London Economics International LLC

Issues related to the demand curve in capacity markets

Prepared for
AESO Adequacy & Demand Curve Working Group
(revised July 27, 2017)

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Who is London Economics International LLC?

London Economics International (LEI) is a global economic consultancy with expertise analyzing markets and advising on market design questions and policy reforms in electricity and infrastructure sectors. LEI has extensive experience working in Alberta – starting with the initial wave of deregulation of the electricity sector. LEI has completed regulatory advisory and private sector consultancy work all around the world since it was founded in the period of restructuring of the electricity, water and gas sectors in the UK in the late 1980s. In the US markets, LEI has been active in supporting various clients – ranging from regulators and policymakers to utilities, ISOs, IPPs, power traders, competitive retailers, end-users, and various investors in the sector – over a range of regulatory and competitive market issues.

- **Julia Frayer** is Managing Director of LEI, specializing in economic analysis and evaluation of infrastructure assets, such as power plants, natural gas-related infrastructure, electricity transmission and distribution systems, and utilities, as well as market design and expert economic advisory services for power markets.
- **Bridgett Neely** is Senior Advisor at LEI, specializing in strategic, economic, and policy issues related to the clean energy sector, including market design, policy design, and program design and launch.

AESO SAM 1.0 laid out a reasonable starting point for the design of the demand curve but additional details are required to develop numerical values

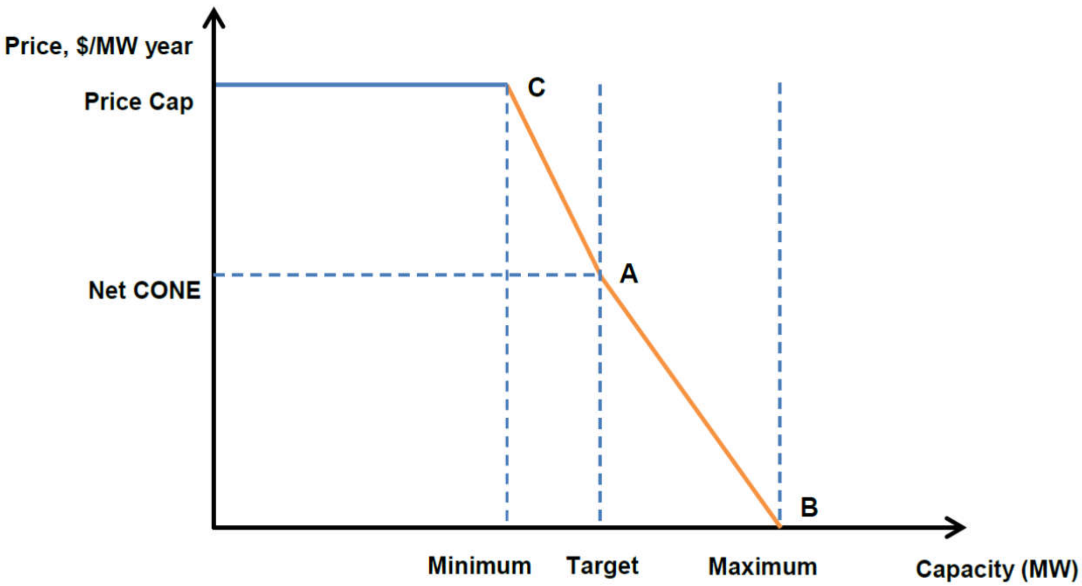

Figure 1: Stylized / illustrative Capacity Demand Curve

AESO proposal for capacity market demand curve

- Downward sloping demand curve
- Price cap at greater of Gross Cone or net CONE
- Net CONE using a generic CCGT as reference technology

Source: AESO Straw Proposal (SAM 1.0)

LEI recommendations for capacity market demand curve

- Downward sloping, going out in line with historical realized reserve margins (35% internal reserve margin sets the "foot" of the demand curve) to smooth impact of capacity changes in small market
- Net CONE for least cost/best fit technology – peaker may be better choice for Alberta
- Index CONE and resulting capacity price to carbon tax changes in the future

Alberta's "unique" market characteristics must serve as underpinning for demand curve parameters

Key features of the Alberta market	Implications for market design
Relatively small market in MW terms and concentrated market	• A single unit addition or single unit exit/retirement can dramatically impact market prices (in capacity and energy) – a flatter demand curve to the right of net CONE can help moderate such volatility • Flatter demand curve can also moderate market power concerns
51% industrial load – much higher than most other markets	• Such customers extremely sensitive to costs but also want to have high levels of reliability to support their business operations - demand curve design needs to facilitate viable new investment (in net CONE value and price cap) • Opportunity cost of the lack of reliability should be considered in setting the appropriate reserve margin target
Climate Leadership Plan mandating 40% of current supply (coal) to retire in less than 15 years and replacing with renewables	• Demand curve design must be able to attract new generation investment - without any biases in generation technology choices • When there is oversupply, demand curve needs to also motivate existing resources to be available and avoid premature retirement • Government's renewable investment plans needs to be managed so as not to derail the market signals for new investment from the capacity market

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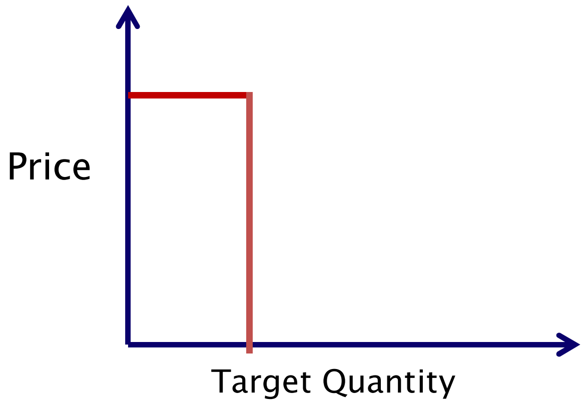
Demand curve in the capacity market can take various shapes, depending on the characteristics of the system, customer needs and goals of the regulator

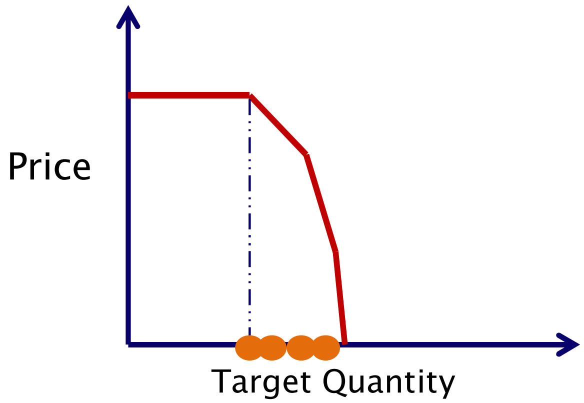
- **The demand curve is not the result of pure market dynamics but is meant to represent the AESO's willingness to buy capacity (insurance against insufficiency of supply) and is the result of specific, administered values for key parameters:**
  - the price cap (reflects the cost of a "reference technology")
  - the target quantity of capacity needed (reflects desired reserve margin)
  - the slope of the curve articulates the opportunity or tradeoff between varying levels of resource adequacy and market cost
  - several possible "shapes" exist – depending on what objective is given priority

VERTICAL



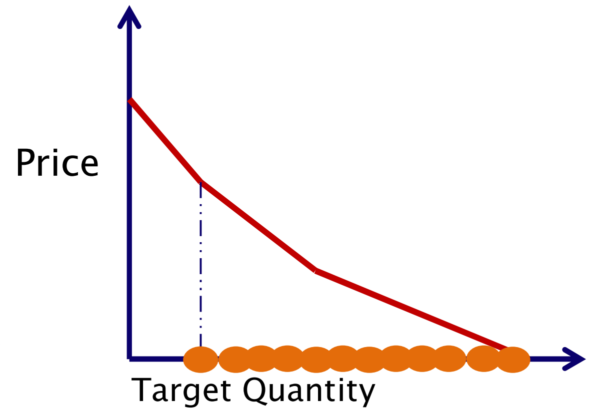
- Does not explicitly set price: prices can go to price cap or fall to zero – theoretically, zero payments for all if system is oversupplied – leads to volatility

CONCAVE



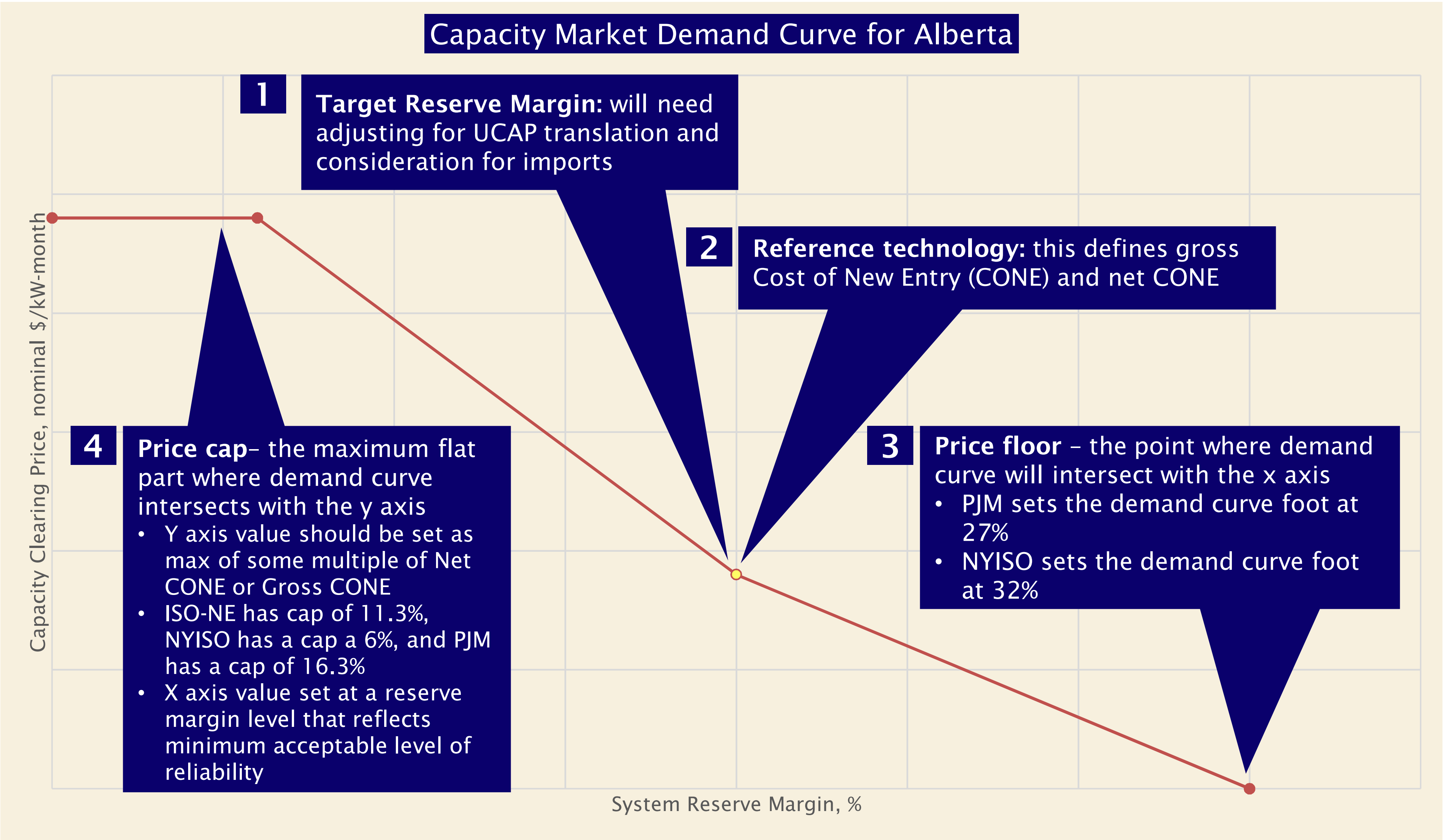
- Dis-incentivizes over-investment, because prices drop off steeply to the right of the target capacity (where supply would exceed demand)

CONVEX

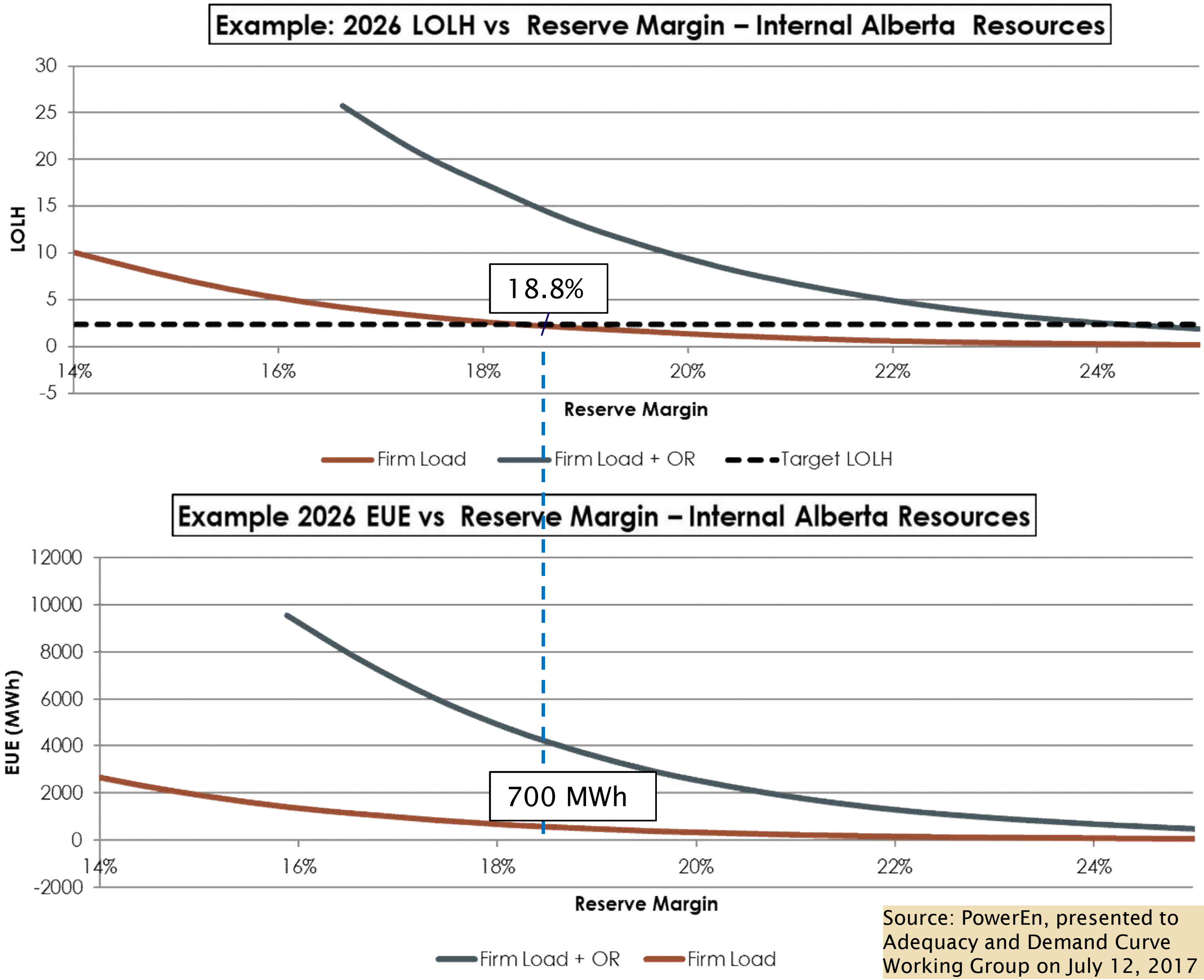


- Provides steeper price increases to the left of target capacity (large incentive when supply is short of demand) and reduces volatility when supply exceeds demand

Determining the shape and position of the demand curve requires deciding on reference technology and reserve margin, and estimating costs for the reference technology



In order to decide on the capacity market demand curve, the target reserve margin needs to be selected

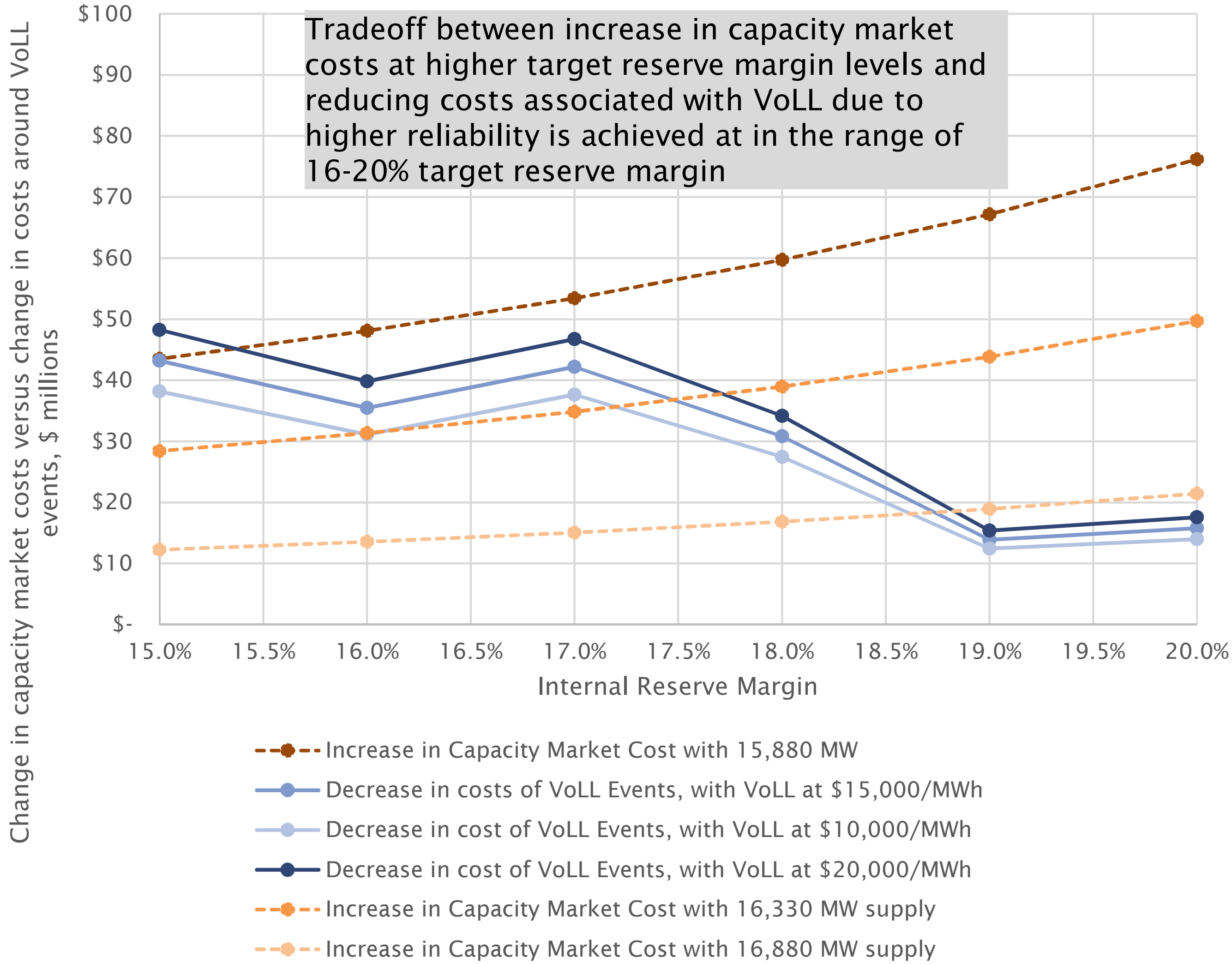


Source: PowerEn, presented to Adequacy and Demand Curve Working Group on July 12, 2017

- **Based on PowerEn's analysis, a target (internal) reserve margin in the range of 20% is needed to ensure that the Loss of Load Hours ("LoLH") remain below the 2.4 hours a year (1 day in 10 years) for firm load**
- **At this range of target reserve margin, Alberta would have approximately 700 MWh in Expected Unserved Energy ("EUE")**

Economic tradeoffs are also embedded in the choice of target reserve margin - what are the costs of the capacity market versus the cost to consumers from an expected loss of load event?

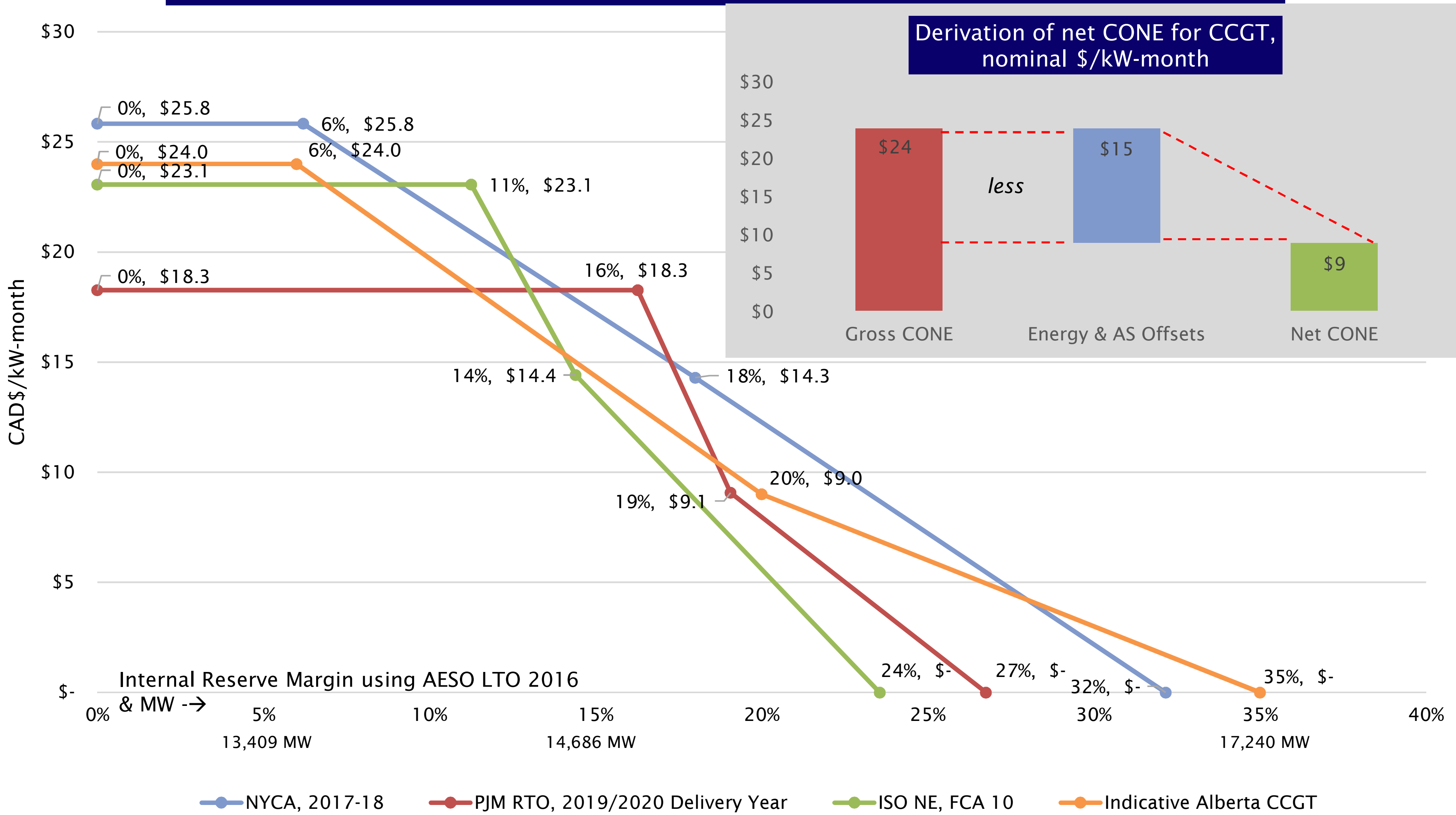
Comparing changes in capacity market costs to the change in opportunity cost of unserved load in a given year



- **The capacity market demand curve represents AESO's willingness to pay for insurance on supply adequacy**
  - AESO can choose different levels of "coverage"
  - Capacity price is like the premium you pay on car insurance
- **It is too expensive to insure for all events which is why AESO sets the requirement for how much capacity it buys with some acknowledgment that it may see some rare events of supply inadequacy (i.e. 1 day in 10 years)**
- **However, it is possible that there will be supply inadequacy**
  - Then energy prices will rise well above short run marginal costs to keep the lights on

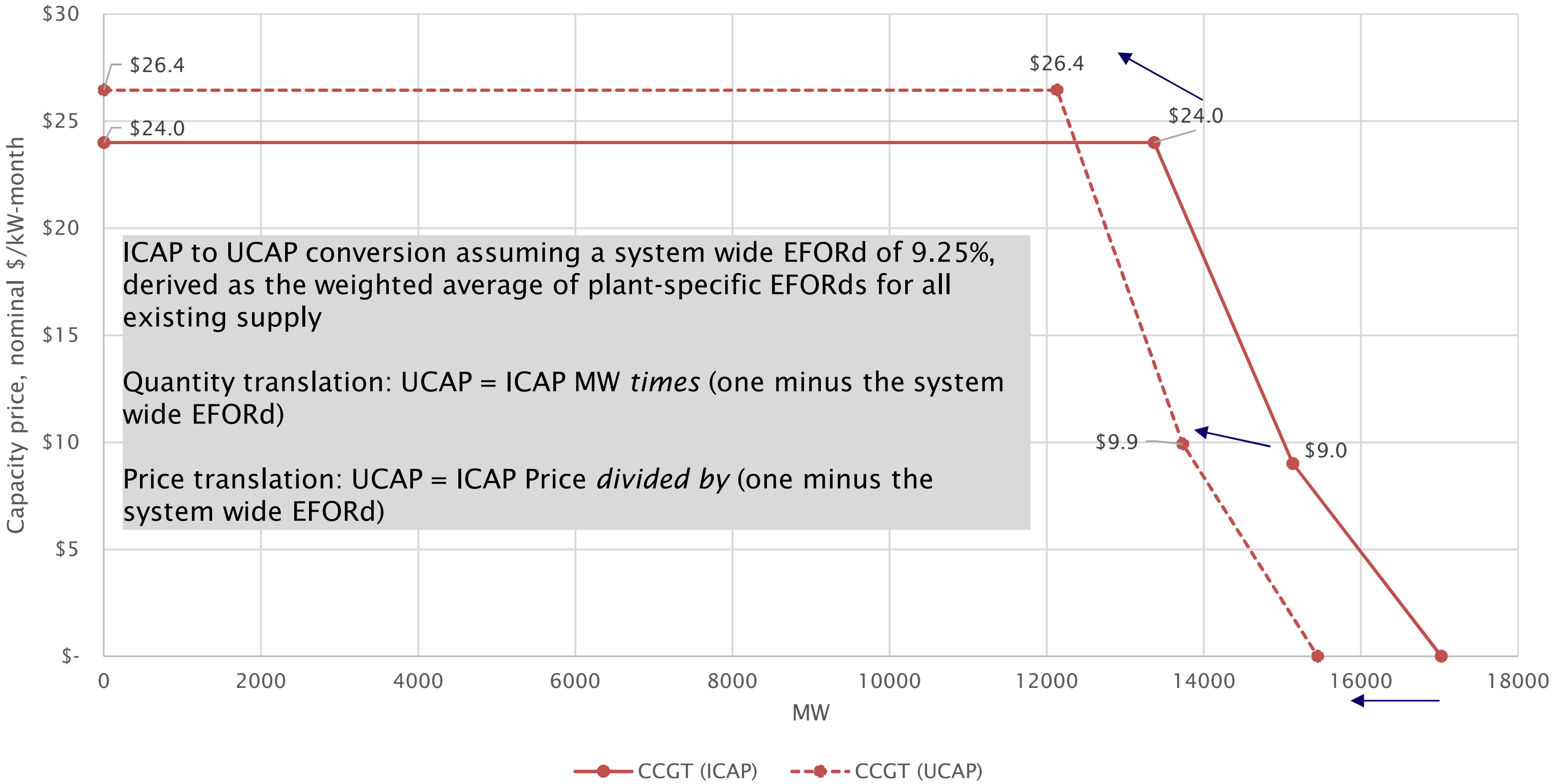
If we assume CCGT as reference technology (per SAM 1.0) coupled with LEI's estimates of net CONE, the resulting demand curve for Alberta is comparable to those in US markets

Capacity Market Demand Curve across US jurisdictions and comparison against indicative demand curve in Alberta for 2021 in CAD$ (CAD$1=US$0.75)



Translating from ICAP to UCAP creates an inward and upward shift in the demand curve

Indicative Capacity Market Demand Curve for Alberta using a CCGT as reference technology with UCAP or ICAP
(Internal)



Note: Please see NYISO ICAP manual for ICAP to UCAP translation in NY and http://www.pjm.com/markets-and-operations/rpm.aspx for PJM

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CONE represents the levelized annual total fixed cost of a new entrant in the wholesale power market in $/kW-year terms

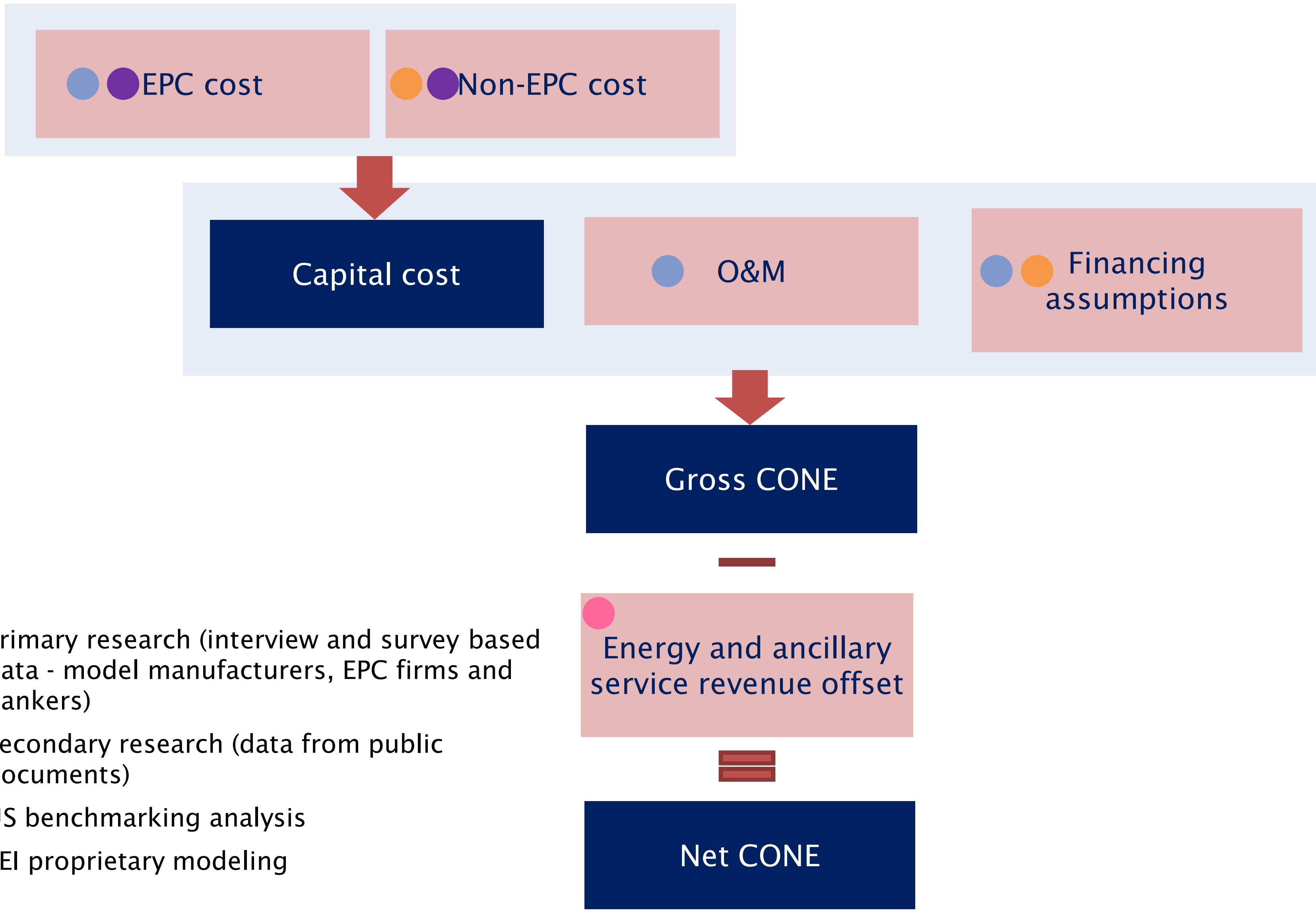
- **Gross CONE has both capital and operating costs, with capital costs levelized over time using generic financing assumptions**

Net CONE = Gross CONE − Net Energy and ancillary services profits

- **What is the purpose of the Net CONE?**
  1. Required parameter to set the AESO's willingness to pay for capacity at around the target reserve margin (i.e., "reference price" point on demand curve)
  2. Net CONE on the demand curve helps create a linkage between the capacity and energy market – if energy market conditions allow for higher expected energy profits to new entrant, capacity prices will be lower, and vice versa (lower expected energy profits = higher capacity prices)
  3. Comparing Net CONE estimates for different technologies helps AESO choose the "least cost" new entrant technology for defining the "reference price" on the demand curve
     - choosing a technology the precludes others may have implications for energy market and ancillary services markets (e.g., CCGT is riskier than peaker in a small market like Alberta, given its exposure to risk of new entry)
     - Net CONE for CCGTs may be more difficult to accurately forecast than peaker

	NYISO	ISO-NE	PJM	Mexico	UK
Reference technology	Frame peaker	Frame peaker	Frame peaker	Frame peaker	CCGT

LEI has applied a bottom-up approach to estimate the Gross CONE and Net CONE values for Alberta's capacity market



- Primary research (interview and survey based data - model manufacturers, EPC firms and bankers)
- Secondary research (data from public documents)
- US benchmarking analysis
- LEI proprietary modeling

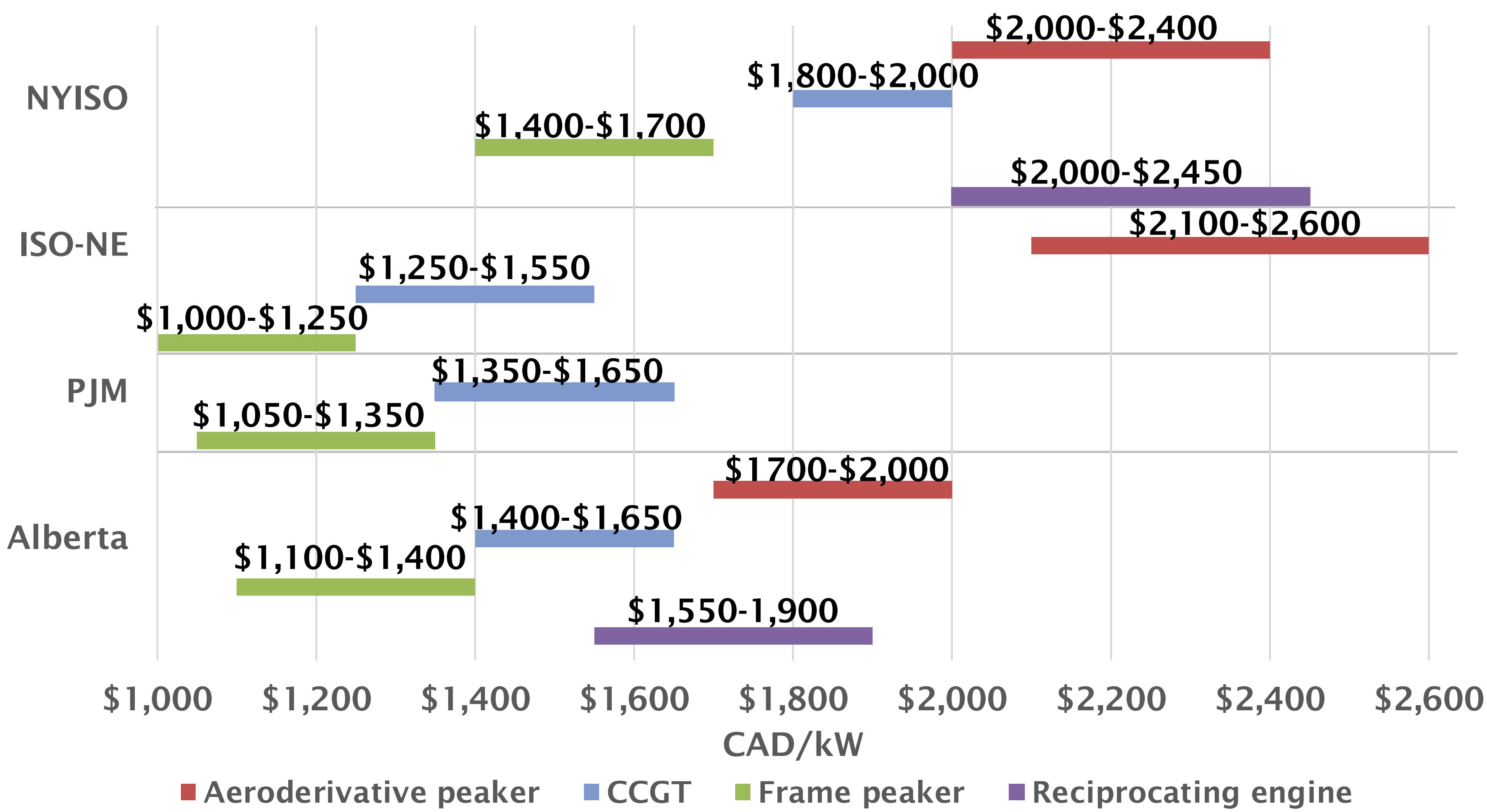
Based on experience in other capacity markets and current expectations for new entry in Alberta, LEI has selected four reference technologies for consideration

	Aeroderivative peaker	CCGT	Frame peaker	Reciprocating engine
Configuration	10 × 0	2 × 1	2 × 0	10 × 0
Typical nameplate capacity (MW)	100-200	500-800 (but smaller possible)	100-200	100-200
Net heat rate (Btu/kWh)	8,000-9,000	7,500-7,900	10,000-11,000	7,300-7,700
Estimated in other markets for use as reference technology (* current reference)	ISO-NE, NYISO	PJM, ISO-NE, NYISO	PJM*, ISO-NE*, NYISO*	NYISO
Recent installation in Alberta	180 MW Deerland Peaking Station in 2017 (est.)	873 MW Shepard Energy Centre in 2015	105 MW Grand Prairie in 2012	9.3 MW Elmworth in 2015

Source: GE; Wartsila; third party database provider

Capital cost estimates for CCGTs and frame peakers in Alberta are largely in line with estimates from other US markets

Comparison of capital cost range for various technologies in Alberta relative to US Northeast markets (in CAD terms)



Source: US CONE studies, LEI research
Note: Numbers in the chart are in 2021 nominal dollar value.

Generic financing assumptions used in demand curve re-set process in US markets are not compatible with risks of novel capacity market in Alberta and evolving supply mix

Lessons from interviews

- **Alberta's new market design infuses a lot of uncertainties**
  - Market design uncertainty – exact form and rules for a capacity market are still under development
  - Policy/regulatory uncertainty – Climate Leadership Plan with new renewables and carbon tax regime changes
  - Large influx of renewable entry – impact on energy market, and profitability of certain classes of new generation
- **Financiers unwilling to engage until more concrete details emerge around market rules and will be looking for revenue stability and government commitment in the long run**
- **Bank financing may be more likely than bond financing, as the "novelty" and unprecedented nature of Alberta's market may not palatable for traditional lenders in bond market**
  - Bank debt more flexible, but will likely include features such as cash sweeps, amortization of principal, and financial covenants to mitigate risks – reduces leverage
  - Bank debt shorter – essentially 5 years or less – with refinancing risk
- **Cash flow will be key metric along with debt service coverage ratios ("DSCR")**
  - Most merchant generators have a credit quality below investment grade

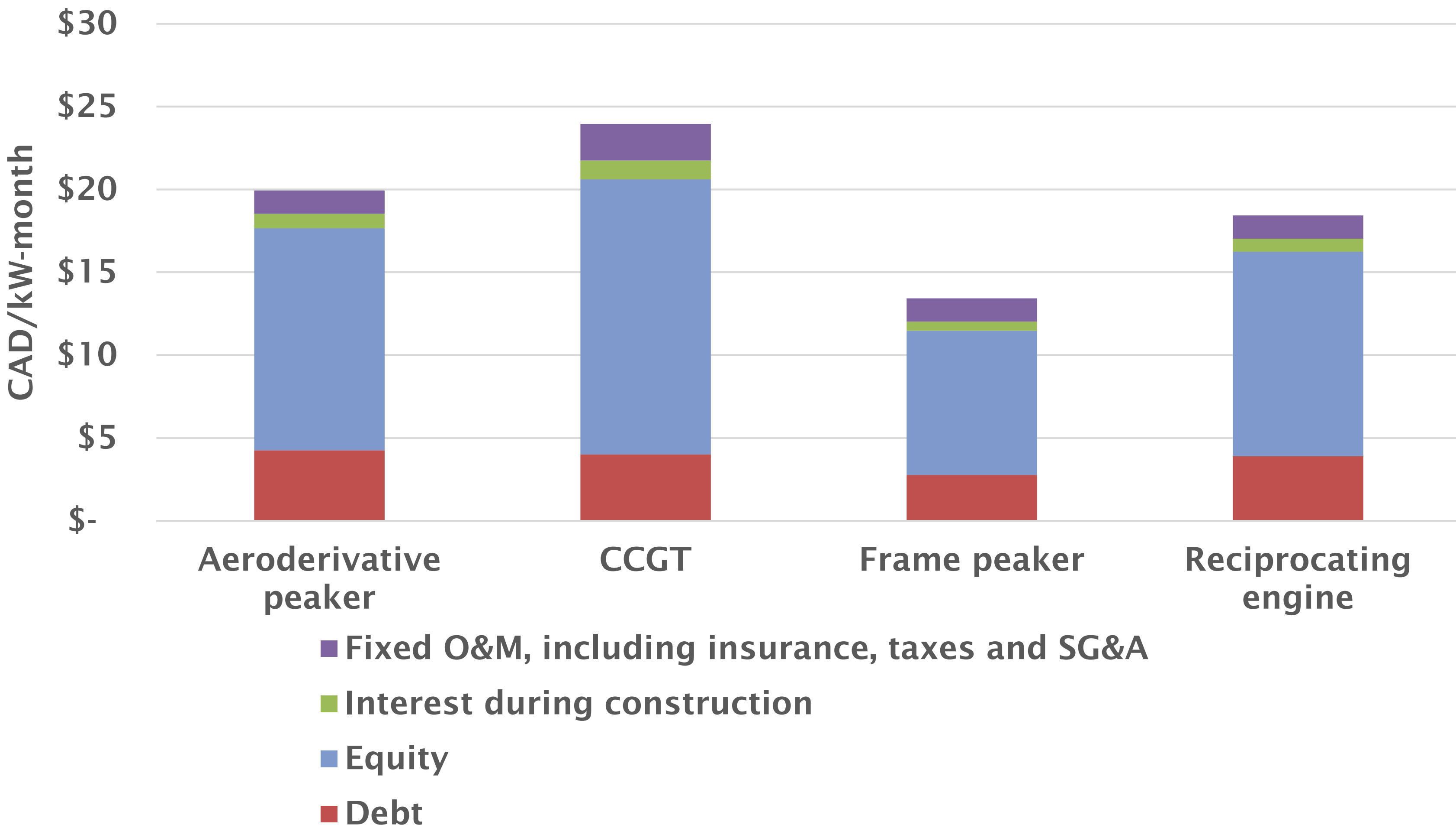
Implications for Alberta

- ***LEI found need for lower leverage to support DSCR, as compared to US markets***
- ***Shorter repayment terms in acknowledgement of market risks, especially for CCGT***
- ***CCGTs may be more risky than peakers given government's renewable integration plans***

Parameters	NYISO	ISO-NE	PJM	Alberta (CCGT)	Alberta (peaker)
Financing term	20 years	20 years	20 years	10 years	20 years
Cost of Debt	7.75%	7%	7%	6% - 7%	6% - 7%
Cost of Equity	13.40%	13.80%	13.80%	10% - 13.5%	10% - 13.5%
Debt-Equity Ratio	55/45	60/40	60/40	20/80 – 30/70	30/70 – 40/60
Effective Tax Rate	39.62%	40%	40%	27%	27%
WACC	8.36%	8.0%	8.0%	8.3% -11.8%	7.8% - 11.0%

Financing assumptions and capital cost are the two most important determinants of Gross CONE

Components of Gross CONE (using midpoint of ranges) for Alberta generic resources



Note: Numbers in the chart are in 2021 nominal dollar value.

While a generic frame peaker has a lower capital cost and gross CONE than a generic CCGT, its Net CONE is slightly higher than CCGT due to a smaller expected energy & AS offset

- **The cost of new entry in Alberta is lower than US markets in general**
  - The capital cost and Gross CONE of CCGT and frame peaker is comparable with US markets while the capital cost of aeroderivative peaker and reciprocating engine is lower
- **LEI's modeling suggests that the choice of least cost/best fit technology and setting of the Net CONE value is highly contingent on the financing and risk assessment of various generation technologies within the Alberta market**

(CAD/kW-month)	Aeroderivative peaker	CCGT	Frame peaker	Reciprocating engine
Gross CONE	\$16.5-\$23.5	\$21-\$28	\$11-\$17	\$15-\$22.5
Energy revenue offset	*Not estimated*	\$13-\$15	\$3-\$5	*Not estimated*
Ancillary services revenue offset	*Not estimated*	\$0.7-\$1.1	\$0.5-\$2	*Not estimated*
Net CONE	*Not estimated*	\$5-\$14	\$4 - \$13.5	*Not estimated*

Note: Numbers in the table are in 2021 nominal dollar value.

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Most capacity markets decide on the demand curve foot as a reflection of value ascribed to incremental generating capacity – larger foot value preferable in a smaller market to mitigate volatility

	ISO-NE	NYISO	PJM	UK
Foot value	23.6% internal reserve margin	32.2% internal reserve margin	27% internal reserve margin	No pre-determined price floor described in the rules. The clearing price for the auction is found once the auction clears
Rationale	Floor based on a target reserve margin that will be sufficient to achieve in a target loss of load expectation ("LOLE") of 1-in-87 based on repeated probabilistic simulations	*The NYISO sloped demand curves are meant to "reflect, as accurately as the New York ISO can reasonably measure it, the reliability value of incremental generating capacity"* – Evaluation of the New York Capacity Market, Final New York Capacity Report, March 5, 2013	*"PJM recommended convex curve that shows procurement below the reliability requirement only 16 percent of the time. It meets the 1-in-10 objective and it allows RPM to better handle year-to-year volatility in system conditions"* - FERC Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing (Docket ER-14-2940-000). November 28, 2014	No specific rationale. DECC. Electricity Market Reform: Consultation on Proposals for Implementation. October, 2013

Historical reserve margins in Alberta ranged between 15% and 35% (source: PowerEn)

In most markets, demand curve cap is set administratively, with a preference to err on the high side to ensure sufficient investments can be attracted when the system is short on capacity

	ISO-NE	NYISO	PJM	UK
Cap value	1.6 times the net CONE and 11% reserve margin	1.5 times gross CONE, and 6% reserve margin	Maximum of 1.5 times the net CONE or 1 times the gross CONE and 16% reserve margin	250% of net CONE set administratively
Rationale	*"ISO-NE selected a demand curve cap to reflect a balance between a) reducing price volatility and b) providing price incentives to maintain reliability"* - ISO New England Inc., before the Federal Energy Regulatory Committee, regarding a Forward Capacity Market Demand Curve	No specific discussion on setting of the demand curve cap	*"PJM believes this curve strikes an appropriate balance between reliability and minimizing cost to consumers"* – FERC Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing (Docket ER-14-2940-000). November 28, 2014	"*administrative price cap at a higher level to ensure there are opportunities for a wider range of projects / technologies to set the price and ensure that the auction clears."* - DECC. Electricity Market Reform: Consultation on Proposals for Implementation. October, 2013

LEI is in agreement with the approach adopted in the PJM market for pricing of cap, especially as there is uncertainty about future energy & ancillary services revenue estimates in the initial cycles of capacity market in Alberta; for quantity, LEI recommends at least 6% reserves (or higher)

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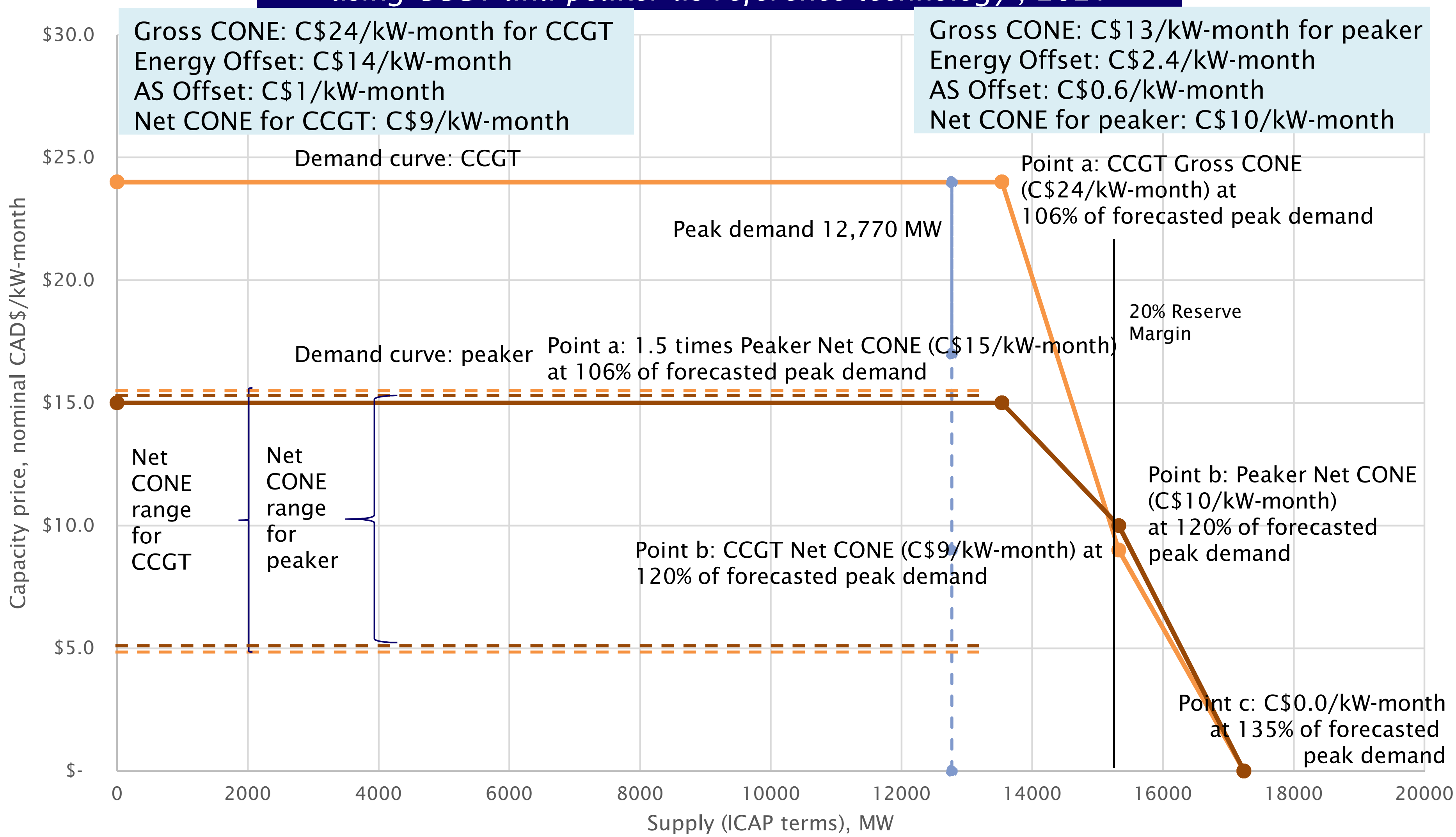
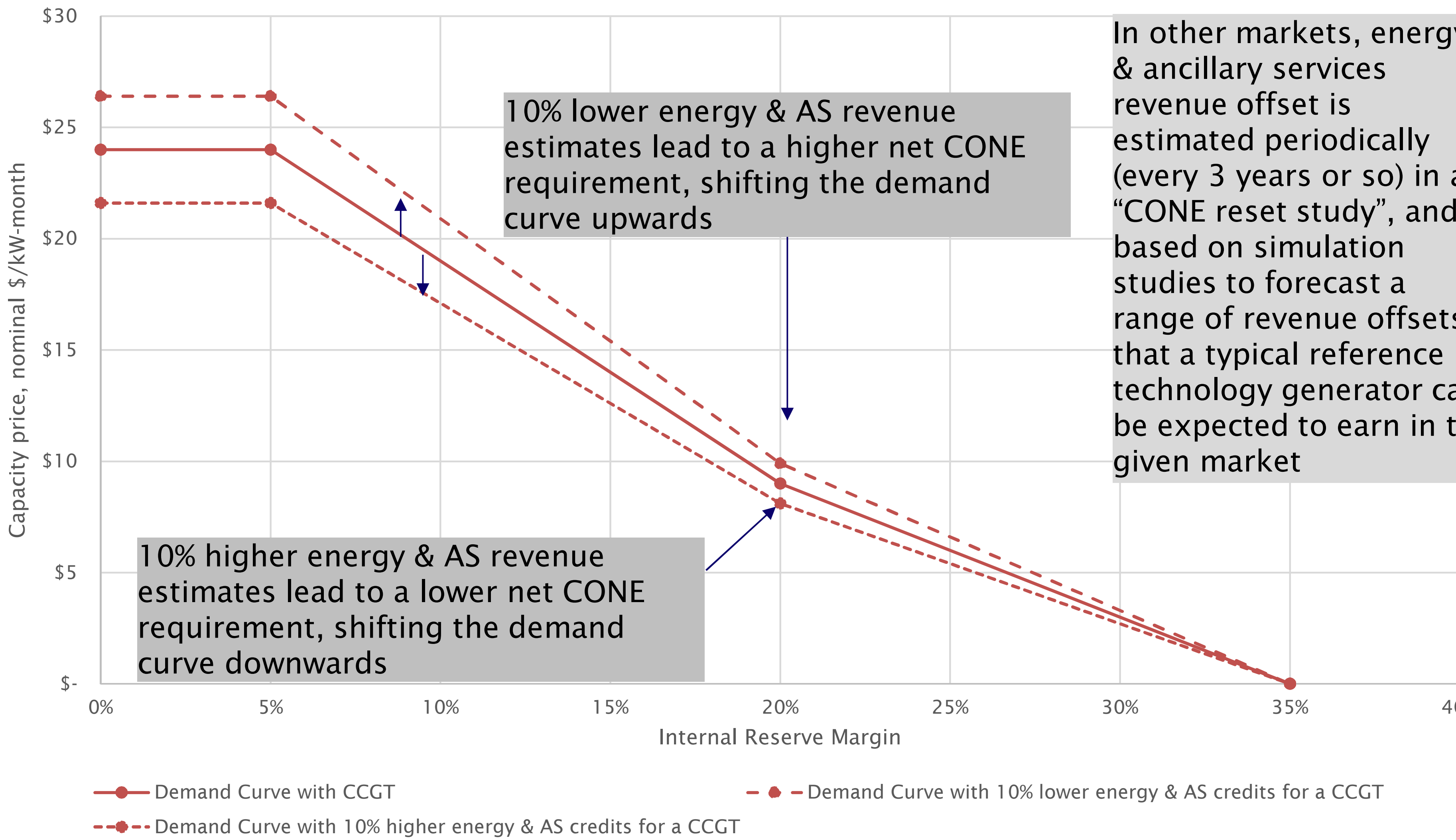
Alberta demand curve generally in same range if a CCGT or peaker is chosen – with slight differences once capacity quantities fall below reserve margin target

Indicative capacity market demand curve (internal) in ICAP terms
using CCGT and peaker as reference technology , 2021



Setting net CONE using a CCGT is more complicated – forecast error around future energy profits can swing net CONE values

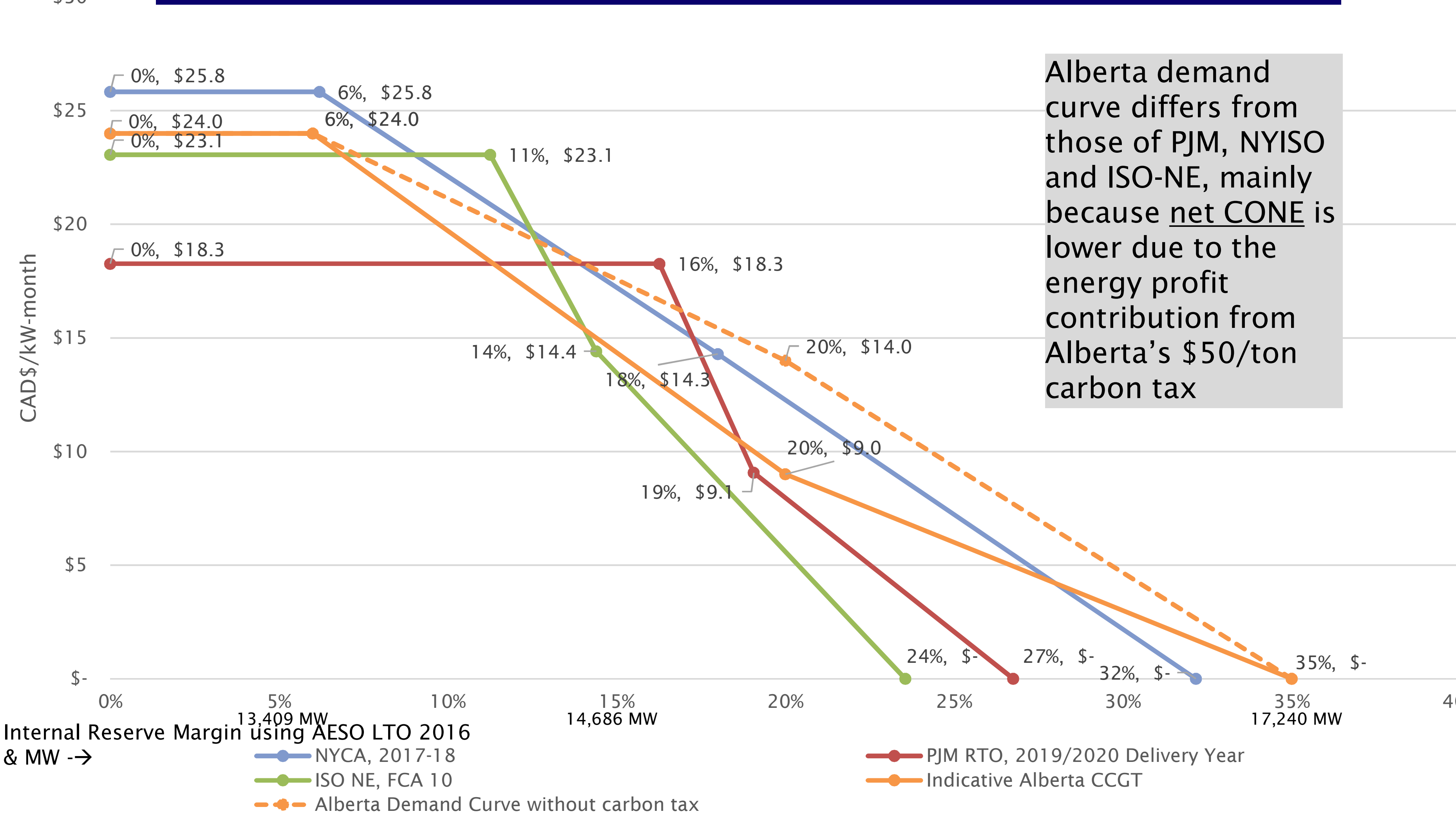
Capacity market demand curve for a CCGT with various levels of Energy & AS revenue estimates for a CCGT, CAD $/kW-month



In other markets, energy & ancillary services revenue offset is estimated periodically (every 3 years or so) in a "CONE reset study", and is based on simulation studies to forecast a range of revenue offsets that a typical reference technology generator can be expected to earn in the given market

Carbon tax in Alberta creates material impacts on net CONE if CCGT is the reference technology

Capacity Market Demand Curve across US jurisdictions and comparison against indicative demand curve in Alberta using CCGT as reference technology in 2021 in CAD$ (CAD$1=US$0.75)



Risk of carbon tax changes may undermine financing of new generation without some sort of backstop from government

- **By 2022, the carbon tax may climb to $50/tonne – raising energy prices, but new CCGTs do not pay this and therefore get a big "bump up" in energy profit margins**

	$/kW-month	% Share of Gross Profits
Energy profit margin	$ 9.0	38%
Carbon tax-related energy profits	$ 5.2	22%
A/S profit margin	$ 0.8	3%
Capacity revenues	$ 9.0	38%
	$ 24.0	

- **If the net CONE is set using the expected future carbon tax levels, net CONE should be $9/kW-month; if no future carbon tax is assumed, net CONE should be $14/kW-month for CCGTs**

2021 CAD$/kW-month	With carbon tax	Without carbon tax
Gross CONE	$24.0	$24.0
Energy Offset	$14.2	$9.0
AS Offset	$0.8	$0.8
Net CONE	$9.0	$14.2

- **If the tax is repealed in the future, the capacity market will undermine the financial viability of the new entrants**
- **Alternatively, if the net CONE is set assuming no carbon tax (and market participants "buy" into this concept), the capacity price will be much higher and there is a risk that the AESO will be overcompensating capacity providers if indeed the carbon tax does evolve to high levels and boost energy profits in the future**
- **Backstop from government could be as simple as an index change to some percentage of capacity market prices, triggered by a change in carbon tax**

Unlike a CCGT, removing the carbon tax reduces the net CONE because it removes some costs for the peaker without necessarily reducing the energy offset

- **Impact of carbon tax is much lower on peakers given that they receive significantly less energy market revenues**
- **By 2022, the carbon tax may climb to $50/tonne – raising energy prices, but new peakers will have to pay a higher carbon tax, reducing their energy market profit margins**

	$/kW-month	**% Share of Gross Profits**
Energy profit margin	$ 2.9	22%
Carbon tax-related energy profits (payments)	-($ 0.5)	-4%
A/S profit margin	$ 0.6	5%
Capacity revenues	$ 10.0	77%
	$ 13.0	

- **If the net CONE is set using the expected future carbon tax levels, net CONE should be $10/kW-month; if no future carbon tax is assumed, net CONE should be $9.5/kW-month for peakers**

2021 CAD$/kW-month	**With carbon tax**	**Without carbon tax**
Gross CONE	$13.0	$13.0
Energy Offset	$2.4	$2.9
AS Offset	$0.6	$0.6
Net CONE	$10.0	$9.5

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Demand curve design process will need to account for Alberta's special characteristics – new market design, regulatory uncertainty and small market

- **Based on LEI's independent survey of capital costs and other components of gross CONE, frame peaker has a lower capital cost and gross CONE than a CCGT but a CCGT has a lower net CONE… but is CCGT the right choice?**
  - CCGT is an unusual choice for a reference technology for a capacity market in Alberta – with exception of UK, no other capacity market with a demand curve uses CCGTs
- **LEI recommends thinking about least cost/best fit for selection of reference technology**
  - In Alberta, a peaker as a reference technology will be a better fit (size wise) and may be lower risk given net CONE is not as dependent on future E&AS revenues
  - Choosing a peaker would not preclude CCGT entry, but using a CCGT may limit development of peakers
- **Setting of the cap and foot is usually tailored to market specifics and "negotiated" without significant empirics**
  - LEI suggests that cap is based on range needed to maintain capacity to cover contingency reserves
  - Cap of the demand curve should be set high enough to provide price incentives for continued participation in the capacity market, but not too high to increase cost to consumers – LEI agrees with SAM (1.0) recommendations
  - Foot of the demand curve should recognize small market size – LEI suggests looking at realized reserves in past and imputed elasticity to reduce price volatility due to retirements and new entry of a single plant
- **For the net CONE to be "right", estimate of energy & ancillary services revenues needs to be modeled off future conditions**
  - Historical statistics not relevant given the many changes in the market by 2021
- **Carbon tax structure in Alberta is a unique policy risk which will affect the net CONE**
  - In order to prevent wrong investment signals and under or over-entry, LEI recommends indexing resulting capacity price to future carbon tax changes