GENERATOR RESPONSE TO INTRAHOUR LOAD FLUCTUATIONS

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Abstract—Although system loads fluctuate rapidly and are typically measured at 2-second intervals by utility control centers, generation does not track these high-speed fluctuations. Analysis of data from a large Midwestern control area shows that generation tracks load at roughly the 1- to 2-minute level. In addition, some of the generating units assigned to this regulation service actually contribute to the regulating burden.

I. INTRODUCTION

Electricity consumption varies with time. These temporal variations include moment-to-moment fluctuations plus hour-to-hour changes associated with diurnal, weekly, and seasonal patterns. Because electricity cannot be easily stored, electric utilities use computers and communications equipment to control their generating units to closely track these time-varying loads. As long as a single entity (the vertically integrated utility) was responsible for meeting all the requirements to supply loads and maintain reliability, it was only necessary to ensure that sufficient generating capacity was available at all times. With industry restructuring, the introduction of competition, and the unbundling of generation services, it is necessary to quantify both the burdens that individual loads place on the system and the contributions that individual generators make to carrying those burdens. This paper develops a framework for determining what contributions are made by generators to following load, based primarily on data from a Midwestern control area. A larger report also examines the details of load fluctuations, both intra- and interhour variations [1].

The purpose of this paper is to examine empirically the responses of a utility's generating resources to short-term system load changes. We analyze data, primarily from one control area, to see how it maintains area-control error (ACE) close to zero in an effort to meet the A1 and A2 criteria. We compare the dynamics of loads and load-following generation across time-averaging periods that range from 10 seconds to 2 minutes. We examine the minute-to-minute performance of the generators that provide regulation (i.e., that are on automatic-generation control, AGC), individually and collectively.

To conduct these analyses, we use data for two days (one in December 1995 and one in June 1996) for a Midwestern control area. This utility has a summer peak demand of about 18,000 MW and an average hourly demand during a year of about 9700 MW. Over the course of a year, the hour-to-hour load changes range from about -1500 MW/hour to +1500 MW/hour, with an average of the absolute change equal to about 340 MW/hour. The data we analyze include generation and load, both measured at 10-second intervals. (Load is calculated as the difference between generation and net interchange out.)

II. AGGREGATE GENERATOR RESPONSE TO LOAD FLUCTUATIONS

Figure 1 shows the 10-second "speeds" for load and generation from midnight to 1 a.m. Loads move up or down at an average rate of 74 MW/minute and change direction more than 200 times per hour. The figure illustrates the differences in the dynamics of loads and generation. Clearly, generation varies much less than does load. Specifically, the average 10-second load fluctuation is 12.3 MW, and the average generation fluctuation is two-thirds less, 4.2 MW. While load reverses direction 56% of the time, generation reverses direction only 35% of the time.

One cannot tell from these data whether generation responds slowly to load changes because the generating units are unable to respond more quickly or because control systems do not request faster response. We suspect the latter, because utility AGC systems typically filter the raw ACE signal to avoid having generators move up and down unnecessarily. AGC strategies seek to "avoid unnecessary rapid maneuvering of unit generation (or the chasing of high frequency components of demand change)" [2]. More broadly, advanced AGC systems can reduce generator movement by both filtering historical ACE signals and by forecasting future loads for the next several minutes [3].

Fig. 1. Fluctuations in system load and total generation (measured at 10-second intervals) from midnight to 1 a.m.

These short-term (~10-second) mismatches between generation and load are made up by the rest of the Eastern Interconnection. That is, for brief periods, this control area first leans on the interconnection (i.e., it undergenerates) and then other control areas lean on it (i.e., it overgenerates). These presumably uncorrelated discrepancies, which disappear with the longer time-averaging periods discussed below, are equivalent to short-term inadvertent interchanges.

This control area assigns about 150 MW to regulation, equivalent to 2.3 times the standard deviation of load fluctuations. (This is actually ±150 MW or 300 MW of total range. Following upswings in load requires additional capacity and therefore additional capital costs as well as additional fuel and maintenance costs. Following downswings in load requires suboptimal dispatch of generation, which involves only additional operating and maintenance costs.) In principle, the control area could assign more generating capacity to load following and assign capacity that has greater ramping capability to reduce these short-term mismatches.

Figure 2 shows that when the time interval for averaging loads and generation is increased from 10 seconds to 1 minute, the load and generation patterns look quite similar. By similar, we include both the amplitude of fluctuations and the frequency with which direction changes. Even at the 1-minute interval, however, generation moves more slowly than does system load. Specifically, the standard deviation of the generation ramp rate is 23 MW/minute, compared with 30 MW/minute for system load. And generation fluctuations reverse direction 19% of the time, compared with 49% for loads. The results shown in Fig. 2 suggest that the generator response to load changes at the 1-minute level is both damped and delayed.

Fig. 2. Fluctuations in system load and total generation (measured at 1-minute intervals). Compare Figs. 1 and 2.

To explore the appropriate time interval more fully, we compared the standard deviation of load fluctuations with that for generation fluctuations for several time-averaging intervals, ranging from 10 seconds to 2 minutes (Fig. 3). Only when the averaging interval reaches 1.5 minutes do the two curves meet. This result suggests that generators either cannot or do not follow load fluctuations at the 10-second level. Rather, generation follows load at roughly the 1.5-minute level. This time interval is roughly consistent with the statement that the "... velocity limits of the generators will not allow control response to load components with a period in the order of 2 minutes or less" [4].

Fig. 3. Standard deviations of load and generator fluctuations for different time-averaging intervals.

We also examined the correlation coefficient between load and generation fluctuations for different time lags between generation and load. Consistent with the results presented above, the correlation coefficient reached its maximum at two minutes. In other words, generation appears to follow 10-second or 30-second fluctuations in loads with a two-minute delay.

One utility calculated the amount of generation it assigns to regulation on the basis of the requirement to meet the A1 criterion at least 90% of the time. Its analysis of raw and filtered ACE showed that its regulating units respond at a rate of 18 to 25 MW/minute to meet A1 90% of the time. Multiplying 22.5-MW/minute (an average rate) by 10 minutes yields a total capacity of 225 MW assigned to regulation, about 2% of peak load.

Pacific Gas and Electric, on the other hand, split its load-following requirement into two parts: micro-load following (a few seconds to 10 minutes) and macro-load following (10 minutes to several days) [5]. It calculated a total load-following requirement of 0.74% (123 MW) of peak demand. Of this total, 0.25% (42 MW) was needed for micro-load following. The order-of-magnitude difference between the two utility estimates of regulating requirements (2% vs 0.25%) may occur because of differences in how the utilities characterize the short-term load fluctuations (regulation) and the longer-term changes in load. Differences in load characteristics (e.g., volatile loads, such as steel mills), generator characteristics (i.e., MW/minute capabilities), and system size may also contribute to this difference in regulating requirement.

III. INDIVIDUAL GENERATOR RESPONSE TO LOAD FLUCTUATIONS

The same utility that provided data on 10-second loads and aggregate generation for a day in December 1995 also provided data on the outputs of the individual generating units on regulation. These regulating-unit data are for a 24-hour period in June 1996. We aggregated these data from the 10-second level to 1-minute averages. For the 4-hour period from 10 a.m. to 2 p.m., the 10 units on regulation had an average output of 2800 MW, 21% of total generator output during that time. The standard deviation of the output from these 10 units was 800 MW, compared with 450 MW for the remaining units. The ratio of standard deviation to mean (coefficient of variation, COV) for the regulating units was 28%, compared with 4% for the nonregulating units. These statistics show that the output from the regulating units varied much more than that from the nonregulating units, as expected.

During any given period, some of the regulating units were moving in one direction, and other units were moving in the opposite direction. Between 10 a.m. and 2 p.m., regulation in the "primary" direction averaged 12.0 MW/minute, while regulation in the "counter" direction averaged 2.1 MW/minute. This counterregulation averaged 19% of the primary regulation during this 4-hour period. Figure 4 displays this phenomenon from 10 to 11 a.m.

Fig. 4. Changes in output for the 10 units on regulation from 10 to 11 a.m. The solid line shows the net change in generator output, and the dashed line shows the fraction of output that is moving in the counter direction.

Several factors explain this counterregulation [6]:

- The AGC signals from the control center to each generator are unit-specific and reflect that unit's regulating range, ramp rate, and turnaround time (the amount of time it takes the unit to change direction). Thus, the control center might ask fast-response units to change direction, while allowing slow-response units to continue ramping in the original direction.

- The control signals are based on both historical ACE values and on near-term (5 to 15 minute) forecasts of loads, which will modulate the signals sent to individual units. For example, if the forecast shows increasing loads over the next 15 minutes (a reflection of interhour load changes), then a small drop in loads (the intrahour fluctuations) may not necessarily result in a reduction in the output from regulating units.

- The A1 criterion requires the control area to achieve an instantaneous power balance at least once every ten minutes. Meeting this criterion can force AGC to cycle rapidly, always ramping some units up or down. Because of differences in the speed with which individual units can respond, such AGC signals can create situations in which units are not operating in unison.

- Previous AGC signals may have moved some units away from the midpoint of their operating ranges or may have moved units out of economic order. Thus, the signals to some units may be moving these units back while using others to perform the regulating function at certain times.

- Errors in the communications and control systems can cause generators to respond inappropriately (e.g., with time delays or even in the wrong direction) to AGC signals.

Because of these factors, at any given time, some generating units are providing regulation service, and other units are consuming regulation service. That is, some units should receive payments for the regulation service they provide to the system and some units should be charged for the regulation burden they impose on the system. The Bonneville Power Administration implicitly recognizes these competing roles of generation in its wholesale rates [7]. Bonneville maintains 280 MW (about 3% of its 9000 MW of generation) for regulation. Of this total, 90% is used to control for variations in load, and 10% for generator variations.

A utility's ability to follow rapid load fluctuations depends on the mix of generation online and on AGC. The individual units on regulation move up and down with various speeds. Hydro units can respond at 50 to 100% of their output per minute, combustion turbines at 10 to 20% per minute, and coal units at 1 to 3% per minute. Nuclear units are generally not used for regulation. Figures 5 and 6 show the minute-to-minute changes for two units on regulation. Figure 5 shows a unit that followed closely the control-center's AGC signals, with a ramp rate that reached 2%/minute (positive at 6 minutes and negative at 11 and 12 minutes). Figure 6 shows a unit that responded poorly to the AGC signals, at one point increasing ACE by 31 MW.

Fig. 5. The minute-to-minute output from a generator providing regulation service.

Fig. 6. The minute-to-minute output from a generator providing regulation service, but doing so poorly.

IV. CONCLUSIONS

Using data on loads and generation from a large Midwestern control area, we examined the performance of generating units, both individually and in aggregate, to follow intrahour load fluctuations. Comparing the dynamics of load and generator fluctuations shows that the generators follow load fluctuations at roughly the 1- to 2-minute level; that is, generators either cannot or do not follow higher-frequency load fluctuations. We also saw that some of the generating units assigned to regulation contribute to the regulating burden that the utility faces. For example, during one 4-hour period, the units moving in the "primary" direction followed load with an average movement of 12.0 MW/minute. At the same time, regulating units moving in the "counter" direction averaged 2.1 MW/minute in the wrong direction.

The present analysis leads to the following thoughts on issues that require further data and analysis. Additional research is required, we believe, because the results presented here are based on very limited data, primarily from one utility for only a day or two. Clearly, electric-industry restructuring will require further definition and quantification (amounts, costs, and prices) of the services that generating units provide.

What is the relationship between the amount and speed of generating capacity assigned to regulation and the magnitude and speed of intrahour load changes? For this control area, the amount of generating capacity assigned to regulation (150 MW) is 2.3 times the standard deviation of load changes (66 MW). How does this "proportionality constant" vary by day of the week and season for this control area, and how does it vary across control areas?

What is the appropriate period over which to measure regulation requirements? Although utility automatic-generation-control systems typically obtain data at 2-second intervals, this is surely not the appropriate time period for control, although it may be appropriate for data collection. Based on our comparison of the speed with which generators and loads vary, we suggest that a 1- or 2-minute averaging period should be used to measure the magnitude and speed of load changes.

How accurately and rapidly do (and must) individual generating units follow the AGC signals that the control center sends them? To what extent are some units moving counter to the direction that the AGC signals request? Is the amount of regulation that utilities currently provide appropriate? What effects would changes in the amount of regulation have on customer service, reliability, and cost?

V. REFERENCES

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