Simulating the Value of Advanced Electricity Storage:

Initial Results from a Case Study of the Ontario Power System

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ABSTRACT

This paper describes the use of system dynamics to aid long-term planning for the power system in Ontario, Canada. Our work focused on the value of an investment by NRstor, Inc in bulk energy storage using GCAES, the General Compression Advanced Energy Storage™ technology. The models simulate the air pumped into an underground cavern when electricity prices are low and the generation from the air released when prices are high. This arbitrage value is combined with other services such as the displacement of capacity and the integration of wind generation. The models have been used to promote learning among the members of the NRstor/GCAES project team and among the key agencies involved in planning and operating the Ontario power system.

The modeling system provides a unique perspective on ways to obtain multiple services from a single storage facility. And from a system dynamics perspective, the system demonstrates a unique way to combine short-term operational models with a long-term planning model. This combination has proved successful in promoting team learning through simulations of short-term and long-term dynamics in an internally consistent and mutually reinforcing manner. The paper concludes with Ontario's plans for the storage project and for the modeling system.

Background on Energy Storage

Energy storage in the power industry can take many forms and serve many purposes, as illustrated in Figure 1. The focus of this paper is the value of bulk energy storage technologies found in the upper-right corner of Figure 1. These technologies are often described as providing 1,000 MW of generating capacity and carrying sufficient energy in storage to sustain that power generation for many days.

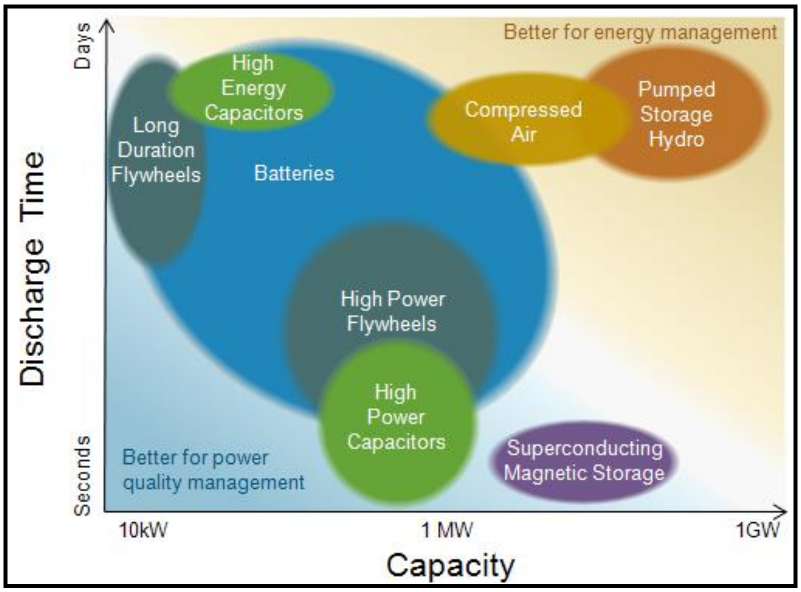

Figure 1. Classification of electricity storage technologies (EIA 2013).

The most familiar form of bulk energy storage is pumped storage hydro. Interest in pumped storage hydro is growing rapidly across the USA, as indicated by the map in Figure 2. Thornton (2012) noted that FERC preliminary permits for new pumped storage facilities totaled 39,000 MW. Adding these facilities to the existing capacity would increase pumped storage capacity by nearly three-fold.[1]

The interest in storage goes far beyond pumped storage as investors look to all of the technologies to provide value to the electricity grid (PIER 2011). The interest is closely associated with the growing challenges of integrating renewable electricity generation. For example, a recent news article (Reuters 2013) describes the surging interest in California -- where the state's aggressive renewables target would require the addition of up to 1,300 MW of new storage by 2020.[2]

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[1]Proposed projects would increase the pumped storage capacity in the Pacific Northwest even more dramatically. There are 13 project proposals in the states of Washington, Oregon and Idaho. Their completion would increase the pumped storage capacity in the entire western power system (ie, the entire WECC) by four-fold (NPCC 2007).

[2]The preliminary procurement goal for the year 2020 is 1,325 MW, according to a recent CPUC ACR (2013). The Reuters news article reported that storage is seen as energy's *Holy Grail* because of the efficiency it brings to the grid. Reuters also noted that venture capitalists have "poured $2.2 billion into storage in the last five years, over double the investment of the previous five years."

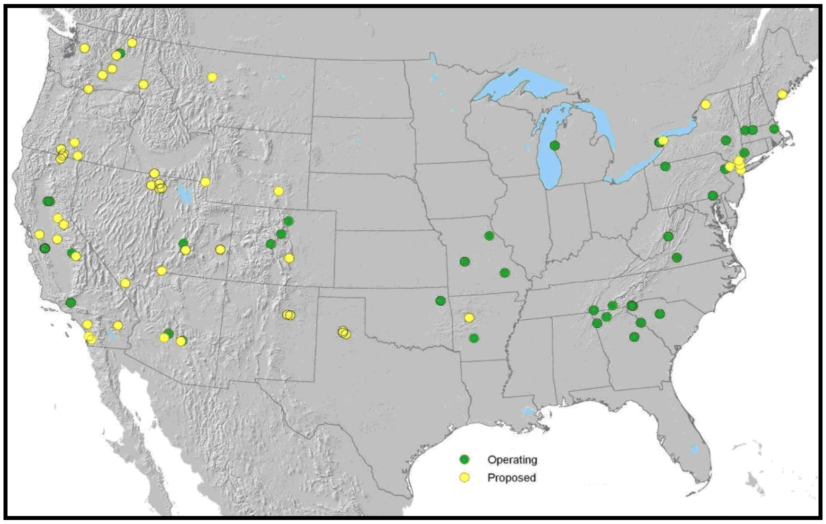

Figure 2. Pumped storage in the USA (Thornton 2012, Parformak 2011).

Insight on the potential size of the storage market is provided by the Pacific Northwest National Laboratory's assessment of energy storage for grid balancing and arbitrage (PNNL 2012).[3] Their report focused on the size the storage needs in the WECC, the interconnected electricity system in the western USA. The assessment produced useful rules of thumb for estimating the storage needs associated with intra-hour balancing requirements to address variability in both the load and the renewable generation. The PNNL investigators provided two general conclusions to help one assess the size of the growing market for storage:

- The first conclusion is that balancing requirements typically range from 3% to 5% of peak. For a large system with 25,000 MW of peak load, for example, one would expect 1,000 MW of balancing services to deal with variations in loads and the variability of traditional thermal generating resources.
- The second key conclusion from the PNNL assessment is that balancing services will inevitably increase as more and more wind capacity is added to the system. A simple rule of thumb suggests a ten-to-one ratio between extra wind and extra balancing. In other words, an extra 10,000 MW of wind capacity would impose a need for an extra 1,000 MW of balancing services.[4]

[3]The PNNL is one of the laboratories that provide research support to the US Department of Energy. Other energy laboratories are also heavily involved in storage assessments, especially the Sandia National Laboratories (2010) and the National Renewable Energy Laboratory (NREL 2010).

[4]The 10-to-1 ratio is midway in the range from a low of 5-to-1 to a high of 14-to-1 (PNNL 2012, p. vi). Their analysis of the entire WECC indicated 14,440 of new wind capacity to meet Renewable Portfolio Standards. PNNL estimated that this new wind capacity would create the need for additional balancing services of 1,530 MW. Scaling this example down to 10,000 MW indicates the need for an additional 1,060 MW of balancing reserves. Given the uncertainties, it is useful to round to 1,000 MW (ie. easier to remember). Additional balancing services might be provided by the flexible generating resources on the existing power system. However, as the existing system makes full use of its flexible resources, new investments are required. These often take the form of new gas-fueled combustion turbines (CTs). Indeed, CTs appear so often in Integrated Resource Plans (IRPs) that investigators from the Lawrence Berkeley Laboratory called for IRPs to consider alternative methods of

The Ontario Power System

The power system in Ontario serves a peak load of approximately 25,000 MW. Electricity generation is dominated by nuclear which supplies over half of the energy needs. Hydro generation provides around 22%, and natural gas generation around 15%. A remarkable achievement has been the reduction in coal generation to only 3% of total generation.[5] Renewable generation accounts for a small fraction (around 5%) now, but Ontario has ambitious goals to expand clean energy capacity to 10,700 MW by the year 2018.[6]

Ontario has also operated a conservation program to promote efficient use of electricity. Previous efforts are estimated to have lowered the total energy demand by 5%. The programs explained in the 2010 long-term plan would be responsible for lowering total energy demand by 14% by the year 2030. Ontario has recommitted to the efficiency goals with a "conservation first" emphasis in the most recent planning document (Ministry of Energy 2013).

With a peak load of 25,000 MW, the PNNL rule of thumb indicates that 1,000 MW of balancing services are needed to meet the variability in current loads and traditional thermal resources. discussions with Ontario planners suggest that most of this balancing requirement can be provided by the flexible hydro resources in the system.

With the aggressive wind acquisition program in Ontario, the second PNNL rule of thumb would suggest the need for additional balancing services to deal with the variability in wind generation.

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wind integration (LBNL 2008, p. 234), with the goal of avoiding the gas price risk and the carbon price risk associated with CTs.

This paper focuses on the GCAES storage technology as an alternative method for wind integration. GCAES provides bulk storage similar to the storage that has been traditionally provided in hydro pumped storage projects. Ontario has an existing pumped storage unit at the Adam Beck facility on the Niagara River, but the province lacks suitable sites for major expansion of pumped storage. Compressed air energy storage, the other technology in the upper right corner of Figure1, could be the answer. This paper focuses on GCAES, an advanced form of compressed air energy storage that uses adiabatic compression to avoid the need to burn natural gas when generating electricity. The simulation results indicate that GCAES could delivers huge benefits relative to gas-fueled CTs when we count the social cost of carbon along with the economic costs of electricity.

[5] Coal generation increased dramatically in the late 1990s, adding significantly to Ontario air pollution. The assessment of the environmental costs led to a government decision to phase out coal-generation (Ministry of Energy 2012). Since 2003, coal generation has been reduced by 70%, and this reduction is largely responsible for the decline in power sector CO2 emissions. The phase out is especially noteworthy since it was accomplished without the imposition of a carbon tax or a carbon market. Clearly, the social cost (ie, environmental cost) of CO2 emissions is taken seriously in Ontario.

[6] The clean energy goal is 10,700 MW of non-hydro renewable capacity by 2018. This is an aggressive target, even for renewable technologies like wind which can be added to the system with relatively short construction intervals. Ontario expects wind to meet the majority of the goal, but there will be contributions from bioenergy and solar photovoltaic (PV) as well. Ontario has already achieved large investments in wind with a highly regarded Feed In Tariff (FIT) program. (The program has been cited, along with the German tariff, as an example of "best practices" to achieve transparency, longevity and certainty needed to deliver an investor-response that will yield the required volume, without inefficient cost to the consumer or taxpayer" (DB Climate Change Advisors 2009, p. 22).) Ontario's future plans call for a new procurement system for acquisition of renewable projects with capacity over 500 kW.

If wind capacity provides 10,000 MW of the 10,700 MW clean energy goal, for example, one would expect a need for an additional 1,000 MW of balancing reserves.

So, Ontario planners face the question of how best to meet the additional need for balancing reserves. There are active discussions of whether the additional1,000 MW of balancing could be provided from untapped flexibility in the hydro resources. And, as is often suggested in IRPs, the 1,000 MW of balancing might be provided by gas-fired CTs used to provide wind integration. Our suggestion is that Ontario planers consider an investment in a 1,000 GCAES facility. The new storage facility could provide a combination of different services, including the 1,000 MW of balancing services that are associated with the rapid expansion of wind capacity.

The System Dynamics Modeling System

The modeling system is comprised of the two, interconnected models shown in Figure 3. The long-term planning model simulates a 30-year interval from 2013 to 2043. The model proceeds one month at a time, and the entire simulation is completed in a second or two. The long-term model is supported by information obtained from the operations model. It simulates a typical week by proceeding one hour at a time. This simulation is also completed in a second or two. The inputs for the operations model are selected to match the corresponding results for a particular month and year in the long-term model. The operational simulations provide aggregate measures of performance of GCAES. These are transferred to the long-term model to simulate the value of GCAES in reducing the total cost of power to the load distribution companies. The combination of a long-term planning model working in tandem with a short-term operations model was a crucial to promoting discussions among members of the project team and among the many agencies in Ontario. The ability to cross quickly from one time frame to another is likely to be of general interest to members of the system dynamics community.[7]

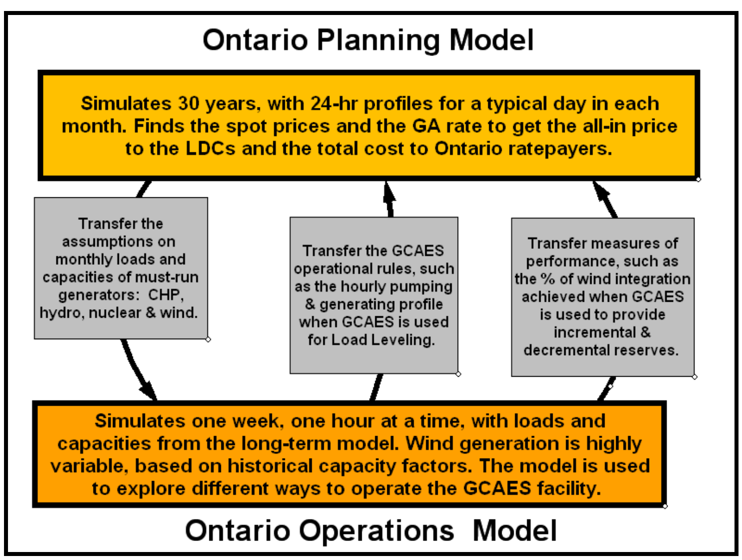

Figure 3. Design of the modeling system.

[7] A similar approach is under development at WSU to put system dynamics to use in support of planning at the National Parks in the USA (Ford, Nguyen and Beall 2012).

Model Views

Most briefings began with the view in Figure 4. The gray boxes are navigation buttons that take the user to the three sectors of the model. The graph shows generation in the peak hour of each month of the base case simulation. Some of the important inputs have been assigned sliders so they can be changed from the opening view.

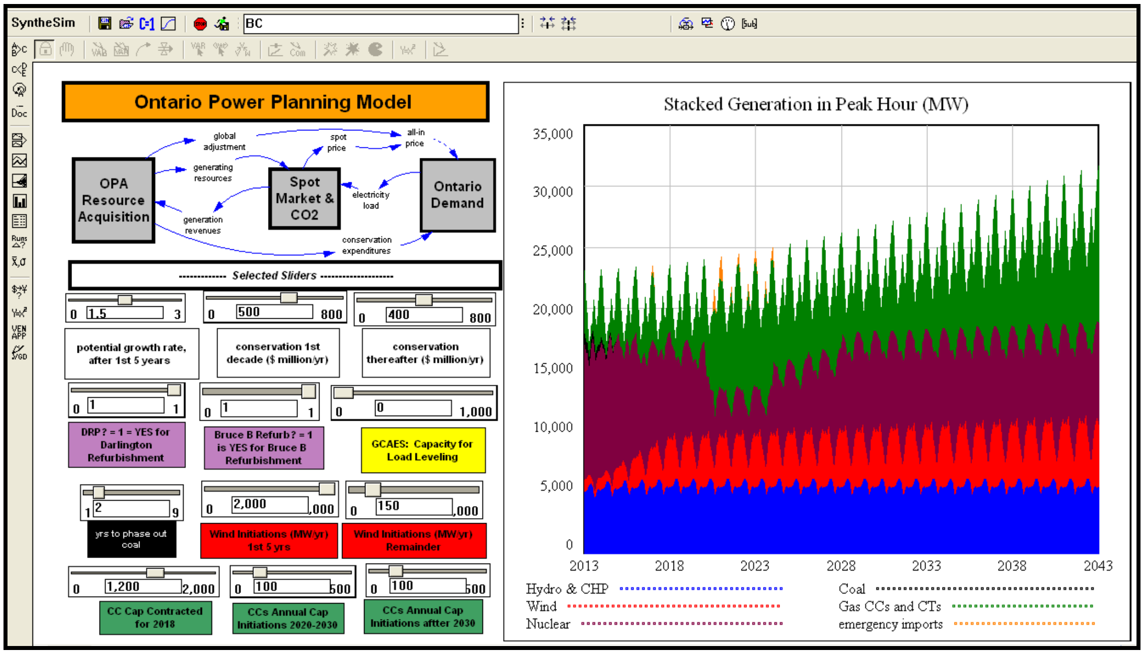

Figure 4. Opening view of the Long-Term Planning model.

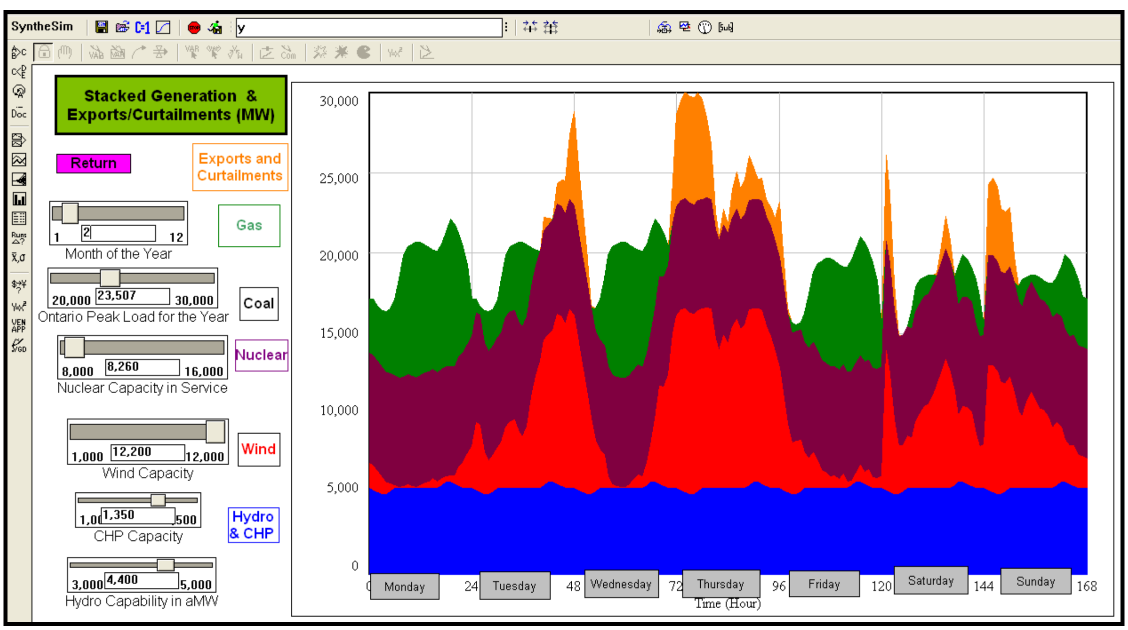

Figure 5. Corresponding view of stacked generation in the operations model.

Figure 5 shows the corresponding view of stacked generation as the operations model simulates a typical week in February of 2008. Notice that time is in hours, and the simulation proceeds chronologically through the 168 hours in the week. This chronological approach allows one to see the impacts of the wide variations in wind generation that can appear in time frames too small to be simulated in the long-term model.

Figure 6 shows the key stocks and flows in the operations model. The energy stored in the underground cavern is influenced by three sets of pumping and generating flows. These flows are shaped by the team's ideas for the best way to use the facility for load leveling (LL), wind integration (WI) or curtailments reduction (CR). Figure 7 shows the change in energy storage in a simulation with all 1,000 MW of GCAES used for load leveling (ie, for energy arbitrage).

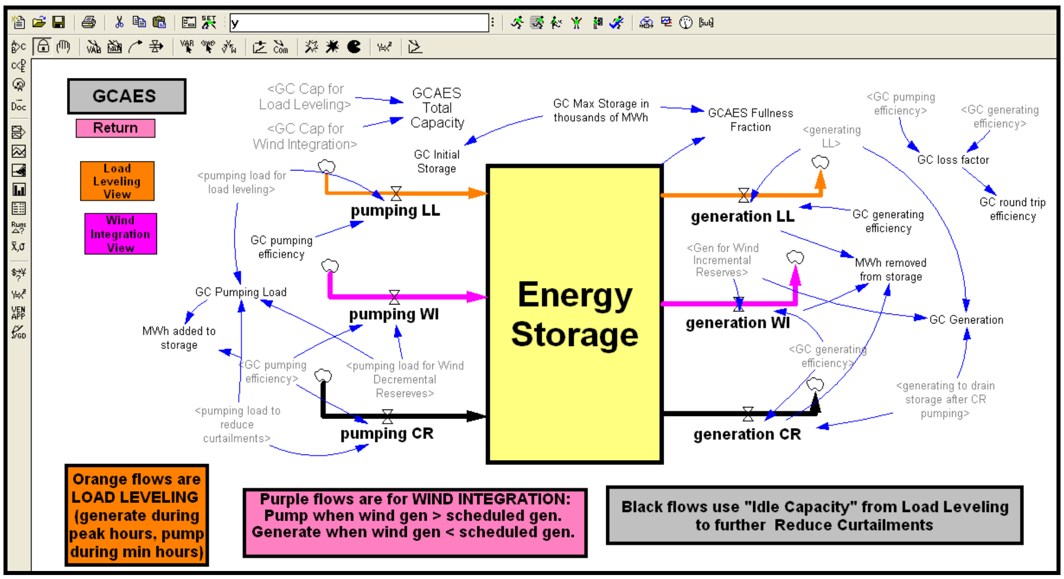

Figure 6. View of the key stocks and flows in the short-term operations model.

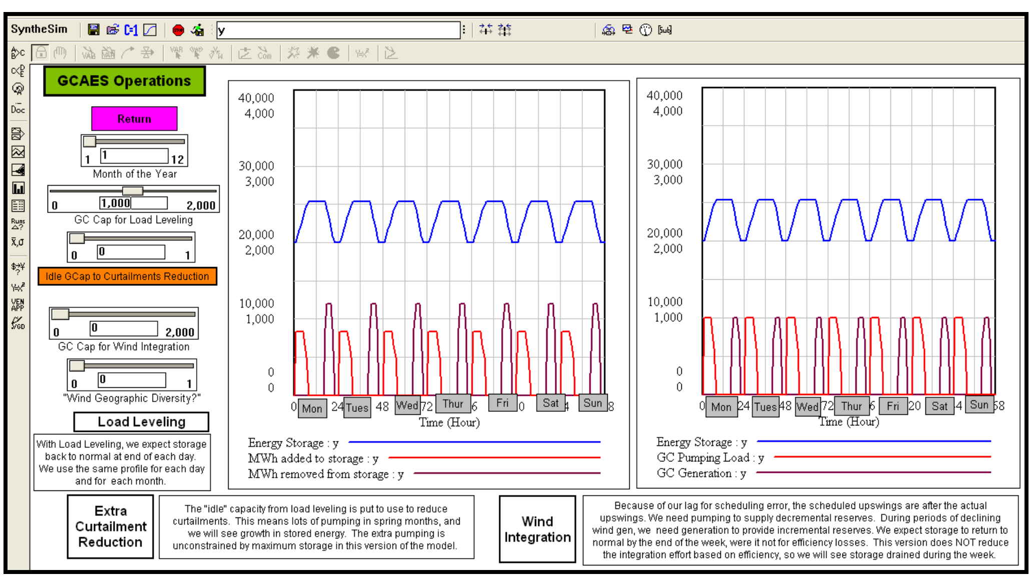

Figure 7. GCAES operations view in a simulation with
1,000 MW applied to load leveling (ie, energy arbitrage).

Figure 8 shows the opening view of the spot market sector. The gray buttons navigate to views of the model diagrams; the green buttons navigate to model results. Additional buttons allow for easy viewing of lists of model assumptions and for 24-hour dispatching plots to help team members check the hourly spot prices and generation in the long-term model.

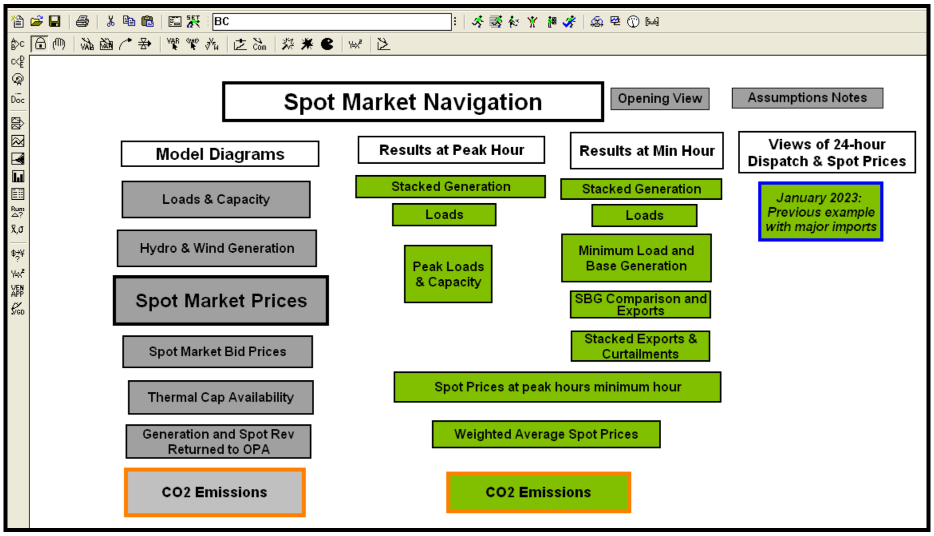

Figure 8. Navigation buttons in the opening view of the spot market sector.

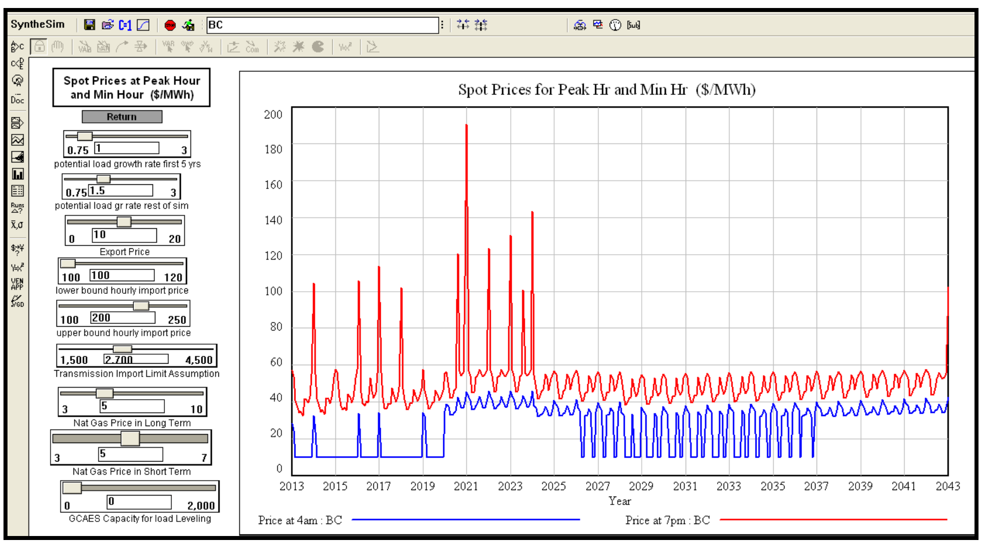

Figure 9. Base case results for the key spot prices in the long term model.

The peak hour and minimum hour spot prices are shown in Figure 9. The spot price patterns make sense given the relative abundance of resources in the first 7 years, followed by less resources during the 2020-2025 period when major nuclear facilities are out of service for refurbishment. After 2025, peak-hour spot prices return to the range expected when gas-fueled combined cycle plants are on the margin.

CO2 emissions are shown in Figure 10. The emissions are calculated for each hour of a typical day in each month of the simulation. The model then calculates daily emissions and expands the results to report annualized emissions on the left graph. The stacked contributions to total emissions are shown in the graph on the right. Emissions are quite low in the first 5 years, due largely to the phase out of Ontario's coal-capacity. Emissions increase sharply when major nuclear units are taken out of service, and they decline again when the units return to operation. The long-term growth in emissions is caused by the increased dependence on gas-fired generation. Figure 10 alerts Ontario planners that more carbon-free resources are needed if the goals for CO2 emissions are to be satisfied.

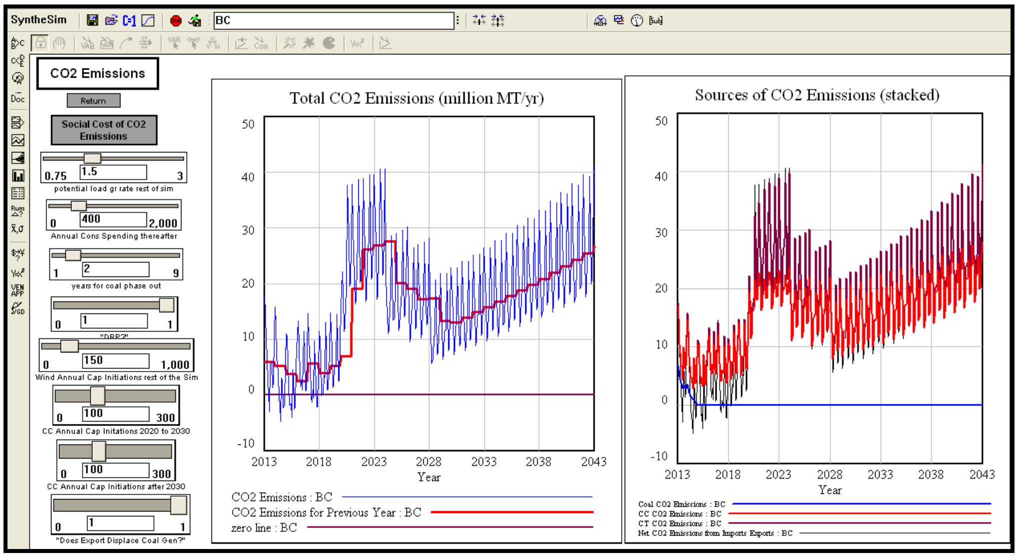

Figure 10. Base case results for Ontario's CO2 emissions in the long-term model.

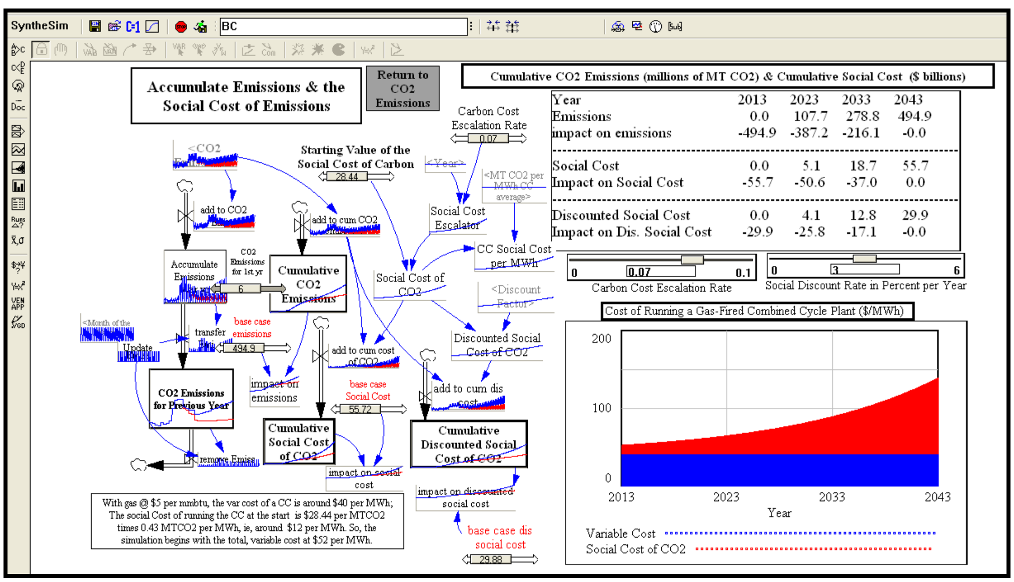

Figure 11 Base case results for CO2 emissions and their social cost.

Figure 11 shows the social costs of the CO2 emissions.[8] The base case simulation shows cumulative emissions of 495 million MT of CO2. The social cost of the emissions grows to

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8 The model uses the Canadian government value of $28.44 per MT CO2 at the start of the simulation. The social cost is escalated over time based on the rates derived from a US Government (2010) Interagency Working Group.

$495 billion. Simulation studies show that increased investment in carbon free generation or in conservation programs can lead to billions of $ reduction in the social cost of carbon. In the case of conservation programs, the increased effort can also lead to billions of $ reduction in the cost of power to the local distribution companies.

Figure 12 shows the operations model results for a simulation with 1,000 MW of GCAES devoted to wind integration in January of 2028. The base case assumes that wind capacity will reach 12,200 MW, and historical capacity factors are used to represent the major swings in generation shown in the left graph. We estimate the likely differences between scheduled wind generation and actual wind generation based on a lag structure that creates a close match with the work on wind integration in the Bonneville control area by Llewellyn (2011). The right-side graph shows the simulated operation of the GCAES generators in blue as they provide incremental (INC) reserves when the wind generation is below the schedule. The GCAES pumping load is shown in red as the pumps operate to provide decremental (DEC) reserves when the wind generation is above the schedule. The simulation indicates that the 1,000 MW facility could completely eliminate the scheduling error in 90% of the hours of the week. This result is combined with many other results from the operations model to create the performance curves used in the long-term model. The long-term model is then used to find the $ value of the wind integration that could be achieved over the 20-year life of GCAES. The result is $5.09 billion in value.

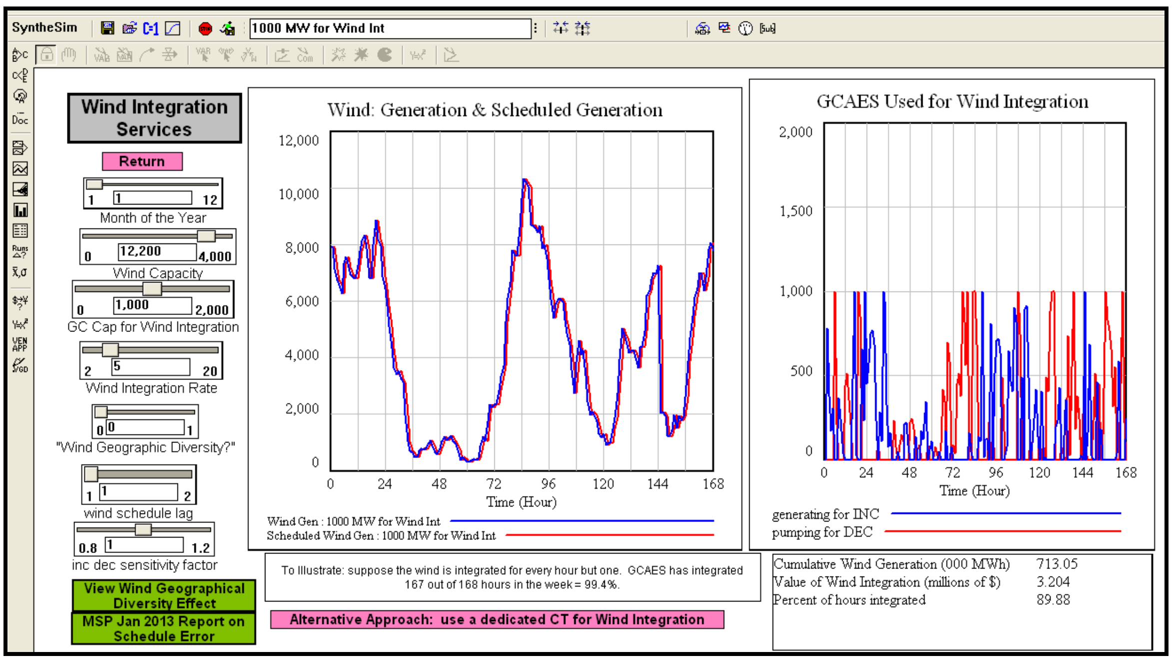

Figure 12. Results from application of 1,000 MW of GCAES toward wind integration during a typical week of January of 2028.

Figure 13 provides perspective on the 1,000 MW GCAES provision of INC and DEC reserves compared to the use of a 2,000 MW CT facility. The CT would be designed to operate at 50% capacity factor for all hours and months of the year, providing a base line for the provision of INC and DEC reserves. If one assumes that the CT facility could make the large, rapid swings in the right-side graph, the facility could deliver the equivalent performance as GCAES. The red line in the right-side graph shows the CO2 emissions associated with the CT's operations. They grow to over 120,000 metric tons in just one week of operation.

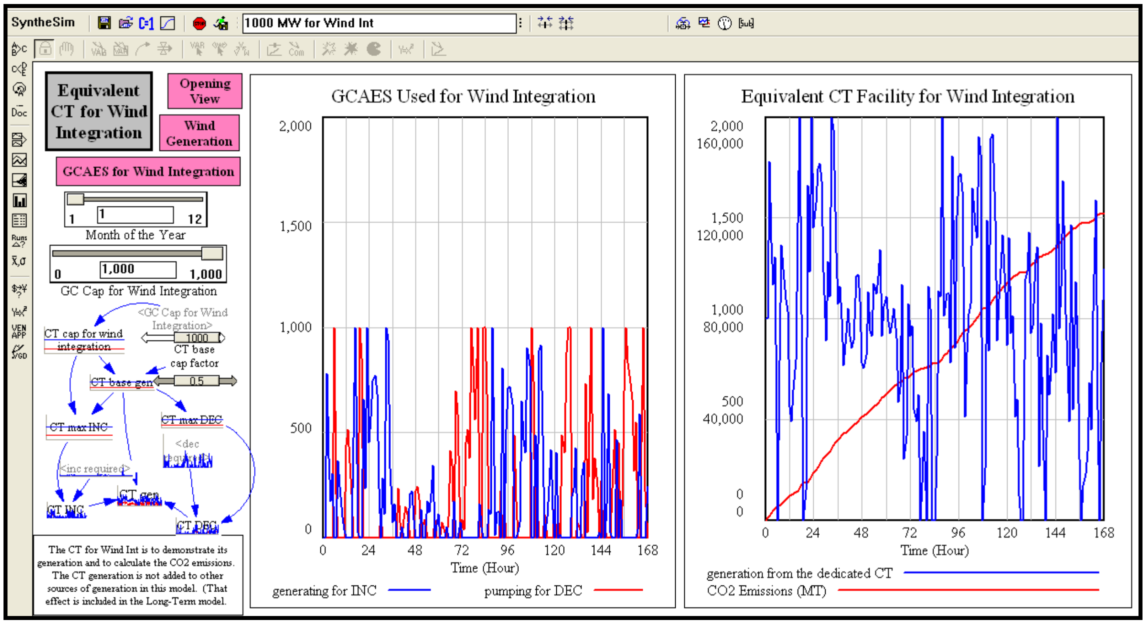

Figure 13. Wind integration results with a 1,000 MW GCAES (on the left) and a 2,000 MW CT facility (on the right).

Figure 14 concludes the presentation of model views by showing the total costs to the load distribution companies (the LDCs) over the 20-year life of the GCAES facility. This cost serves as an economic figure of merit for judging the value of the storage facility. In this example, a 1,000 MW GCAES is used for load leveling for 4 months/year of high loads. A capacity credit is claimed by lowering the size of the CT addition for 2021 by 1,000 MW. The model simulates the benefit to the LDCs as $2,283 million.

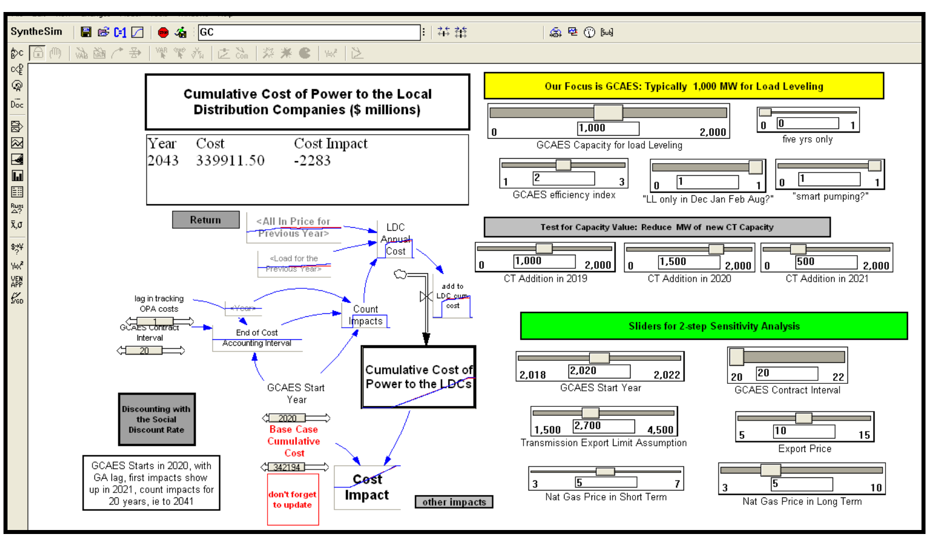

Figure 14. Value to the Load Distribution Companies from the use of 1,000 MW of GCAES for a combination of load leveling (energy arbitrage) and displacement of new CT units.

Figure 14 concludes the presentation of different views of the system dynamics models. With the exception of Figure 6, the views deal entirely with results. This style of presentation was chosen to match the way the model was presented in briefings with energy agencies in Ontario. The model was designed for rapid, interactive display of simulation results to promote group discussion. The key feature was the easy access to dozens of graphs with relevant sliders to allow rapid sensitivity testing. The key observation of interest to the system dynamics community is that the discussions were fueled by the presentation of model results, not by showing the underlying feedback structure.[9]

Simulated Value of GCAES

The GCAES facility has been simulated under a wide range of conditions as we search for the best value to the LDCs. The simulations have considered a GCAES with different sizes, different efficiencies, different starting dates, different operating lives and different months of operation. We have also examined the use of GCAES as a facility dedicated to one value or as a multi-purpose facility. A summary of some of the key results is shown in Figure 15.

The first bar in the chart shows just over $2 billion in value when GCAES is used for load leveling for all months of the year. The value of load leveling, combined with reduction in CT investment is well below the likely cost of the facility. The limited value from load leveling arises from the limited spread in spot prices and from the regulatory rules involving the cash flow payments from the generators to the Ontario Power Authority (OPA). Although the $2 billion is below the likely cost of GCAES, the low value did not come as a surprise to members of the modeling team, nor was it a surprise to the Ontario agencies.

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[9] The feedback focus is at the heart of the system dynamics method, and the incorporation of key feedbacks often provides a unique perspective on the system behavior. This is certainly true in the electric power industry where the ability of system dynamics modelers to represent key feedbacks provided an exceptional capability to simulate problems such as the *death spiral* (Ford 1997).

There is nearly universal agreement within the system dynamics community on the importance of simulating the key feedbacks that allow the models to provide an endogenous perspective on system behavior. But there can be important differences of opinion on when to "close the loop" in the course of a modeling engagement devoted to team learning.

The approach in the Ontario study was to not "close the loop" on several well-known, feedback processes. Price feedback to retail demand, for example, was not included since we reasoned that the feedback effects would be small. The endogenous additions of new generating resources were also left out of the model. Our approach was to leave resource additions to the user, with a mix of sliders readily available so that meeting participants could make suggestions for resource additions. In a sense, the participants were "closing the loop" in their thinking about the system, and the ensuing discussion led to team learning about appropriate timing and magnitude or resource additions.

As a third example, the key feedback loops governing the mix of resource additions were not simulated in the model. Rather, we left the mix of resources to the model user, with the relevant sliders within easy reach. This approach led to simulation results that were more dramatic and easier to understand, thus promoting discussion among the participants.

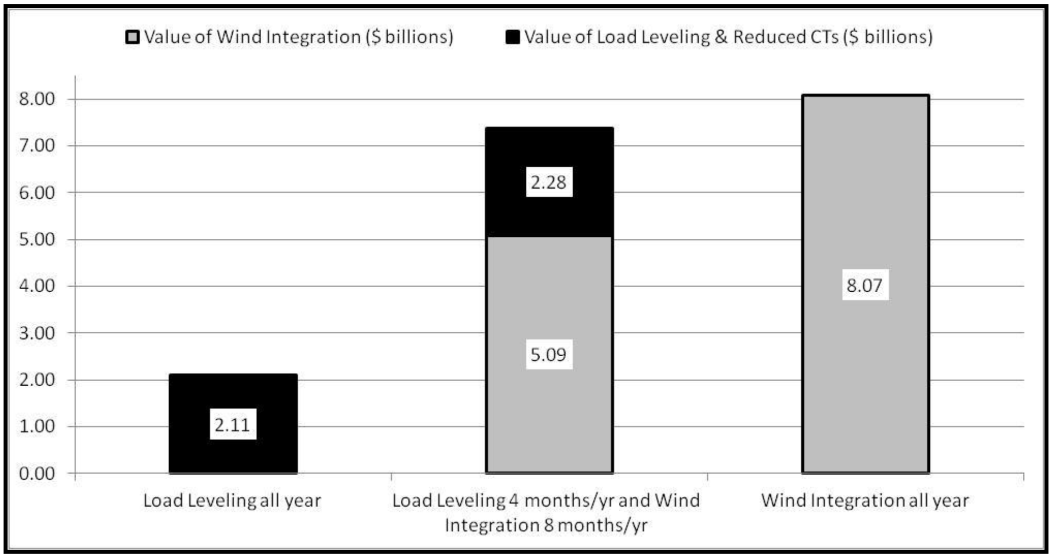

Figure 15. Summary GCAES values, with the middle case showing over $7 billion in value due to a combination of load leveling, reduced CTs and wind integration.

The more interesting results are the second and third bars in Figure 15. They show values in excess of $7 billion, values which exceed the likely cost of the storage facility. The middle bar shows the value from using GCAES to deliver multiple services. The facility concentrates on load leveling during the four months of the year with peak loads, and it switches to wind integration for the other eight months of the year. The combined value is a $7.37 billion reduction in the cost of power to the LDCs, a value which exceeds the likely cost of the storage facility. The third bar shows over $8 billion in value when GCAES is dedicated to wind integration services for 12 months/year.

Future Plans

These encouraging value results indicate that GCAES warrants further consideration as a storage resource in Ontario's long term energy plan. The results also support the case for creating a small-scale test facility. The testing phase is important for a new technology like GCAES, and the results of the test should shed further light on the best ways to use the new storage facility.

Discussions are also underway on the best ways to expand and improve the system dynamics models. Several Ontario agencies have volunteered to help with model improvements. The improved models would be designed for more realism in the portrayal of the Ontario power system, while retaining the highly interactive features which have proved useful in the first year of the project. The goal is improved models and greater learning in Ontario.

Improved modeling methods in Ontario can set an example for planners in other provinces and states. The lack of suitable cost-effectiveness methods has been identified as one of the barriers hindering the broader adoption of emerging storage technologies (CPUC ACR 2013, p. 3). The system dynamics approach used in the Ontario case study has the potential to help planners remove this barrier.

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Acknowledgements

The Ontario study was initiated by NRstor, Inc of Toronto, Ontario. Major credit goes to Annette Versuren and Alexander McIssac for setting the study goals and for guiding the project to achieve maximum learning, both among the members of the modeling team and among the many energy agencies that have participated. The ideas and suggestions from energy agencies' staff and executives have been an invaluable part of the modeling process.

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