitors (this is illustrated in Example 14.1).

- The reactive power generated by a shunt capacitor is proportional to the square of the voltage; during system conditions of low voltage the var support drops, thus compounding the problem.

(b) Regulated shunt compensation

A *static var system (SVS)* of finite size will regulate up to its maximum capacitive output. There are no voltage control or instability problems within the regulating range. When pushed to the limit, an SVS becomes a simple capacitor. The possibility of this leading to voltage instability must be recognized.

A *synchronous condenser*, unlike an SVS, has an internal voltage source. It continues to supply reactive power down to relatively low voltages and contributes to a more stable voltage performance.

(c) Series capacitors

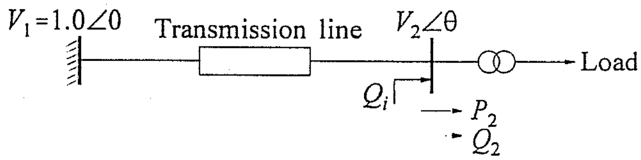
Series capacitors are self-regulating. The reactive power supplied by series capacitors is proportional to square of the line current and is independent of the bus voltages. This has a favourable effect on voltage stability.

Series capacitors are ideally suited for effectively shortening long lines. Unlike shunt capacitors, series capacitors reduce both the characteristic impedance (Z_C) and the electrical length (θ) of the line (see Chapter 11). As a result, both voltage regulation and stability are significantly improved.

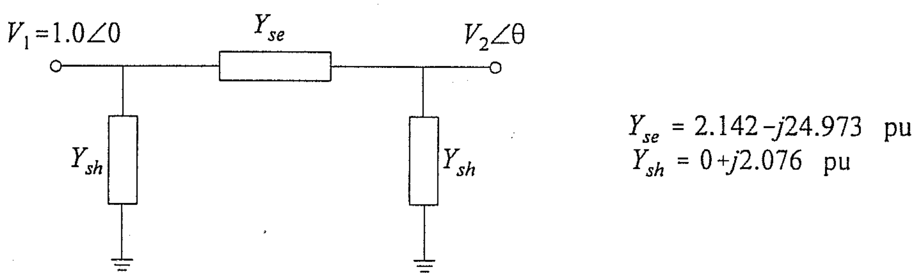
Example 14.1

Figure E14.1 shows the system representation applicable to a 322 km (200 mi), 500 kV transmission line supplying a radial load from a strong system. The line parameters are expressed in per unit on 100 MVA and 500 kV base.

(a) With the sending end voltage (V_1) maintained at 1.0 pu, generate Q-V curves at the receiving end for four different values of receiving end load power: 1300, 1500, 1700, and 1900 MW assumed at unity power factor. Together with the Q-V curves of the transmission system, plot the shunt capacitor Q-V characteristics with the reactive power injection at 1.0 pu voltage being 300, 450, 675, and 950 MVAr, respectively. Examine the effectiveness of shunt



(a) Schematic diagram



(b) Equivalent π circuit representation of line

Figure E14.1 A 322 km, 500 kV line supplying a radial load

capacitor compensation as a means of providing reactive power compensation. Assume that the load at the receiving end exhibits a constant MVA steady-state characteristic due to the action of transformer tap changers.

(b) If the reactive compensation at the receiving end is in the form of an SVC with a capacitive limit of 950 MVAr, examine voltage stability of the system as P_2 is gradually increased from 1300 MW to 1900 MW.

Solution

(a) Figure E14.2 shows the steady-state Q_i-V_2 characteristics of the transmission line and the shunt capacitors.

The transmission line characteristics are shown in solid curves. These curves represent the relationship between voltage at the receiving end bus and injections of reactive power at that bus, each corresponding to a given level of receiving-end power, assumed at unity power factor.

The relationships between voltage and the reactive power produced by shunt capacitors are shown in dashed lines. The intersection between a solid curve and a dashed line establishes the steady-state operating point corresponding to the respective receiving-end power and shunt capacitor rating.

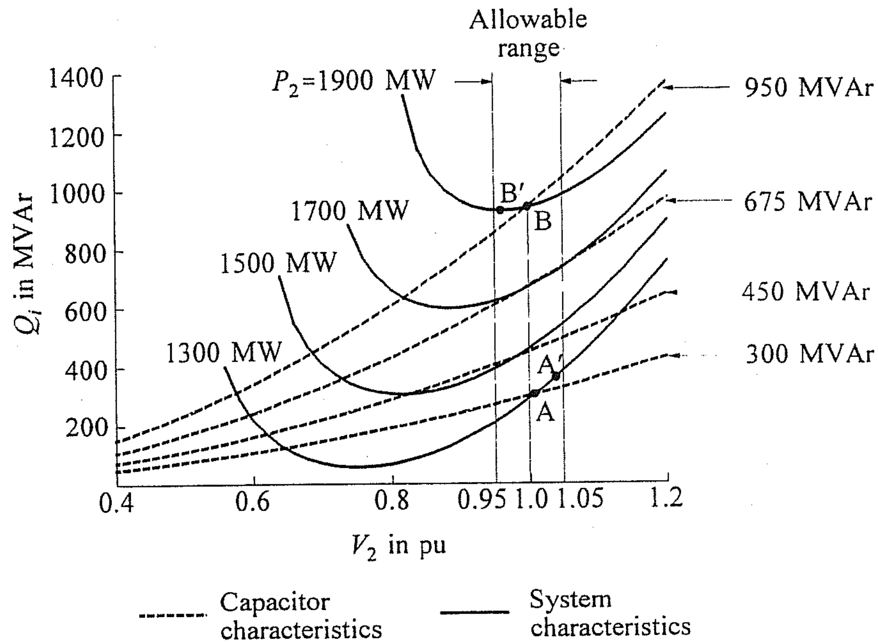


Figure E14.2 System and shunt capacitor steady-state Q-V characteristics; capacitor MVAr shown at rated voltage

Let us examine the steady-state system performance with a load level of 1300 MW and a capacitor bank of 300 MVAr, represented by the operating point A. At this point the slope $\Delta Q/\Delta V$ of the system is greater than that of the shunt capacitor; this represents stable operation. When perturbed by a small transient disturbance, the system returns to operating point A. The addition of a small amount of capacitance as represented by operating point A′ results in an increase in voltage, a characteristic normally expected.

The situation is quite different at operating point B, with a receiving power of 1900 MW and a capacitor bank of 950 MVAr. Now, the slope $\Delta Q/\Delta V$ of the system is less than that of the capacitor. A small perturbation leads to progressive deviation in V_2. An increase of shunt capacitor by a small amount, as represented by point B′, results in a decrease in bus voltage.

We thus see that at very high levels of shunt compensation, stable operation is not possible. The limiting load power level is about 1700 MW requiring a shunt capacitor of 675 MVAr. At this level, the slope $\Delta Q/\Delta V$ of the system is nearly equal to that of the shunt capacitor.

In the above analysis we have considered only the steady-state performance with the load at the receiving end maintaining constant MVA due to transformer ULTC action.

The transient response depends on the inherent load characteristics. For example, with a constant current load characteristic, switching additional load when operating at point B causes a transient reduction of V_2 and P_2. The system is voltage stable in the short term. However, the action of the transformer ULTC, as it attempts to raise the secondary voltage, causes an increase in primary (line) current. This results in a decrease in V_2 and P_2. The voltage V_2 decreases with each tap movement until the tap changer reaches its limit. The system settles at low values of V_2 and P_2.

(b) Figure E14.3 shows the steady-state Q_i-V_2 characteristics with a *static var compensator* (SVC). The SVC maintains constant voltage V_2 until its maximum capacitive output limit of 950 MVAr is reached. Consequently, for values of P_2 less than 1900 MW, the SVC maintains V_2 at 1.0 pu. When P_2 reaches 1900 MW, the SVC hits its capacitive limit and its characteristic is that of a simple capacitor. This leads to voltage instability.

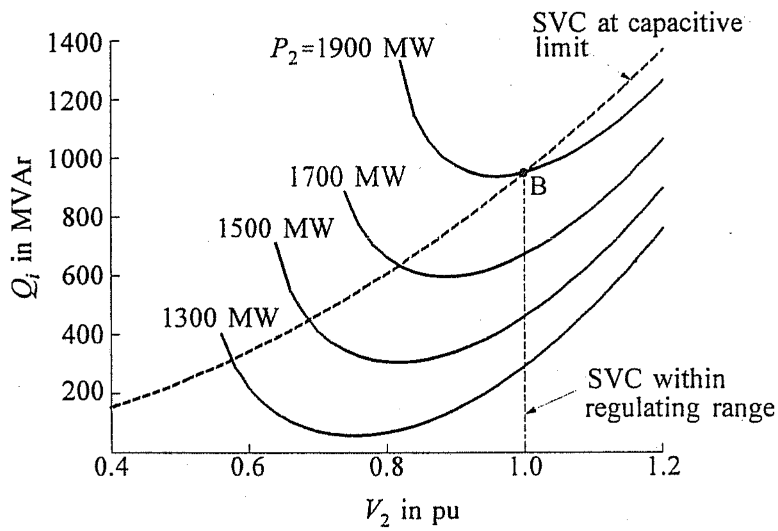


Figure E14.3 System and SVC Q-V characteristics; SVC capacitive limit 950 MVAr

14.2 VOLTAGE COLLAPSE

Voltage collapse is the process by which the sequence of events accompanying voltage instability leads to a low *unacceptable* voltage profile in a significant part of the power system.

Voltage collapse may be manifested in several different ways. We will describe a typical scenario of voltage collapse, and then provide a general characterization of the phenomenon based on actual incidents of collapse.

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11.4 Voltage Stability

Yakout Mansour

Voltage stability refers to the ability of a power system to maintain its voltage profile under the full spectrum of its operating scenarios so that both voltage and power are controllable at all times.

Voltage instability of radial distribution systems has been well recognized and understood for decades (Venikov, 1970; 1980) and was often referred to as load instability. Large interconnected power networks did not face the phenomenon until late 1970s and early 1980s.

Most of the early developments of the major HV and EHV networks and interties faced the classical machine angle stability problem. Innovations in both analytical techniques and stabilizing measures made it possible to maximize the power transfer capabilities of the transmission systems. The result was increasing transfers of power over long distances of transmission. As the power transfer increased, even when angle stability was not a limiting factor, many utilities have been facing a shortage of voltage support. The result ranged from post contingency operation under reduced voltage profile to total voltage collapse. Major outages attributed to this problem were experienced in the northeastern part of the U.S., France, Sweden, Belgium, Japan, along with other localized cases of voltage collapse (Mansour, 1990). Accordingly, voltage stability imposed itself as a governing factor in both planning and operating criteria of a number of utilities. Consequently, major challenges in establishing sound analytical procedures, quantitative measures of proximity to voltage instability, and margins have been facing the industry for the last two decades.

Voltage instability is associated with relatively slow variations in network and load characteristics. Network response in this case is highly influenced by the slow-acting control devices such as transformer on-load tap changers, automatic generation control, generator field current limiters, generator overload reactive capability, under-voltage load shedding relays, and switchable reactive devices. The characteristics of such devices as to how they influence the network response to voltage variations are generally understood and well covered in the literature. On the other hand, electric load response to voltage variation has only been addressed more recently, even though it is considered the single most important factor in voltage instability.

Generic Dynamic Load-Voltage Characteristics

While it might be possible to identify the voltage response characteristics of a large variety of individual equipment of which a power network load is comprised, it is not practical or realistic to model network load by individual equipment models. Thus, the aggregate load model approach is much more realistic.

Field test results as reported by Hill (1992) and Xu et al. (1996) indicate that typical response of an aggregate load to step-voltage changes is of the form shown in Fig. 11.12. The response is a reflection of the collective effects of all downstream components ranging from OLTCs to individual household loads. The time span for a load to recover to steady-state is normally in the range of several seconds to minutes, depending on the load composition. Responses for real and reactive power are qualitatively similar. It can be seen that a sudden voltage change causes an instantaneous power demand change. This change defines the transient characteristics of the load and was used to derive static load models for angular stability

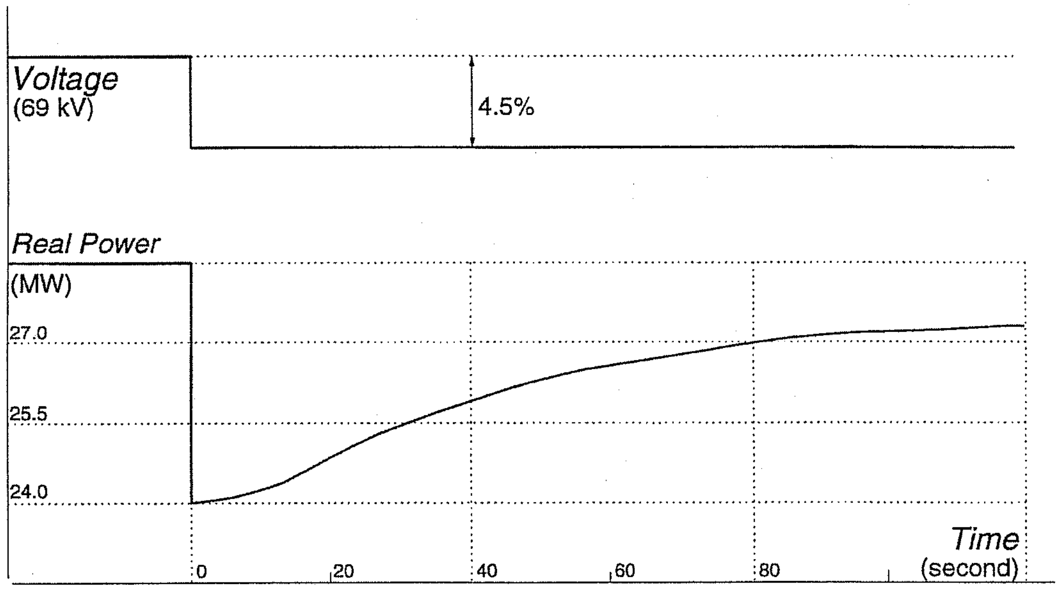


FIGURE 11.12 Aggregate load response to a step voltage change.

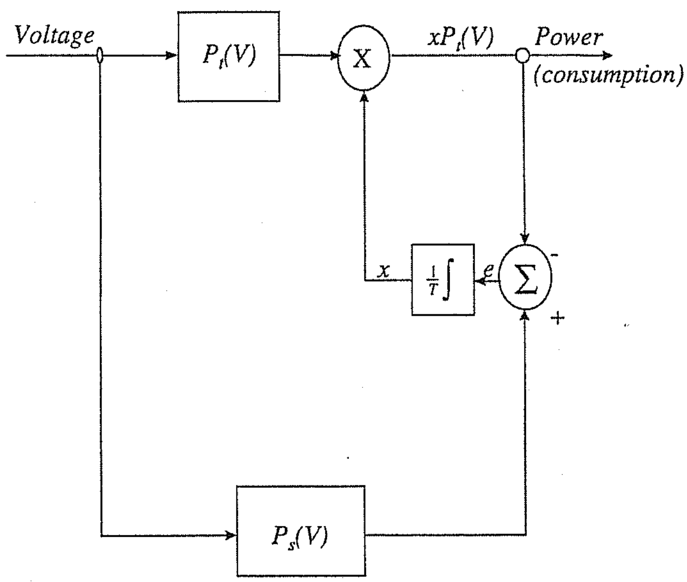


FIGURE 11.13 A generic dynamic load model.

studies. When the load response reaches steady-state, the steady-state power demand is a function of the steady-state voltage. This function defines the steady-state load characteristics known as voltage-dependent load models in load flow studies.

The typical load-voltage response characteristics can be modeled by a generic dynamic load model proposed in Fig. 11.13. In this model (Xu et al., 1993), x is the state variable. $P_t(V)$ and $P_s(V)$ are the transient and steady-state load characteristics, respectively, and can be expressed as:

$$P_t = V^a \quad \text{or} \quad P_t = C_2V^2 + C_1V + C_o$$

$$P_s = P_oV^a \quad \text{or} \quad P_s = P_o\left(d_2V^2 + d_1V + d_o\right)$$

where V is the per-unit magnitude of the voltage imposed on the load. It can be seen that, at steady-state, state variable x of the model is constant. The input to the integration block, $E = P_s - P$, must be zero and, as a result, the model output is determined by the steady-state characteristics $P = P_s$. For any sudden voltage change, x maintains its predisturbance value initially because the integration block cannot change its output instantaneously. The transient output is then determined by the transient characteristics $P - xP_t$. The mismatch between the model output and the steady-state load demand is the error signal e. This signal is fed back to the integration block that gradually changes the state variable x. This process continues until a new steady-state ($e = 0$) is reached. Analytical expressions of the load model, including real (P) and reactive (Q) power dynamics, are:

$$T_p \tfrac{dx}{dt} = P_s(V) - P, P = xP_t(V)$$

$$T_q \tfrac{dy}{dt} = Q_s(V) - Q, Q = yQ_t(V)$$

$$P_t(V) = V^a, P_s(V) = P_o V^a; \quad Q_s(V) = V^\beta, Q_s(V) = Q_o V^\beta$$

Analytical Frameworks

The slow nature of the network and load response associated with the phenomenon made it possible to analyze the problem in two frameworks: (1) long-term dynamic framework in which all slow-acting devices and aggregate bus loads are represented by their dynamic models (the analysis in this case is done through dynamic simulation of the system response to a contingency or load variation), or (2) steady-state framework (e.g., load flow) to determine if the system can reach a stable operating point following a particular contingency. This operating point could be a final state or a midpoint following a step of a discrete control action (e.g., transformer tap change).

The proximity of a given system to voltage instability is typically assessed by indices that measure one or a combination of:

- Sensitivity of load bus voltage to variations in active power of the load.
- Sensitivity of load bus voltage to variations in injected reactive power at the load bus.
- Sensitivity of the receiving end voltage to variations in sending end voltage.
- Sensitivity of the total reactive power generated by generators, synchronous condensers, and SVS to variations in load bus reactive power.

Computational Methods

Load Flow Analysis

Consider a simple two-bus system of a sending end source feeding a $P - Q$ load through a transmission line. The family of curves shown in Fig. 11.14 is produced by maintaining the sending end voltage constant while the load at the receiving end is varied at a constant power factor and the receiving end voltage is calculated. Each curve is calculated at a specific power factor and shows the maximum power that can be transferred at this particular power factor. Note that the limit can be increased by providing more reactive support at the receiving end [limit (2) vs. limit (1)], which is effectively pushing the power factor of the load in the leading direction. It should also be noted that the points on the curves below the limit line *Vs* characterize unstable behavior of the system where a drop in demand is associated with a drop in the receiving end voltage leading to eventual collapse. Proximity to voltage instability is usually measured by the distance (in *PU* power) between the operating point on the *P–V* curve and the limit of the same curve.

Another family of curves similar to that of Fig. 11.15 can be produced by varying the reactive power demand (or injection) at the receiving end while maintaining the real power and the sending end voltage constant. The relation between the receiving end voltage and the reactive power injection at the receiving

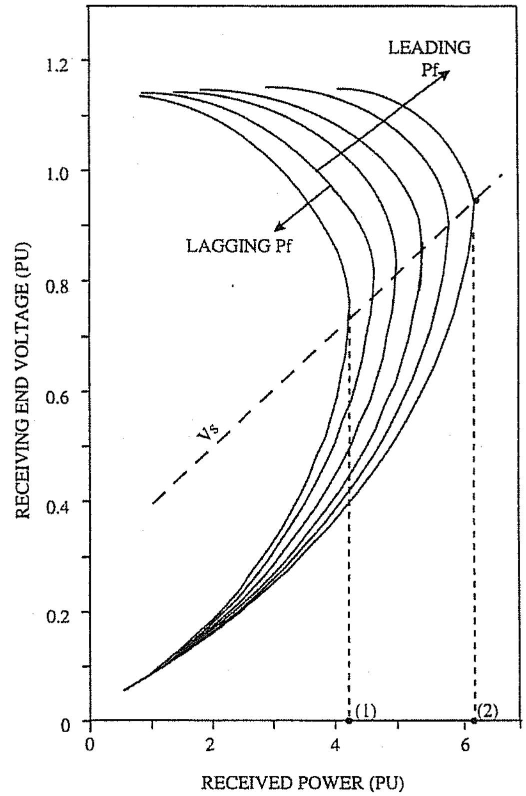


FIGURE 11.14 Pr-Vr characteristics.

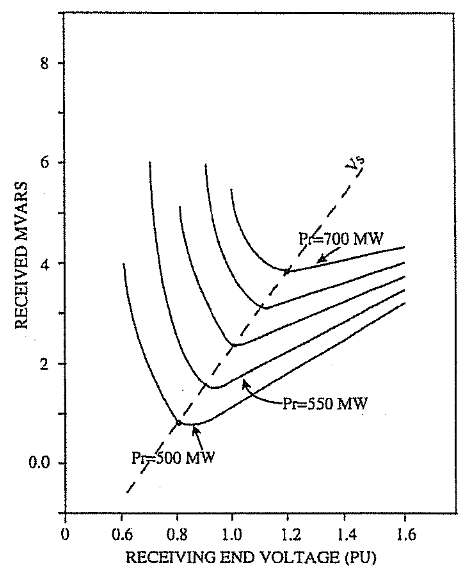


FIGURE 11.15 Q-Vr characteristics.

end is plotted to produce the so called *Q–Vr* curves of Fig. 11.15. The bottom of any given curve characterizes the voltage stability limit. Note that the behavior of the system on the right side of the limit is such that an increase in reactive power injection at the receiving end results in a receiving end voltage rise while the opposite is true on the left side because of the substantial increase in current at the lower voltage, which, in turn, increases reactive losses in the network substantially. The proximity to voltage instability is measured as the difference between the reactive power injection corresponding to the operating point and the bottom of the curve. As the active power transfer increases (upwards in Fig. 11.15), the reactive power margin decreases as does the receiving end voltage.

The same family of relations in Figs. 11.14 and 11.15 can be and have been used to assess the voltage stability of large power systems. The *P–V* curves can be calculated using load flow programs. The demand of load center buses are increased in steps at a constant power factor while the generators' terminal voltages are held at their nominal value. The *P–V* relation can then be plotted by recording the MW demand level against a central load bus voltage at the load center. It should be noted that load flow solution algorithms diverge past the limit and do not produce the unstable portion of the *P–V* relation. The *Q–V* relation, however, can be produced in full by assuming a fictitious synchronous condenser at a central load bus in the load center. The *Q–V* relation is then plotted for this particular bus as a representative of the load center by varying the voltage of the bus (now converted to a voltage control bus by the addition of the synchronous condenser) and recording its value against the reactive power injection of the synchronous condenser. If the limits on the reactive power capability of the synchronous condenser is made very high, the load flow solution algorithm will always converge at either side of the *Q–V* relation.

Sequential Load Flow Method

The *P–V* and *Q–V* relations produced results corresponding to an end state of the system where all tap changers and control actions have taken place in time and the load characteristics were restored to a constant power characteristics. It is always recommended and often common to analyze the system behavior in its transition following a disturbance to the end state. Aside from the full long-term time simulation, the system performance can be analyzed in a quasidynamic manner by breaking the system response down into several time windows, each of which is characterized by the states of the various controllers and the load recovery (Mansour, 1993). Each time window can be analyzed using load flow programs modified to reflect the various controllers' states and load characteristics. Those time windows (Fig. 11.16) are primarily characterized by:

1. Voltage excursion in the first second after a contingency as motors slow, generator voltage regulators respond, etc.
2. The period 1 to 20 sec when the system is quiescent until excitation limiting occurs
3. The period 20 to 60 sec when generator over excitation protection has operated
4. The period 1 to 10 min after the disturbance when LTCs restore customer load and further increase reactive demand on generators
5. The period beyond 10 min when AGC, phase angle regulators, operators, etc. come into play

Voltage Stability as Affected by Load Dynamics

Voltage stability may occur when a power system experiences a large disturbance such as a transmission line outage. It may also occur if there is no major disturbance but the system's operating point shifts slowly towards stability limits. Therefore, the voltage stability problem, as other stability problems, must be investigated from two perspectives, the large-disturbance stability and the small-signal stability.

Large-disturbance voltage stability is event-oriented and addresses problems such as postcontingency margin requirement and response of reactive power support. Small-signal voltage stability investigates the stability of an operating point. It can provide such information as to the areas vulnerable to voltage collapse. In this section, the principle of load dynamics affecting both types of voltage stabilities is analyzed by examining the interaction of a load center with its supply network. Key parameters influencing voltage stability are identified. Since the real power dynamic behavior of an aggregate load is similar to its reactive power counterpart, the analysis is limited to reactive power only.

Large-Disturbance Voltage Stability

To facilitate explanation, assume that the voltage dynamics in the supply network are fast as compared to the aggregate dynamics of the load center. The network can then be modeled by three quasi-steady-state

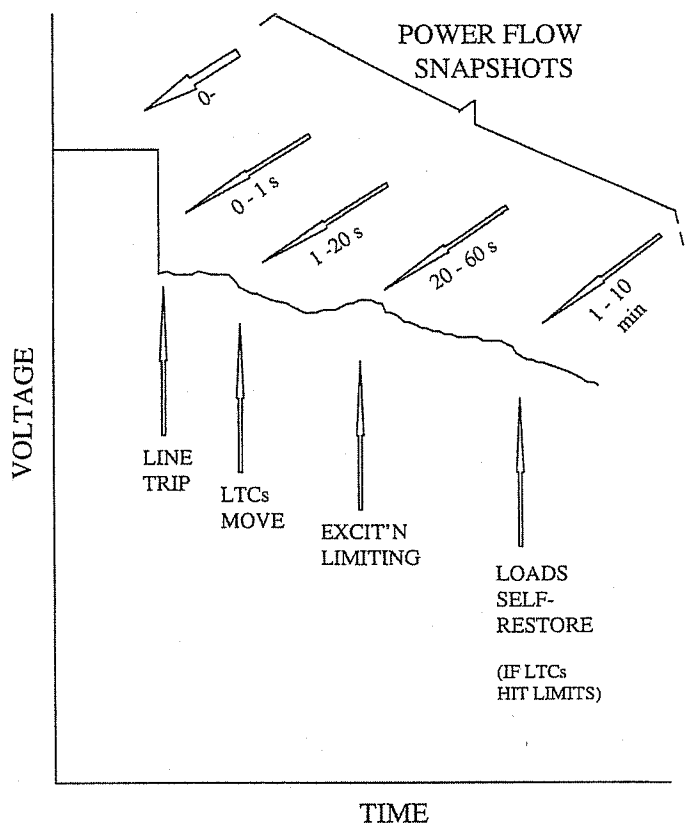
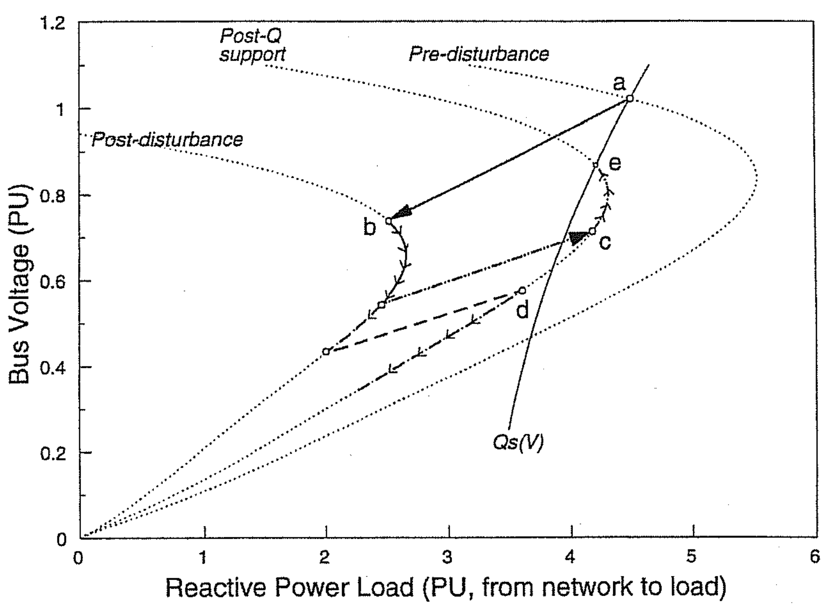


FIGURE 11.16 Breaking the system response down into time periods.



The network experiences an outage that reduces its reactive power supply capability to the postdisturbance V–Q curve. The aggregate load responds (see section on Generic Dynamic Load-Voltage Characteristics) instantaneously with its transient characteristics ($\beta = 2$, constant impedance in this example) and the system operating point jumps to point b. Since, at point b, the network reactive power supply is less than load demand for the given voltage:

$$T_q \frac{dy}{dt} = Q_s(V) - Q(V) > 0$$

The load dynamics will try to draw more reactive power by increasing the state variable y. This is equivalent to increasing the load admittance if $\beta = 2$ or the load current if $\beta = 1$. It drives the operating point to a lower voltage. If the load demand and the network supply imbalance persists, the system will continuously operate on the intersection of the postdisturbance V–Q curve and the drifting transient load curve with a monotonically decreasing voltage.

If reactive power support is initiated shortly after the outage, the network is switched to the third V–Q curve. The load responds with its transient chracteristics and a new operating point is formed. Depending on the switch time of reactive power support, the new operating point can be either c, for fas response, or d, for slow response. At point c, power supply is greater than load demand ($Q_s(V) - Q(V) < 0$). The load then draws less power by decreasing its state variable, and as a result, the operating voltage is increased. This dynamic process continues until the power imbalance is reduced to zero, namely a new steady-state operating point is reached (point e). On the other hand, for the case with slow response reactive support, the load demand is always greater than the network supply. A monotonic voltage collapse is the ultimate end. A numerical solution technique can be used to simulate the above process. Equations for the simulation are:

$$T_q \frac{dy}{dt} = Q_s(V) = Q(t): \quad Q(t) = yQ_t(V)$$

$$Q(t) = Network(V_s t)$$

where the function *Network* $V_s t$ consists of three polynomials each representing one V–Q curve. Figure 11.17 shows the simulation results in V–Q coordinates. The load voltage as a function of time is plotted in Fig. 11.18. The results demonstrate the importance of load dynamics for explaining the voltage stability problem.

Small-Signal Voltage Stability

The voltage characteristics of a power system can be analyzed around an operating point by linearizing the load flow equations around the operating point and analyzing the resulting sensitivity matrices. Recent breakthroughs in the computational algorithms made those techniques efficient and helpful in analyzing large-scale systems, taking into account virtually all the important elements affecting the phenomenon. In particular, singular value decomposition and modal techniques should be of particular interest to the reader and are thoroughly described by Mansour (1993); Lof et al. (IEEE Paper, 1992); Lof et al. (1992); and Gao et al. (1992).

Mitigation of Voltage Stability Problems

The following methods can be used to mitigate voltage stability problems.

Must-Run Generation. Operate uneconomic generators to change power flows or provide voltage support during emergencies or when new lines or transformers are delayed.

Series Capacitors. Use series capacitors to effectively shorten long lines, thus decreasing the net reactive loss. In addition, the line can deliver more reactive power from a strong system at one end to one experiencing a reactive shortage at the other end.

Shunt Capacitors. Though the heavy use of shunt capacitors can be part of the voltage stability problem, sometimes additional capacitors can also solve the problem by freeing "spinning reactive

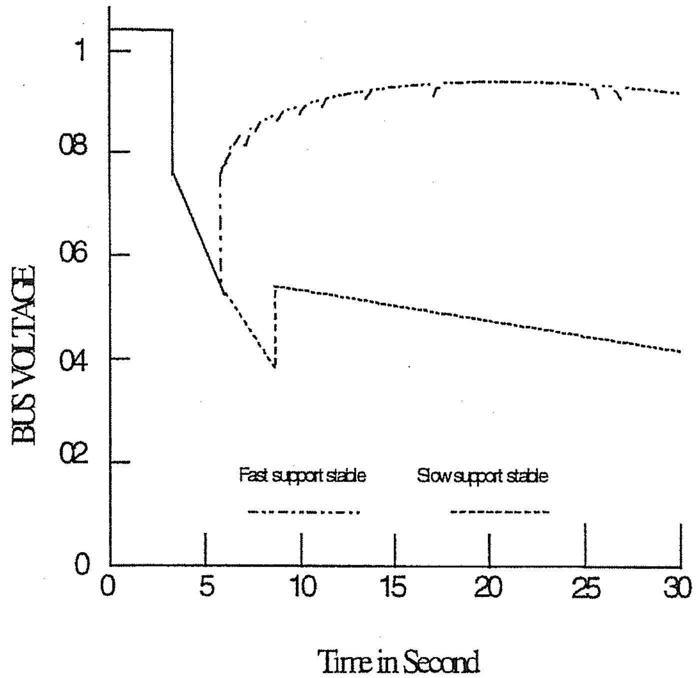


FIGURE 11.18 Simulation of voltage collapse.

reserve" in generators. In general, most of the required reactive power should be supplied locally, with generators supplying primarily active power.

Static Var Compensators (SVC). SVCs, the modern counterpart to the synchronous condenser, are effective in controlling voltage and preventing voltage collapse, but have very definite limitations that must be recognized. Voltage collapse is likely in systems heavily dependent on SVCs when a disturbance exceeding planning criteria takes SVCs to ceiling.

Operate at Higher Voltages. Operating at higher voltage may not increase reactive reserves, but does decrease reactive demand. As such, it can help keep generators away from reactive power limits, and thus help operators maintain control of voltage. The comparison of receiving end *Q–V* curves for two sending end voltages shows the value of higher voltages.

Undervoltage Load Shedding. A small load reduction, even 5 to 10%, can make the difference between collapse and survival. Manual load shedding is used today for this purpose (some utilities use distribution voltage reduction via SCADA), though it may be too slow to be effective in the case of a severe reactive shortage. Inverse time-undervoltage relays are not widely used, but can be very effective. In a radial load situation, load shedding should be based on primary side voltage. In a steady-state stability problem, the load shed in the receiving system will be most effective even though voltages may be lowest near the electrical center (though shedding load in the vicinity of the lowest voltage may be more easily accomplished, and will be helpful).

Lower Power Factor Generators. Where new generation is close enough to reactive-short areas or areas that may occasionally demand large reactive reserves, a .80 or .85 power factor generator may sometimes be appropriate. However, shunt capacitors with a higher power factor generator having reactive overload capability, may be more flexible and economic.

Use Generator Reactive Overload Capability. Generators should be used as effectively as possible. Overload capability of generators and exciters may be used to delay voltage collapse until operators can change dispatch or curtail load when reactive overloads are modest. To be most useful, reactive overload capability must be defined in advance, operators trained in its use, and protective devices set so as not to prevent its use.

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11.5 Direct Stability Methods

Vijay Vittal

Direct methods of stability analysis determine the transient stability (as defined in Section 11.1 and described in Section 11.2) of power systems without explicitly obtaining the solutions of the differential equations governing the dynamic behavior of the system. The basis for the method is Lyapunov's second method, also known as Lyapunov's direct method, to determine stability of systems governed by differential equations. The fundamental work of A. M. Lyapunov (1857-1918) on stability of motion was published in Russian in 1893, and was translated into French in 1907 (Lyapunov, 1907). This work received little attention and for a long time was forgotten. In the 1930s, Soviet mathematicians revived these investigations and showed that Lyapunov's method was applicable to several problems in physics and engineering. This revival of the subject matter has spawned several contributions that have led to the further development of the theory and application of the method to physical systems.

The following example motivates the direct methods and also provides a comparison with the conventional technique of simulating the differential equations governing the dynamics of the system. Figure 11.19 shows an illustration of the basic idea behind the use of the direct methods. A vehicle, initially at the bottom of a hill, is given a sudden push up the hill. Depending on the magnitude of the push, the vehicle will either go over the hill and tumble, in which case it is unstable, or the vehicle will climb only part of the way up the hill and return to a rest position (assuming that the vehicle's motion will be damped), i.e., it will be stable. In order to determine the outcome of disturbing the vehicle's equilibrium for a given set of conditions (mass of the vehicle, magnitude of the push, height of the hill, etc.), two different methods can be used:

1. Knowing the initial conditions, obtain a time solution of the equations describing the dynamics of the vehicle and track the position of the vehicle to determine how far up the hill the vehicle will travel. This approach is analogous to the traditional time domain approach of determining stability in dynamic systems.
2. The approach based on Lyapunov's direct method would consist of characterizing the motion of the dynamic system using a suitable Lyapunov function. The Lyapunov function should satisfy certain sign definiteness properties. These properties will be addressed later in this subsection. A natural choice for the Lyapunov function is the system energy. One would then compute the

EXHIBIT B

THE ELECTRIC POWER ENGINEERING HANDBOOK

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4.11 Reactive Power Compensation

Rao S. Thallam

The Need for Reactive Power Compensation

Except in a very few special situations, electrical energy is generated, transmitted, distributed, and utilized as alternating current (AC). However, alternating current has several distinct disadvantages. One of these is the necessity of reactive power that needs to be supplied along with active power. Reactive power can be leading or lagging. While it is the active power that contributes to the energy consumed, or transmitted, reactive power does not contribute to the energy. Reactive power is an inherent part of the "total power." Reactive power is either generated or consumed in almost every component of the system, generation, transmission, and distribution and eventually by the loads. The impedance of a branch of a circuit in an AC system consists of two components, resistance and reactance. Reactance can be either inductive or capacitive, which contribute to reactive power in the circuit. Most of the loads are inductive, and must be supplied with lagging reactive power. It is economical to supply this reactive power closer to the load in the distribution system.

In this section, reactive power compensation, mainly in transmission systems installed at substations, is discussed. Reactive power compensation in power systems can be either shunt or series. Both will be discussed.

Shunt Reactive Power Compensation

Since most loads are inductive and consume lagging reactive power, the compensation required is usually supplied by leading reactive power. Shunt compensation of reactive power can be employed either at load level, substation level, or at transmission level. It can be capacitive (leading) or inductive (lagging) reactive power, although in most cases as explained before, compensation is capacitive. The most common form of leading reactive power compensation is by connecting shunt capacitors to the line.

Shunt Capacitors

Shunt capacitors are employed at substation level for the following reasons:

1. Voltage regulation: The main reason that shunt capacitors are installed at substations is to control the voltage within required levels. Load varies over the day, with very low load from midnight to early morning and peak values occurring in the evening between 4 PM and 7 PM. Shape of the load curve also varies from weekday to weekend, with weekend load typically low. As the load varies, voltage at the substation bus and at the load bus varies. Since the load power factor is always lagging, a shunt connected capacitor bank at the substation can raise voltage when the load is high. The shunt capacitor banks can be permanently connected to the bus (fixed capacitor bank) or can be switched as needed. Switching can be based on time, if load variation is predictable, or can be based on voltage, power factor, or line current.
2. Reducing power losses: Compensating the load lagging power factor with the bus connected shunt capacitor bank improves the power factor and reduces current flow through the transmission lines, transformers, generators, etc. This will reduce power losses (I^2R losses) in this equipment.
3. Increased utilization of equipment: Shunt compensation with capacitor banks reduces kVA loading of lines, transformers, and generators, which means with compensation they can be used for delivering more power without overloading the equipment.

Reactive power compensation in a power system is of two types — shunt and series. Shunt compensation can be installed near the load, in a distribution substation, along the distribution feeder, or in a transmission substation. Each application has different purposes. Shunt reactive compensation can be inductive or capacitive. At load level, at the distribution substation, and along the distribution feeder, compensation is usually capacitive. In a transmission substation, both inductive and capacitve reactive compensation are installed.

Application of Shunt Capacitor Banks in Distribution Systems — A Utility Perspective

The Salt River Project (SRP) is a public power utility serving more than 720,000 (April 2000) customers in central Arizona. Thousands of capacitor banks are installed in the entire distribution system. The primary usage for capacitor banks in the distribution system is to maintain a certain power factor at peak loading conditions. The target power factor is .98 leading at system peak. This figure was set as an attempt to have a unity power factor on the 69-kV side of the substation transformer. The leading power factor compensates for the industrial substations that have no capacitors. The unity power factor maintains a balance with ties to other utilities.

The main purpose of the capacitors is not for voltage support, as the case may be at utilities with long distribution feeders. Most of the feeders in the SRP service area do not have long runs (substations are about two miles apart) and load tap changers on the substation transformers are used for voltage regulation.

The SRP system is a summer peaking system. After each summer peak, a capacitor study is performed to determine the capacitor requirements for the next summer. The input to the computer program for evaluating capacitor additions consists of three major components:

- Megawatts and megavars for each substation transformer at peak.
- A listing of the capacitor banks with size and operating status at time of peak.
- The next summer's projected loads.

By looking at the present peak MW and Mvars and comparing the results to the projected MW loads, Mvar deficiencies can be determined. The output of the program is reviewed and a listing of potential needs is developed. The system operations personnel also review the study results and their input is included in making final decisions about capacitor bank additions.

Once the list of additional reactive power requirements is finalized, determinations are made about the placement of each bank. The capacitor requirement is developed on a per-transformer basis. The

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Contents

LINEAR PROGRAMMING ADAPTED FOR OPTIMAL POWER FLOW

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ABSTRACT

A linear programming formulation suitable for Optimal Power Flow solution is presented. The classical linear programming formulation is reviewed first. Next, modifications are made to this classical formulation for solving the Optimal Power Flow problem. The solution procedure is then presented along with suitable examples to clarify the approach. Alternative formulations dealing with sparsity and infeasibility are also discussed.

INTRODUCTION

Linear programming has been recognized for several decades as a reliable and robust technique for solving a large subset of optimization problems with linearized relationships. The purpose of this text is to overview the classic linear programming formulation and to describe enhancements which make linear programming more suitable for the solution of power system applications, particularly the Optimal Power Flow problem.

A rigorous theoretical presentation will not be attempted as many textbooks already exist to serve that purpose, e.g. [1], [2]. Rather, a practical understanding of the linear programming algorithm will be provided in relation to power system modeling and applications.

An earlier tutorial included a section on linear programming as applied to Constrained Var Dispatch [3]. The Constrained Var Dispatch features are also reviewed in this text.

Stott, et al. ([4], [5], [6]) have done considerable work in evaluating linear programming techniques and applying them to the solution of power system optimization problems. Their work is also reviewed in this text.

The overriding objective of this tutorial text is to present linear programming formulations and solution techniques which achieve an efficient solution to the Optimal Power Flow problem.

DEFINITIONS

The following notations will be used throughout this text:

Vectors are shown in boldface using small letters

Vectors are column vectors unless followed by an apostrophe (e.g. **x'**) in which case it is a row vector

Matrices are shown in boldface using capital letters; a matrix transpose is indicated by a capital letter followed by an apostrophe (e.g. **S'**)

A variable or quantity preceeded by a 'delta' sign, (e.g. $\Delta\mathbf{x}$) signifies a change in that quantity from some initial value or solution

A vector followed by a subscript (e.g. $\mathbf{x}_C$) denotes a subset of the elements in the vector

Multiplication is implicit when two quantities (any combination of vectors, Matrices, or scalars) are shown next to each other separated only by a single space, e.g. **A x** or **c' x**.

The symbols shown below will be used to identify the associated quantities or variables throughout this text:

$\mathbf{x}$ - the total set of variables to be solved for by the linear programming algorithm, $\mathbf{x} = \{\mathbf{x}_C, \mathbf{x}_S\}$, see below

z - the quantity to be minimized (or maximized), termed the objective function and expressed as a linear function of the variables. Note that this function is given here as a combination of control costs and constraint violations.

The solution procedures described in this text will minimize z unless otherwise stated. Note that maximizing z is the same as minimizing -z.

$\mathbf{x}_C$ - the subset of variables which comprise the independent control variables

$\mathbf{c}$ - the incremental control and penalty costs, i.e. the linear sensitivities between the objective function and the variables

In some formulations, the penalty costs associated with constraint violations and hence with the slack variables are contained in a separate vector, **d**. The vector **c**, in these formulations is then limited to control variable costs.

$\mathbf{c}_C$ - the subset of incremental costs which are associated with the control variables, i.e. incremental control costs

$\mathbf{b}$ - the set of constraint limits, where the constrained quantities are expressed as a linear function of the control variables

$\mathbf{b}_C$ - limits on the control variables. The enforcement of these limits is trivial because of the problem formulation. Thus, $\mathbf{b}_C$ is not usually represented in the equations, and the vector **b** does not include them. Even though **b** addresses only the constraints, it will be stated as **b** rather than $\mathbf{b}_S$ for simplicity and for consistency with the standard formulation.

$\mathbf{y}$ - the set of constrained quantities, expressed as a linear function of changes in **x**. **y** may actually be a non-linear function of **x**, $\mathbf{y(x)}$

$\mathbf{x}_S$ - the subset of variables which represent the differences between the constrained quantities and their associated limits. These variables are termed slack variables (note that the term artificial variable is also used, see text below)

$\mathbf{c}_S$ - the subset of incremental costs which are associated with the slack variables, i.e. incremental penalty costs

$\mathbf{d}$ - the set of incremental penalty costs, $\mathbf{c}_S$, expressed as a separate vector. This vector is used in formulations where violations are recognized as infeasible and are

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symmetry, while transpose symbols, ', are always used to show a vector represented as a row rather than a column.

Summarizing the above equations:

- Equation (33) is used to solve for the state variable changes given a change in the control variables
- Equation (34) is used to solve for changes in all constrained quantities given the change in the state variables
- Equation (40) is used to compute a new set of sensitivity factors for a constraint violation which is to be resolved

The basis matrix relationship is still represented by equation (11) and the equations which are derived from it. Slack variables are still represented for binding constraints to deterine when a binding constraint can resolve a new constraint by moving within its limits. The key is that the set of represented constraints, and hence the dimension of **B**, is limited to the subset of binding constraints which is normally very small in number. Hence the inversion of **B** is straightforward and efficient due to its small dimension.

Several unique features of this algorithm include:

- An additional violated constraint is selected to be added to the basis in each iteration. This means that the basis dimension increases by one unless the variable selected to resolve the constraint is the slack variable of another constraint, in which case that other constraint leaves the basis
- The variable selected to resolve the constraint violation is modified as necessary to bring the constrained quantity back to its violated limit, regardless of the selected variable's own limits
- The most violated constraint selected in each iteration may represent a control variable, since control variable violations may be incurred in the process of bringing the worst violation back to its limit

CONSTRAINED VAR DISPATCH

Due to its inherrant non-linearity, the control of power system var resources and associated control voltage settings requires special considerations when formulated for linear programming. This section of the text describes such a formulation which was applied in Energy Management Systems.

Primary Var Dispatch Objective

The primary objective of a constrained var dispatch is to eliminate any bus voltage violations with minimal control movement. Since voltage violations will be modeled as penalty costs, the violations will be minimized if they cannot be eliminated. The minimal control movement objective assumes that there is a rationale for the existing operating conditions and such conditions should be deviated from as little as possible.

The voltage violations are typically penalized about one hundred times more than control movement. Penalization by a factor of ten rather than one hundred will tend to reduce the number of modified control resources to those which are most significant. This reduction normally yields a more realistic and viable control strategy, i.e. one which can be practically implemented. On the other hand, increasing the penalization to a factor of one thousand may occasionally resolve a violation which could not be eliminated at lower penalty costs.

Secondary Objectives

Secondary objectives can also be represented. Two examples are the reduction of losses and the preservation of var reserve. These secondary objectives can improve an existing set of control settings or operating conditions, especially when there are no existing voltage violations.

Loss Reduction

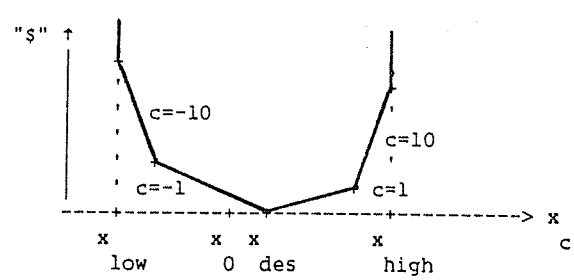
Linearized reactive loss factors can be computed in a manner similar to the well known calculation of the real power loss factors used for economic dispatch. The reactive loss factors relate real power losses to changes in reactive rather than real power injections. Desired operating points from which control movement is to be minimized are adjusted from the original operating points in a direction which reduces losses. This direction is determined from the algebraic sign of the loss factors. Operating points are only adjusted for controls with associated loss factors above a minimum threshold, i.e. only when significant loss reduction is indicated.

Due to the high non-linearity of losses with respect to voltages, the change in the desired operating point should be limited to a relatively small control step, e.g. 10 Mvar or a single tap step. Further adjustment should be made only after recomputing the loss factors to account for the first set of control steps taken.

Loss minimization can be achieved through this approach over a period of time in a "tracking" sense, i.e. through a series of small control setting adjustments after which losses are reevaluated.

Var Reserve Preservation

Var reserves represent the ability to respond in the required direction without running into an operating limit. Thus var reserves are maintained or maximized by discouraging var control movement close to a limit. This is achieved by increasing the penalty of control movement within a control band of either limit. The control cost applied to a var resource may be represented by a piecewise linear curve as shown below:



In the above figure, c represents the penalty cost. 10c is applied within a reserve control band of each limit. The difference between xdes and xo represents the change from an initial operating setpoint to reduce losses.

Var Resource Control Variables

Var resources typically include excitation control systems in both generators and synchronous condensors, tap changing (TCUL or LTC) transformers, and switchable shunt devices (capacitors, reactors, or SVS's). Each of these resources is represented as a control variable in terms of bus var injections. Control voltage settings are also modeled as control variables in a manner described in the following subsection.

Generator var limits should be represented as a function of the Mw output of the unit. Passive shunt controls (capacitors, reactors, etc.) should have their Mvar limits adjusted as the square of the voltage magnitude on the connected bus. Transformers are represented as a pair of var injections, one on each of the connected busses, as a function of the off-nominal tap setting (see Appendix).

Single shunt elements or banks of them are discrete rather than continuous in nature. Unless integer programming is applied, however, they must be modeled as continuous. The recommended approach consists of two passes. In the first pass, the variables are modeled as continuous. If any discrete variable is not at a limit (or breakpoint for banks of elements) following the first pass, it is extrapolated to the limit or breakpoint towards which it was moving. If this extrapolation does not cause any significant increase in voltage violations, it is left at this extrapolated limit or breakpoint, otherwise it is moved back to its original setting or the breakpoint it most recently moved away from. In the second pass, all discrete variables are held at the limits or breakpoints determined from the processing described above, while the remaining variables are modified further, if possible, to compensate for the roundoff of the discrete variables.

Transformers may normally be treated as continous variables and then rounded off to the nearest tap step.

Control Voltage Settings

Control voltages are indirectly treated as additional control variables by modeling them as soft voltage constraints whose violations are penalized by the same relative amount as control movement. The voltage constraint limits are clamped at the original control setting, assuming that this was the desired operating condition which should be deviated from as little as possible. In this manner, both generator var changes and control voltage changes are accounted for, thereby avoiding excessive changes in one when only the other is controlled.

Local Voltage Control

Local voltage control represents isolated control action dedicated to keeping a specific bus voltage constant. This type of control is often referred to as primary control and is localized rather than global in nature. The constrained var dispatch formulation represents the locally controlled bus voltages as constant and cannot modify the locally controlled voltage settings.

Local voltage control busses are modeled as constant voltage, i.e. as voltage reference busses in the sensitivity matrix.

The advantage of local voltage control representation are twofold:

- The number of control variables is reduced, thereby improving performance (locally controlled voltages are not control variables)
- The numerical stability of the solution is enhanced (power flows have been known to diverge with an insufficient number of P-V or voltage reference busses)

Local voltage control busses are typically those remote from the violations which need to be resolved, or those at which the desired voltage is known a priori. Local voltage controls should have sufficient capacity to maintain the desired voltage, otherwise they need to be modeled as controllable so that control limits may be recognized and appropriately simulated. Such modeling of local voltage control in the var dispatch algorithm requires representation of the control voltage setting as an additional voltage constraint whose limits are clamped at the desired control setting. Such a voltage constraint has its violation penalized the same amount as any other voltage violation, i.e. ten to one-thousand times control movement.

It is possible to penalize a given voltage violation more or less than another violation simply by changing the relative value of the coefficient in the '**c**' vector of equation (1) just as it is possible to penalize the movement of one control more or less than another by modifying the associated 'cost' coefficient in the '**c**' vector of equation (1).

Voltage Constraints

The set of voltage constraints enforced by the Constrained Var Dispatch algorithm normally include only those bus voltages which are either outside of acceptable operating conditions or are anticipated to move outside of such conditions. Most of these constraints can be identified by the algorithm itself as a function of the base case or a modified voltage solution. Constraint violations detected from a modified voltage solution, are those which tend to violate their limits when the original set of constraint violations are eliminated. These additional violations are detected in subsequent iterations using the modified voltage solution supplied by the preceeding iteration. The var resources must be redispatched to constrain both sets of voltages, i.e. intial violations and consequent violations.

Experience can dictate the prespecification of voltages to be included in the original set of constraints. Such prespecified voltages include those which are not close to limits in the base solution but which are known from experience to violate their limits when other violations are resolved.

Constraint Redundancy

Voltage constraints are frequently related and redundant in that the resolution of the worst or 'key' violation in the set will automatically resolve the others. Such key voltages have been referred to as pilot point voltages [12]. It is beneficial to detect such redundant voltages and either determine the key voltage constraints to be represented or have them prespecified from experience. Numerous heuristic techniques can be used to identify redundant sets of constraints and select only the worst one in the set.

Representation and enforcement of only the key voltage constraints can greatly reduce the problem dimension without affecting the optimal solution, thereby significantly enhancing performance.

Voltage/Var Sensitivity

Linear (first order) sensitivities are required for LP to relate changes in var injections to changes in bus voltages. These sensitivities are computed from the B" matrix relationship used in the Fast Decoupled Power Flow [7]. It is important to note that only local control busses are modeled as constant voltage in B". A bus is not modeled as constant voltage in B" if a var resource controlled by OVD is connected to it.

Alternative sensitivity matrices may be employed such as a submatrix of the Jacobian, evaluated at the base solution. Another alternative matrix, L" [8], assumes constant Mw flow but allows the voltage angles to change as a function of changes in var flow.

Since a given per-unit voltage change is about ten times more significant than the same per-unit change in a var injection, i.e. a 0.1 p.u. var injection change is typically required to achieve a 0.01 p.u. voltage magnitude change, control voltage violations are actually penalized ten times more than var control movement to achieve the same relative effect. Since per-unit tap changes cause per-unit control voltage changes of an equal magnitude (sensitivity of one), transformer tap control movement is also weighted ten times more than changes in var injections.

Sensitivity between voltage and vars is more linear when a quantity termed 'mega-ampere reactive' or 'Mars' is used in place of Mvar. Mars are equal to Mvars divided by the voltage magnitude on the connected bus:

$$\text{Mar} = \text{Mvar}/\text{V}$$

Constraint Limit Adjustment for Non-linearity

Voltages computed by a "verification" power flow are generally different than the voltages predicted by LP using linearized sensitivities. The voltage constraint limits enforced by LP may be adjusted to compensate for this difference. For example, assume a base voltage of 1.14 p.u. and a high voltage limit of 1.10 p.u. on a given bus. If the LP algorithm predicted a voltage change of -0.04, i.e. a change from 1.14 to the limit of 1.10, but the power flow computed the voltage as 1.12, then the voltage actually changed only half as much as predicted, i.e. -0.02 instead of -0.04. Extrapolating this undershoot, a predicted change of -0.08 might be expected to result in an actual change of -0.04. A predicted change of -0.08 can be obtained by setting the high limit to 1.06, i.e. 0.08 below the base value.

The changes in the voltage limits described above are exponentially filtered to smooth and dampen the constraint limit changes, thereby preventing abrupt and excessive change.

The formula used to adjust the limits is:

$$\text{LIM}' = \text{A} * (\text{Vo} + \text{RAT} * (\text{LIMo} - \text{Vo})) + (1. - \text{A}) * \text{LIM} \quad (41)$$

LIM = previous value of adjusted limit
LIM' = new (updated) value of adjusted limit
LIMo = actual (unadjusted) limit

$$\text{RAT} = (\text{Vlp} - \text{Vo})/(\text{Vpf} - \text{Vo})$$

Vlp = voltage magnitude predicted by LP
Vpf = voltage magnitude computed by power flow
Vo = initial (starting point) voltage magnitude

A = exponential filter coefficient ($0 < A < 1$)

This correction to the voltage limits helps to account for non-linearity and also for the effects of local var controls (generator vars and transformer taps) reaching their limits.

It is only necessary to correct a limit if one of the following is true:

- The limit is binding (Vlp = LIM)
- The limit is underresolved (Vpf > LIM > Vlp) (*)
- The limit is overresolved (Vlp > LIM > Vpf) (*)

(*) - for LIM = high limit, reverse inequalties for low limit

Constraint Selection

In each iteration, voltage constraints are identified and selected on the basis of the most recent voltage solution. In the first iteration, this voltage solution is the base case solution; in each subsequent iteration, this voltage solution is the results of the previous iteration. A voltage violation rating is computed for any monitored bus. This violation rating measures the severity of an existing violation or the likelihood of a potential violation. One possible measure is:

$$V_{rat} = \text{ABS}(2\,V - V_h - V_l)/(V_h - V_l) \quad (42)$$

V_{rat} = Voltage Violation Rating

V = Actual voltage (from most recent solution)

V_h, V_l = High and Lower Voltage Limits

A previously constrained voltage already has a computed voltage violation rating and this rating is not changed. If the voltage violation rating is above a threshold value, the voltage is constrained. If the number of constraints exceeds the constraint sizing, only the constraints with the largest voltage violation ratings are retained.

If constraint limits are adjusted for non-linearity in a given iteration, new constraints are not added until the following iteration. This avoids premature identification of new constraints which would not qualify after the original constraint limits were adjusted for non-linearity.

Iterative Approach

The constrained dispatch algorithm is iterative in nature. Each iteration involves a both a linear programming solution and a verification power flow to account for non-linearity. Each new iteration can involve one or more of the following changes:

- identification of additional constraints (typically voltages which violated their limits as a result of the control variable modifications in the previous iteration)
- modification of constraint limits or weighting to account for non-linearity detected in the previous iteration
- recomputation of sensitivity or cost coefficients

Two types of iterations are possible, with one iteration being an inner loop of the other:

- Retry - This inner loop iteration goes back to the starting point of the previous iteration under the assumption that the previous iteration may have gone in the wrong direction
- Track - This outer loop iteration establishes a new, updated starting point as the results from the last in a series of retry iterations and proceeds from there with a new set of retry iterations

The steps involved with the Retry and Track Iterations are shown below:

```
BASE CASE POWER FLOW

IDENTIFY REACTIVE POWER CONTROLS

DO WHILE (Track) CONVERGENCE NOT OBTAINED

    COMPUTE AND FACTOR SENSITIVITY MATRIX

    IF LOSS REDUCTION REQUESTED

            COMPUTE INCREMENTAL LOSS FACTORS

    ENDIF

    FORM INCREMENTAL COST SEGMENTS

    DO WHILE (Retry) CONVERGENCE NOT OBTAINED

        IF NOT THE FIRST (Retry) ITERATION

            ADJUST CONSTRAINT LIMITS FOR NON-
            LINEARITY

        ENDIF

        IF THE FIRST (Retry) ITERATION

            SELECT VOLTAGE CONSTRAINTS FROM BASE
            SOLUTION

        ELSE

            ADD VOLTAGE CONSTRAINTS FROM LAST
            (Retry) SOLN

        ENDIF

        RESTORE DATA TO BASE CASE VALUES

        COMPUTE SENSITIVITY FACTORS FOR NEW
        CONSTRAINTS

        LINEAR PROGRAMMING OPTIMIZATION

        TEST FOR CONVERGENCE (Retry Iterations)

        VERIFICATION POWER FLOW

    ENDDO

    UPDATE BASE CASE SOLUTION

ENDDO
```

Convergence Criteria

Each retry iteration of the Constrained Var Dispatch differs from the previous iteration in that new voltage constraints were identified and/or voltage limits were adjusted. The solution is terminated, i.e. no more retry iterations are necessary, when one or more of the following conditions are true:

- The maximum number of iterations has been reached
- The control movement is the same (within a tolerance) as the movement computed in the previous iteration. Recall that each retry iteration begins from the base case solution.

A new tracking solution is attempted when the new base solution, i.e. that arrived at from the final retry iteration, represents a significant enough change such that new sensitivity and cost factors at this new solution point could require further control changes.

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EXHIBIT C

ELECTRIC POWER
RESEARCH INSTITUTE

The Integration of Large-Scale Renewable Resources into the Spanish Power System

Highlights of Discussions Held During a Visit to Spain, June 1–3, 2010

Organized by the Electric Power Research Institute (EPRI)

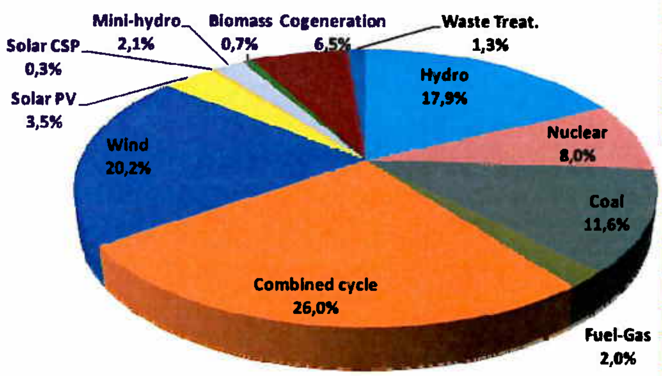
for International Power Industry Executives

July 2010

Spain has successfully integrated a large penetration of renewable resources into its power system. Spain has 93.3 GW of generating capacity to supply 266,486 MWh (2008) with a peak summer demand of 41.1 GW (2010) and winter demand of 44.4 GW (2009). As of May 2010, 20.2% of Spain's generating capacity is wind, supplying 13.7% of electric power production in 2009, and reaching levels greater than 40% in one day (e.g., 52% early on Sunday, November 8, 2009). As such, Spain is often referred to as a world leader in the successful integration of wind. In fact, Spain ranks fourth in the world in wind generating capacity with 19.2 GW (2009). With regard to solar power generation, as of May 2010, Spain has 3.6 GW of solar power generation capacity, supplying 2% of its overall 2009 electric energy needs.

It was with this in mind that the Electric Power Research Institute (EPRI) arranged visits to Spain to develop an understanding of Spain's accomplishments by engaging directly with executives from Spain's Association of Electric Utilities (UNESA), Transmission System Owner and Operator (Red Electrica), two of its distribution utilities (Iberdrola and Gas Natural Fenosa), and Spain's largest wind power producer (Iberdrola Renovables).

Spain's embracing of renewables has come about due in part to issues of energy security. Approximately 85% of the country's energy is imported (70% as oil and gas, 15% as coal). The other main considerations are post-Kyoto environmental policies coupled with some uncertainty in Spain's support of nuclear power. Nevertheless, it is notable that Spain's advances in renewables have, to date, been more than matched by advances in adding natural gas-fired generation, which has been essential to meeting Spain's extraordinary growth in electric demand (doubling of demand in 15 years, 1981–2006). Having accomplished this, the country is far better positioned to handle intermittent generation than it would otherwise be.



Technology	MW	%
Hydro-power	16.657	17,85
Nuclear	7.455	7,99
Coal	10.856	11,63
Fuel-Gas	1.849	1,98
Combined cycles	24.294	26,04
Total (ordinary regime)	61.111	65,49
Wind power generation	18.842	20,19
Solar PV	3.268	3,5
Solar CSP	281	0,3
Biomass	647	0,69
Special regime hydro	1.965	2,11
Cogeneration	6.027	6,46
Waste treatment	1.170	1,25
Total (special regime)	32.199	34,51
Total	93.310	

Figure 1 – Installed Capacity in Spain, May 2010 (Source: Red Electrica de España)

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Spain's success in the more specific tasks of integrating wind and solar results from four important elements:

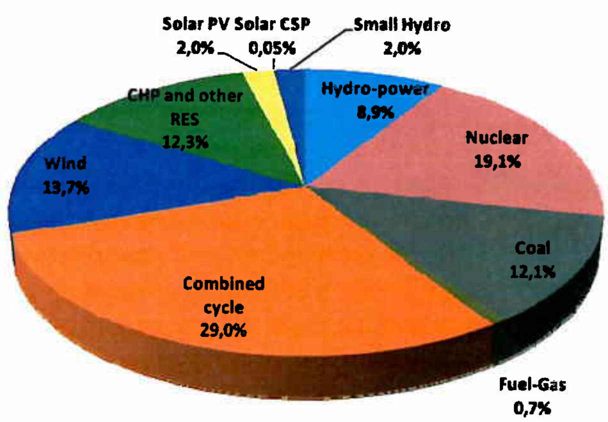
1. Substantial incentives offered to wind developers and solar energy suppliers.
2. The ability to plan, finance, and deploy an expanding national transmission infrastructure in a timely manner.
3. The large-capacity reserve margin with 93.3 GW installed and a peak demand of only 45 GW coupled with the ability to cycle 36 MW of thermal power plants and substantial hydro capacity, as well as 4000 MW of pumped hydro to manage against wind's variability.
4. A robust renewable power generation control infrastructure.

Although Spain has achieved remarkable changes in power generation, power transmission, gas supply infrastructure, market liberalization, and industry structure within a single decade, these have been accompanied by mounting financial challenges and stresses to the enabling policies. Exacerbated by economic recession, further policy adjustments can be expected particularly in areas of lessened price incentives and deferred timetables for reaching goals set for gas infrastructure and renewables. The adequacy of flexible generation is critically important to taking wind generation nearly whenever and wherever the wind blows. While abundant at present (especially natural-gas–combined-cycle generation, plus hydroelectric power and pumped storage, and to a much lesser extent coal-fired steam plant generation), flexible generation might require suitable incentives in the future to ensure adequacy. It is not yet clear that flexible generation is adequately "valued" and compensated. The discussions during these meetings principally addressed technical factors and policies most directly related to transmission, planning, and operations.

Regardless of today's economy, Spain's future use of renewables for power generation will increase substantially. Spain is part of the European Union (EU) and legally bound to achieve the EU's 2009 Directive regarding renewable energy sources. That Directive has established a 20% target for renewables in 2020 across all sectors and includes electricity, heating, cooling, and transport. Each EU member state has a national target based on a fixed increase of 5.5% over the current level of renewables, plus a variable increase indexed on the member state's GDP. In the case of Spain, the target is also 20%. To meet that target, the Spanish National Renewable Energy Action Plan to 2020 has recently been published (http://ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm) and sets a target of about 40% of renewables in electricity production.

Incentives

The rapid growth of renewables in Spain began in 2005 when the first of several royal decrees was signed. These decrees have established feed in tariffs for wind that result in guaranteed prices per



Special Regulation Regime

Renewable:	Non Renewable:
Minihydro	Cogeneration
Biomass	Coal
Wind	Fuel - Gas oil
Industrial waste	Refinery gas
Urban waste	Natural gas
Solar	

Figure 2 – Demand Supply 2009 (Source: Red Electrica de España)

kilowatt hour of either the market price plus a premium (approximately 29 EUR/MWh, which shrinks with climbing prices and includes cap and floor provisions) or a minimum of approximately 73 EUR/MWh for a period of 25 years. Thereafter, it decreases at 5% per year. The price for wind power production averaged 77 EUR/MWh. Figure 3 illustrates the wind bonus structure.

Incentives (bonuses) vary according to the day-ahead market marginal prices providing a floor payment (black line). If market prices are high, wind power does not receive incentives.

Regarding solar power production, a royal decree was issued for what is referred to as a *Special Regime,* which includes renewables and cogeneration. This Special Regime offered 466 EUR/MWh for the first 371 MW of solar PV to apply. It stipulated that completion by 2008 was necessary. A total of 4000 MW applied; 3000 MW was authorized. For concentrating solar-thermal, 500 MW was solicited at a feed-in tariff of 269 EUR/MWh. After receiving 10,000 MW in applications, the government allowed 1500 MW. Even at these greatly reduced (but still substantial) incentive rates, responses have reached their newly imposed quotas in only several months. As of May 2010, 382 MW of concentrating solar power (CSP) has been installed. However, there are plans to increase the deployment of this resource at a rapid pace, so that by 2011 Spain should surpass 1000 MW of operating CSP (the existing 382 MW plus 718 MW under construction). Another 1372 MW has been approved for construction and is expected to operate by 2013, totaling approximately 2500 MW of CSP.

The wind and solar incentives are out of balance with the production of these resources. In 2009, wind provided over 15% of energy generated and accounted for 16% of the cost of production, while the 2% provided by solar energy systems represented 16% of the cost supply. Projections are that by 2013, wind energy will produce 19% and will account for 18% of the cost of production, while photovoltaic (PV) solar will contribute only 3% of the energy of the system and consist of 15% of the total cost of the system. CSP is currently accounting for 8% of the production cost of the system in 2013 in spite of currently providing only 1% of the energy.

Because Spain's wholesale power rate averages between 4 and 6 EUR/MWh and the average retail rate for electricity is approximately 11 EUR/MWh (see www.eia.doe.gov/emeu/international/elecprii.html), both far below these incentive prices, an ongoing "tariff deficit" is generated by under-recovery from the cost of renewables. This deficit is endorsed by the government, securitized, and then sold to

Incentives (bonuses) vary according to the day-ahead market marginal prices providing a floor payment (black line). If market prices are high, wind power does not receive incentives.

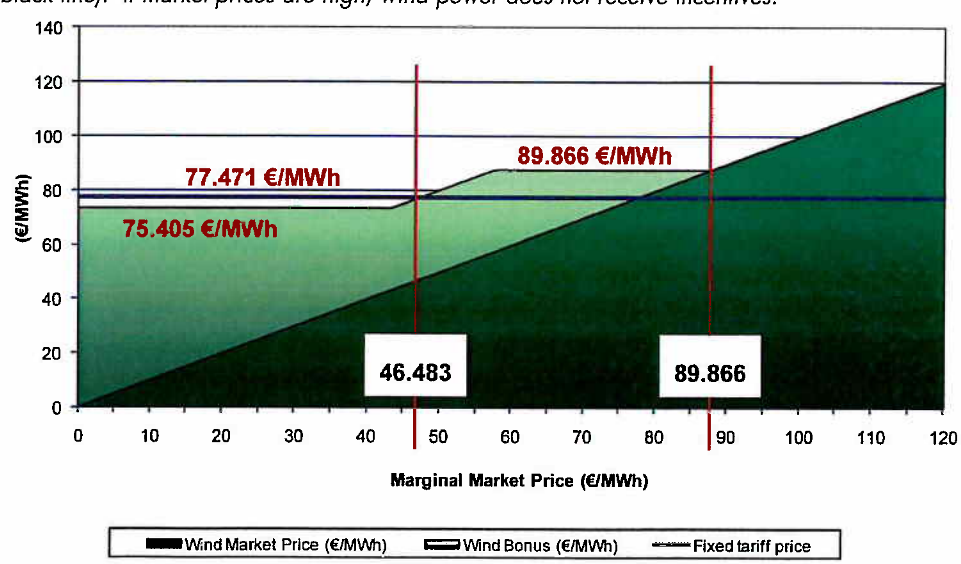


Figure 3 – Wind Energy Incentive (bonus) Structure in Spain (Source: Red Electrica de España)

banks based on the government's assured obligation.[1] The subsidies to renewable energy in 2009 in Spain have been close to 5 billion Euros, but out of this, 50% went to PV, while PV generated only 2% of total electricity. This compares with 15% electricity generated by wind, which received "only" 22% of the subsidy.

Renewable power production is first in the dispatch order, unless system constraints are present. The Spanish market operator, OMEL (Mercado De Electricidad or Operator del Mercado Iberico de Energia) is forced to set wholesale power prices to zero when significant amounts of wind and hydro power production are available. This occurred 15% of the time during the first quarter of 2010 (www.omel.es).

During late June 2010, unconfirmed Spanish press reports indicated that due to Spain's current economic situation there are new deliberations between the Socialist government and the major opposition party—the Conservatives—to establish a new energy plan for Spain. Apparently, all energy topics are on the table, including a move to reduce the energy payments to renewable energy producers. The most frequently mentioned approach is to reduce the number of hours per year they are permitted to earn the bonus. In the meantime, utilities report that scheduled electricity rate increases have been frozen, allowing the tariff deficit to approach 20 billion Euros.

Natural Gas-Fired Generation

Spain has excess generating capacity that can be used in part to balance against the variability of wind, resulting from substantial additions of gas-fired–combined-cycle combustion turbines. Between 1984 and 1997, Spain built nine coal plants totaling 4 GW. Spanish market liberalization, tight reserve margins, strong demand growth, and attractive natural gas prices led to an investment cycle in combined-cycle plants that began in 2002. These combined-cycle units were expected largely to displace oil peaking facilities and coal generation. Combined cycle was also chosen for its lower investment costs, ease of licensing, and competitive fuel costs versus coal. As an unintended consequence, coal was not displaced for the following reasons:

- Gas prices increased, allowing coal to remain competitive
- CO_2 prices from 2005 to 2007 were lower than expected
- Subsidies were extended to domestic coal plants

As a result of these factors as well as demographic changes and cost factors already mentioned, coal declined less than expected while new gas capacity grew substantially. In 2009, low gas prices made the combined-cycle units competitive again. But although coal generation was not competitive, maintaining the coal industry and mining jobs is a priority for the Spanish government.

The Spanish electricity market was liberalized in 1998 after which generation and rental operations became competitive and transmission and distribution remained regulated. At the same time, Red Electrica was reaffirmed as the independent system operator and OMEL as an independent market operator.

Transmission

All of Spain's transmission assets were consolidated in 1985 under Red Electrica (REE). REE is a Spanish company whose shares are openly traded (some public capital remains). REE is responsible for managing the access, construction, maintenance, and system operations of the grid in the Spanish power system.

By royal decree, REE must provide grid access to renewable resource developers. Spain's renewable resources are located at some distance from both load centers and the grid. With REE's authority to take wind generation, its transmission programs have resulted in a tendency to over-install transmission. Intermittent renewable power generation resources make sub-optimal use of the network. For example, Spain's wind farm load factor averages 25% of installed power. Spain has 189 km of 400 kV lines per GW of installed capacity as compared to approximately 100 km per GW in most of Europe. Current plans are to add substations and bays (positions on substations) including one hundred 200 kV buses and fifty 400 kV buses.

Spain's grid capacity lacks strong support from the rest of Europe. Spain's only access to the rest of the continent is through France. Its four interconnections with France total only 1400 MW. Plans are underway to build one 1000 MW dc line to strengthen ties and eventually to build another 1000 MW line to increase the total transfer capacity to France to 4000 MW. Most geographic areas with large penetrations of renewables resources depend on close interties with their neighbors to maintain system reliability. Greater interconnections would be particularly helpful to Spain when its wind or wind and hydro production are at peak levels.

[1] The tariff deficit stood at about 11 billion Euros going into 2008. It grew by another 5 billion Euros that year or, measured against consumption, an amount of ~19 Euros/MWh. Royal decrees in mid-2009 targeted 2013 for elimination of tariff deficits, with fees to consumers rising incrementally in the interim. It is not entirely clear when the tariff deficit will be paid and how much of the burden will be taken as a public expense.

REE conducts plans for grid reinforcement, modernization, and expansion as needed. Those plans are reviewed and approved by the Spanish Government Ministry of Industry, Tourism, and Commerce (MITYC). Once plans are approved, REE constructs the reinforcements and expansion. The government adjusts the transmission tariff as needed to accommodate REE's expenditures. There is only one national "postage stamp" transmission tariff. Therefore, there are no locational price signals that might inhibit the development of remote renewable resources.

Approximately 20% of REE's grid expansion budget consists of renewables integration projects. This includes facilities directly related to renewables as well as those indirectly needed to accommodate the flows resulting from renewables integration. Transmission facilities needed for renewables integration include:

- New overhead and underground lines
- The upgrading of existing lines
- New substation transformers
- New and upgraded substations

Because only one entity—REE—owns and builds transmission, cost allocation is not an issue.

REE believes that there are two major remaining technical issues with regard to renewable resources on its power system: increased vulnerability to voltage dips and both the variability and lack of firmness of the resources.

System Operations

At present, Spain has 4000 MW of pumped hydro but no other source of electric energy storage or demand response programs to help balance against the variability of wind and solar. As such, beyond the use of pumped hydro, Spain must either modulate hydro production or force thermal generation to cycle (principally by

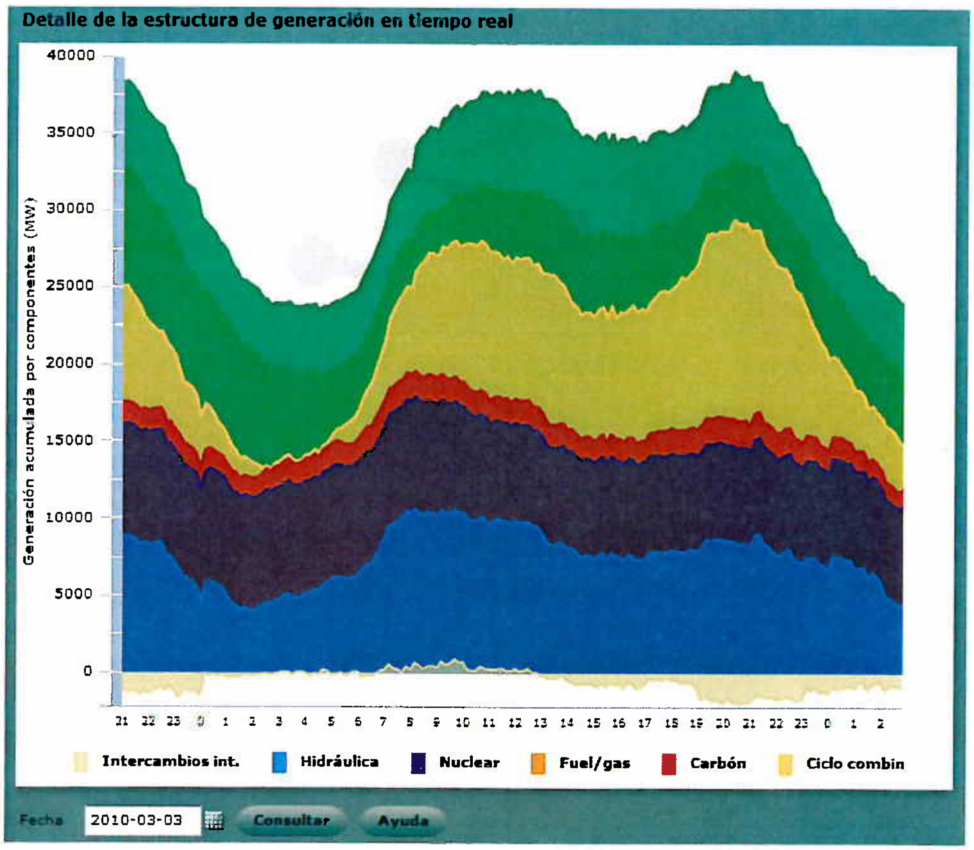


Figure 4 – The Extent to Which Combined-Cycle Combustion Turbines (Ciclo Combin) are Cycled Based on March 3, 1010 (Source: Red Electrica de España)

cycling natural gas-fired–combined-cycle units). It does both very effectively. For example, on March 3, 2010, 27 combined-cycle units were operating during peak hours and only 1 was operating during off-peak hours. REE maintains a daily update with past-day search capability on all generation sources at the following site: https://demanda.ree.es/generacion_acumulada.html. An example of cycling of combined-cycle generation can be seen in Figure 4 on page 6.

There are clearly implications for both the cost of maintenance and deterioration of the combined-cycle units. Because new generation investments get capacity credit that pays almost 40% of the investment cost, this helps provide incentives to construct thermal generation such as combined-cycle plants even as wind dominates the energy market.

REE requires all generators with nameplate ratings over 10 MW to have real-time telemeasurement and control and to have the ability to receive instructions and feedback responses that any actions directed were taken.

Ancillary services payments are made to generators classified as "manageable." To be designated as such, a facility must undergo tests. Manageable renewable resources may participate in voltage control during high production periods. On an increasing number of occasions, wind producers have been asked to "spill wind" or curtail production (see Figure 5). They are not compensated for this. These occurrences are expected to increase as wind penetration continues to grow.

Spain's wind production is highly variable both hour by hour and day to day. For example, Spain's record high production capacity was on February 24, 2010 at 12,916 MW, and the record low was on June 3, 2009 at 164 MW. On most days, wind production peaks at night. Downward ramps in wind production in the mornings often increase morning ramp-ups of conventional generation in the summer.

REE has experienced wind generation tripping due to voltage dips. As a result, it has been monitoring voltage and generator performance since 2005. An operational procedure has been implemented as part of the Spanish grid code that establishes situations in which generators must remain connected in order to allow ride-through in the event of a fault. Starting January 1, 2008, all new wind facilities had to comply with this regulation. Existing plants have made the necessary retrofits to comply, and only 1000–1500 MW are to be adapted. REE now runs real-time simulation to model scenarios of three-phase faults in 70 of its 400 kV substations. These simulations allow the system operator to take actions using this new capability to avoid generation tripping.

Voltage control for conventional generation is typically done at the substation. That is not sufficient where a large penetration of renewable generation exists. REE has instituted a system to incent renewable generators to provide reactive power. This involves the opportunity to receive a bonus or suffer a penalty for +8 to -4% of 78.44 Euro per MWh, depending on the power factor. The system operator issues instructions to modify the power factor settings.

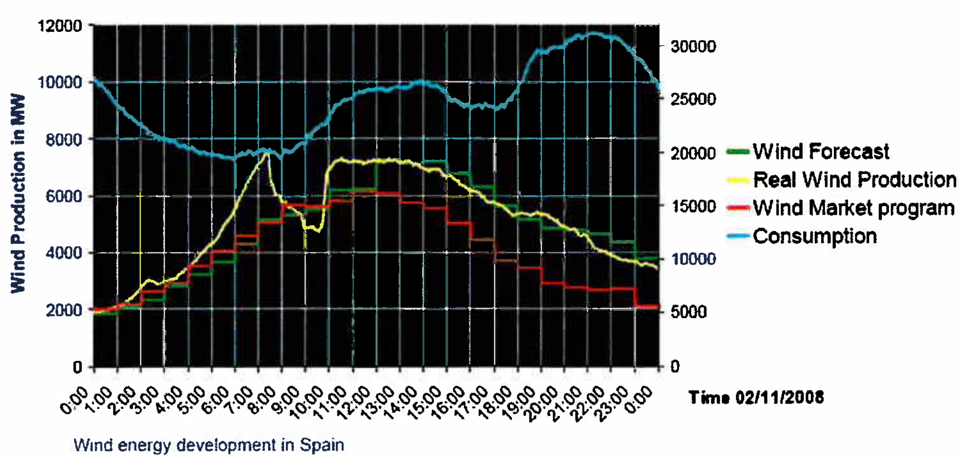


Figure 5 – Example of High Off-Peak Load and Generation Imbalance (Source: Red Electrica de España)

Since April 1, 2009, generators have been ordered to operate at power factors between 0.98 and 0.99 inductive in order to eliminate sudden changes in the voltage profile and avoid high voltages. REE believes that the ultimate solution is to enable voltage control for all generators greater than 10 MW. A key issue remains as to when and how to automate and whether this requires a local, regional, or national structure.

At present, solar PV power generation is not substantive. However, REE has no observability (no monitoring and no control) of the 3,268 MW of PV power generation. As the installed MW of solar PV expands, this will become an increasing problem. Spain's winter peak demand is in the evening, when PV makes no contribution.

Concentrating solar thermal has a positive correlation with summer peak demand. In the winter, molten salt energy storage and limited (~15%) hybridization with natural gas can allow these systems to produce during the daily peak hours.

Control Center for Renewables

The "crown jewel" in Spain's integration of renewable power generation is the creation of the Control Center for Renewable Energy (CECRE). CECRE was established by REE and is now part of its control room. It enables control and supervision of all of Spain's renewable power production. This includes wind, solar, biomass, small-scale hydro, cogeneration, and municipal solid waste power generation. All renewables over 10 MW are required to be connected to a renewable energy source control center, which in turn is linked to the CECRE. Specifically, the goal of CECRE is to maximize the production of renewable energy while maintaining system reliability.

CECRE is integrated into REE's control structure. CECRE has solid communication links with generation control centers for monitoring and control. CECRE can issue setpoints to all wind generators over 10 MW automatically. CECRE may issue wind generation curtailments when demand falls below what is provided by must-run units.

A critical part of CECRE is a wind generation forecasting system. This forecasting system is composed of three components: a database on the wind farms, a prediction algorithm based on a self-adaptive time series, and a forecast combination module. It uses as input real-time wind power and probabilistic wind forecasting and combines them into a "multi-model" forecast. It provides detailed hourly forecasts up to 48 hours in advance. The system was developed in a MATLAB environment. MATLAB (from MATrix LABoratory) is a high-level technical computing language and interactive environment for algorithm development. It was developed by The MathWorks, a global provider of software for technical computing and model-based design. Input data come primarily from meteorological forecasts from The Spanish Meteorological Agency, AEMET (Agencia Estatal de Meteorologia); Meteologica, a Spanish firm specializing in forecasting and mathematical modeling services for wind power generation; and real-time production data from 94% of wind farms updated on a 20-minute basis.

EU Climate Change and Energy Policy Goals

In 2007, European heads of state signed on to a challenging set of climate change goals for 2020. Come to be known as the *Twenties Policy*, these included three goals of "20" as follows: a binding 20% reduction in greenhouse gas (GHG) emissions, based on 1990 emissions and rising to 30% if an "acceptable" international agreement is reached; a mandatory target of 20% of all energy from renewable sources, focusing on transport, heat, and electricity; and a non-binding target of 20% improvement in energy efficiency compared with "business as usual."

An EU Climate and Energy Package was agreed upon by the European Institutions in 2008–2009 and provides the policy instruments for delivering these goals. These policies include a Greenhouse Gas Effort Sharing Agreement between member states regarding the sectors not included in the Emissions Trading Scheme, an EU Emissions Trading Scheme Review, an EU Renewable Energy Sources Directive, and an EU Geological Storage of CO_2 Directive.

The EU Renewable Energy Sources Directive establishes a 20% target for renewables in 2020 (rising from 8.5% in 2006). The percentage is based on total final energy consumption in all sectors, including electricity, heating and cooling, and transport. Under this directive, each member state is set a national target based on a fixed increase of 5.5% over its current percentage of renewables, plus a variable increase indexed on its GDP (the average rise is 11.5%). These targets are legally binding on EU member states. Under this scheme, Spain's target is 20% by 2020, increasing from 8.7% in 2006.

Natural Gas Infrastructure

Spain would not have been successful in building out so much gas-fired–combined-cycle combustion turbine capacity if not for its multiple coastline-facing seas and its proximately to North Africa to facilitate access to LNG. For Spain, the move to gas has primarily meant purposefully diversified LNG imports (e.g., Algeria and Egypt, Nigeria, Qatar, and even Trinidad – Tobago) for 75% of supplies. Pipelines from Algeria provide the remainder, supplemented by small transshipments through France. Spain's emergence as a major gas consumer is notable in several respects. Across Continental Europe, its consumption peaked in 2008 at 38.6 billion cubic meters, then dropped 10% during the 2009 recession. Spain is well behind Germany and Italy as well as France and the Netherlands in natural gas consumption. However, Spain has experienced the largest recent growth in gas consumption in Europe. At 27 billion cubic meters of LNG imports in 2009, Spain is not only the largest user of LNG in Europe, but the third largest user of LNG in the world, exceeded only by Japan and South Korea.

Spain's LNG regasification capacity in 2009 stood at 60.1 billion cubic meters. Some long-term plans indicate expansion to about 80 billion cubic meters during the decade. The current utilization rate of this capacity is about 40–45%, which is close to the European average and a reflection not of the inefficient use of capital, but of how this capacity serves varying seasonal requirements.

Spain's exploitation of natural gas has been reinforced by the co-development of Spain's LNG facilities (regasification and tank storage), bulk pipelines, and underground storage. This has been enabled under the authority of Enagas, whose position as gas transmission operator is comparable to that of Red Electrica for the electric sector. Gas infrastructure has been extensive. However, targets set by the Ministry of Industry, Tourism, and Commerce (MITYC) for high pressure gas additions have been scaled back, reflecting delays in pipeline and storage development. Movement on the development of connections to France is accelerating in 2010. This is in part a result of the EU's South Gas Regional Initiative. This initiative encourages private and government stakeholders to make commitments through "open seasons" to invest in needed pipelines that will enhance energy security throughout Europe. A portion of this plan that involves links to southwest France has obtained subscribers, whereas links to southeast France are pending. Entities involved in this initiative include Enagas, Naturgas Energia (a major natural gas distributor in the north of Spain), TIGF in the south of France, and GRTgaz in the north of France. GRTgaz is the entry point for gas from the Netherlands and Norway through Belgium. Targets for expansion are truly ambitious, with a vision that Spain, already the lead entry point of LNG into Europe, will enable LNG to provide meaningful competition with Russian Gas.

With progress on international natural gas connections now in sight, the weakest link in Spain's gas infrastructure is its undersized gas storage capacity with limited withdrawal rates. Projects now underway will achieve a doubling of this capacity. The result will be 20–22 days of supply, a level of security that Enagas still considers quite low in the European context. On the surface, some of these elements of Spain's increase in its gas infrastructure appear to represent overkill. However, some of these activities offer substantial contributions to the security of Europe's natural gas supply: gas storage and links with France and through France to the rest of Europe.

Eight forecasting models are embedded into the system. Each model is based on different hypotheses according to the dynamics of the input data. For example, parametric models are used for new wind farms where less data are available, whereas non-parametric models are used where ample data are available. Mean absolute error (MAE) in REE's forecast for day-ahead predictions with respect to real production is less than 15% and less than 4% with respect to installed capacity. These error rates are among the best in the world.

Lessons Learned

Applying Spain's experiences to other countries suggests that renewable technology can be influenced by several factors:

1. The availability of incentives can play a role in stimulating the development of renewable power generation. However, incentives can cause deficits in retail and/or wholesale power markets and must be offset with government subsidies or increases in the price of electricity to avoid amassing debt.
2. Requiring transmission and distribution entities to provide access to the power system at no cost is a clear incentive to assist developers.
3. Country-wide regional planning of transmission with cost allocation across all areas served—regardless of the location of the transmission—eliminates cost allocation issues (see the sidebar on the creation of ENTSO-E on page 11).
4. Centralized authority to approve planning and siting streamlines the implementation of reinforcement or expansion of the system and eliminates roadblocks to development.
5. Intermittent resources will require substantial new balancing resources and/or a combination of balancing resources and strong interconnections with neighboring countries. The cost of these resources and interconnections must be included in the cost of renewables. Aggressive development of all balancing resources applicable to the country should take place while incorporating operation and control and establishing appropriate market products. This should include:
    - Storage in any form, particularly pumped-storage hydro, batteries, plug-in hybrid electric vehicles, and electric vehicles.
    - Fossil units that can be cycled, particularly combustion turbines.
    - Demand-response program, including direct load control, interruptible and curtailable rates, real-time or critical-peak pricing, and dynamic pricing ("prices-to-devices").
6. As environmental constraints on the operation of fossil-fueled power generation tighten and their market participation becomes threatened, allowances and incentives might be needed to sustain their participation and availability for use as balancing resources. This must include consideration of the increased O&M cost burden on these balancing resources.
7. Large control areas allow much greater flexibility and lower costs in operating and controlling a portfolio of resources than multiple smaller control areas.
8. Mandating that non-dispatchable renewable resources are "must-run" could reduce overall CO_2 emissions—if proper real-time planning and dispatching is used. Caution needs to be exercised that mandating must-run does not, in fact, increase CO_2 emissions.
9. Establishing national and regional control centers for renewables with mandatory monitoring and control coupled with establishing incentives for curtailing wind and providing frequency regulation by "spilling" wind (and other intermittent resources) provides operational flexibility to maximize renewable energy production while maintaining reliability. These centers should include:
    - State-of-the-art renewable forecasting technology, including ramp-rate prediction software. Although Spain's wind forecasting technology is "world class," the discipline needs substantially more research and development to optimally operate a power system with a substantial penetration of renewables.
    - "Grid codes" that require all renewable resources over a certain size to provide zero voltage ride-through capability and mandate volt/VAR control capability as a reliability resource to the system. Volt/VAR capability in wind power generation can be provided by the use of power electronic interfaces on wind turbine generators such as doubly-fed induction generators or advanced inverters on PV systems.

ENTSO-E

In 2008, the European Union directed the formation of ENTSO-E, The European Network of Transmission System Operators for Electricity. ENTSO-E replaces six former transmission system operator organizations (ATSOI, BALTSO, ETSO, NORDEL, UCTE, and UKTSOA). As such, it represents 42 TSOs from 34 countries, serving 525 million citizens with 828 GW of generation and 305,000 km of transmission lines.

ENTSO-E is charged with the development of network connection rules for Europe in 12 areas, including balancing rules, security, reliability, third-party access, congestion management, data exchange, and settlement. The development of ENTSO-E was driven in part from the realization that optimal development of renewable power generation in Europe would be enhanced if the EU had consistency and transparency in its ability to plan and operate the power systems. The EU, as a whole, has significant variability in its wind and solar resources. Operating the EU as one "virtual" system would allow the increased use of a higher penetration of these resources. When wind is strong in Germany, for example, it might be weak in Spain and vice versa. Open rules and operating procedures coupled with adequate system interconnections would enable the greater sharing of renewable resources across member state boundaries. In particular, there is inherent difficulty in harmonizing standards and facilitating the development of renewable power generation across 42 separate TSOs.

In its first three years of operation, ENTSO-E is to initiate grid codes in market-related, system operations–related, and system development–related areas. In 2009, ENTSO-E identified wind connection as the most prominent topic for an urgent and rapid introduction of network codes. The objective of the development of wind connection codes is to facilitate the adoption of best practices, remove roadblocks, reduce development and investment costs, and harmonize the structure and content of national codes.

Three EU energy policy goals drive the need for the EU to operate as if it had one TSO: sustainability and greenhouse gas emissions, competitiveness and market integration, and security of supply. These three will in turn result in the development of more renewables (located farther from the load), more heating and mobility using electricity, more long-distance power flows, and more optimal resource sharing. All of these will require a significant increase in transmission expansion and modernization in Europe. In the next five years alone, the EU will need 42,100 km of new lines, requiring an investment of between 23 and 28 billion Euros.

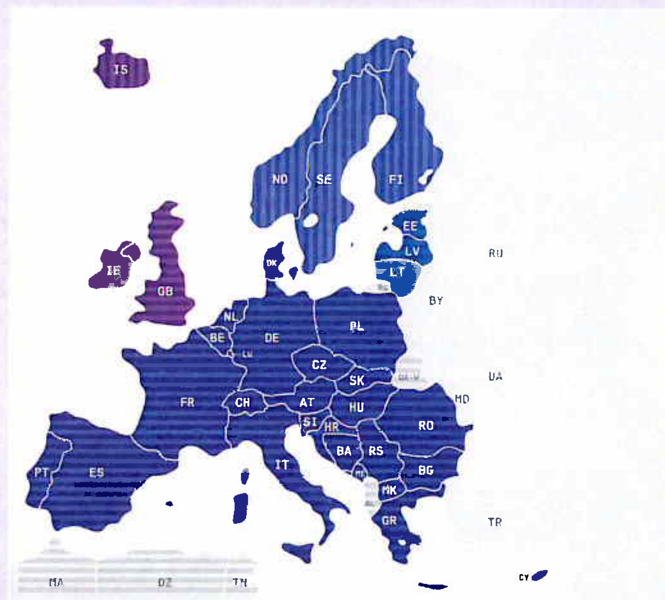


Figure 6 – European Network of Transmission System Operators for Electricity (Source: ENTSO-E 2010)

One example of a renewable energy operation center is owned and operated by Iberdrola's subsidiary, Iberdrola Renovables, called *CORE (Renewable Energies Operation Center)*. CORE monitors and controls 204 wind farms totaling 6,000 MW and 68 mini-hydro plants across Europe and in Mexico. CORE centralizes operations and control of these resources in real time. Through sensors and communications, CORE can remotely identify problems and dispatch crews to quickly rectify them. Iberdrola Renovables is the world's largest wind operator, with 11,000 MW installed and 55,000 MW under development.

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Bulk Integration of Variable Energy Resources Program

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CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service list for the captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 30th day of September 2010.

/s/ Jane Ostapovich
Jane Ostapovich