Appendix A

Arbitrage and Peak Shaving.

The curious effect of energy storage is that it impacts both demand and supply. Before energy storage is introduced into the electric system, it is reasonable to assume that there is a period of low demand, (represented by a vertical line Y in figure A1, below), characterized by low prices, and a period of peak demand characterized by peak prices. The electricity demand, or load, is represented by vertical lines because in the model it is considered to be inelastic.

Once storage is introduced into the electric system, it is assumed that it will engage in arbitrage. Although in economic literature, the term “arbitrage” refers to profit derived from price differential between markets, here it refers to selling electricity from storage at peak hours and charging it during low demand.

Charging of a storage system moves the low demand curve to the right, because the demand for electricity that existed before storage was introduced into the system, is now increased by the amount of electricity necessary to charge the storage system. The consequence of moving the demand curve from Y to YY in the figure below is an increase in prices. Here it is necessary to make a few simplifying assumptions. The CBM model is based on hourly nodal prices, which makes it possible to determine daily peak and bottom prices, but it doesn’t have daily consumption figures. It does, however, have expected volume of monthly energy consumption. Consequently, to estimate the increase in prices associated with the rightward shift of the demand curve, the bottom price(s)[1] are multiplied by a percentual increase in demand, from Y to YY on the graph below. The increase is calculated as the sum of low demand and additional demand attributed to charging storage, divided by low demand.

Energy storage also shifts the supply curve. The supply is assumed to be upward sloping. Consequently, for any quantity of electricity demanded, an increase in number of suppliers (in this case energy released from storage) shifts the supply curve to the right and decreases the price of electricity. The decrease in price is assumed to be proportional to increased supply. Specifically, the decrease is equivalent to the percentage monthly energy released from storage represents in terms of total monthly energy consumed. This assumption is made because we have no data on the inverse of the price elasticity of supply (percentage change in price due to percentage change in quantity supplied). For example, if the monthly energy released from storage is equivalent to 1% of the monthly energy consumed in the system, the peak prices decrease by 1%. Naturally, this assumption can be adjusted once hard data is available.

It is important to note that this is a very simplistic model of arbitrage calculations. It does not consider instances where only a part of stored energy is released, or the storage is not fully

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[1] If the storage system is charged during one hour, the monthly bottom price is used, If, for example it is charged in three hours, the average of three lowest monthly prices is used. The monthly bottom price is defined as the average of daily lowest prices. The second lowest monthly bottom price is defined as the average of the second lowest daily prices, etc. The same logic applies to peak monthly prices.

charged. Also, while losses associated with charging and discharging each technology are considered for calculating costs and revenues associated with charging and released energy, losses are not considered in estimating how monthly system consumption increases or decreases prices faced by a storage operator (it could be argued that the overall energy consumption in the system increases by the amount of energy losses associated with each technology). However, since we already make general assumptions about the relationship between the power price and the amount of energy consumed without specific data, pretending to introduce a higher level of detail adds complexity to the model without improving the credibility of results. That said, it is critical to consider – and the model does consider - the precise losses associated with each technology in calculating per MWh earnings or costs for energy released or stored, respectively.

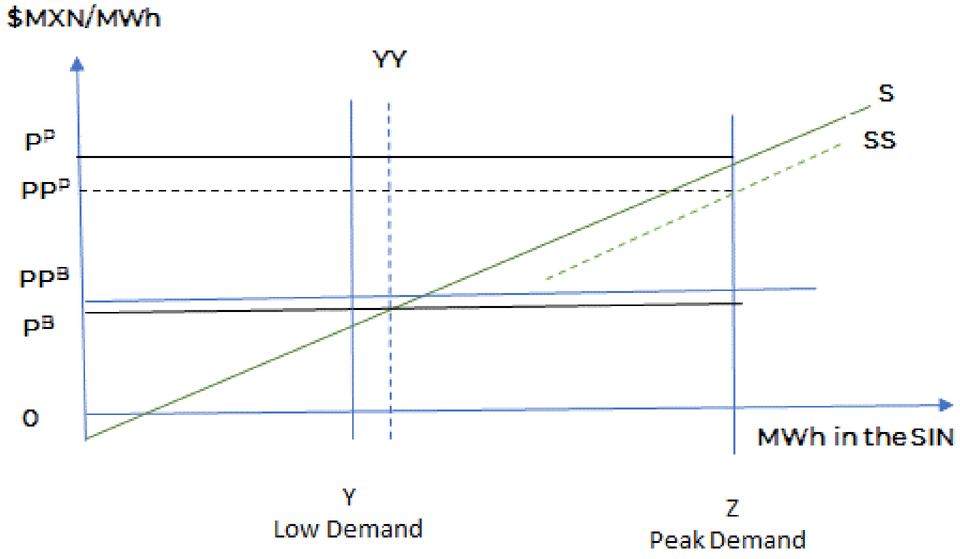

Figure A1.

Y – Low Demand, MWh

YY – Low Demand + Energy Used to Charge Storage, MWh

S – Electricity supply curve

SS – Electricity supply curve, where energy released from storage forms a part of supply

P^P – Peak power price

P^B- Bottom power price

PP^P – Peak power price as a result of increased supply associated with energy released from storage

PP^B – Bottom power price as a result of increased demand associated with energy used for charging storage

Another assumption that is important to consider deals with the continuity of charging and discharging. Arbitrage is estimated based on the volume of energy released from storage (a function of the storage technology: capacity, length of useful operating life, number of daily cycles, etc.), multiplied by the relevant price. If a battery storage, for example, is charged and discharged three times during a day, where each charging and discharging takes three hours, the model will use nine highest hourly prices to calculate revenue and nine lowest hourly prices to calculate cost of the energy stored. In terms of prices, this assumes a continuous discharge for nine hours, and a continuous charge for nine hours. In reality, it would be more correct to use the three lowest prices only for the first charge. If prices are continuously rising from bottom to peak prices, then the second charge should consider seventh, eighth, and nineth lowest prices, not forth, fifth, and sixth. Nevertheless, the model calculation holds relatively well for large systems like CAES or PHS, which cannot cycle numerous times per day. However, for systems that only need a few hours to charge and discharge, this assumption is less precise. The charge and discharge times for each technology are based on data sheets contained in the Technology Catalogue, and various discharges are allowed per day as long as the hours used for charging and discharging do not exceed 24. The CBM calculates the charging time as a function of discharge time determined by the model user.

While arbitrage represents the benefit to the storage owner and/or operator from market transactions, it also creates positive economic benefits (externalities) which are not captured in the price of those transactions.

The side effect of arbitrage (buying energy at low prices and selling it when the prices are high) is peak-shaving. By injecting electricity into the system during high market prices, storage effectively is lowering those prices by increasing supply. The benefit of peak shaving is a product of energy released into the system and the magnitude of the peak price decrease.

For example, if peak price were $65/MWh, and releasing 10MWh of energy from storage would decrease the peak price to $63/MWh, then the arbitrage revenue would be 10MWh*$63/MW, while the value of peak shaving would be $2/MWh*10MWh.

Energy Consumption

The energy consumption figures are derived from PRODESEN 2019-33 which states the total 2018 consumption in MWh in both Sistema Interconectado Nacional (SIN) as well as Baja California Sur (BCS). The same publication also provides expected annual consumption growth, the peak demand in 2018 in terms of MWh/h, and monthly consumption as a percentage of annual consumption. This information served to construct annual consumption pattern using the indicated annual growth rate.

According to PRODESEN, the peak demand occurred in June, while August what the month during most energy was consumed. Since the difference between energy consumed in June and August was 0.4%, for sake of modelling it was assumed that in the future the month with the peak demand will coincide with the month where most energy is consumed.

Costs

The costs associated with each storage technology are derived from the Technology Catalogue data sheets which include EPC, Capex, and Opex, storage volume, charge and discharge efficiency as well as years of useful life. The costs are reported in US dollars, while revenues are quoted in Mexican pesos. The latest available exchange rate at the time the calculations were made is used. Since most calculations are made in 2020 currency, use of inflation is optional in case there is desire to see nominal figures.

The nominal (dynamic) exchange rate in the model is increased according to the purchasing power parity, i.e. according to the ratio of inflation rates between the US and Mexico.

Congestion.

The price of congestion at each node is determined in relation to a reference node, in both SIN and BCS. A congestion of 0 at node X doesn´t mean that node X is not congested, it just means that its congestion is no different than that at the reference node (which might or might not be 0 in absolute terms). Congestion component of the local marginal price (PML, for its acronym in Spanish)[2] can be positive or negative. If congestion is negative, it means that the generator has to pay for congestion, or that he has difficulty injecting electricity into the system (might be due to abundance of cheaper energy). If congestion is positive, on the other hand, it means that the load competes for limited energy supply and the load pays the cost of congestion.

From a social perspective, congestion is a cost independently of who pays for it. Consequently, the total difference in congestion between nodes is considered. It is also assumed that alleviating congestion decreases its nodal price in a linear form. Theoretically, storage large enough could eliminate congestion at a node in question, so the value of congestion relief can be defined as the difference in congestion between two nodes multiplied by the amount of energy released and a factor by which energy released decreased the price of congestion. Graphically, if releasing energy from storage would not lower the congestion price, the benefit to the storage operator from releasing energy would be equal to the price of congestion (P) multiplied by the amount of the energy released (X), or the area of the rectangle in the graph below. However, since it is assumed that the storage large enough can decrease congestion price from P to 0, the benefit to the storage operator is half of the aforementioned rectangle, or more specifically, as energy released from storage approaches X, the price of congestion approaches 0, consequently the benefit to storage operator from alleviating congestion is equivalent to the area of the triangle in the graph below (P-0)*(0-X)*1/2.:The most straight forward assumption, based on the graph below, suggests that the factor could be ½..

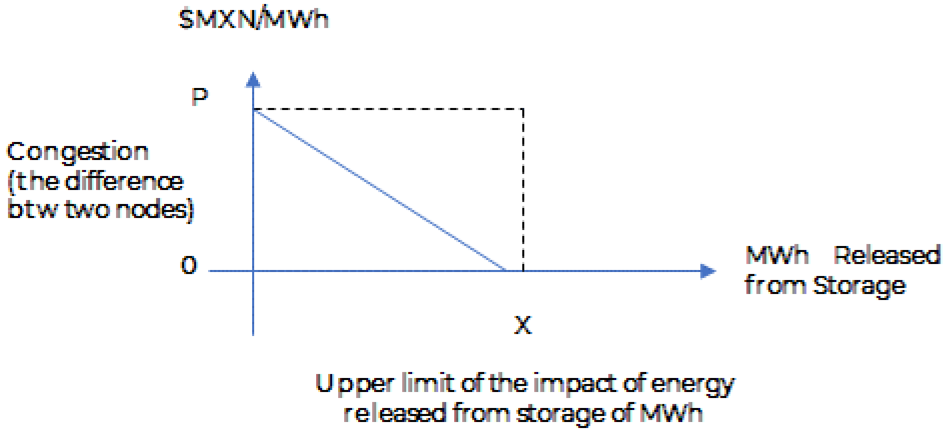

Figure A2

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[2] Precio Marinal Local

Mitigation

One of the principal assumptions of the study is that energy released from storage system is displacing peaker generation plants. The CBM not only permits the user to choose the generation type displaced by storage, but also the generation type used to charge storage. Mitigation is calculated as the difference in CO2 that would be produced by displaced technologies, and CO2 produced by technologies used for charging storage. The CBM also considers the CO2 in electricity that is classified as losses.

Voltage Control

Voltage control, and specifically synchronized condenser, is the principal cost associated with ancillary services. According to calculations of ancillary services tariff published on the CRE website, voltage control accounts for approximately 95% of the costs of ancillary services. The tariff for ancillary services for 2020, according to Agreement A/039/2019 is $5.6 MXN/MWh. For reasons specified above the CBM does not consider other ancillary services, but it does consider voltage control as a possible source of revenue. That is because reactive energy (i.e. voltage control) can be supplied simultaneously with active energy. Consequently, the model assumes that each MWh of active energy released is accompanied with one MWh of reactive energy which is remunerated with $5.32 MXN/MWh ($5.60 MXN * 0.95).