Costs of Primary Frequency Regulation

Notes: Nicholas W. Miller 12/27/2017

Introduction

The issue of costs to providers of primary and secondary frequency control services is complex, and there is surprisingly little hard cost data to support discussions. Therefore, my comments are more anecdotal than comprehensive. Further, the frequency control practice in the NEM is so radically different than my primarily North American experience, that further caution is needed. I have spent some time studying the frequency control practice in the NEM, but I have little confidence that I truly understand the nuances. It is an astonishing arrangement. Finally, these are my thoughts and opinions, and don't represent any official views of General Electric.

Scope

The language of frequency control is not uniform or universal. In the NEM, the FCAS service definitions and market enforcement have created requirements and incentives for dynamic behavior that is, apparently, rather different than many other systems. For these notes, I limit my discussion to functions that would typically be part of "governor" response. That is, autonomous reaction to locally measured changes in grid frequency (or synchronous machine speed, acting as a measurement proxy for grid frequency).

Overview

The costs to providers of primary frequency control fall into four major categories:

1. **Opportunity Costs.** Providing this service, at the expense of using capability that could be creating some other value for the resource owner. For generation plants, this is most often forgoing energy sales in order to maintain headroom. This concept applies to all generation, including non-synchronous resources like wind and PV.

2. **Efficiency Costs.** Running the resource at a condition that uses the available fuel (gas, coal, water, wind,..) less efficiently.

3. **Wear & Tear Costs.** These are costs associated with the dynamics of actually providing the service. They can include faster aging of components like actuators, increased maintenance or shorter intervals, accelerated thermal aging for fossil plants, higher forced outage rates.

4. **Stability Costs.** These are costs associated with driving resources into operating conditions for which sustained stable operation may be compromised. For example, primary response to high positive rate-of-change-of-frequency (RoCoF) presents a risk to gas turbines that can result in unit trips (and accompanying wear).

Opportunity Costs

AEMC and the markets seem to have a good handle on this. In general, being dispatched below rated power when a unit is on the economic margin represents a cost. It is worth noting that some plants have some room above their maximum economic dispatch for which they can provide frequency response. The opportunity cost for these resources is essentially zero. In contrast, for resources like wind and solar PV, the opportunity cost is the value of the forgone power production, plus other benefits like forgone tax or renewable credits. Another aspect is, in a sense negative:

withholding the service from plants that can provide the service for zero or low cost, allows the market price for the service to rise.

Efficiency Cost

There are three aspects of efficiency cost that are germane here:

1. The steady-state heat rate for most fossil plants has a relative maximum that is typically near the plant's maximum dispatch. Being dispatched below (or above) this point incurs a penalty. These costs are generally captured by production simulation programs. In practice, there are some nuances that can be relevant here: the heatrates are not always monotonic, and there can be relative maxima along the heatrate curves. These vary by plant, and can influence bidding and preferred dispatch points.
2. The second efficiency cost is associated the dynamics of changing operating points. There is a penalty for responding to transient changes that are associated with governor action. These costs are poorly quantified, but widely regarded (in the US, at least) as being small.
3. The third efficiency cost is associated with the operating mode of steam turbines. Turbines running with valves wide open (VWO) cannot provide rapid frequency response. The only mechanism to increase power is to increase steam production in the boiler. In order to provide "governor response", there must be some latitude for valve motion. This can mean that there is some throttling with the control valves, that results in a poorer heat rate/efficiency penalty. Some steam turbines run at their best heat rate with their governors active, others including (typically) the steam turbine of a combined cycle power plant, normally run VWO.

Wear & Tear Costs

The cost of providing PFR from synchronous machines is often conflated with a broader spectrum of costs associated with "cycling". Cycling, associated with response to markets – i.e. changes in dispatch, and commit/decommit cycles – have substantial impact on thermal plants. Claims of huge increases in O&M costs, reduction in life, and increases in pollution have all been ascribed to cycling. In practice, the impacts are complex and quantitative data is scarce. In one of the most comprehensive studies of the costs due to increased cycling of thermal plants that accompanies increased wind and solar was done by NREL, GE, Aptech and others.[1] It found that nearly all the costs of cycling are associated with startup. Those costs could be in the range of $0.14 to $0.67/MWHr of wind and solar delivered to the system, under fuel price and operating conditions that save $28-29/MWhr of fuel; i.e. about 0.5% to 2% of fuel savings. The report includes quantitative data. However, the cost of providing PFR was negligible in this context.

Stability Costs

This is a consideration for systems with high RoCoF. I authored a report for AEMO that examined the vulnerability of various equipment to high RoCoF. In this narrow context, the primary concern is for gas fired generation. Aggressive governor response to rapidly changing frequency, especially increasing frequency (as happens on the backswing of violent frequency event), can cause

[1] Executive Summary: http://www.nrel.gov/docs/fy13osti/58798.pdf Full Report: http://www.nrel.gov/docs/fy13osti/55588.pdf 2-page Fact Sheets: http://www.nrel.gov/docs/fy13osti/59064.pdf

combustion instabilities in gas turbines that can cause units to trip. Controls may need to be modified, and response may need to be limited. The issue is complex, and full, detailed evaluation of the robustness of specific plants can easily exceed $100k – sometimes by many times.

Some perspectives from US members of the NERC Essential Reliability Services Task Force.

Background

The issues and cost concerns raised by AEMC have been the subject of inquiry in North America as well. As a member of the NERC ERSTF,[2] I've been active in many of the discussions. It is worth noting that, in general, there is an interconnection regulatory requirement for all synchronous generation to be equipped with governors, and to have those governors active.[3] In 2016, the ERCOT (Electric Reliability Council of Texas; aka TRE – Texas Reliability Entity) requirement that all wind generation also be equipped with active primary frequency response controls came into effect. It is of some further interest to note that ERCOT has experienced a steadily declining level of required purchase of frequency response services since the rule came into effect. I believe that the system has experienced a drop in the cost of procuring those services as well.

I took the opportunity to solicit comments from some US colleagues that are knowledgeable and active in this topic. The one sentence take-away from this conversation is:

> *Concerns about the cost of providing PFR seem to be almost completely absent, or at least silent,in the US, to date.*

Comments from Julia Matevosjana, at ERCOT, indicated that the regulatory interconnection requirement for active governor controls has been in place for a long time. In ERCOT, it is argued that given the relatively small size of the Texas grid (with around 80 GW of installed capacity) and the limited connection with other grids via DC links, that ERCOT needs to be self-reliant with respect to frequency support so everyone should do their part. That is, if everyone, including wind and solar assists, then each generator would have to do just a little. In ERCOT there's no requirement to keep headroom available unless they participate in AS market. The most recent change was tightening governor dead bands to 0.017 Hz from 0.036 Hz.

John Simonelli from the New England ISO indicated that, similar to ERCOT, the requirement for active governor control has been documented for a very long time in their Operating Procedure No. 14 -Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources. This was not something they really monitored until BAL-003 and NERC alerts were received. Then, with the help of the phasor management units (PMUs) and a few convenient system events they began a deep data dive. They found a significant portion of the fleet had squelched response. As a result, they dragged out OP-14 and the NERC alert and went out to the plants on an "educational tour" together with increased focus on ongoing compliance.

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[2] North American Electricity Reliability Corporation Essential Reliability Services Task Force

[3] In North America, interconnection requirements are analogous to generator connection requirements in the NEM.

Most plants did not push back on cost nor complain too much. Many were not aware of the squelched response of their plants and were willing to correct things. While there were a number of plants that had odd deadbands, many of the issues circled back to distributed control systems (DCS) that were focused on adhering to the ISO's dispatch signal (under threat of economic penalties for failure to follow dispatch instruction) and not frequency control. They had a few holdouts that complained about cost including a couple of larger combined cycle (CC) units and a few that were not sure the investment was worth it given how long the units would be still operating (retirement in the near-term horizon). John thought that in the case of the larger CC units, the plants eventually had the manufacturers' SMEs in to tune their DCS to meet the ISO's dispatch control and PFR requirements. Rumors were that they incurred supposed costs of about $100K to get them back in to retune things.

Of late they have been getting a little static from PV builders (5 to 20MW size) who do not account for frequency control, nor read OP 14, in their initial design, and then have to come up with the $$ to install and test the controls. Those costs are rumoured to be between $10K to $75K once you account for technician cost and consultants.

Some closing comments:

Most of this information is from a grid perspective, and isn't coming directly from resource owners or thermal plant designers. There is expertise within GE that can probably shed some additional light on details of plant response. However, if experience is an indication, the answer will be "it depends". The issues of cost and efficiency are detailed and subtle. Any cost we are considering are going to be small compared to myriad other factors (like ambient conditions, fuel quality, operating history, …) High resolution answers likely will be expensive and plant specific. I understand the AEMC is more interested in guidance, rather than this level of detail. I will see if the real experts on thermal plant design and control have inputs which can be shared.

NWM

More thoughts on the cost of Primary Frequency Response (PFR) from Steam Turbine-Generators.

NW Miller 3-5-2018

Quantitative information is scarce. I had a lengthy discussion with a retired steam turbine expert after I sent you my earlier thoughts. The discussion centered around the options and compromises associated with providing PFR from steam turbines. I add that to earlier discussions I had with steam experts at GE, that focused on getting better PFR from steamers. Late last week, I got additional input from GE experts that are presently working on control and performance upgrades for the present generation of steam turbine-generators. The discussion is specifically for underfrequency. And per our earlier conversation, this input should be taken as informed opinion, and is specifically not official input or guarantees of performance from GE.

There are three, somewhat separate issues of importance:

Throttling losses

I continue to believe that if there are any substantive variable costs to generation owners, it will be here. The inlet steam paths to the high pressure turbine are complex, and designed to minimize unnecessary pressure drops, while maintaining proper steam flow into the 1st stage buckets. The design is made more complicated by the need to have good performance over a range of power levels. My expert showed that some designs have minimal throttling at or near rated power, and that additional steam flow is accomplished by further opening steam paths. This type of arrangement should have small or zero marginal efficiency penalty for maintaining some headroom and providing PFR.

The following figure is copied from a textbook by one of my GE friends. The figure shows a representative heat curve for a unit with multiple valve points (I think this is a so-called 'partial arc'). It shows the non-monotonic nature of the real heatrate curve. My hand annotations show that, for example, on this machine throttling back 5% would have small (0.1-0.2%) efficiency penalty. The annotation shows further that there are more substantial possible penalties around the valve points – my rather simple construct suggests that in the extreme, efficiency penalties of a few percent are possible. (More from the book is in the attachment). I think It is also worth noting that these 1st derivative discontinuities are completely disregarded in bulk power system modeling for economics (i.e. the dotted line is used in production cost simulations). I personally would take that as evidence that the nuances of valve points are not significant in the macro sense of overall system economic operation, even if they are important to individual resource owners.

In order to run at part load, regardless of the valving arrangement, units can use a combination of sliding pressure and valve control. These hybrid control arrangements use boiler control to manage the steam pressure to a level appropriate for the desired power level. The valves then throttle further. The key point is that the amount of headroom, i.e. the incremental power expected to be available from PFR, will have substantial impact on the efficiency penalty. Maintaining, say, 10% headroom (on the machine rating base), could have an efficient penalty in the range of 0.8 to 1.4% (for one "representative" curve I found).

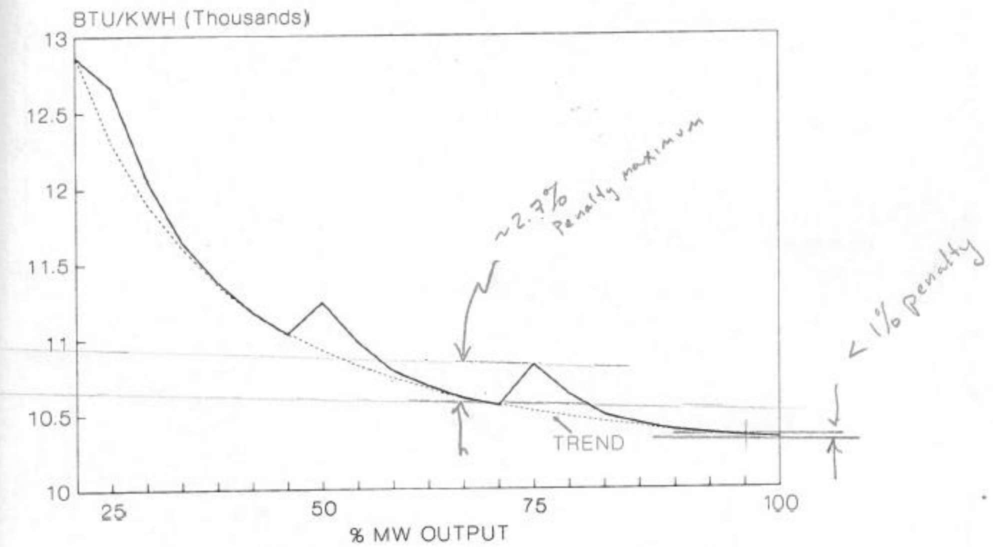

FIGURE 12.5 Average heat rate.

REFERENCE: H.G. STOLL, LEAST-COST ELECTRIC UTILITY PLANNING, WILEY, 1989

Sustainability

The increase in steam flow associated with PFR action will start to depress the steam pressure in the upstream steam cavity. This is replenished by increasing steam production over time, but the time constants are relatively long. Consequently, the PFR may not be sustained as long as necessary/required. The differences between boiler and HRSG designs can be substantial, with some systems having much more steam inventory than others. In some steam systems, there are opportunities to divert steam from other paths to help maintain the pressure into the HP turbines. For example, it is possible for a unit master load control to close steam bleedings connected to low pressure heaters and feed-water tank, which diverts steam to intermediate pressure and low-pressure turbines. This also requires control of condensate to feed water tanks and other steps. In short, this is complicated and not highly generalizable.

It is important to understand that controls for steam turbines have continued to evolve, and take advantage of huge increases in processing power and amounts of high fidelity measurements that can brought into real-time controls. There is a wide spectrum of upgrade services available to owners of fossil resources that can improve plant performance. These upgrades will typically improve heatrates, emissions performance, start and stop times, ramp-rates, minimum turn-back and dynamic performance …e.g. PFR. Decision making for investment in existing plants is complex, and I won't dwell on this topic, other than to note that, in my opinion: (a) improvements are likely to be possible, and (b) it is unlikely that investment solely for the purpose of improving PFR will make sense. Teasing out costs specifically associated with PFR improvements is not simple. The businesses that provide turbine services (this includes GE, which is very good at it), have sophisticated tools that can calculate impacts of myriad factors on plant efficiency. These tools are necessary for creation of economic value propositions for the resource owners, so that they can decide whether investments in upgrades make business sense.

The point being that, it is possible with non-trivial effort, to calculate specific impacts of a wide-variety of changes and alternative operating strategies on heatrates. The extensive study funded by DOE and performed by GE energy Consulting, Intertek AIM and NREL - "Cost-benefit Analysis of Flexibility Retrofit for Coal and Gas-fired Power Plants" addresses the spectrum of upgrades that can make thermal plants better participants in high wind and solar systems. The results are likely to be highly relevant to the situation in Australia. The report includes a variety of cost data.

Wear & Tear

This is an area that is a bit contentious. As noted in earlier communication, thermal units in the US generally take this a cost of being connected with relatively little complaint. There is little hard evidence that I've found to suggest otherwise. As I noted in earlier discussions, islanded applications with violent load swings are a known risk for wear and tear on hot gas paths in gas turbines. The general, casual response from power plant experts to whom I've spoken is that wear & tear on steam valves associated with active governor control is a non-issue. The notion that a very few plants providing all of the PFR in a system with small (i.e. US-style) frequency deadbands might experience undo added maintenance or higher forced outages was met with skepticism by the few people I talked to. GE's co-authors, Intertek AIM, on the NREL report have some useful expertise in this area. I can provide contact information for Nikhil Kumar (Steve Lefton tragically died in a small plane crash shortly after the report was issued).

I hope this information will be of use to AEMC,

Best regards,

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