Regulating reserve performance assessment for the Alberta Electric System Operator: project summary

A., Grewal; M., Dubois-Phillips; M., Wrinch; Jang, D.

For the publisher's version, please access the DOI link below./ Pour consulter la version de l'éditeur, utilisez le lien DOI ci-dessous.

https://doi.org/10.4224/21277590

NRC·CNRC Energy, Mining and Environment

Regulating Reserve Performance Assessment for the Alberta Electric System Operator

Project Summary

Document #: NRC-EME-55756

Date: March 18, 2016

Authors: A. Grewal, M. Dubois-Phillips, M. Wrinch, D. Jang

Principal Investigators: K. Kabiri, D. Song

National Research Council Canada | Conseil national de recherches Canada

Canada

1. Executive Summary

Electric system operators require operating reserve to help instantaneously balance supply of and demand for electricity in real time [1] . Regulating reserve is the specific type of operating reserve used to provide a balance between generation and load within a given balancing authority. System operators also use regulating reserve to maintain the scheduled exchange of power through the interties with neighbouring control areas while maintaining the nominal system frequency of 60 hertz [1]. Providers of regulating reserve capacity must be responsive to a request for power between a pre-determined high and low range. Regulating reserve service has historically been provided by unloaded synchronized conventional generators such as hydro, gas and coal. New advancements in storage technologies such as batteries and flywheels are available that can deliver energy very quickly, while accurately following a centrally dispatched power set-point signal while their energy is available. These advanced energy storage reserves are classified as fast-acting assets in that they can ramp their power up or down within seconds as compared to minutes for conventional assets. As a growing proportion of new generation from variable renewable sources like wind and solar are brought on-line, the need for efficient regulating reserve has increased. As a result, the Alberta Electric System Operator (AESO) and National Research Council (NRC) were interested in understanding if adding fast-acting assets to the regulating reserves would result in a reduction of the overall reserve requirements and therefore lead to efficiencies and cost savings for the system. The AESO commissioned the NRC to evaluate the performance of conventional assets and quantify the benefit of including fast-acting assets into the mix within the AESO's balancing authority area, the Alberta Interconnected Electric System (AIES).

The study was conducted in two parts:

1. The performance of conventional (hydro, gas and coal) regulating reserve assets were first quantified by assessing how closely they followed the Automatic Generation Control (AGC) command signals. This was accomplished by analyzing actual data from fourteen distinct 30 minute "grid events" recorded by the AESO.
2. Since the AIES generation fleet does not yet include any fast-acting assets, dynamic computer simulations were performed using operational data from eight of the fourteen grid events. The simulation results were then analyzed to quantify the impacts to overall regulation performance as the amount of fast-acting assets was incremented in four steps from 0-100% of the total regulation fleet.

Using a well-defined evaluation methodology described in section 4, the measured performance of the conventional assets was found to correlate with their relative ramp rates (hydro being the fastest, and coal the slowest). The averaged performance scores (by asset class) from the fourteen events are as follows:

Asset Class	Averaged Regulation Performance
Hydro	85.6%
Gas	75.3%
Coal	67.4%

The second part of the study suggests that improvements in overall AIES fleet performance could be realized by incorporating fast-acting assets, but that further study is required to fully assess the optimal mix of regulation assets. The simulation results generated by this initial study indicated that the most significant performance improvement was achieved when half of the regulating reserve fleet was modelled with fast-acting assets, and when the assets were operated near the middle of their regulation range. Under this scenario, the average reduction in Area Control Error (ACE) was 33%. However, with higher proportions of fast-acting assets in the fleet, the simulated response became oscillatory. Potential limitations associated with the system modelling and/or the inability of the current AGC algorithm to exploit the full performance of fast-acting assets were described as potential topics to explore in future optimization studies.

Since it is widely expected that the growth of renewable variable generation will continue, a corresponding need for more efficient regulating reserve to maintain system reliability and performance is also expected. While there is clearly a role for fast-acting assets to positively impact system performance, further study and results aggregation from markets already dispatching fast-acting assets is required to inform a specific policy reform or change to market rules.

2. Abbreviations

Item	Description
ACE	Area Control Error
AESO	Alberta Electric System Operator
AGC	Automatic Generation Control
AIES	Alberta Interconnected Electric System
CPS1	Control Performance Standard 1
EMS	Energy Management System
NERC	North American Electric Reliability Corporation
NRC	National Research Council
SCADA	Supervisory Control and Data Acquisition – A system wide computer controller
RR	Regulating Reserve
WECC	Western Electric Coordinating Council

Contents

3. Introduction

The North American electrical grid is a collection of generating regions comprised of interconnected generators operating synchronously at a nominal frequency of 60 Hz. System operators like the Alberta Electric System Operator (AESO) must balance generation and load in real time to maintain reliable service to its customers. In addition, they must manage stability in response to events that occur outside their jurisdiction through various interties that connect the Alberta system to British Columbia, Saskatchewan and Montana.

The AESO is the sole buyer of operating reserve under Alberta's current electricity market structure. Operating reserve acts as a safety net, making extra power available to help instantaneously balance supply of and demand for electricity in real time, and stabilizing and protecting the interconnected electric system in the event of unforeseen problems affecting generating pool assets [1]. There are two types of operating reserve: regulating reserve and contingency reserve.

> **Regulating reserve** is used to provide a balance between generation and load within the Alberta balancing authority area while maintaining the agreed power interchange schedule (cross area power flow) on the interconnections with British Columbia and Montana [1].
>
> **Contingency reserve** is used to restore the balance between the supply of and demand for electricity to the electric system following a contingency or unforeseen event threatening the reliable operation of the electrical system. Contingencies can include events such as the sudden loss of a generating unit, loss of wind generation capacity, an unanticipated increase in demand, or the disconnection of one of the interconnections that links Alberta to a neighboring jurisdiction. Contingency reserve is further separated into spinning reserve and supplemental reserve (known as non-spinning reserve in jurisdictions outside of Alberta) [1].

Frequency and intertie regulation has traditionally been achieved using certain generators (assets) held in reserve as part of a regulating reserve scheme. A regulating reserve range is provided by operators of these assets for Automatic Generation Control (AGC) operation. Regulating reserve range is the total amount of generation made available between the upper and lower regulating limits. The low regulating reserve limit is the energy dispatch or transmission must run output, whichever is greater, plus the amount of contingency reserve directed by the system operator for that asset. The high regulating reserve limit equals the low regulating reserve limit plus the amount of regulating reserve dispatched by the system operator for that asset. The difference between the high and low limits is the regulating reserve range of the generating unit/reserve asset [2].

Commands are dispatched by an automated Energy Management System (EMS) connected to each generator through a Supervisory Control and Data Acquisition (SCADA) network. The EMS algorithms compute the AGC set points within an established regulating reserve range to compensate for the moment-to-moment changes in load and generation on the AIES [2].

Generator (asset) owners are paid for their participation in the regulating reserve scheme. This is known as the ancillary services market. In some markets (e.g. PJM), generators that can respond more quickly are paid more than those with slower response times (ramp rates), and is compliant with the US Federal Energy Regulatory Commission's (FERC) Rule No. 755 [3]. This concept is known as pay for performance.

Traditional generation assets (hydro, gas, coal) have limitations with respect to response times. The increase in generation, along with the added complexity of integrating renewable generation, is expected to significantly increase the demand for and cost of regulating reserve from conventional sources. These demands are prompting system operators like the AESO to allow competition from fast-acting assets such as batteries and flywheels to the fleet of regulating reserve providers. These storage technologies respond much faster than traditional generators but have limitations on the amount of energy they can provide. Their faster ramp rates can potentially lead to a reduction in overall reserve requirements leading to potential cost savings for balancing authorities like the AESO.

To understand the impact the new class of fast-acting assets could have on overall reserves requirement, and assess the potential for displacing conventional generating units currently providing this service, the AESO and NRC, in collaboration with Powertech Labs, conducted the study summarized herein.

4. Methodology

The performance of conventional regulating reserve assets (Hydro, Gas and Coal) was first quantified based on how well they follow the AGC power set point. This performance score can be used by system operators to calculate performance-based payments for each regulating reserve asset. The methodology applied was developed from the IEEE article "Performance-Based Pricing of Frequency Regulation in Electricity Markets" [4], and performance scores were calculated for each individual generator and then averaged for each class of conventional asset in the fleet.

Since fast-acting assets have not yet been deployed in the AIES, there is no historical data to assess their performance. A model-based approach applying a dynamic simulation algorithm using DSA*Tools*[1] was therefore applied for the second part of the evaluation. A baseline performance metric of existing combined regulating reserves was created to model the AESO regulation reserve fleet. Baseline performance of the conventional fleet was verified through simulations of actual event recordings in the TASMo[2] database. Increasing amounts of fast acting assets were then added to the simulation model to compare against the baseline performance from the conventional fleet.

[1] DSA*Tools*™ is proprietary software developed by Powertech Labs.
[2] TASMo is Alberta Electric System Operator Grid Information Database

4.1 Conventional Asset Performance Assessment

These actual recorded events were used to study fourteen 30-minute time windows using year 2013 as shown in Table 1. Each event was characterised by variability due to the scheduled flow on the interties or ramping wind generation that caused energy imbalance on the system. Conventional hydro, gas, and coal regulating reserve assets made up 38%, 58% and 6% respectively, of the units in the AGC fleet for these events.

Table 1: Recorded events used for individual asset performance analysis

30 Minute Event Details		Units on AGC		
Event	**Date**	**Hydro**	**Gas**	**Coal**
1	6/18/2013	3	3	1
2	7/17/2013	2	2	1
3	3/22/2013	2	4	1
4	7/22/2013	2	2	1
5	9/18/2013	1	5	0
6	9/26/2013	3	5	0
7	9/24/2013	2	4	0
8	9/27/2013	3	4	0
9	1/4/2013	2	4	1
10	1/6/2013	3	4	0
11	4/20/2013	3	3	0
12	4/4/2013	2	4	0
13	4/4/2013	3	3	0
14	4/4/2013	3	3	0

Average performance scores for each individual asset were calculated based on the methodology described in [4] and further developed in the study. The averaged performance scores listed in Table 2 are represented as percentages and quantify how well the output of a unit follows the AGC control signal.

Table 2: Individual Asset Performance Score

Asset Class	Average Performance Score
Hydro	85.6%
Gas	75.3%
Coal	67.4%

The results were in accordance with the inherent properties of the asset. For example, hydro units are able to change their outputs faster than gas and coal and therefore followed their AGC set-points more closely.

4.2 Combined Fleet Performance Assessment

Of the fourteen events eight were chosen (1,2,3,4,7,8,9,10) to analyze the performance of the AGC fleet using a combination of fast-acting assets compared to that of a fleet using only conventional regulating reserve assets. The following steps were followed:

1. The Control Performance Standard 1 (CPS1) value for each of the recorded events was calculated
2. A simulation model of the AGC fleet was developed based on the eight events
3. Simulation iterations were run with an increasing percentage of fast-acting assets
4. Area Control Error (ACE) was calculated for each iteration. The greater the reduction in ACE, the better the simulated fleet performance.

The Control Performance Standard 1 (CPS1) is a statistical measure of Area Control Error (ACE) variability and its relationship to frequency error [5] and is defined by the North American Electric Reliability Corporation (NERC) [6]. CPS1 values are used to assign each balancing authority, like the AESO, a share of responsibility for control of steady-state interconnection frequency [6]. The relationship between ACE and frequency is such that over-generation of power results in positive ACE values and frequency increases, and under-generation for a given load results in negative ACE and decrease in interconnection frequency. The CPS1 number captures these relationships using statistical measures to determine each balancing authority's contribution. For the eight events analyzed in this study, the AESO contributed to correcting the frequency deviation in the Western Electric Coordinating Council (WECC) 40% of the time. This data was then used to model the AESO's control philosophy and deployment of ancillary services.

Power flow files used for this study were simplified by having the Montana Alberta Transmission Line not in service; the DC intertie to Saskatchewan was represented by a simple load whereas the interties between British Columbia and Alberta were modeled. The rest of the WECC system was reduced to an equivalent system of three large generators connected to one bus on the British Columbia side. The modelled system was validated by confirming that the change in frequency of the simulated system was the same as that observed in the actual system.

Simulation models were then set up using the following steps to reproduce power generation (including wind), load profiles, and intertie schedule changes:

1. A basic model for the AESO's AGC control, using the Passive Equalization ACE Control (PEAC) algorithm was developed and validated through playback simulations using recorded data from the Energy Management System (EMS) TASMo grid information database.
2. Simulation models were created to represent wind and load profile variations and Alberta-British Columbia intertie schedule changes.
3. Once the basic model with conventional regulating reserve assets was validated, a model for a generic fast-acting asset was developed.
4. Fast-acting assets were then added to the regulating reserve fleet for each simulated event.

5. Performance of the conventional asset fleet was compared to that of a fleet consisting of 10%, 25%, 50% and 100% of fast-acting assets (SIM 1)
6. A second set of simulations (SIM 2) were run with a reduced loop delay of 6 seconds to quantify further reduction in ACE that could be achieved by using faster communication pathways.
7. Finally, due to constraints in the AESO control algorithm, a new set of simulations were investigated utilizing modified algorithms with a different control philosophy.

Reduction / increase in average ACE values for each modeled event are summarized in Figure 1. Larger positive values in indicate better fleet performance, while negative values indicate worse than baseline performance, and zero indicates there was no benefit.

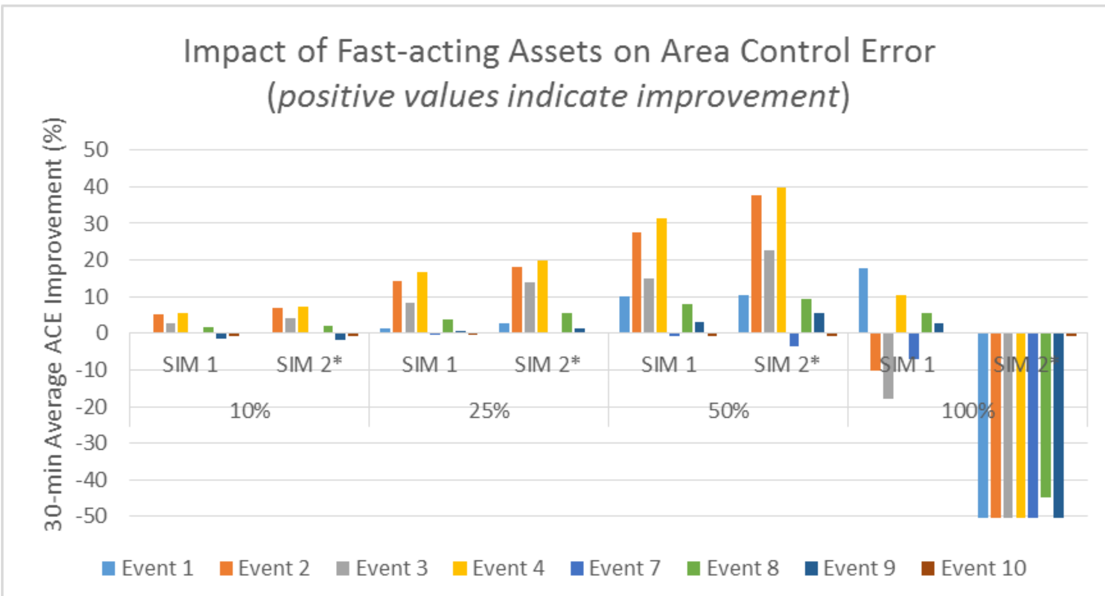

Figure 1: Comparison of improvements in Area Control Error (ACE) for simulated events

When only considering events 2, 3, and 4, in which the AGC fleet was generally operating near the middle of their regulation ranges, the average improvement in ACE was 33% from the SIM 2 simulation with 50% of the assets modelled as fast-acting.

The current AESO AGC control algorithm was not designed to efficiently utilize fast-acting assets since it does not prioritize based on ramp rates The algorithm generates set points based on a 3 minute ramp rate that are too long to exploit the available performance from fast-acting assets. Further AGC algorithm development would be required to fully realize the benefits offered by fast acting assets.

5. Conclusion

Regulating reserves in Alberta were studied through the analysis of measured AESO data and dynamic simulations of its electric system with varying proportions of fast-acting assets in its pool of regulation assets. The analysis revealed that fast acting assets positively impact system response times under certain conditions; however, additional study is required to adequately inform a specific policy reform or change to the requirement for regulating reserves. The findings of the current evaluation are summarized as follows;

- Overall fleet performance appears to be highly dependent on how closely the assets are operating to the limits of their regulating reserve range.
- The most significant improvement to regulation response was observed when the conventional reserve fleet is replaced with 50% fast-acting assets.
- If resources are not close to the limits of their regulation range, the improvement in performance becomes more prominent.
- At 100% replacement (all conventional assets replaced by fast-acting assets), the performance was inconclusive as the simulation results only revealed control instability. This behaviour could be a result of the current AGC control philosophy being incompatible with the fast–acting assets.

6. References

[1] Alberta Electric System Operator, "www.aeso.ca," 23 December 2014. [Online]. Available: http://www.aeso.ca/downloads/2013-005R_Operating_Reserve.pdf.

[2] Alberta Electric System Operator, "www.aeso.ca," 23 December 2014. [Online]. Available: http://www.aeso.ca/downloads/2013-006R_Regulating_Reserve.pdf.

[3] Federal Energy Regulatory Commission, "www.ferc.gov," 20 October 2011. [Online]. Available: https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

[4] A. D. Papalexopoulos and P. E. Andrianesis, "Performance-Based Pricing of Frequency Regulation in Electricity Markets," *IEEE Transactions of Power Systems,* vol. 29, no. 1, 2014.

[5] Regulation Performance Senior Task Force PJM Interconnection, "www.pjm.com," 12 October 2013. [Online]. Available: https://www.pjm.com/~/media/documents/ferc/2013-filings/20131016-er12-1204-004.ashx.

[6] North American Electric Reliability Corporation, "www.nerc.com," 26 January 2011. [Online]. Available: http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf.

7. Glossary

Ancillary Services: Services necessary to support the generation and transmission of energy from generating resources to customers while maintaining reliable operation of the system with acceptable levels of voltage and frequency. Examples of ancillary services include operating reserve, transmission must-run service, load shed scheme service, and black start service.

Area Control Error (ACE): The instantaneous difference between actual interchange (generation or load) and scheduled interchange, taking into account the effects of frequency bias, time error and unilateral inadvertent interchange if automatic correction is part of the automatic generation control of the interconnected electric system, and a correction for metering error.

Balancing Authority: A responsible entity that integrates resource plans ahead of time, maintains load-interchange generation balance within a balancing authority area and supports interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission and loads within the metered boundaries of the balancing authority and for which the balancing authority maintains load-resource balance.

Fast-acting Assets: Energy storage resources such as batteries and flywheels that can ramp up or down very fast and can follow a set-point signal very accurately.

Frequency Regulation: The AC current frequency must be held within tight tolerance bounds in order to synchronize generation assets for electrical grid operation. Frequency regulation is mainly provided by ramping (up and/or down) of generation assets. Different methods include generator inertia, adding and subtracting generation assets, dedicated demand response and electrical energy storage.

Frequency Response: The ability of a system or elements of the system to react or respond to a change in system frequency calculated as the sum of changes in demand, plus the change in generation, divided by the change in frequency; typically expressed in MW/0.1 Hz.

Operating Reserve: The capability above system demand required to provide for regulation, load forecasting errors, forced and scheduled equipment outages, and local area protection. It consists of spinning reserve and non-spinning reserve.

Ramp Rates: The rate of change in output of a generating unit, often measured in MW/minute.

Regulating Reserve (RR): The component of operating reserve that is responsive to automatic generation control and frequency imbalance that is sufficient to provide normal regulating margin.

Regulating Reserve Range: The total amount of generation (MW) made available for automatic generation control operation between the upper and lower regulating limits of each generating asset providing the regulating reserve service.

Spinning Reserve: Part of the contingency reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system.

Supplemental Reserve (non-spinning): Part of the contingency reserve that is generation capable of being connected to the interconnected electric system and loaded within 10 minutes or a load connected to the interconnected electric system which can be reduced within 10 minutes.

Synchronous Generators: Generators that operate at synchronous speed such that the rotational frequency of the equipment's rotor matches the frequency of the power system to which it is connected.

Intertie: A transmission interconnection to a neighbouring electric system that allows power to be imported and exported.