

Integration of Renewable Generation in California

Coordination Challenges in Time and Space

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Abstract—The successful integration of intermittent and distributed electric generation from renewable resources can be viewed as a coordination problem at multiple scales in both space and time. This paper presents an overview of coordination issues relative to the goals for renewable integration in California.

Keywords: *renewable; intermittence; distributed generation, firming resources; voltage regulation; protection*

I. Introduction

In the U.S. state of California, explicit goals for grid-connected renewable generation have been set in the form of a 33% portfolio standard for the year 2020 [1], and by Governor Brown’s plan to interconnect an additional 12,000 MW of renewable generation at the distribution (medium voltage) level [2]. While there is not yet broad consensus among experts as to how difficult or costly it might be to achieve these goals, it is clear that, in California as elsewhere, the successful integration of intermittent and distributed resources at such high penetration levels will entail both technical and organizational challenges. Though diverse, these challenges can be systematically characterized as a problem of coordination in time and space.

In essence, renewable and distributed resources introduce spatial and temporal constraints on resource availability: we cannot always have the resources where we want them, when we want them. Though the same is true to some extent for any energy resource, the constraints associated with renewables may be more stringent, or they may simply be different from those constraints around which legacy power systems were designed and evolved over the course of the past century.

The unique and in many cases novel constraints introduced by renewable resources should be addressed not only to mitigate problems and overcome difficulties, but also with a view toward maximizing the benefits that these resources can offer. Doing so will require new efforts at coordination, on an ever finer scale of resolution in time and space, while simultaneously keeping in view the large-scale strategic objectives and systemic properties of the entire electric grid.

II. Coordination in Time

A. Comparative Time Scales

Temporal coordination relates to the time-varying behavior of a renewable resource and its interaction with other time-varying components of the grid – some controllable, some not. These other components include electric demand, storage and firming generation of various types, with the function of balancing instantaneous power. Of interest here is not only the hourly output profile of each resource, but its dynamic behavior on much finer time scales, with relevant issues including ramp rates, frequency regulation and a.c. stability.

The operation of power systems has changed in recent years in that the time scale on which various decisions need to be made has been pushed out in both directions: At one end, long-term strategic planning has taken on a special significance in view of greenhouse gas reduction goals to be achieved over the course of the decades ahead. Simultaneously, owing to a combination of economic and technical pressures, grid operators must increasingly pay attention to the grid’s dynamic behaviors, some of which occur within a fraction of an a.c. cycle. The entire range of these relevant time increments in electric grid operation and planning spans an astounding fifteen orders of magnitude: from the micro-second interval on which a solid-state switching device operates, to the tens of years it may take to bring a new fleet of generation and transmission resources online – which, to put in perspective, we can express as a billion seconds. This range is illustrated graphically in Fig. 1, which situates some of the important aspects of grid operation along a logarithmic time scale.

B. Resource Intermittence

The fact that solar and wind power are intermittent and non-dispatchable is widely recognized. The interesting question is how to address intermittence at different time scales with different resources or mitigation techniques. Distinct problematic components of time-varying behavior include the following:

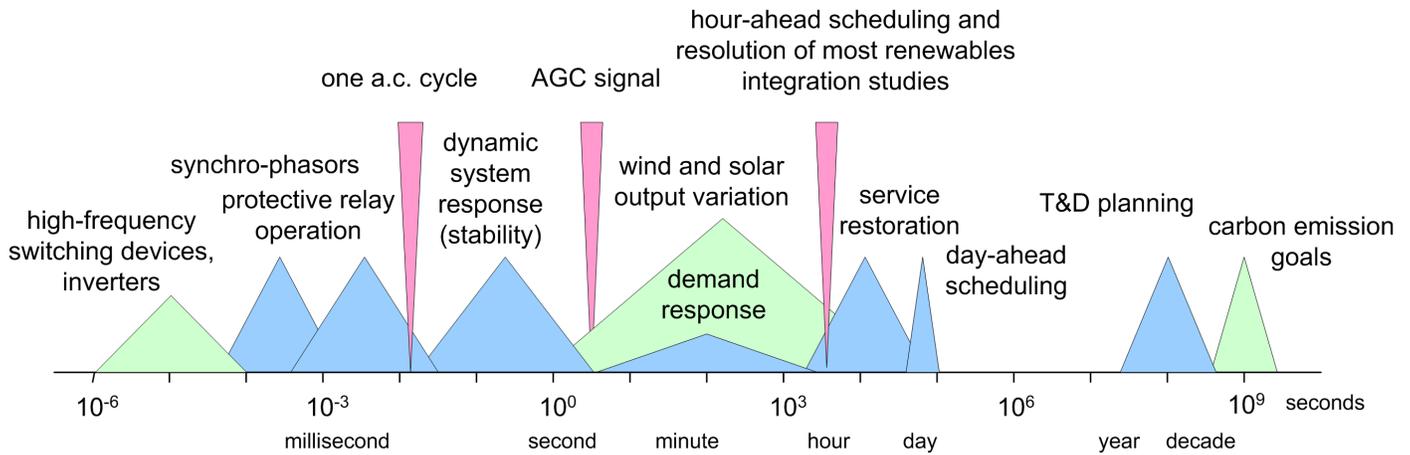


Figure 1. Time scales in electric grid operation.

- High variability of wind power (proportional to the cube of wind speed), on the order of minutes and seconds;
- Relatively high correlation of hourly average wind speeds among prime wind areas in California (i.e., lack of diversity);
- Overgeneration at night (when wind power exceeds load minus generation that is physically or contractually required to run);
- Time lag between solar generation peak and afternoon demand peak in California, on the order of hours;
- Solar output variation due to passing clouds on the order of minutes and seconds, with some local correlation;
- Limited forecasting abilities, especially on the order of minutes.

In principle, the variability of renewable generation output can be offset by any combination of three types of firming resources: generation, storage, and demand response. However, the response characteristics of each of these resources must be matched to the time scale of the variation.

As the main (if not sole) option historically, firming generation is the best understood. Obviously, generation reserves to compensate for intermittent generation are an economic liability, especially if these assets are utilized with very low capacity factors. From the perspective of system-wide coordination, a key problem has to do with the implications of thermal lag time in conventional steam plants. This can require fossil-fuel units with CO₂ and other undesirable emissions to operate at times (including over night) only to stay warm, so as to be responsive when needed – thus compromising or potentially negating the original goal of emissions reductions. For these reasons, California is increasingly looking to storage and demand response to compensate for renewable intermittence.

Electric storage technologies for utility-scale applications have seen significant advancement in recent years. Beyond the well-established and comparatively economical pumped hydroelectric storage (which is highly site-constrained and unlikely to allow for significant future expansion in California), options in various stages of development and demonstration include compressed air electric storage (CAES), flow batteries, flywheels, hydrogen electrolysis, supercapacitors and superconducting magnetic energy storage (SMES). Also, it is technically feasible that plug-in electric vehicles in vehicle-to-grid (V2G) mode could serve as a distributed storage resource. In the face of substantial costs, a key implementation challenge for storage lies in the definition of the value proposition – that is, the valuation of diverse services offered to the grid by a given storage resource – and the design of appropriate incentive mechanisms that account for risk and reward sharing among utilities, consumers and third parties. Incentive mechanisms for distributed storage will also require a new regulatory framework.

Demand response offers a fundamentally novel approach to reconciling generation and load. To date in California, efforts to shift demand in accordance with the grid's needs have been largely limited to time-of-use rates with a relatively crude time resolution of multiple hours. Interruptible load is a crude instrument as well, and a last resort for grid operators. The major expected innovation lies in the use of information and communication technologies that enable the rapid and direct control of certain loads, without adverse impacts on end users. The focus is on thermostatically controlled loads such as water heaters or air conditioners whose duty cycle can be shifted slightly, in effect representing thermal energy storage for the grid. Models have suggested that large numbers of such loads, coordinated with a control signal such as Automatic Generation Control (AGC) on the order of several seconds, could in aggregate provide a substantial resource for grid operators, serving as both up- and down-regulation [3].

Traditional models for matching large contributions of renewable resources with firming resources have used a standard one-hour time resolution. Hourly modeling addresses crucial concerns about resource availability and fits into standard planning tools, such as filling the area under a load duration curve. Yet operational concerns in the California system are increasingly focused on much shorter time scales than an hour. For example, there may be plenty of reserve generation capacity, but a lack of fast-responding resources that can follow a rapid variation of generation and load. Key characteristics of firming resources therefore include not only their total capacity, but response times and ramp rates (e.g., megawatts per minute). Furthermore, if the firming service is to be provided by an aggregate of a large number of small units, the ability to quickly and reliably direct their coordinated behavior is of the essence. The effective and economical implementation of any of these firming resources vitally depends on improved forecasting abilities for solar and wind resources on increasingly shorter time scales.

C. *Inertia*

Reconciling electric demand and supply in an a.c. power system means balancing both real and reactive power (megawatts and megavars), with discrepancies observable as changes in frequency or voltage. Balancing real power amounts to holding the a.c. frequency constant, using operator dispatch (also referred to as tertiary frequency control) on the scale of minutes, and corrective signals such as AGC or secondary frequency control that generators receive externally on a four-second interval. Even finer adjustments, however, occur internally at large generators that serve to stabilize system frequency: actively, through the use of a governor (a feedback system that adjusts mechanical power in response to small changes in rotational speed, known as primary frequency control), and passively, through the generators' mechanical rotational inertia, which serves as the grid's ultimate short-term energy storage. All of these adjustments depend upon the inherent stabilizing feedback of electromagnetic forces that keep a.c. generators synchronized and locked into a precise position (voltage phase angle) relative to each other. This stabilizing function of large, synchronous generators has been absolutely essential to the operation of a.c. power systems since their inception.

A key question is how a.c. stability will be impacted by a combination of long-distance power transfers and an increasing contribution from renewable resources. It is well known that power flows across long transmission distances (on the order of 1,000 km across the Western United States) are often limited not just by thermal but by stability constraints – that is, a potential loss of stabilizing feedback between generators, if the voltage phase angle separation between them gets too large. Historically, grid operators addressed stability concerns with conservative line ratings or rules of thumb. More recently, the use of synchro-phasor technology, which provides a comparison of voltage phase angles at different

locations via precise GPS time stamp, has allowed the direct observation of the grid's stability characteristics. For the Western United States, these observations have brought some troubling news: we now know of low-frequency power oscillations, observed as voltage angle oscillations on the order of several hertz, which characteristically appear across wide areas but were not predicted or explained by standard models [4].

The effect of large additions of renewable generation on a.c. stability in general and these oscillations in particular is not yet well understood. First, by contributing to long-distance power transfers between prime resource areas and load centers, the aggressive development of renewables could exacerbate pre-existing wide-area stability problems.

Second, and more fundamentally, solar photovoltaic (PV) arrays and advanced wind turbines feed the grid through solid-state, switch-controlled generators (inverters) whose dynamic behavior differs from that of conventional rotating machines.¹ Without mechanical inertia, electronic switch-controlled generation does not intrinsically stabilize the grid frequency. An increasing proportion of PV and wind generation will therefore place a greater burden of frequency control on the remaining synchronous machines. The crucial impact would be on the grid's ability to absorb and recover from contingencies, such as a sudden loss of generation or transmission, since a given change in load would tend to cause a greater change in system frequency.

The PV or wind penetration level that would begin to show such adverse impacts is not obvious. One important observation is that even if reduced system inertia causes no immediate problem or instability, the additional demands on primary frequency control may erode the system's reserves of secondary frequency control and thus compromise system reliability, unless deliberate steps are taken to account for the new operational requirements [5]. Further modeling and simulation are needed in this area, including the evaluation of mitigating techniques.

One solution approach is known as a "virtual synchronous generator" [6]. The idea is to program an inverter in such a way as to mimic the intrinsically stable, inertial behavior of a rotating machine. As mandated by the laws of physics, this requires providing a modicum of energy storage (analogous to the rotational kinetic energy of a large machine), but only for a short time interval. The main challenge of this approach lies in the intelligent control of the electronic circuitry to provide virtual inertia – starting with the determination of how, precisely, any given generator should behave so as to provide an optimal resource for the system.

¹ This concern does not apply to solar thermal power, which uses conventional steam turbine generators.

III. Coordination in Space

A. Comparative Distance Scales

Spatial coordination refers broadly to the way resources are interconnected, and ultimately connected to loads, through the transmission and distribution (T&D) system. More precisely, we are interested in the location-specific effects of a given resource being connected in a particular place: geographically, of course, but also functionally in relation to other components of the T&D system. A significant class of challenges to the integration of renewable resources is associated primarily with distributed siting, not only the intermittence of output; these challenges apply to any distributed generation, whether renewable or not. Spatial coordination issues thus include transmission capacity (high voltage and extra high voltage) as well as several distinct aspects of distribution infrastructure (medium voltage), such as protection and voltage regulation. Fig. 2 situates these issues on a logarithmic scale of distances.

B. Transmission Capacity

The richest solar and wind resource areas in the western United States tend to be far from population centers, creating the need for expanded transmission capacity. New construction of transmission lines is problematic, however, due to public acceptance and environmental concerns. In the face of societal constraints on traditional transmission build-out, engineering solutions may focus either on less visible or impactful transmission technologies, or on approaches to permit increased utilization of existing transmission infrastructure. The former include underground cables, new conductor materials, and engineered line and system configurations. The latter include dynamic thermal ratings, power flow control such as flexible a.c. transmission systems (FACTS) devices, fault current controllers, intelligent protection systems such as adaptive relaying, and advanced stochastic modeling and planning tools [7]. What these tools have in common is that they provide transmission operators with new, more refined means to evaluate and control *where* power is, or should be, flowing.

The upgrading of transmission infrastructure for California will also have to address stability issues such as the low-frequency oscillations mentioned above. It may be for this reason alone that conventional expansion of transmission capacity is not a viable solution for large-scale integration of renewable resources, but that increasing reliance on high-voltage d.c. links as well as newer technologies will be required.

C. Distributed Siting and Local Issues

At the primary and secondary distribution (medium and low voltage) level, interconnected generation resources – to date, primarily solar PV – present a different set of concerns. These arise largely from the functional location of distributed resources on the grid, and from their potentially uneven,

clustered spatial distribution. The impacts of high penetration levels of distributed generation (DG) relative to local load may vary widely, from zero to highly problematic to beneficial, depending on the particular characteristics of individual distribution circuits. Some of the key technical issues are:

- Generation and load modeling;
- Voltage regulation;
- Protection;
- Islanding.

1) Generation and Load Modeling

From the grid perspective, small distributed generation (DG) is observed in terms of net load (demand minus generation). Since telemetry is not standard for generation units under 50 MW in California, neither the amount of actual generation nor the actual, unmasked load may be known to the utility or system operator. Without this information, however, it is impossible to construct an accurate model of loads on a given distribution circuit. Such models are important both for purposes of forecasting future load, including ramp rates, and for ascertaining system reliability and security in case the DG fails. Improved models of distribution systems with high local DG penetration will have to account for both generation and load explicitly in order to predict their combined behavior.

With DG representing a growing proportion of total generation resources, some level of appropriately disaggregated information about what lies behind a substation will also become of vital interest to the California Independent System Operator (CAISO).

2) Voltage Regulation

Electric utilities are required to provide voltage at every customer service entrance within a permissible range. Throughout the United States, this range is generally $\pm 5\%$ of nominal voltage; the State of California aims to reduce electric energy consumption by restricting this range to the lower end, $+0/-5\%$, in a program called Conservation Voltage Reduction (CVR). However, due to the relative paucity of instrumentation in the legacy distribution system, the precise voltage at different points in the distribution system is often unknown. Instead, it may simply be estimated by engineers as a function of system characteristics and varying load conditions.

The equipment used for achieving voltage regulation in distribution systems also tends to offer limited refinement of control. Standard devices include load tap changers at substation transformers (which adjust the effective turns ratio through movable contacts), voltage regulators on distribution lines (which step up voltage part way down a feeder to counteract voltage drop), and capacitors (which reduce the slope of voltage drop by providing reactive power locally). These devices may or may not be equipped with communication, so the actual voltage levels at different locations may not be observable to distribution operators.

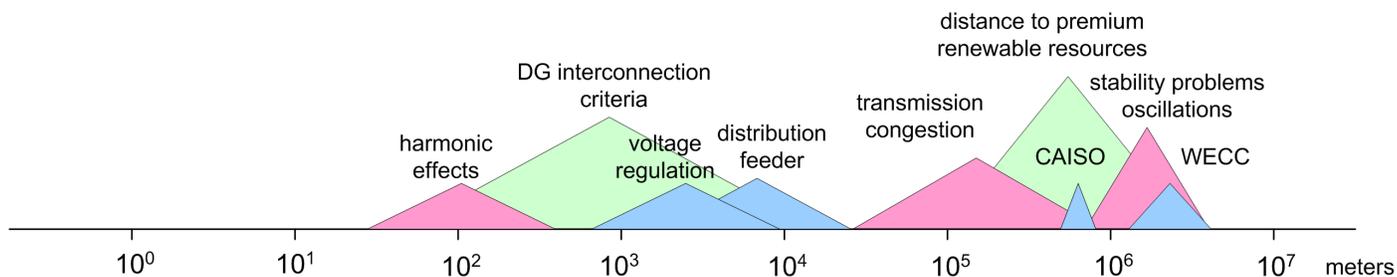


Figure 2. Distance scales for power system planning and operation.

The addition of significant amounts of DG on distribution circuits at some distance from a substation now introduces variations that legacy voltage regulation equipment was not designed to address. Specific areas of concern include the following:

- Maintaining voltage in permissible range: Regulation equipment may not be capable of assuring consistent customer voltages with DG on and off.
- Wear on existing voltage regulation equipment: Frequent changes in DG output may shorten the life of mechanical components attempting to adjust voltage, which were typically designed to operate only twice or so daily.
- Reactive power (VAR) support from DG: Modern inverters can supply continuously adjustable voltage, or positive or negative reactive power. However, the distribution infrastructure is not yet capable of utilizing this service, lacking not only the communications channels but appropriate models and strategies for integrated volt-VAR control involving DG.

Owing to the limitations of voltage regulation on many distribution circuits today, interconnection requirements have focused on preventing DG from “driving” the voltage on a feeder by limiting it to a passive role and capping its penetration relative to feeder load. With 12,000 MW of connected DG in California, however, this conservative approach might no longer be feasible. Increased data analysis and feeder modeling as well as physical infrastructure upgrades will likely be required not only to accommodate higher local penetrations, but to take full advantage of what DG can deliver.

3) Protection

Like voltage regulation, the legacy protection equipment was not designed for the presence of DG. With the exception of few urban areas, California’s distribution feeders are operated in a strictly radial manner, assuming unidirectional power flow from the substation out. Protective devices such as circuit breakers and fuses are coordinated accordingly, providing one-way overcurrent protection for nested zones on a radial feeder.

The presence of distributed generation complicates protection coordination in several ways:

- Reverse power flow: A fault on the circuit must now be isolated not only from the substation (“upstream”) power source, but also from DG.
- Fault current contribution: Until the fault is isolated, DG contributes a fault current that must be modeled and safely managed.
- Relay desensitization: Shifting fault current contributions can compromise the safe functioning of other protective devices: it may delay or prevent their actuation (relay desensitization), and it may increase the energy (I^2t) that needs to be dissipated by each device.

California’s interconnection standards limit permissible fault current contributions (specifically, no more than 10% of total for all DG collectively on a given feeder). The complexity of protection coordination and modeling increases dramatically with increasing number of connected DG units, and innovative protection strategies are likely required to enable higher penetration of DG.

One such set of strategies are known as transfer trip schemes (similar to adaptive relaying at the transmission level). Transfer trip schemes involve communication among protective devices, rather than autonomous operation. This means that a device may actuate, or not actuate, based on currents measured elsewhere and on a programmed decision algorithm, rather than solely on what it senses at its own location. Research is still needed to determine how protection schemes can best be adapted to safely handle power flow from multiple locations within the distribution system.

4) Islanding

Standard utility operating procedures in the United States do not permit power islands supported by DG. The main exception is the restoration of service after an outage, during which islanded portions of the grid are re-connected in a systematic, sequential process; in this case, each island is controlled by one or more utility-operated generators. Technical reasons for this conservative policy include the safety of line crews, assurance of power quality, and proper re-synchronization; arguably, these practices are also based on an important cultural component.

Interconnection rules for distributed generation thus focus on preventing unintentional islanding. To this end, they require that DG shall disconnect in a specific time frame (e.g., 10 cycles) in response to disturbances such as voltage or frequency excursions that might precede an isolation of the distribution feeder from its substation source – thus, if the circuit becomes isolated, it will not be energized by the DG.

This conservative approach, however, tends to conflict with utilizing the DG as a resource for grid support, with capabilities such as low-voltage ride-through. It also precludes the use of DG to enhance local reliability by servicing, say, a neighborhood during a system outage. There is no consensus among experts yet on how best to reconcile the competing goals of minimizing the probability of unintentional islanding, while also maximizing the beneficial contribution from DG.

As for permitting DG to intentionally support power islands, some important questions are how power quality might be safely and effectively controlled by different types of resources, and what requirements and procedures would have to be in place to assure the safe creation and re-connection of islands. Ongoing research on microgrids is investigating the technical dimensions of these islanding issues, along with the effective combination of DG with local storage, thermal end uses and intelligent controls that allow for heterogeneous power quality and reliability among loads [8]. The extension of the microgrid concept from a single customer’s premises to the larger distribution system, however, also hinges on legal and regulatory issues (such as power transfers between customers) that are likely to remain controversial for some time.

iv. Conclusion

The successful integration of intermittent and distributed generation from renewable resources can be viewed as a coordination problem at multiple scales in both space and time. These coordination challenges are expected to increase substantially at the higher penetration levels that are anticipated for California by the year 2020. In general, these

challenges appear to be solvable (and interesting) engineering problems for which technical solutions exist. However, the integration of new technologies into the legacy power system, especially at the distribution level, is neither trivial nor likely to be cheap. The cost of infrastructure upgrades that may become necessary to enable the most aggressive utilization of renewable resources – and public willingness to socialize these costs – could emerge as an important constraint on the deployment rate of renewables in California.

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