Refinement to Comparison between sequential selection and co-optimization between energy and ancillary service markets

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Draft for discussion

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Executive Summary

As a continuation of a previous publication, *Comparison between sequential selection and co-optimization between energy and ancillary service markets (2017)*[1], model refinement was performed to normalize the input data to ensure comparison of like-modelled results. Whereas the first analysis indicated little or no efficiency gain at low priced hours, the results were not intuitive and therefore further analysis was conducted to examine the nature of the results and provide a further drill down into the overall impact between sequential and cooptimization.

Two calculation methods were compared to each other, a block specific revenue calculation and a system calculation. The block specific calculation resulted in all hours benefiting from co-optimization as expected and was done mainly to build a foundation on which to perform system level calculations, which are more relevant to the Alberta context. The system level calculations, as used in the first modelling, show that co-optimization would still result in overall benefits under the assumptions, but not in all hours. The system level benefits from co-optimization are realized only when revenue changes from the energy market outweigh energy changes in the ancillary services market.

The ancillary services market has an indexing mechanism with a bid price which in influential in determining the cost/benefit of co-optimization at the system level. The higher the bid price, the higher the revenues in the ancillary services market and consequently the more hours in which sequential selection could result in lower revenues compared to a co-optimized system. Further work could be done to test the sensitivity of bid prices or consider changing the negative priced offers to cost based offers in order to realize additional benefit.

This further analysis concludes that co-optimizing the energy and ancillary services markets lead to a more efficient outcome overall when compared to a sequentially selected mechanism. In years that exhibit relatively lower system marginal prices, benefits from co-optimization ranged from 1% to 2% of total revenue, under the assumptions stated in this paper.

- While all hours show block specific revenue in co-optimization is always lower or equal to sequential selection, on average 40% of hours show that system level revenues are more in sequential selection. This is because the change in SMP times Energy Demand is less than the change in clearing price times contingency reserve required.
- Even though a significant number of hours show that sequential selection at the system level is more cost efficient, overall co-optimization comes out on top when total dollars are calculated.
- While co-optimization shows significant revenue reduction compared to sequential selection, the models were not offer mitigated. The years 2016 and 2017 are closest to a variable cost model and shows the least gain from co-optimization compared to all the previous years.
- Other benefits are not quantified in this paper, such as reduction in forecast errors due to methodology and timing changes, potential elimination of the standby market and simplification of the indexing mechanism, but are anticipated to lead to more efficient outcome.
- Other qualitative factors were also considered in this paper, such as the diminishing need for a standby product and a decrease in forecast error that would result in benefits. Other risks and benefits have been previously highlighted in EAS WG -Ancillary Services Market – Issues and

[1] See References for document link.

Options (2017)[2], including the black box nature of a co-optimization model which will reduce transparency of offers selected for the energy and ancillary services markets.

[2] See Reference for document link

Analysis

After a preliminary analysis further model refinement was done to evaluate some counter-intuitive results and in order to more accurately compare sequential procurement to co-optimization. Some assumptions were further refined to normalize the supply stack for comparison. In order to ensure the comparisons were valid, the sequential selection approach was modeled instead of using historical data in order to remove any discrepancies between the two models.

This means that system marginal prices and revenues calculated are indicative and not comparable to historical prices and revenues. This process in its entirety ensures the sequential model can be comparable to the co-optimized model.

Sample size

It was not possible to use the entire year sample due to infeasible hours, however the same sample that was used for sequential selection was also used for co-optimization. Infeasible hours occur when the linear programming algorithm is unable to meet all constraints. All constraints programmed were hard constraints, i.e. Energy demand must be met, contingency reserve requirement must be met and assets cannot allocate more MW than their AC.

Sample sizes of feasible hours and resulting System Marginal Prices (SMP).

Table 1 - Sample sizes and System Marginal Prices

Year	Sample size	Average SMP from Co-optimized model ($/MWh)	Average SMP from Sequential model ($/MWh)
2013	8597	109.79	120.17
2014	8640	66.62	70.48
2015	8689	41.24	43.16
2016	8758	18.48	18.63
2017	8683	22.23	22.74

Results meet expectations that SMP's are lower in a co-optimized system compared to a sequentially selected system.

The hypothesis going in is that co-optimization will result in lowering, or equaling production costs as compared to sequential model, the question was to test by how much. However, since no cost information is readily available, a revenue analysis was done instead. The assumption is that reduced revenues translate to reduced costs.

The hypotheses are below:

Hypothesis #	Hypothesis	Results
1	Aggregate block specific revenue for the co-optimized model should be less than or equal to, sequentially selected model. This calculation is more like as pay-as-bid based on Ontario's example.	Hypothesis is proven true in all hours
2	Aggregate system level revenues based on single price clearing for the co-optimized model should be less than or equal to a sequentially selected model This calculation uses AESO's current mechanism.	Hypothesis is proven true in some, but not all hours

In this model, the benefit from co-optimization always occurs when pay-as-bid type calculations are used to compare revenues between both models (hypothesis #1). When using a single clearing price, the benefit only occurs when the change in 'SMP times energy demand' outweighs the ancillary curve change in 'clearing price times contingency reserve' volume. A decision tree in more detail can be found in Appendix A – Concepts, that helps separate the situations in which sequential selection yields benefit over co-optimization.

Aggregate block specific revenue

Once co-optimization and sequential selection were modeled, individual block price and quantities from the merit orders were multiplied and aggregated for both the energy and ancillary service markets. The aggregate numbers are negative as prices in the AS markets are typically offered in at negative values and generally, but not always; outweigh the positive numbers in the energy market.

Table 2 - Block Specific Aggregate Revenue

Year	Revenue Co-optimization (nominal $)	Revenue Sequential (nominal $)	Difference (nominal $) (negative implies reduction in revenue due to co-optimization)	Percentage of revenue (benched on Cooptimized model)
2013	-2,572,355,326	-2,546,390,975	-25,964,351	1.0%
2014	-2,398,430,852	-2,385,947,426	-12,483,426	0.5%

Year	Revenue Co-optimization (nominal $)	Revenue Sequential (nominal $)	Difference (nominal $) (negative implies reduction in revenue due to co-optimization)	Percentage of revenue (benched on Cooptimized model)
2015	-2,093,378,793	-2,088,434,492	-4,944,301	0.2%
2016	-1,783,520,452	-1,782,581,929	-938,523	0.1%
2017	-1,757,962,206	-1,756,650,877	-1,311,329	0.1%

2013 had higher prices and more opportunity for co-optimization to lower revenues. Over the years as prices fall, the gain from co-optimization decreases, but overall all the years were more efficient than sequential selection.

When frequency is considered, all hours showed a benefit or breakeven. Breakeven is defined as the hours in which revenues were equal in both models.

Table 3 - Frequency of hours with benefit from block specific calculation

Year	Hours where co-optimization benefits	Breakeven hours	Hours where sequential selection benefits
2013	6,874	1,723	0
2014	6,395	2,245	0
2015	6,009	2,680	0
2016	7,158	1,600	0
2017	6,966	1,717	0

Aggregate System level revenues

The system level methodology is different, in that it used system marginal prices and AS clearing prices to calculate revenues instead of individual block Price Quantity pairs. System level revenues are system marginal price in every hour multiplied by corresponding volume dispatched, as well as applying an indexing mechanism to the AS offers as is done in the current market and then aggregating both revenue streams. The indexing mechanism has been discussed in the previous paper.

Table 4 - Aggregate system level revenue

Year	Revenue Co-optimization (nominal $)	Revenue Sequential (nominal $)	Difference (nominal $) (negative implies reduction in revenue due to co-optimization)	Percentage difference (Benchmarked on co-optimized model)
2013	8,146,810,282	8,905,776,205	-758,965,923	-9.3%
2014	5,250,153,395	5,547,120,723	-296,967,322	-5.7%
2015	3,569,991,612	3,733,313,503	-163,321,891	-4.6%
2016	1,581,077,048	1,591,671,614	-10,594,566	-0.7%
2017	1,955,699,317	1,999,872,009	-44,172,693	-2.3%

Co-optimization has overall benefits, and as found in the previous analysis, higher priced years tend to have the best opportunity for co-optimization. However, not all hours showed that co-optimization has lower revenues than sequential selection using system level calculations. The benefits only occur if the changes in energy market revenues outweigh changes in AS revenues. Refer to decision tree previously mentioned.

Table 5 - Frequency of system level benefit

Year	Hours where co-optimization benefits	Breakeven hours	Hours where sequential selection benefits
2013	2,842	2,468	3,287
2014	2,357	3,097	3,186
2015	1,344	4,304	3,041
2016	1,094	3,446	4,218
2017	1,094	3,368	4,221

Specific Examples

Two examples are discussed.

Table 6 - Examples and results

	System Level	Block Level
Example 1	Lowers revenues compared to sequential selection	Co-optimization more efficient
Example 2	Raises revenues compared to sequential selection	Co-optimization more efficient

Example 1 – 15 Aug 2016 HE 15

In this example, co-optimization lowered system marginal price by $50/MWh and raised ancillary services marginal offers by $16/MWh. Both block level calculation and system level calculations show a benefit from co-optimization.

Table 7 - Summary example 1

	Co-optimized	Sequential	Change
Block level revenues ($ nominal)	-195,516	-194,576	-940
System level revenue ($ nominal)	578,559	1,159,527	-580,968
System Marginal Price ($/MWh)	49.80	99.89	-50.09
AS Clearing Price ($/MWh)	43.80	85.84	-42.04
AS Marginal Offer ($/MWh)	-52	-68	16

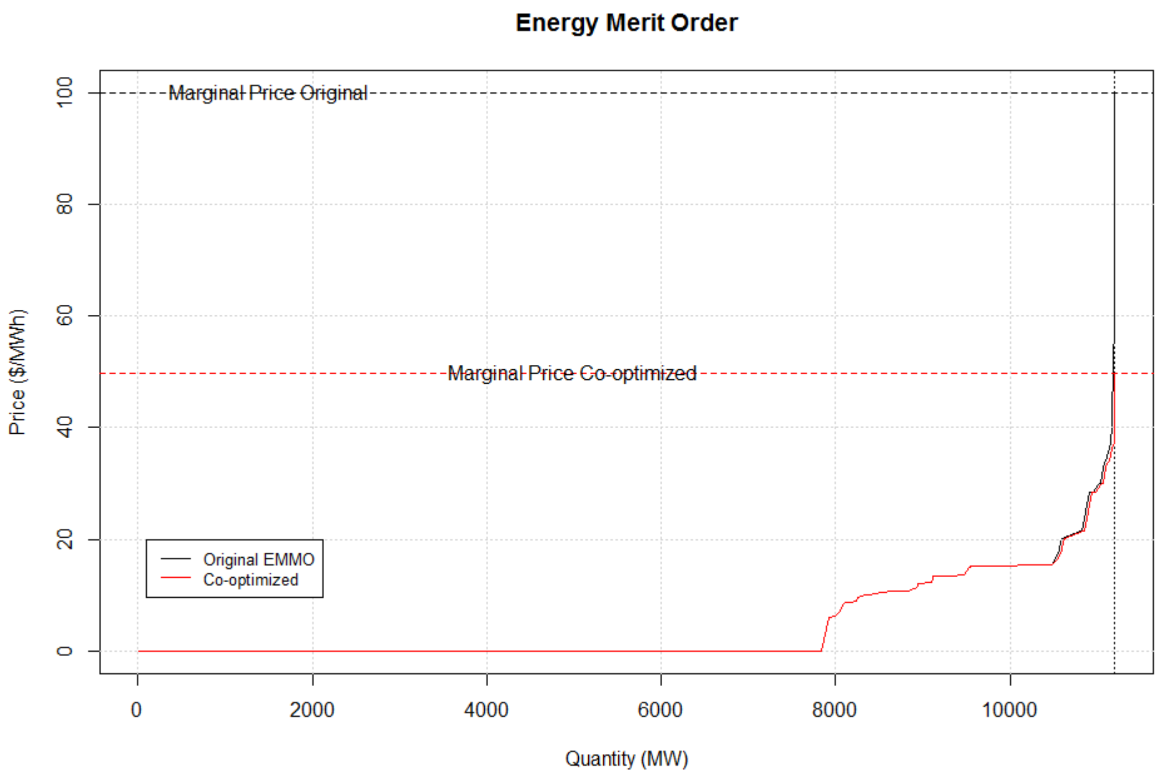


Figure 1 - Energy Merit Order Curve Example 1

Figure 2 - AS Merit Order Curve Example 1

Example 2 – Jan 5, 2016 HE 18

In this example, co-optimization raised ancillary services marginal offers by $28/MWh and there was no change in the system marginal price. Block level calculations showed a benefit and system level calculations showed a relatively small efficiency loss from co-optimization due to changes in Ancillary revenues outweighing changes in Energy revenues.

Table 8 - Summary example 2

	Co-optimized	Sequential	Change
Block level revenues ($ nominal)	-258291.28	-257485.54	-805.74
System level revenue ($ nominal)	908281	901281	7000
System Marginal Price ($/MWh)	77.34	77.34	0

	Co-optimized	Sequential	Change
AS Clearing Price ($/MWh)	77.34	63.34	14
AS Marginal Offer ($/MWh)	-40.00	-68.00	28

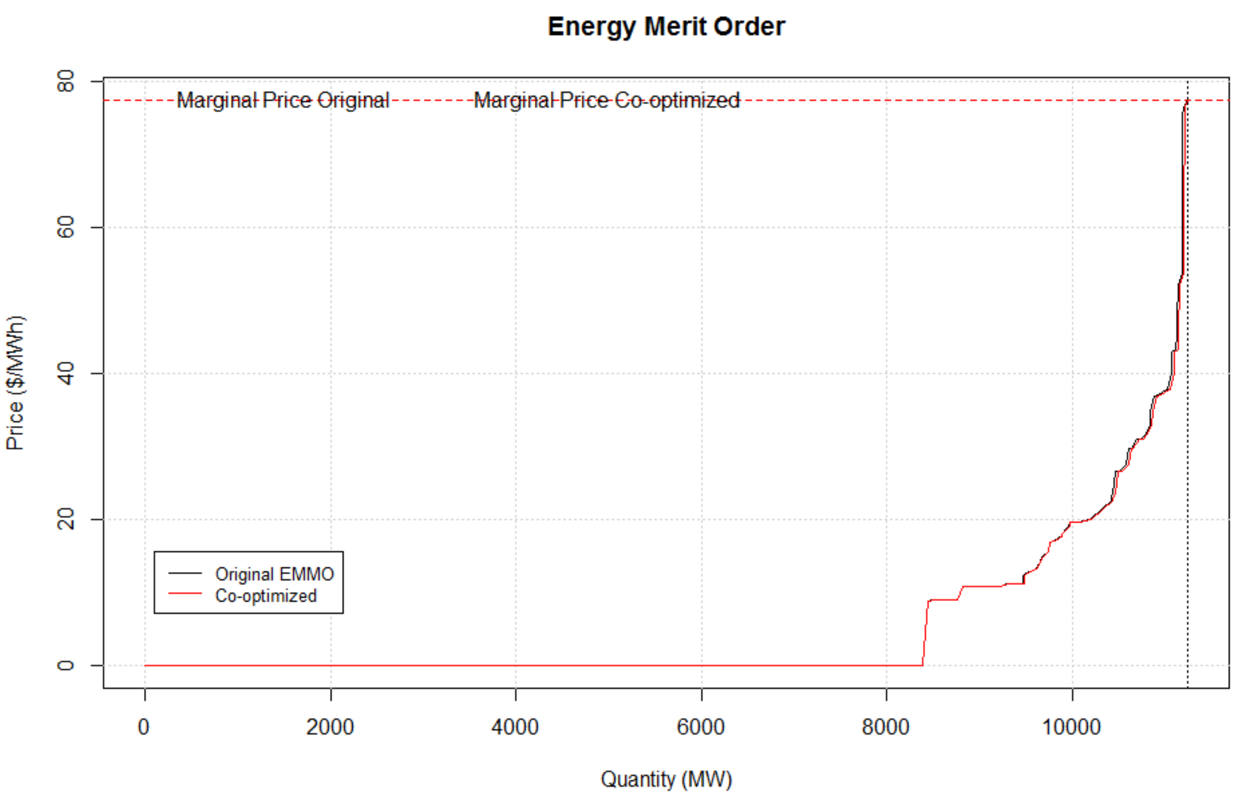


Figure 3 - Energy Merit Order Curve Example 2

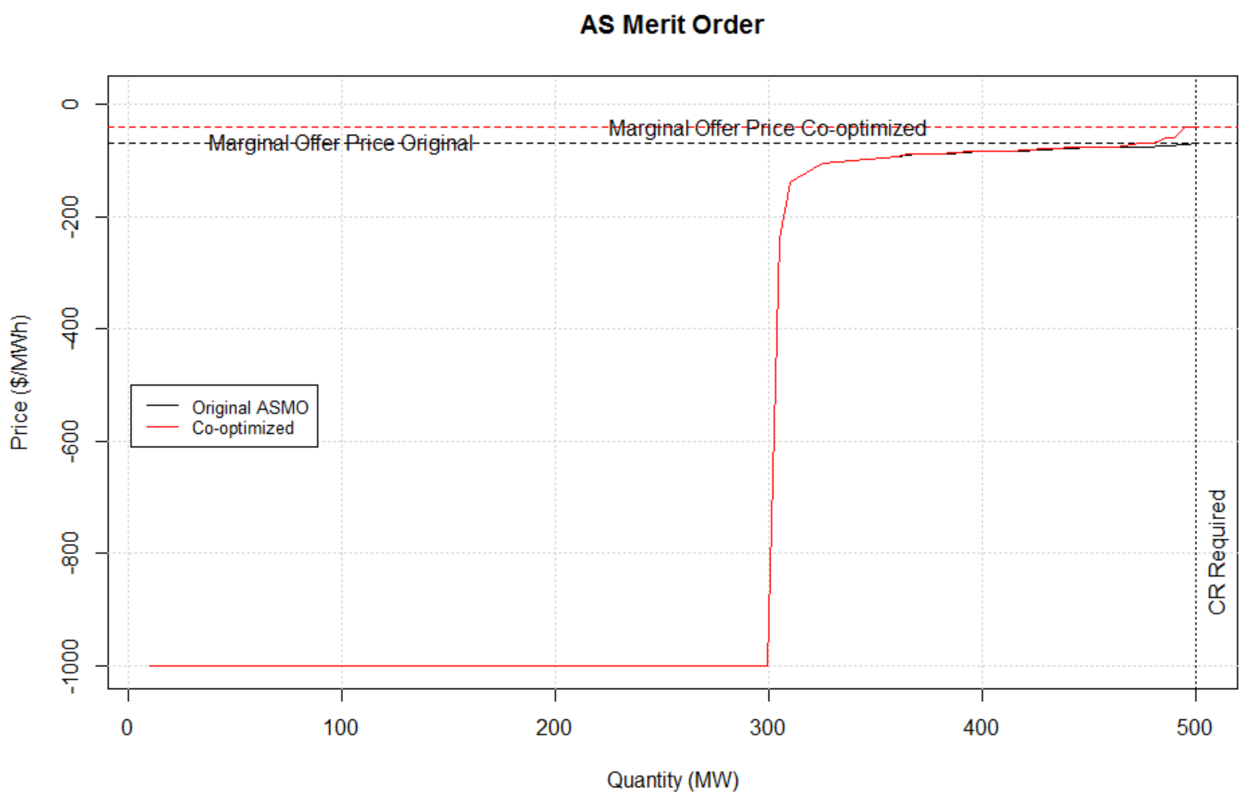


Figure 4 - AS Merit Order Curve Example 2

Assumptions

This paper focuses on refining the preliminary co-optimization model paper previously released in August 2017 after receiving feedback from AESO internal staff as well as external consultants. Below are initial assumptions and the changes made.

Table 9 - Assumption changes

Initial assumptions	Changes to assumptions
Offer curves are as is, historically taken	Offer curves in both sequential and co-optimized markets have been capped at individual available capability numbers in order to cap the MW allowed in both markets. This makes the MW uniform in both markets. With the same dataset, sequential selection was also modeled instead of using historical data. The adjustment was necessary in order to normalize the sequential and co-optimized curves.

Initial assumptions	Changes to assumptions
	This differs from the original analysis where sum of blocks were assumed to be the cap. Offer behavior was not adjusted as it is assumed that the years cover aggressive bidding to marginal pricing.
Only active contingency reserves are optimized with the energy market, spinning and supplemental were treated equally	No change
Prices are calculated as per today's market methodology, that is, AS prices are indexed to pool price. Same methodology for calculating equilibrium and clearing prices. Marginal prices were calculated after sequential selection and/or co-optimization.	No change
Assets can participate in either market, but must have offers in both (or offers will be created at zero)	No change
Constraints/Congestion not taken into account. No engineering concepts typically found in a co-optimization algorithm considered	No change
Contingency requirements are volumes procured in D.A.M -	No change
Assumes blocks are flexible	No change
Virtual assets were not considered	As per assumption 1, the stack was normalized and AC's were introduced. Since virtual assets have 0 AC, no volume can participate in the market

Other considerations

While the decrease in revenues is an implication, choosing whether to co-optimize or to remain with sequential selection should also consider other benefits.

Day ahead procurement and forecast error

Currently, the AESO procures contingency reserves one day ahead based on forecasted CR volumes, and if procurement of active reserves falls short during real time, the AESO will use standby reserves. This introduces forecast error and could potentially lead to situations where there insufficient active contingency reserve to facilitate imports.

With co-optimization, the full ancillary services offer curve can be optimized closer to real time to meet contingency reserve requirements and therefore the likelihood of falling short of active reserves drops.

With more real time information, the AESO will be able to allow imports to flow having sufficient contingency reserves. The incidence of conscripting generation assets is also anticipated to decline as it relates to day ahead procurement.

Standby product

Additionally with close to real time access to a full ancillary services offer curve, the increased liquidity may lead to a standby product to become obsolete saving costs. Historically standby costs have averaged approximately $25 M from 2012-2016 (2016 Annual Market Statistics).

Indexing mechanism and negative offers

An influential factor is the indexing mechanism used by the AESO in calculating the clearing price in the ancillary services market. Currently the ancillary service marginal offer is averaged with a bid price and the resulting equilibrium price is added (or indexed) to the pool price. This bid represents the value AESO places on contingency reserves and raises the ancillary service marginal offer. Raising the bid price would increase revenues and in the Alberta market would likely result in more hours that are efficient with sequential selection approach. Further work has to be done to quantify the amount.

As a result, the AESO should consider leaving the bid price as is, in order to extract efficiency, or changing the AS offer structure such that cost based offers are accepted instead of negative priced offers., similar to other jurisdictions like IESO (Guide to Operating Reserve (2011)). An advantage of cost based pricing is simplicity in understanding AS pricing.

Further qualitative benefits and risks are highlighted in EAS WG -Ancillary Services Market – Issues and Options (2017).

Closing remarks

- While all hours show block specific revenue in co-optimization is always lower or equal to sequential selection, on average 40% of hours show that system level revenues are more in sequential selection. This is because the change in SMP times Energy Demand is less than the change in clearing price times contingency reserve required.

- Even though a significant number of hours show that sequential selection at the system level is more cost efficient, overall co-optimization comes out on top when total dollars are calculated.
- While co-optimization shows significant revenue reduction compared to sequential selection, the models were not offer mitigated. The years 2016 and 2017 are closest to a variable cost model and shows the least gain from co-optimization compared to all the previous years.
- Other benefits are not quantified in this paper, such as reduction in forecast errors due to methodology and timing changes, potential elimination of the standby market and simplification of the indexing mechanism, but are anticipated to lead to more efficient outcome.

Appendix

Technical Details. Objective function and constraints
Objective is to minimize production costs of energy and ancillary services by finding the ideal mix of price and quantity pairs in the combined energy and ancillary services markets. This ideal mix can be achieved by using linear programming optimization using an lpSolveAPI[3] package.

Objective function is to minimize cost such that:

$$z = \min \sum_{i=1}^{N} [pE_i * qE_i] + [pAS_i * qAS_i]$$

Where pE and qE are energy price and quantity pairs and pAS and qAS are ancillary price and quantity pairs.
In this case offer price is known and quantity is to be determined by the algorithm.
N is the number of offers in the market

Constraints:

$$\sum_{i=1}^{N} BLOCK\ Size_i \leq Available\ Capability$$

$0 \leq \sum_{i=1}^{N}(qAS_i + qE_i) \leq Available\ Capability$

The offered energy in either or both the Energy or AS cannot exceed the unit's capability.

$$\sum_{i=1}^{N} qE_i = Demand$$

Quantity of energy must meet demand

$$\sum_{i=1}^{N} qAS_i = Contingency\ Requirements$$

Quantity of AS offers must meet contingency requirement

[3] https://cran.r-project.org/web/packages/lpSolveAPI/lpSolveAPI.pdf

Concepts

Left shift in a merit order curve, all else equal, increases price or stays the same if on flat part of curve
Right shift in a merit order curve, all else equal, decreases price or same if on flat part of curve

Concept 1

Sequentially selected AS offers form the most cost-effective AS merit order curve. A co-optimized curve can be just as cost effective but is usually not. The co-optimized curve can stay the same as the sequential selected one, or shifts to the left but never to the right.

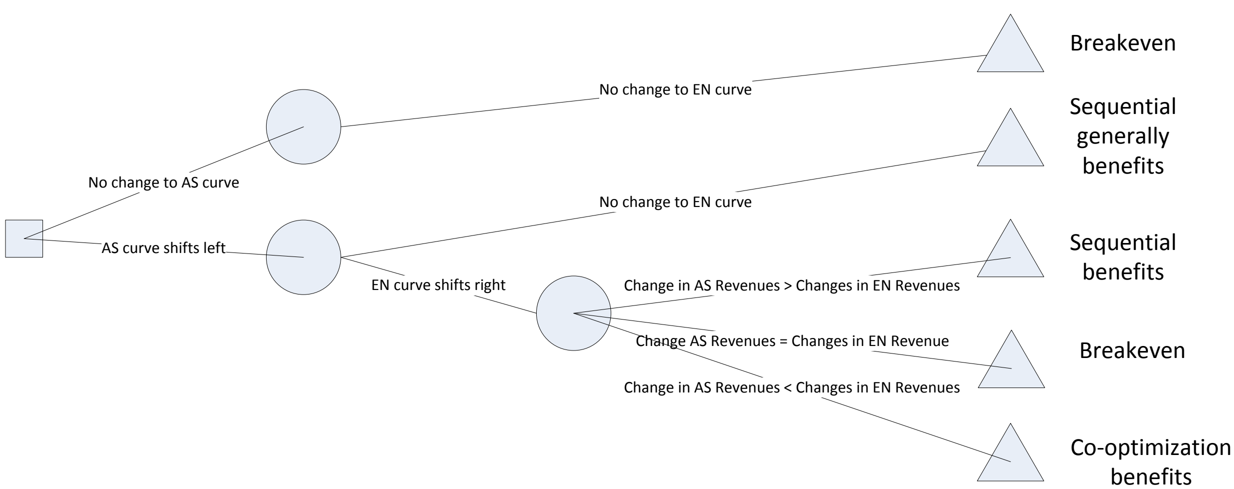
Justification
Sequentially AS offers are first selected from lowest price to highest price and co-optimized AS offers are based on the lowest cost offering between energy and AS and therefore may have MW that are re-assigned to energy instead. This assignment may shift the energy curve to the right.

Concept 2

Allocated MW from co-optimized AS offers to the co-optimized energy market result in lower system marginal prices, and in some instances where the system marginal price block is bigger in MW than re-allocated MW from the AS market, the system marginal price will stay the same. The curve never shifts to the left and always status-quo or to the right.

Justification
Any MW allocated to the co-optimized curve from the AS curves, increases supply and may shifts the merit order to the right lowering system marginal prices. Sometimes, the curve may remain where it is.

Figure 5- Decision tree on benefit from co-optimization and sequential selection



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