EB-2019-0242

Association of Major Power Consumers of Ontario (“AMPCO”)

Kingston CoGen Limited Partnership (“KCLP”)

Panel 4 – Brian Rivard

Examination in Chief Compendium (Revised)

November 28, 2019

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TAB 1

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I, Brian Rivard, of the Town of Paris, in the Province of Ontario, MAKE OATH AND SAY AS FOLLOWS:

A. INTRODUCTION

A.1 Q: Please state your name and occupation.

1. My name is Brian Rivard. I am Adjunct Professor at the Ivey Business School at Western University and the Research Director of the school's Energy Policy and Management Centre.

A.2 Q: For whom are you testifying in this proceeding?

2. I am testifying on behalf of Kingston CoGen Limited Partnership ("KCLP"). Attached hereto as **Exhibit "A"** is a signed copy of Form A pursuant to the Ontario Energy Board's (the "Board") Rules of Practice and Procedure.

A.3 Q: What is your educational background?

3. I hold a Ph.D. and M.A. in Economics from Western University. My field of specialization is industrial organization with an emphasis on the study of competitive markets, economic efficiency, and regulatory economics. I also have a B.A. in Economics from the University of Windsor.

A.4 Q: What is your professional background?

4. A copy of my curriculum vitae is attached hereto as **Exhibit "B"**. I began my career working as an Economist and then as a Senior Economist at the Canadian Competition Bureau. The Competition Bureau is the agency responsible for enforcing the Canadian *Competition Act* and protecting the Canadian economy against anti-competitive business conduct such as collusion or price fixing, abuse of dominant position, and anti-competitive mergers. My primary function as an Economist at the Competition Bureau was to conduct economic analysis in support of the Bureau's various enforcement actions.

5. After briefly working as a Senior Economic Consultant for the economic consulting firm, LECG, I joined the Independent Electricity System Operator ("IESO") (then called the Independent Electricity Market Operator) in 2000 as a Senior Economic Advisor in the Market Assessment and Compliance Division, reporting to the Market Surveillance Panel. Within this role, I was responsible for monitoring the Ontario electricity market for anomalous conduct, including abuses of market power or gaming, and for structural or market design deficiencies.

6. In 2006, I was promoted to Manager of Economics with the responsibility of conducting analysis of the effects of changes in wholesale electricity market design or government policy on the efficient operation of the IESO's wholesale market.

7. In 2010, I assumed the role of Manager of Regulatory Affairs and Sector Policy Analysis. In this role, I represented the IESO on the ISO-RTO Council ("IRC") as a member and Chair of the IRC's Market Committee. The IRC is a member group of North America's competitive wholesale market operators.[1] I was the Chair of the Market Committee at the time the United States Federal Energy Regulatory Commission (the "Commission") issued its Final Rule in Docket No. RM10-17-000, Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets* ("FERC Order No. 745").[2]

8. In 2013, I was appointed the position of Director of Markets. As Director of Markets, I was responsible for evolving the design of the Ontario electricity market to ensure it operated fairly and efficiently. As Director, I oversaw the transition of the responsibility for administering demand response programs from the Ontario Power Authority

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[1] In addition to the IESO, the IRC includes the Alberta Electric System Operator ("AESO"), the California Independent System Operator Corporation ("CAISO"), the Electric Reliability Council of Texas, Inc., ("ERCOT"), ISO New England, Inc., ("ISO-NE"), the Midcontinent Independent System Operator, Inc. ("MISO"), the New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C., ("PJM") and the Southwest Power Pool ("SPP").

[2] Being Tab 8 to the IESO's Book of Authorities in Response to AMPCO's Request for a Stay, dated November 5, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/657752/File/document [FERC Order No. 745].

("OPA") to the IESO. I initiated the design and implementation of the IESO Demand Response Auction ("DRA").

9. In 2015, I left the IESO to join Charles River Associates International as a Principal in their Energy Practice. I advised clients on a variety of issues, most notably competitive wholesale market design, market power and market manipulation issues.

A.5 Q: What is your current position?

10. I am Adjunct Professor and Research Director of the Energy Policy and Management Centre for the Ivey Business School at Western University. My primary role at Ivey is to further the mission of the Energy Centre which is to:

   a. Contribute to energy policy-making through the production and dissemination of evidence-based research and analysis on major policy issues affecting the electricity, gas, oil and pipeline sectors in Canada;

   b. Provide a transparent and reliable forum for industry, government, academia, and interested stakeholders to discuss and exchange ideas on energy sector development and policy; and

   c. Educate students, executives, and government officials on national and global energy sector issues.

A.6 Q: What other professional experiences do you have?

11. I serve as a peer reviewer for the Energy Journal. I am a Member of the International Association of Energy Economists. I am an occasional lecturer at Ryerson University and Osgoode Hall Law School.

A.7 Q: Have you previously submitted testimony before Board or other regulatory agencies?

12. I provided oral testimony before the Board on behalf of the IESO in EB-2007-0040 (regarding the 3x Ramp Rate). I provided written and oral testimony before the

Commission on behalf of Shell Energy North America (US), L.P. in Docket No. EL02-71-057.

A.8 Q: What is the purpose of your testimony in this proceeding?

13. I was retained by counsel for KCLP to review the Association of Major Power Consumers of Ontario's ("AMPCO") Notice of Appeal (the "Appeal") to Market Rule Amendments MR-00439-R00-R05 (the "Amendments") and supporting evidence, and to offer my independent views on the economic merit of AMPCO's position in this proceeding.

14. The Amendments enable the evolution of the IESO's DRA into a Transitional Capacity Auction ("TCA") that will allow non-contracted and non-regulated generators ("non-committed dispatchable generators") to participate in future capacity auctions alongside Demand Response ("DR") resources.

15. The focus of the Appeal is the appropriate level of compensation for DR resources. The IESO provides non-committed dispatchable generators an energy payment if / when the generators respond to an IESO instruction to produce energy based upon their offered price. Under the Amendment, DR resources will not receive an energy payment (or "utilization payment") when DR resources respond to an IESO instruction to reduce their energy consumption (an "economic activation").[3] AMPCO claims that this

[3] Application for Review of an Amendment to the Independent Electricity System Operator Market Rules, Notice of Appeal, EB-2019-0242, filed September 26, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653723/File/document, at para. 12. The terms "energy payment" and "utilization payment" are used interchangeably in the proceeding material. For clarity, a ***utilization payment*** is a payment made to a demand response market participant that responds to an instruction from the system operator (IESO) to reduce the amount of electricity (energy) that they are consuming. The instruction from the IESO to a demand response resource to reduce energy consumption is referred to as an ***energy activation***. For this reason, utilization payments are sometimes referred to as ***activation payments***. Utilization payments at the wholesale market-clearing price are called ***energy payments***. A DR resource could receive an energy activation instruction from the IESO as part of the IESO's economic dispatch process, called an ***economic activation***, as a test of the DR resources capability, or for reliability or emergency reasons. The issue in the Appeal is compensation for economic activation. The IESO plans to compensate DR resources if the IESO instructs the resource to reduce consumption to test the resources capability or for reliability and emergency reasons.

represents inequitable and unfair treatment of DR resources, places DR resources at a competitive disadvantage to non-committed dispatchable generators in the TCA, and results in a TCA that is unfair and inefficient, and effectively anticompetitive and discriminatory. AMPCO also contends that the Commission, in FERC Order No. 745, has definitively recognized "that failure to compensate DR resources for such services is unjust and unreasonable."[4]

16. Counsel further asked that I address the issue the Board raised in Procedural Order No. 2. The Board stated that "it is particularly interested in receiving evidence that describes the experience with compensation for DR in markets in other relevant jurisdictions, and the extent to which that experience is informative in the context of the Amendments having regard to any pertinent differences such as differences in market design or structure."

17. Specifically, my evidence will:

   a. analyze the economic merit of AMPCO's assertions of inequitable and unfair treatment, competitive disadvantage, and the negative impacts on competition and efficiency; and

   b. identify pertinent similarities or differences between the United States wholesale markets and the Ontario market, such as differences in market design or structure, to inform the Board of the applicability of FERC Order No. 745 to Ontario and in the context of the Amendments.

A.9 Q: How is your testimony organized?

18. The remainder of my testimony consists of three parts. In Part B, I offer my analysis of the economic merit of AMPCO's assertions. In Part C, I summarize the conclusions of FERC Order No. 745 and identify unique aspects of the Ontario market that should

[4] *Ibid* at para. 36.

inform a conclusion on the applicability of the Order to Ontario. In Part D, I provide my summary conclusions.

A.10 Q: What are your conclusions?

19. In my opinion, the Amendments provide an equitable treatment of TCA participants. I give evidence that demonstrates the Amendments afford fair and equitable treatment to TCA participants, do not place DR resources at a competitive disadvantage to non-committed dispatchable generators, and promote fair and efficient competition to the benefit of Ontario consumers. I further conclude that the application of FERC Order No. 745 in Ontario will not achieve the effects the Commission intended when it issued its decision. This is due to several unique aspects of the Ontario electricity market, each of which I will speak to herein.

B. AMPCO'S ASSERTIONS ARE VOID OF FACTUAL SUPPORT AND LACK ECOMOMIC MERIT

B.1 Q: What is your understanding of the basis of AMPCO's appeal?

20. The basis of AMPCO's appeal is that generators receive a payment for energy services provided (economic activations) but DR resources do not. AMPCO asserts that this represents "an inequity in treatment between generation resources and DR resources."[5] AMPCO further asserts that this unequitable treatment puts "DR resources at a competitive disadvantage to generators"[6] in the TCA and would allow generators to "effectively and unfairly displace"[7] DR resources in the TCA. AMPCO concludes that this would "undermine competition"[8] and is "inimical to the IESO's own objective of

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[5] *Ibid* at para. 4.

[6] *Ibid* at para. 22.

[7] *Ibid* at para. 4.

[8] *Ibid* at para. 14.

enhancing competition for the benefit of consumers."[9] The failure to compensate DR resources for economic activations "would result in a capacity market that is unfair and inefficient, and effectively anticompetitive and discriminatory."[10]

B.2 Q: What evidence has AMPCO provided to establish competitive disadvantage?

21. AMPCO's assertion of competitive disadvantage is articulated in the Affidavit of Mr. Colin Anderson at paragraphs 12 through 19. Mr. Anderson reasons as follows:

a. In the existing DRA, the only revenue stream available to participants is a capacity payment (called an availability payment). There are currently no payments made for energy activations. If the TCA proceeds in December 2019, non-committed dispatchable generators will qualify for an availability payment and an energy payment when economically activated. DR resources will still only qualify for an availability payment.[11]

b. Non-committed dispatchable generators will be able to submit a capacity offer into the TCA taking into account their anticipated energy payments. They will be able to set a capacity offer price that is lower by the amount of their anticipated energy payments. DR resources will not have the same opportunity.[12]

c. DR resources incur "legitimate costs" when they are economically activated to curtail demand. If they do not receive an energy payment, they will not be able to recover these costs.[13]

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[9] *Ibid* at para. 25.

[10] *Ibid* at para. 45.

[11] Affidavit of Colin Anderson, sworn October 11, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/655144/File/document, at para. 12.

[12] *Ibid* at para. 14

[13] *Ibid* at para. 19.

d. DR resources will have two options on how to deal with this. First, they can include the anticipated cost of activation in their capacity offer price. This would put DR resources at a competitive disadvantage to non-committed dispatchable generators that do not have to include these costs in their capacity offer price. Second, they could omit including the anticipated cost of activation in their capacity offer price, but then risk not recovering these costs when economically activated.[14]

B.3 Q: If a market participant cannot recover legitimate cost in the market does that not place it at a competitive disadvantage to others that can recover their cost?

22. From an economic perspective, if a DR resource incurs a cost when economically activated to curtail demand that it would ***avoid*** if it continued to consume, then it could be competitively disadvantaged by the Amendments. However, AMPCO has provided no factual evidence or even conceptual evidence that explains the nature, magnitude or legitimacy of these ***avoidable*** costs.

23. By contrast, a natural gas fired generator could provide both conceptual and factual evidence that it incurs a fuel cost when economically activated in order to produce energy that it can avoid (save) by not producing. This evidence is readily and publicly available, and is the basis for the energy payments made to these generators.

B.4 Q: Why does it make economic sense to pay a generator an energy payment for economic activation?

24. In order to induce a generator to produce energy, it must receive a payment that allows it to recover its avoidable cost of activation. If it did not receive a payment, it would be in its economic interest not to produce to avoid incurring the fuel cost. To induce efficient energy production, the IESO pays generators the energy market-clearing price to cover these costs.[15] The market-clearing price is designed to reflect the cost to

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[14] *Ibid.*

[15] The IESO currently operates a "two-schedule" pricing and dispatch energy market, which is described in the IESO's "The Single Schedule Market Backgrounder." In the two-schedule system, the physical limitations of the

produce one more MW of electricity (marginal cost), or the value to reduce one more MW of consumption (marginal willingness to pay) on the system. Paying generators this price incentivizes only those generators whose avoidable cost of economic activation is less than the market price. This is how the IESO manages the efficient use of the province's generation assets.

B.5 Q: Based on your experience in the electricity industry, what types of costs might a DR resource incur with an economic activation?

25. To my knowledge, the only cost that a DR resource may incur with an economic activation is the value of lost consumption, or what is sometimes called the value of lost load.[16] The value of lost load is the amount a consumer would be willing to pay to avoid disruption of service (i.e., to maintain its level of consumption). If a DR resource receives an energy activation when its value of lost load is greater than the price it would pay to consume, it would incur a legitimate cost from activation that it could have avoided if it had continued to consume. In this instance, the cost from activation would equal the difference between the value of lost load and the price the DR resource would have paid had it consumed.

B.6 Q: Does AMPCO provide evidence that DR resources are at risk of incurring this cost with an economic activation?

26. No. In fact, the IESO market rules provide DR resources the means to manage this risk. Two types of DR resources can participate in the TCA and the IESO's energy market: dispatchable loads and Hourly Demand Response ("HDR") resources.

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system are ignored in the "pricing" schedule that sets an Ontario-wide market price and establishes the most economic set of resources to meet demand. This requires a second "dispatch" schedule that includes the physical limitations of the system. The result is there are times when resources who cleared the market based on economics are told they cannot proceed, and others that were initially unsuccessful are told they are required to run in order to reliably meet demand. The differences between the two-schedules requires a complex system of out-of-market compensation to some participants.

[16] Navigant's Demand Response Discussion Paper, being Exhibit "I" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document ["Navigant Report"]. The Navigant Report considers the costs associated with curtailment of a DR resource. This is the only type of cost they identified.

27. Dispatchable loads submit hourly energy bids to the IESO that define the quantities of energy they are willing to consume at different price levels. They receive dispatch instructions from the IESO every 5-minutes based on these energy bids. When they consume, they pay the market-clearing price (the 5-minute price) for the amount they consume. When the market-clearing price is above the price in their energy bid, they receive an economic activation to reduce their demand as per the amount stated in their energy bid. Dispatchable loads that are successful in the TCA are eligible to receive an availability payment by submitting and maintaining energy bids in the day-ahead through to real-time markets during a defined availability window that changes between the summer and winter months but generally covers the expected peak demand hours on business days. The energy bid prices must be greater than $100/MWh but less than $2,000/MWh, which is the maximum market-clearing price. As long as the price in the dispatchable load's energy bid reflects their value of lost load, they are not at risk of incurring a cost from an economic activation; they will only be economically activated when the market price exceeds their value of lost load.

28. HDR resources also submit hourly energy bids. When they consume, HDR resources pay the Hourly Ontario Energy Price ("HOEP"). In order to receive an availability payment, HDR resources must submit energy offers within the hours of availability. HDR resources receive a "standby report" in advance of a potential economic activation between 15:00 EST of the day ahead until 07:00 EST on the dispatch day, if the IESO's pre-dispatch schedules signal they could be curtailed for the hours of availability. In this instance, HDR resources must continue to submit energy bids for the dispatch day consistent with their capacity obligation. HDR resources are economically activated when the pre-dispatch 3-hour ahead price is greater than their energy bid price. The HDR resource is notified that they will be economically activated by receiving an Activation Notice approximately 2.5 hours before the start of the first dispatch hour to which it relates. HDR resources may be activated once per day for up to four consecutive hours. Attached hereto as **Exhibit "C"** is a copy of IESO Market Manual 4, which sets out the rules for activating HDR resources at section 7.2. Like dispatchable loads, HDR resources can manage the risk of incurring a cost associated with lost load from an

economic dispatch through their energy price bid. As the IESO evidence indicates, HDR resources have been economically activated on only one occasion since the implementation of the DRA.

B.7 Q: In response to Board Staff Interrogatory question 1, AMPCO provided a list of costs related to curtailment. What are your views on the nature of these costs?

29. AMPCO identified two types of costs related to economic activation under the heading "Cost per Curtailment." AMPCO called the first set of costs "lost opportunity". These costs all influence the price the DR resource is willing to pay to consume, i.e. the value of lost load. AMPCO indicates that there are several things to consider in establishing the value of lost load for a DR resource, and these things vary over time, even day to day and hour to hour. However, these costs all should be captured in the DR resource's energy bid price. As discussed above, the DR resource can avoid incurring a lost opportunity cost by properly estimating its value of lost load and using this estimated value for its energy bid price. This is not to say that it is easy to estimate the value of lost load, and that there is not a risk that the estimate is wrong and that there is ex post regret that they bid too low or too high. This is possible in the same way it is possible that when a generator submits an energy offer with an expectation of its fuel costs and operating conditions: they guess wrong and fail to recover some costs.

30. AMCPO calls the second set of costs "semi-variable costs," which included labour cost and other overhead costs for the production facility. These costs are costs that the DR resource must incur to ensure that they are available as a capacity resource to respond to an economic dispatch. These costs are not avoided if the DR resource is not economically activated. These are costs that can be avoided only if the DR resource chooses not to be available. I would call these costs fixed avoidable costs. For example, if they wanted to operate as a non-dispatchable load, they may require fewer staff on shift to monitor for dispatch instructions from the IESO. These costs should be recovered through the availability payment and not through an energy payment. This is no different than the types of costs that a non-committed generator may incur to make

sure a generator is available to respond to an IESO dispatch. Non-committed dispatchable generators would also need to recover these types of fixed avoidable costs if they choose to sell capacity and be available for dispatch by the IESO. They would include these costs in their capacity offer price, not in their energy offer price.

B.8 Q: If a generator receives an energy payment for balancing supply and demand, but a DR resource does not, is this not inequitable treatment, and does it not place the DR resource at a competitive disadvantage?

31. Contrary to AMPCO's assertion, I contend that *providing* DR resources an energy payment for economic activations would represent *inequitable treatment* and afford DR resources a *competitive advantage* over non-committed dispatchable generators in the TCA. I come to this conclusion by applying the concept of horizontal equity and by way of example.

B.9 Q: What is horizontal equity?

32. *Horizontal equity* requires that people who are alike in all relevant respect be treated the same. It corresponds to common notions of fair play and non-discrimination. For example, if two people have the same pre-tax income, they would have equal after-tax incomes. *Vertical equity* holds that people who differ in relevant respects should often be treated differently. This notion of equity is more contentious. Vertical equity is typically concerned with the "preferred" distribution of wealth in society. What represents the "preferred" distribution of wealth is a normative question that requires a value judgement. For example, it can be argued that those who earn higher pre-tax income *should* pay higher taxes.

B.10 Q: How does this concept of equity draw you to conclude that providing DR resources an energy payment would be inequitable?

33. I come to this conclusion through an example. The example is an adaptation of the example the IESO presented to stakeholders in the Demand Response Working Group

on March 11, 2018 to elicit views on the issue of the equal treatment of "negawatts and megawatts."[17]

34. Consider two companies, DR Corp. and GEN Corp. DR Corp. consumes 6 MW of electricity. Its value of lost load is $10,000/MWh. DR Corp. also owns a behind-the-meter generator. The generator has a capacity of 4 MW. It incurs a cost of $100/MWh to generate electricity. DR Corp. also incurs a fixed cost of $1,000 to staff and maintain the generator so that it is available to produce electricity when needed. If DR Corp. chose not to maintain the generator to be available to produce electricity, it would avoid incurring this cost. This makes the $1,000 a fixed avoidable cost. GEN Corp. is exactly the same as DR Corp. with one arbitrary exception: GEN Corp. is electrically connected to the IESO market metered separately as a load and a generator, while DR Corp. is connected by meter to the IESO market as a load with its generator operating behind the meter. Figure 1 depicts the situation for both companies.

35. To simplify the discussion, assume there is just one hour in the year and based on the prevailing supply and demand conditions, the two companies expect the energy market price to be $100/MWh. Both companies plan to compete in the IESO TCA. DR Corp., because it is metered with the IESO as a load, competes as a DR resource and can offer 4 MW of capacity (the amount of net-metered load it is capable of decreasing through use of its behind-the meter generator). If successful in the TCA, DR Corp. will be obligated to submit an energy bid in the IESO's energy market for 4 MW. The energy bid price that DR Corp. will submit is equal to $100/MWh as it will be less costly to use its generator to self-supply its demand than to buy energy from the IESO energy market at a price higher than $100/MWh. GEN Corp. competes as a non-committed generator and can offer 4 MW of capacity in the TCA. If successful in the TCA, GEN Corp. will

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[17] IESO Presentation to Demand Response Working Group on Utilization Payments Discussion, dated March 1, 2018, being Exhibit "J" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document at 10-14 ["IESO March 1 Presentation"]. A "negawatt" is a unit of energy saved, such as through the curtailment of demand. This issue of whether a "negawatt" and a "megawatt" are functionally and economically equivalent is a contentious issue. The issue was addressed in FERC Order No. 745 where Commissioner Moeller disagreed with the Commission majority that the two were equivalent.

be obligated to submit an energy offer in the IESO’s energy market for 4 MW. The energy offer price it will submit is $100/MWh, which is its marginal cost of generation.

36. Assume in the first instance, as per the Amendments, DR resources do not receive an energy payment for an economic activation. What will be the capacity offer price of each company? I answer this with reference to Figure 1.A.

Figure 1: DR Corp. and GENCorp. are identical in all relevant aspects

Figure 1.A: No Energy Payments for DR Resources

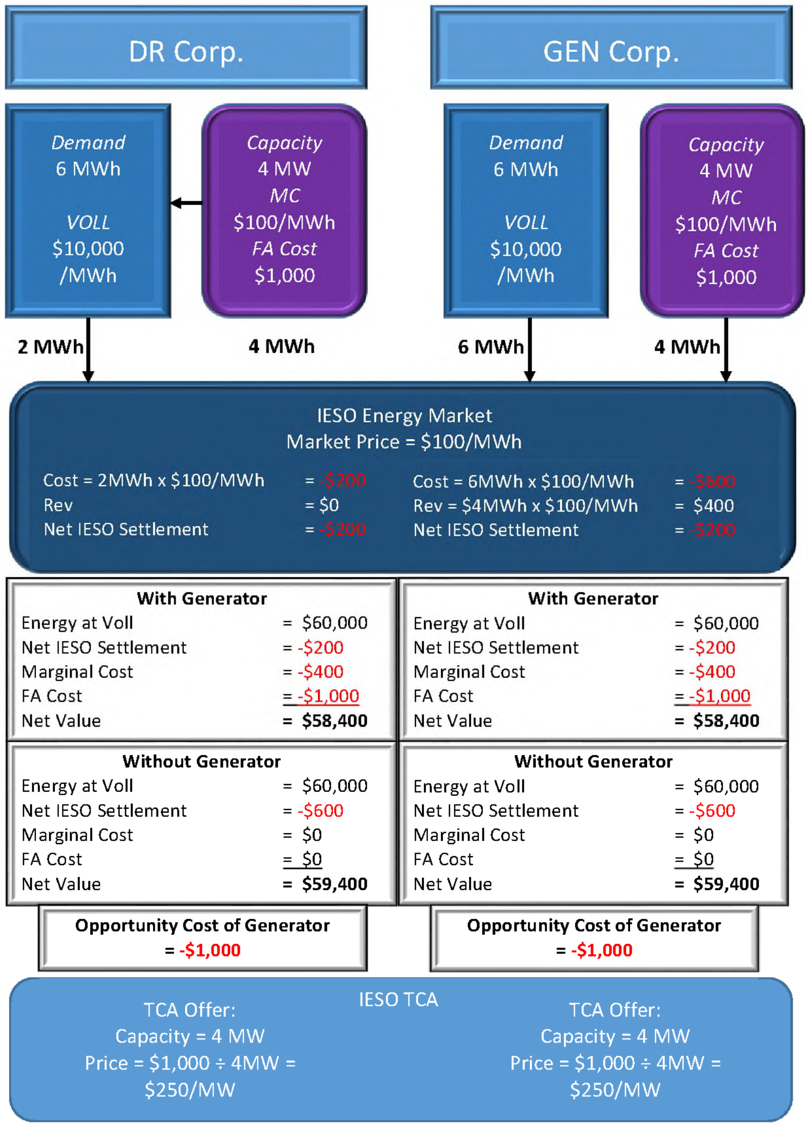
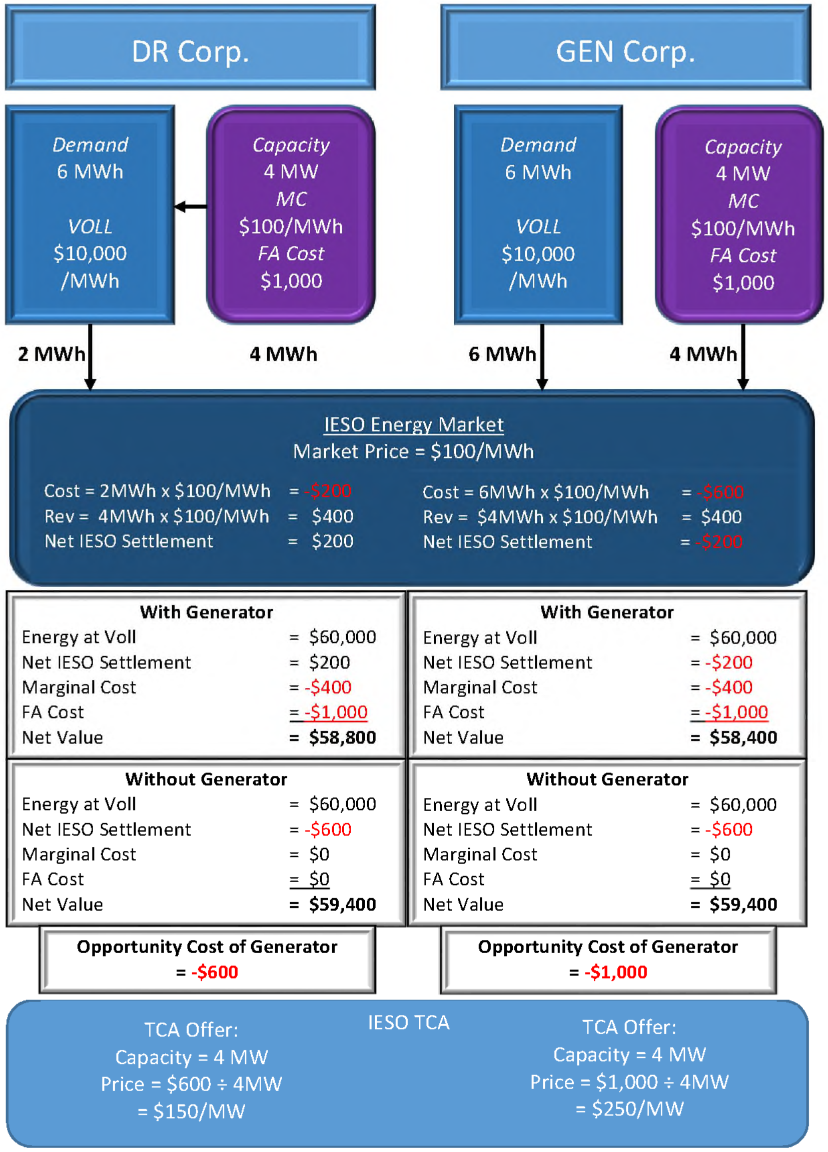


Figure 1.B: Energy Payments for DR Resources



37. With an expected market price of $100/MWh, DR Corp. anticipates that it will receive an economic activation to reduce its net-metered load by 4 MWh. It will not receive an energy payment for this activation, so as AMPCO argues, it will not be able to incorporate this revenue in the calculation of its capacity offer price. DR Corp. will make an energy payment to the IESO of $100/MWh x 2 MWh = $200 for its net-metered demand. It will incur a cost of $100/MWh x 4 MWh = $400 to generate electricity to

supply the balance of its 6 MWh of consumption. It will incur the fixed avoidable cost of $1,000 to ensure the generator is available. Overall, DR Corp. will realize a net value of $58,400 for its activities. These calculations are listed in the box for DR Corp. titled "With Generator" in Figure 1.A (numbers in red are negative values).

38. For it to be profitable for DR Corp. to participate in the TCA, the net value it realizes if successful must be greater than the net value it would realize by shutting down its generator and buying all of its electricity from the IESO. This net value is calculated in the box for DR Corp. titled "Without Generator" in Figure 1.A and is equal to $59,400. The net opportunity cost of DR Corp of participating in the TCA is the difference between these two values and is equal to -$1,000. That is, DR Corp. can increase its net value by $1,000 by shutting down its generator and saving the fixed avoided cost of $1,000 to maintain the availability of the generator. Therefore, to keep the generator available, it must recover this amount in the TCA through the availability payment. DR Corp. will submit a capacity offer price of $250/MW for 4 MW of capacity with the hope of recovering the fixed avoided cost of making the generator available. If it is not successful in the TCA, it will shut down the generator.

39. With an expected market price of $100/MWh, GEN Corp. anticipates that it will receive an economic activation to generate 4 MWh of energy. The IESO will pay GEN Corp. the market price per MWh of energy produced for a total energy payment equal to $400. As AMPCO conjectures, GEN Corp. can anticipate earning this energy revenue when calculating its capacity offer price. **However, it costs GEN Corp. $400 to generate the electricity.** What GEN Corp. factors in to its capacity offer price is not the revenue it earns, but the net revenue it earns which is the difference between the energy payment and variable energy cost. This is the "benefit" that GEN Corp. receives by participating in the energy market. As I will discuss more below, it is important to draw the distinction between the energy payment and the net revenue when considering the AMPCO's assertion of competitive advantage. In this case, the market price and GEN Corp.'s marginal cost are equal; GEN Corp. earns zero net revenue. Like DR Corp., GEN Corp. computes its capacity offer price based on the difference between the net value it realizes

from making its generator available and the net value it realizes if it shuts down the generator, which is -$1,000. GEN Corp. submits a capacity offer price in the TCA equal to $250/MW, the same as DR Corp. This is what we might expect given that DR Corp. and GEN Corp. are identical but for the arbitrary physical positioning of their meters.

40. Assume now that contrary to the Amendments, DR resources are paid the market price for an economic activation. How does this affect each company's participation in the TCA and in the energy market? This is presented in Figure 1.B above.

41. First, note that by receiving the market price for an activation, DR Corp. has an incentive to lower its energy bid price. It will be optimal to use its generator to self-supply its demand whenever the market price is greater than half its marginal generation cost (i.e., market price > $50/MWh). To see this, assume the market price is $51/MWh, and DR Corp. does not use its generator to self-supply. DR Corp. pays $51/MWh x 6 MWh = $306 to the IESO. If instead, DR Corp. does use its generator to self-supply, it pays only $51/MWh x 2 MWh = $102 to the IESO to consume, receives an energy payment for economic activation equal to $51/MWh x 4 MWh = $204, and incurs a generation cost of $400 for a net cost of $298. It is better off to self-supply when the energy market price is $51/MWh. By this reasoning, DR Corp.'s net cost of participation in the IESO market if it self-supplies is lower whenever the market price exceeds $50/MWh. As a result, DR Corp. will lower its energy bid price to $50/MWh from $100/MWh.

42. Now assuming that DR Corp.'s lower energy bid price does not result in a lower energy price (which it could), it will now factor this additional energy payment into its capacity offer price calculation. As Figure 1.B demonstrates, the net value to DR Corp. increases when it is eligible for an energy payment for an economic activation. DR Corp. requires a smaller capacity offer price of $150/MW in order to cover its fixed avoided cost of making its generator available. This capacity offer price is lower than the capacity offer price of GEN Corp.

B.11 Q: Can you summarize what this example demonstrates of AMPCO's assertions of inequality and competitive disadvantage?

43. Yes. The example shows that AMPCO's assertions are incorrect. In my example, DR Corp. and GEN Corp. are identical but for the physical placement of a meter; an arbitrary and irrelevant difference. Horizontal equity requires like treatment for people (or corporations) that are alike. When DR resources do not receive an energy payment for an economic activation, DR Corp. and GEN Corp., whom are identical, are treated alike for their participation in the IESO markets and realize the same net value for their activities. When DR resources receive an energy payment for an economic activation, DR Corp. avoids the cost of consuming by reducing its net-metered load (a benefit). At the same time, it receives a payment from the IESO to avoid this cost (a second benefit). This amounts to a double benefit for the energy service provided (as evidenced by DR Corp.'s willingness to submit an energy bid price that is half its marginal generation cost). As a result, DR Corp. realizes a higher net value than GEN Corp. for participation in the IESO markets, even though the two companies are identical. The preferential treatment gives DR Corp. a competitive advantage over GEN Corp. in the TCA. What amounts to a double benefit for the energy service allows DR Corp. to cover more of its fixed avoided cost through the energy market. DR Corp requires less in the way of an availability payment to cover these costs and hence they can submit a lower capacity offer price than GEN Corp. in the TCA.

B.12 Q: What other conclusion do you draw through this example?

44. Through this example, I can demonstrate that contrary to AMPCO's assertions, paying DR resources an energy payment for economic activations would harm fair and efficient competition. With only slight modifications to the example I described above, I can show that providing DR resources an energy payment for economic activations can lead to more expensive resources being selected before less expensive resources in the TCA and more expensive resources being dispatched ahead of less expensive resources in the energy market.

45. In Figure 2, I assume DR Corp. incurs a fixed avoided cost of $1,100 to staff and maintain its generator to ensure it is available to produce electricity, which is $100 higher than the previous example. DR Corp. is now a higher cost capacity resource than GEN Corp. DR Corp. will have to recover $100 more in the TCA than GEN. If as per the Amendments, DR resources do not receive an energy payment for economic activations, DR Corp. will submit a capacity offer price of $275/MWh in the TCA. It has less chance of success in the TCA than GEN Corp. From the perspective of promoting fair and efficient competition, this is the desired outcome; the least cost capacity resource is selected ahead of the higher cost resource. If in the alternative, DR resources are provided an energy payment for economic activations, DR Corp. can anticipate a benefit of reducing its energy payment to the IESO and receiving an energy payment from the IESO for doing so, (i.e., a double benefit). This reduces the amount of fixed avoided cost that it must recover through the TCA by $400. DR Corp. is now able to reduce its capacity offer price to $175/MW, which is lower than GEN Corp.'s capacity offer price of $250/MW. DR Corp. now has an advantage over GEN Corp. in the TCA, even though it is the higher cost capacity resource. As a result, it is possible that DR Corp. is successful in the TCA and GEN Corp. is not. GEN Corp. would be forced to shut down its generator. This would be a wasteful and inefficient use of the province's resources. Providing DR resources an energy payment for economic activations would be harmful to fair and efficient competition.

Figure 2: DR Corp. has a higher fixed avoided cost

Figure 2.A: No Energy Payments for DR Resources

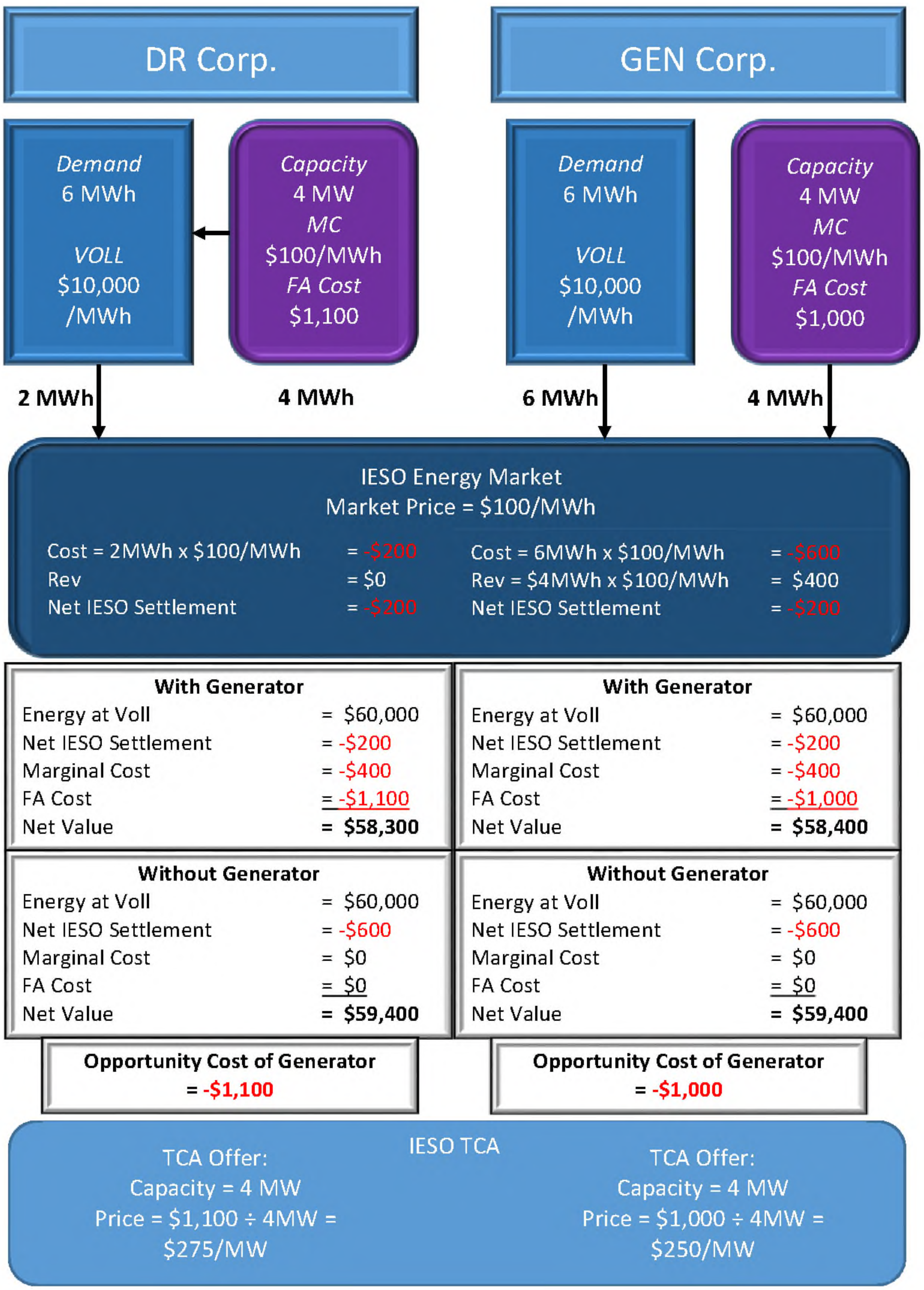


Figure 2.B: Energy Payments for DR Resources

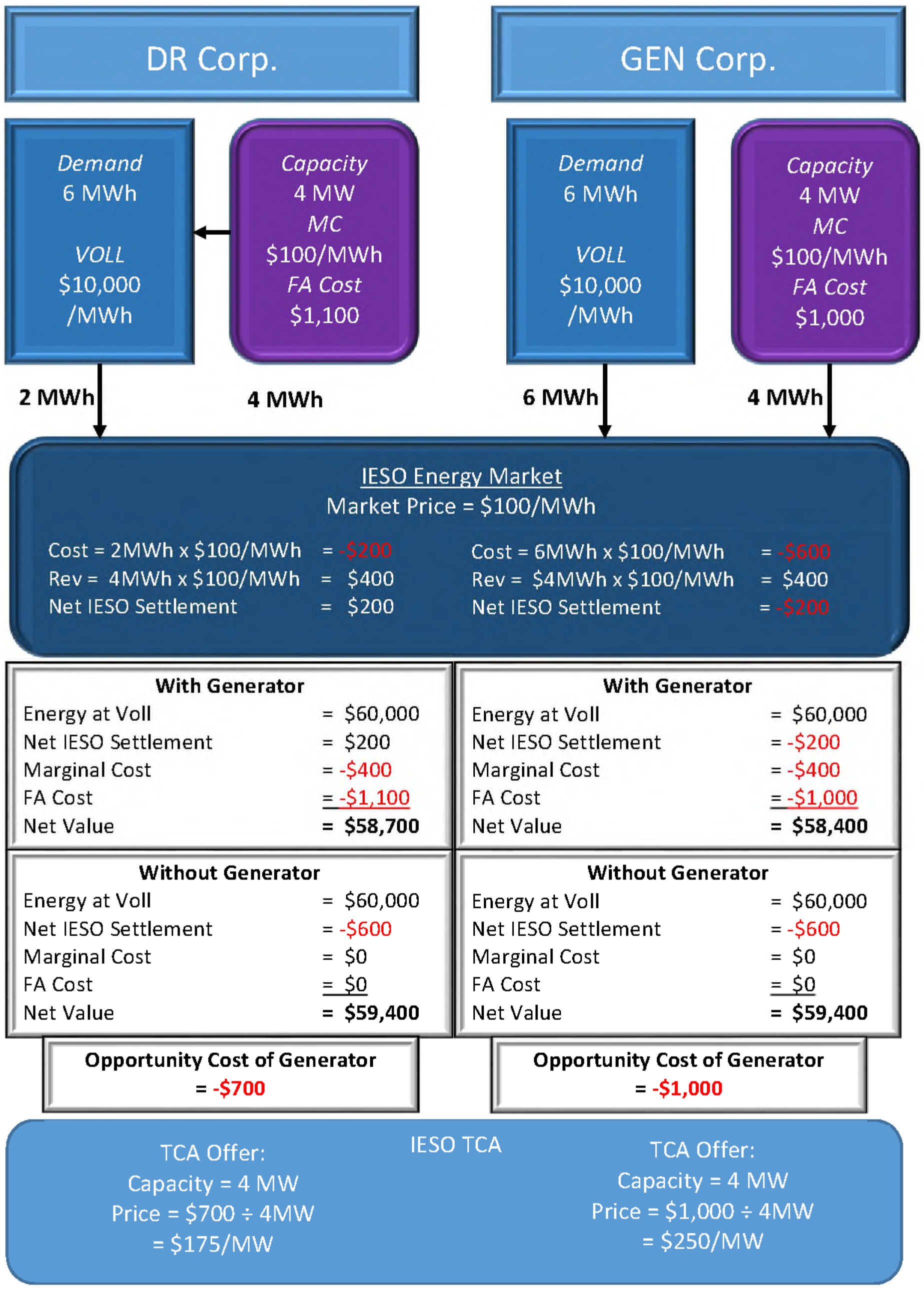


Figure 3: GEN Corp. has a lower marginal generation cost

Figure 3.A: No Energy Payments for DR Resources

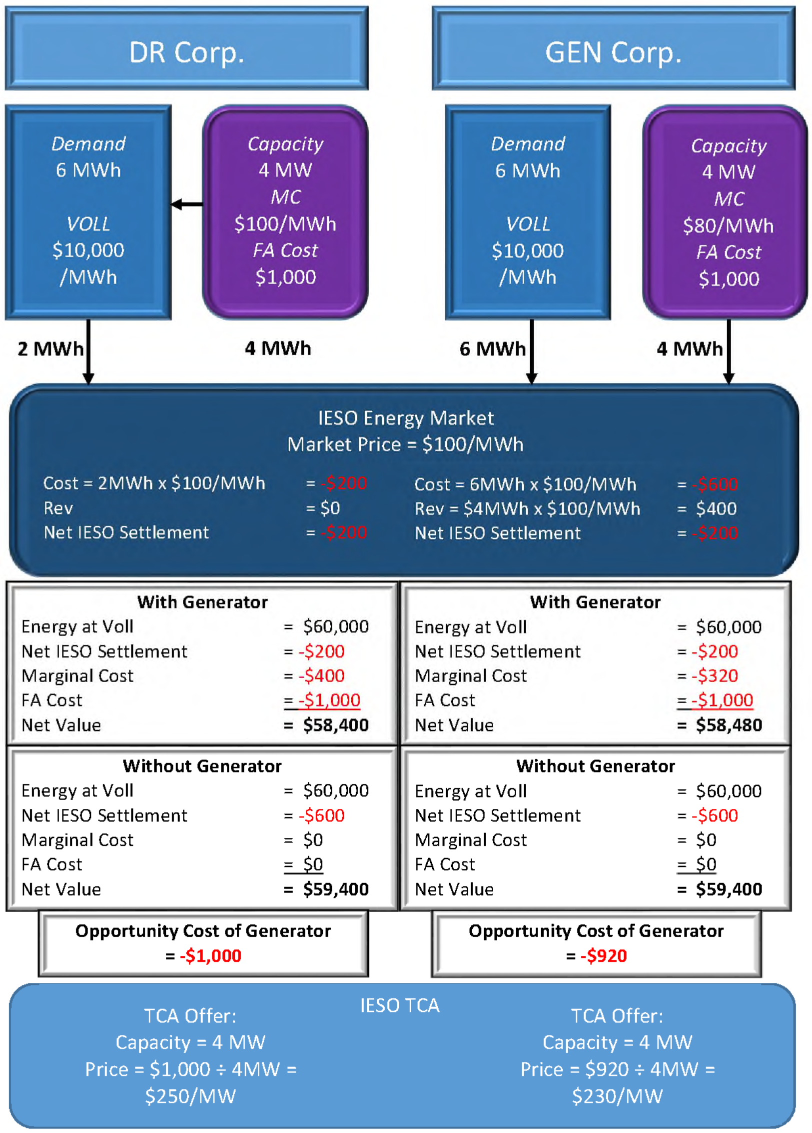
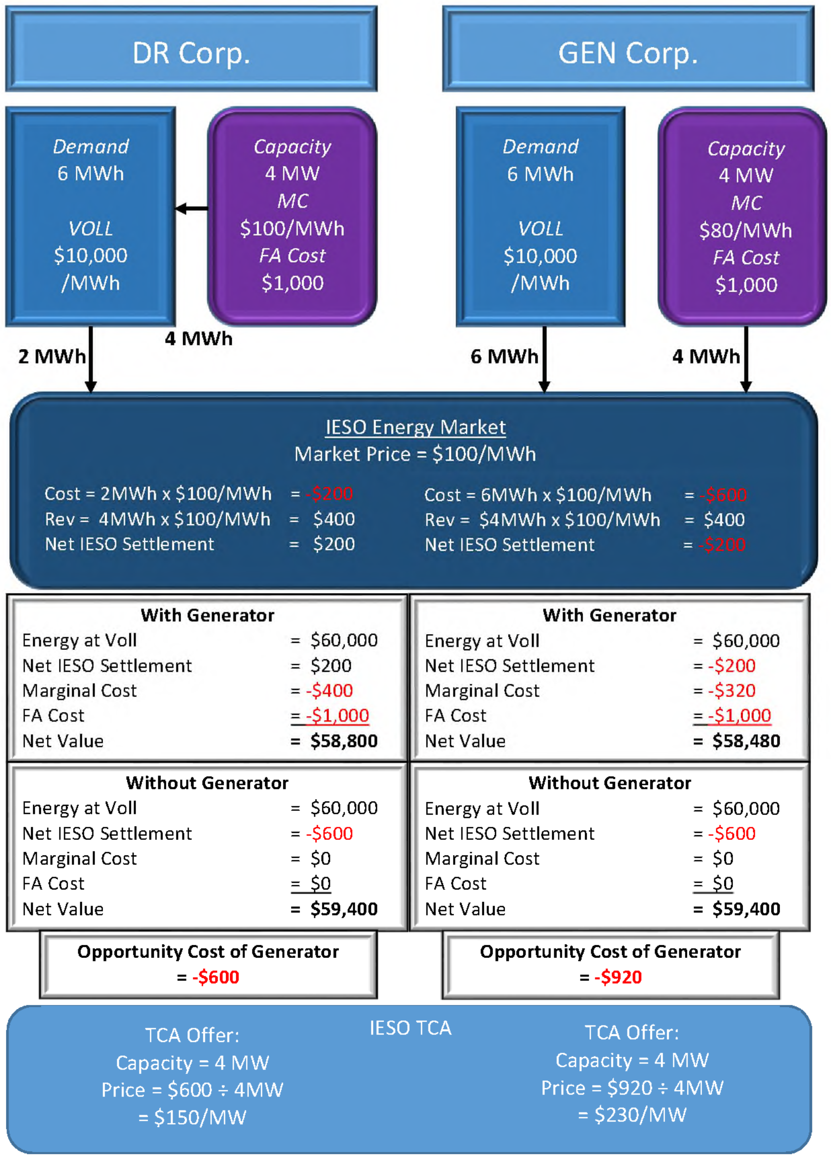


Figure 3.B: Energy Payments for DR Resources



46. In Figure 3, I modify the original example by assuming GEN Corp. has a marginal generation cost of $80/MWh, which is lower than the $100/MWh marginal generation cost of DR Corp. In this case, GEN Corp earns a net revenue equal to the difference between the energy market price of $100/MWh and its marginal generation cost of $80/MWh; a benefit of $20/MWh that it can contribute to the recovery of its fixed avoided cost of making the generator available. It can factor this amount into its capacity offer price. Again, I draw a distinction between the net revenue and the full energy

payment; GEN Corp. will factor only the net revenue into its capacity price calculation as this is the only true benefit it receives from the energy market.

47. If DR resources are provided an energy payment for economic activations, Figure 3 illustrates that DR Corp. will submit a lower capacity offer price than GEN Corp. That is, because of the double benefit DR. Corp. receives from activation (a benefit for the energy payment it avoids and a benefit for the energy payment it receives) it has a competitive advantage over GEN Corp. It is also the case that because DR Corp. lowers its energy bid to $50/MWh, (half of its marginal generation cost) it will be dispatched ahead of GEN Corp. for energy. This is not only harmful to fair and efficient competition in the TCA, it leads to the inefficient dispatch of the province's generation resources, which is in conflict with the IESO's least cost dispatch objective.

B.13 Q: In your examples, you did not consider the effects of the Global Adjustment. How does the Global Adjustment affect your conclusions?

48. The manner in which consumers are charged the Global Adjustment will also provide certain DR resources a competitive advantage in the TCA over non-committed dispatchable generators, even if DR resources are not provided energy payments for an economic activation as per the Amendments.

49. The Global Adjustment is an accounting mechanism through which the fixed costs to build and maintain generation assets in the province and to deliver Ontario's conservation programs are recovered from Ontario electricity consumers. It is, at a high level, calculated as the differences between payments made to generators at the wholesale market price and payments made through regulation or contract that differ from the market price. The Global Adjustment was established in 2005 as a means to attract private investment in new generation capacity and to offer Ontario consumers price stability. The Global Adjustment has become the largest component of an average consumer's electricity cost, representing between 45 to 60 percent of a typical electricity bill. Attached hereto as **Exhibit "D"** is a copy of a policy brief I authored on this subject.

50. The Industrial Conservation Initiative ("ICI") is a government policy that defines how the costs in the Global Adjustment are allocated to different classes of consumers. Large consumers, known as Class A consumers, are charged global adjustment on the basis of their share of the total system demand during the highest five peak hours of the year. Class A consumers include consumers with an average monthly peak demand greater than 1 MW and consumers in certain manufacturing and industrial sectors, including greenhouses with an average monthly demand greater than 500 kilowatts (kW). Smaller consumers, known as Class B consumers, pay Global Adjustment as a monthly fee based on the kilowatt-hours of electricity they consume in the month, or as part of their regulated time of use prices. I understand that most AMPCO members qualify as a Class A consumer.

51. The Board's Market Surveillance Panel has shown that the ICI provides Class A consumers with an extreme price incentive to reduce their demand in the expected system peak demand hours to avoid paying the Global Adjustment. This will provide DR resources that are Class A consumers a competitive advantage over non-committed dispatchable generators in the new TCA. I demonstrate this in Figure 4. Attached hereto as **Exhibit "E"** is the Market Surveillance Panel's Report.

52. Figure 4 assumes the same characters for DR Corp. and GEN Corp. as Figure 1, except it also considers the effects of the incentives provided by the ICI. Both DR Corp. and GEN Corp. qualify as a Class A consumer. Assume that both companies anticipate the Global Adjustment charge to be $5,000/MWh. The Global Adjustment is charged based on the metered quantity consumed at the level of the IESO (i.e., based on metered quantities at the transmission level). As a result, DR Corp. can avoid Global Adjustment charges by self-suppling its demand and reducing its net-metered quantity with the IESO to 2MWh. GEN Corp. cannot avoid Global Adjustment by generating. As Figure 4.A demonstrates, even if DR resources are not provided an energy payment for economic activations, DR Corp. has an extreme incentive to generate electricity to avoid $5,000 x 4MWh = $20,000 in Global Adjustment charges. This decreases the opportunity cost of not incurring the fixed avoided cost to maintain the availability of its generator by

$20,000. DR Corp. is clearly better off by maintaining the availability of its generator; it will do so even if it does not earn an availability payment through the TCA. DR Corp. can offer a capacity price of $0/MWh in the TCA. In effect, the ICI rewards DR resources that are also Class A consumers by compensating them twice for making their generator available; once through the avoidance of the Global Adjustment (which recovers the capacity cost of the committed generator) and once through the availability payment. As Figure 1.B demonstrates, paying DR resources an energy payment for an economic activation would only further DR Corp.'s competitive advantage over the non-committed generator of GEN. Corp.

Figure 4: Effects of the Global Adjustment

Figure 4.A: No Energy Payments for DR Resources

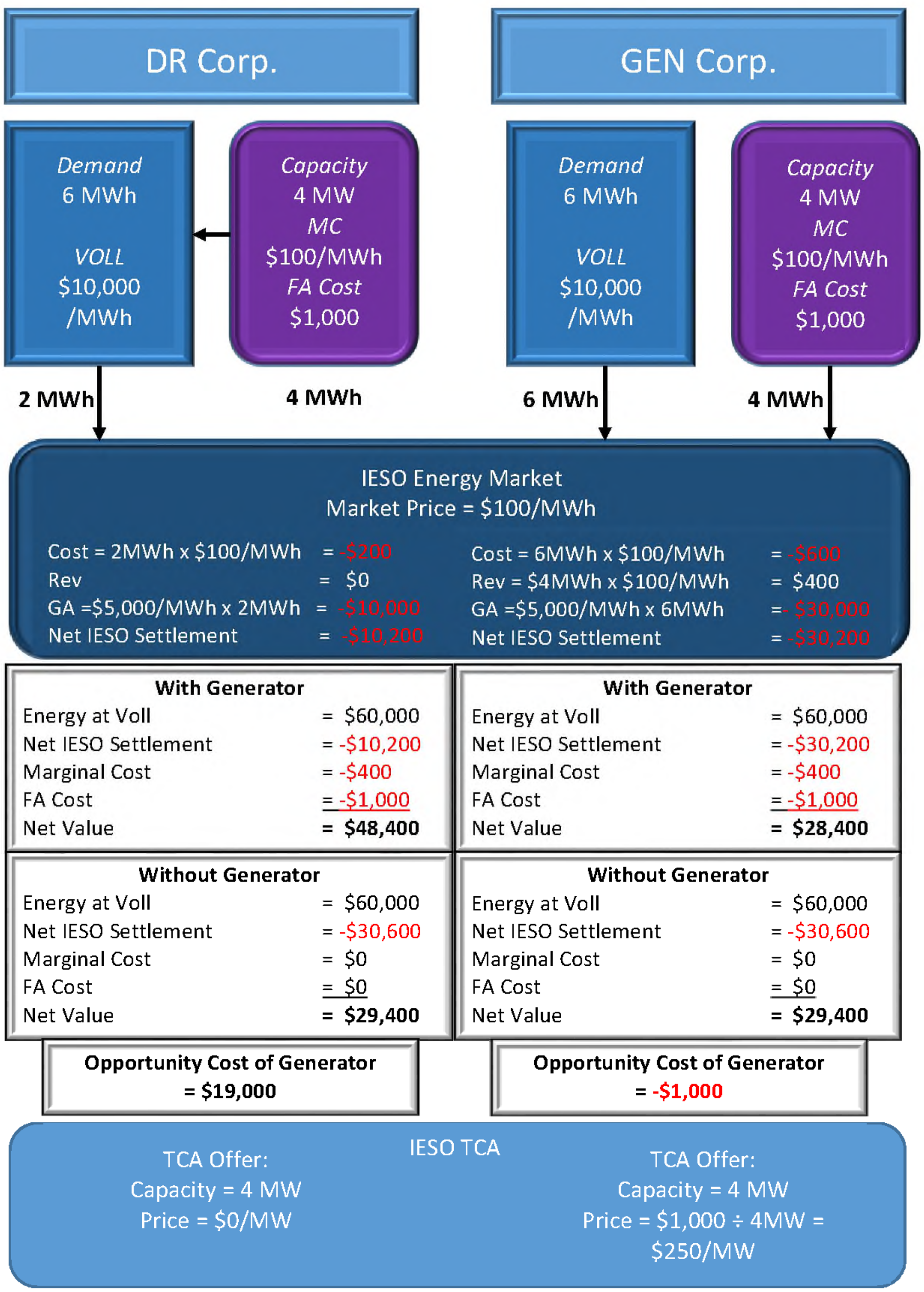
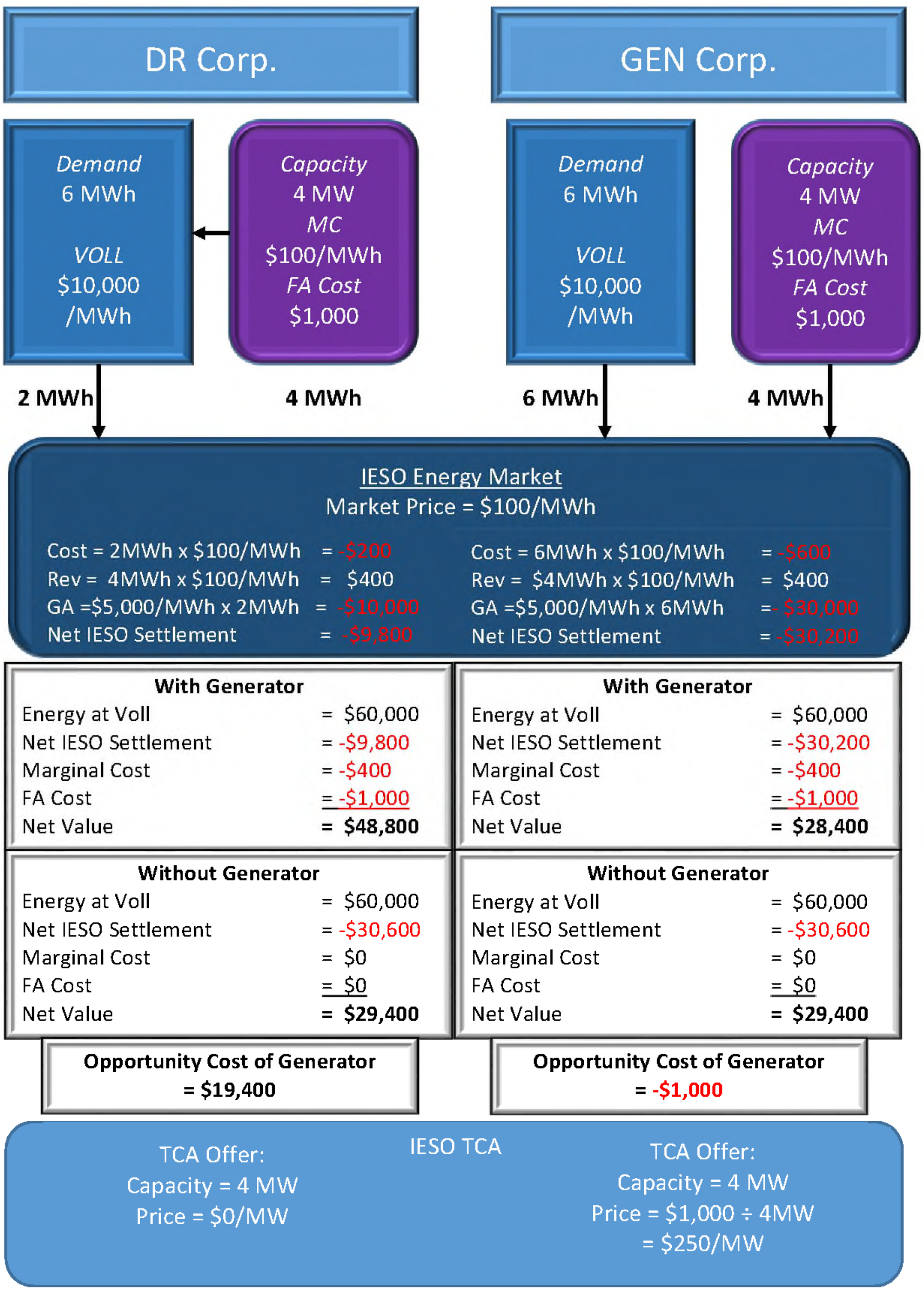


Figure 4.B: Energy Payments for DR Resources



C. APPLICATION OF FERC ORDER NO. 745 IN ONTARIO WILL NOT ACHIEVE THE COMMISSION'S INTENDED EFFECTS

C.1 Q: Can you briefly describe the conclusions of FERC Order No. 745

53. Yes. FERC Order No. 745 addressed the issue of compensation of DR resources in Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") organized wholesale energy markets in the United States.[18] The Commission concluded that when a DR resource satisfies two conditions, it "must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP)."[19] ***First,*** the DR resource must have the capability to provide the service, which is described as displacing a generation resource in a manner that serves to balance supply and demand. ***Second***, the payment of the market price to the DR resource for the provision of the service must be "cost-effective" as determined by a "net-benefits test."

C.2 Q: What was the basis for the Commissions' conclusion?

54. The key objective of FERC Order No. 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets."[20] FERC Order

[18] FERC Order No. 745 at para. 9 focused on "customers or aggregators of retail customers providing, through bids or self-schedules, demand response that acts as a resource in organized wholesale energy markets".

[19] *Ibid* at para. 2.

[20] *Ibid* at para. 5. The Commission states this objective is "consistent with national policy requiring facilitation of demand response." It references Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005):

> "f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying

No. 745 was promulgated on the premise that "active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets."[21] Ensuring the competitiveness of organized wholesale energy markets is "integral to the Commission fulfilling its statutory mandate" and to ensuring "just, reasonable, and not unduly discriminatory or preferential rates."[22] The Commission observed that prior to the Order, "the level of compensation for demand response" varied from market to market, and that "some existing, inadequate compensation structures hindered the development and use of demand response." The Commission acknowledged that customers "must have confidence that appropriate price signals will be sustained by stable competitive pricing structures, before they will make an investment in demand response." Attached hereto as **Exhibit "F"** is a copy of the Commission's Notice of Proposed Rule Making in which these observations were made.

C.3 Q: Did the Commission elaborate on the types of barriers to DR resources that it was concerned with, and how FERC Order No. 745 would eliminate those barriers?

55. The Commission reasoned that "[d]ue to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries."[23] The Commission cited as barriers:

> "the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow

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such technology and devices, but who are part of the same regional electricity entity, shall be recognized."

[21] *Ibid* at para. 9.

[22] *Ibid* at para. 8.

[23] *Ibid* at para. 57.

> electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change."

The Commission concluded, "paying LMP can address the identified barriers to potential demand response providers."[24]

C.4 Q: You indicated that for DR resources to be eligible for compensation it must be cost-effective as determined by the FERC net benefits test. Can you explain this test?

56. Yes. The Commission recognized that paying DR resources the market price to curtail demand would have two effects. First, paying DR resources the market price would encourage more participation of these resources in the energy market. Their participation would involve an energy bid in the wholesale market. Additional energy bids in the market would lead to a lower wholesale energy price whenever a DR resource's bid was selected in the energy market ahead of a generator offer. All other consumers (non-DR consumers) would realize a benefit from the lower price. Second, these non-DR consumers would have to make an additional payment to the DR resource equal to the market price times the amount of demand curtailed. The net benefits test is satisfied when the savings the non-DR consumers realize from the lower wholesale price are greater than the additional payment they must make to DR resource. FERC Order No. 745 refers to this as the "the billing unit effect of dispatching demand response."[25] In this sense, paying DR resources is deemed cost effective if it leads to lower bills for all non-DR consumers.

C.5 Q: Is this how an economist would define "cost-effective"?

57. No. As many commentators noted in the FERC proceeding, in economics, an outcome would be defined as cost-effective if it leads to society making the best use of its

[24] *Ibid* at para. 58.

[25] *Ibid* at para. 3.

available resources. Economist call this an allocatively efficient outcome. An allocatively efficient outcome maximizes the benefits to all participants. This is sometimes called "total surplus" which is equal to the sum of consumers' surplus (the difference between what they are willing to pay and the price they pay) and producers' surplus (the difference between the price they receive and avoided variable cost). The IESO's dispatch model seeks to maximize allocative efficiency or total surplus. The net benefits test seeks to maximize the benefit to non-DR participants, or non-DR consumers' surplus and comes at the expense of producers' surplus. Promoting efficiency is also a purpose of the *Electricity Act, 1998*.

C.6 Q: Do you see any implications for the IESO or Ontario consumers if the IESO were required to apply a net benefits test in order to pay DR resources the market-clearing price?

58. Yes. If the intent of the FERC net benefit test is to compensate DR resources only when it results in a reduction in the bills of non-DR consumers (non-DR consumers' surplus), then the IESO would have to take into account the effect of the Global Adjustment in this calculation. This has two implications for the IESO and Ontario consumers. First, it means that (all else held constant) the net benefits test will be satisfied less frequently (if ever) than in the United States markets.[26] Second, it adds additional complications for the IESO in implementing the test that the United States RTO/ISOs did not have to encounter. Furthermore, as several commenters noted in the FERC proceeding, "cost-effective" as defined by the net benefits test, and "allocative efficiency" are different things. An additional implication of Ontario implementing the net benefit test is that it could, if ever satisfied, contribute to a less efficient dispatch of resources and less efficient use of the province's generation resources. This is a point I already established above.

[26] This same point was recognized in Section 3.2 of the "Navigant Report".

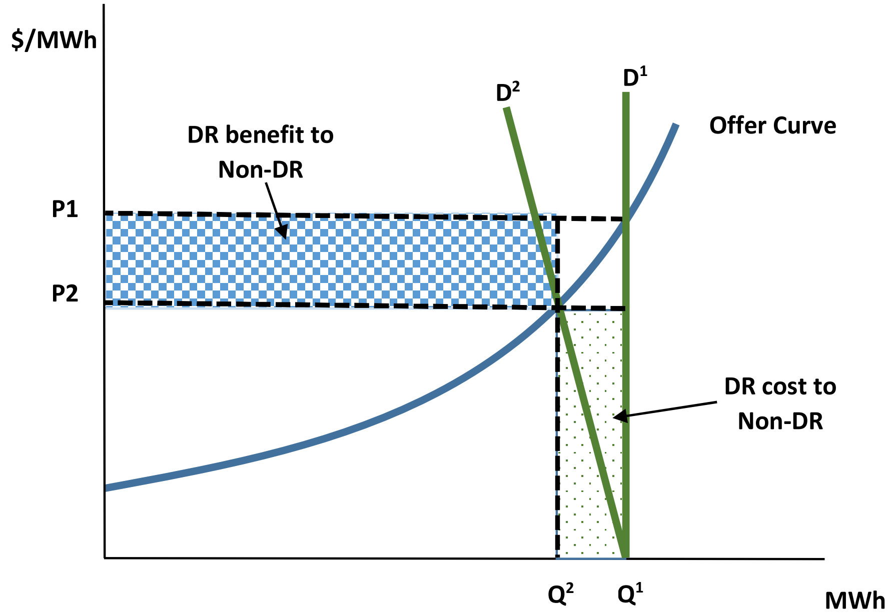
C.7 Q: Can you explain why the Global Adjustment means the net benefits test is not likely to be satisfied on Ontario?

59. Yes. This can be explained with reference to Figure 5. In Figure 5, an hourly offer curve and an hourly demand curve (labeled D^1) are drawn. The demand curve D^1 is drawn under the assumption that DR resources are not provided an energy payment for an economic activation. The market-clearing price is determined as the intersection of the hourly offer curve and the hourly demand curve, which is P^1 in Figure 5. This illustration is based on a figure contained in the Californian ISO's final proposal for implementation of FERC Order No. 745, which is attached hereto as **Exhibit "G".**

60. Paying a DR resource the market-clearing price for an economic activation changes the DR resource's incentives for participation in the market. This was the desired effect of the Commission in FERC Order No. 745. As I outlined above, in the Ontario context, if a DR resource is paid the market price for an economic activation, it will be incentivized to submit a lower energy bid price.[27] This causes the demand curve to become more "elastic" and shift downward. This is represented by the new hourly demand curve D^2 in Figure 5. The lower DR resources' energy bids mean that the market clears at the lower price of P^2.

[27] This point was discussed in the "IESO March 1 Presentation" at 5.

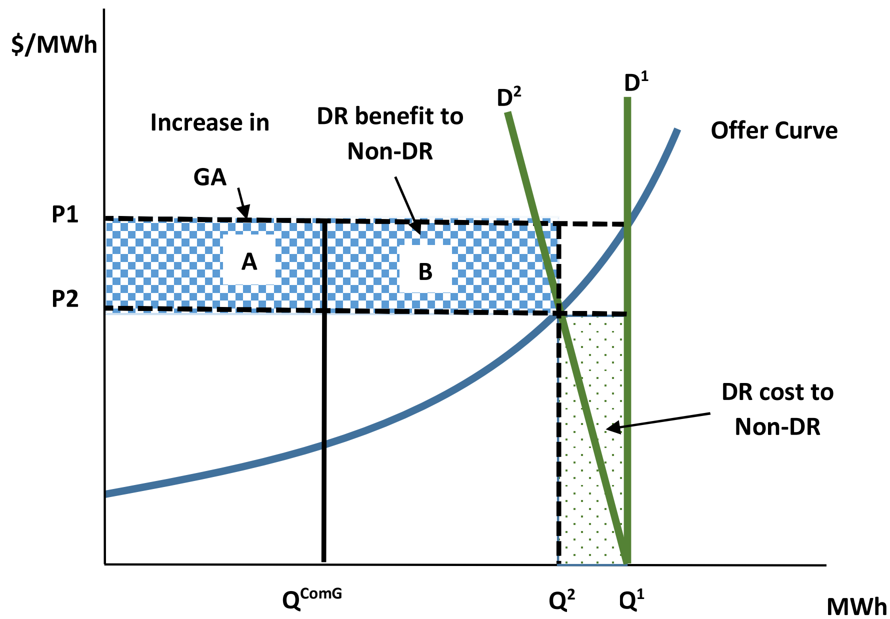
Figure 5: The Net Benefits Test under FERC Order No. 745



61. The FERC net benefits test is satisfied if the savings the non-DR consumers realize from the lower wholesale price are greater than the additional payment they must make to DR resources. Under the FERC model, this occurs when the shaded blue area is greater than the shaded green area in Figure 5.

62. If the net benefits test were applied to Ontario, the IESO would have to incorporate the effects of payments made to contracted and regulated ("committed") generators by non-DR consumers through the Global Adjustment. As discussed above, the Global Adjustment includes differences between payments made to generators at the wholesale market price and payments made through regulation or contract that differ from the market price. If providing DR resources an energy payment for economic activations lowers the market-clearing price as the Commission expected in FERC Order No. 745, in Ontario, a portion of the benefit non-DR resources get from the lower energy price will be offset by an increase in the payments the same consumers have to make to committed generators through the Global Adjustment. This means that all else held constant, the net benefits test condition for compensating DR resources will be satisfied less often in Ontario than in the United States. This is illustrated in Figure 6.

Figure 6: The Net Benefits Test illustrated for Ontario



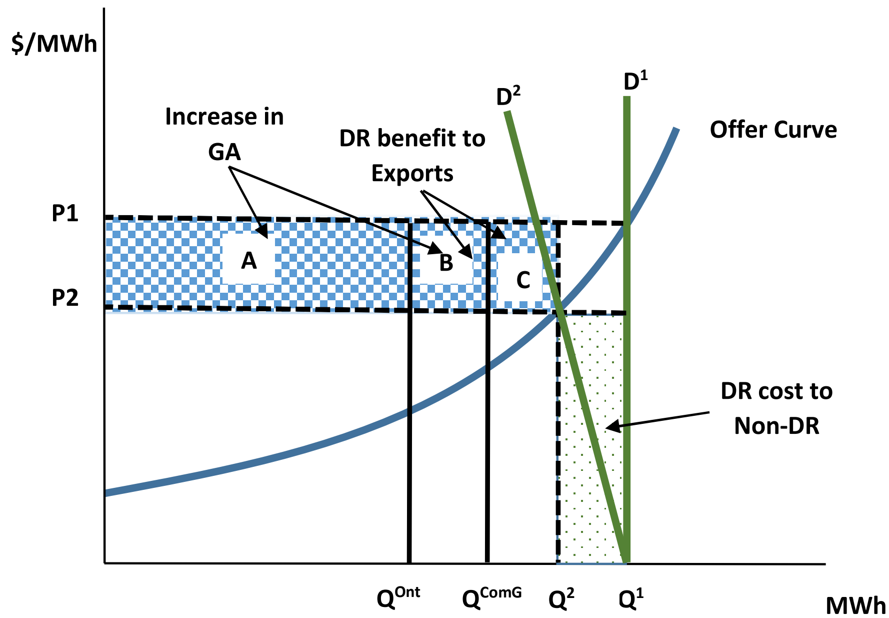
63. In Figure 6, the amount of supply provided by committed generators is Q^{COMG}. When lower energy bid prices of DR resources cause the energy market price to fall from P^1 to P^2, the amount of net revenues earned by the committed generators falls in proportion to the price decrease (the area marked as A in Figure 6). The decline in net revenue is fully offset by higher payments to the committed generators as per their contract terms or regulated rates. Non-DR consumers cover these higher payments through higher Global Adjustment charges. As a result, the benefit that non-DR consumers receive from the lower energy price is reduced by the amount A; they realize the smaller benefit represented by area B. Since the net benefit is smaller in Ontario, it is less likely that the net benefits test condition will be satisfied in Ontario.

C.8 Q: Are there conditions in Ontario in which the net benefits test is certain to fail?

64. Yes. Ontario is a large net exporter. Exporters do not pay the Global Adjustment. In many hours, committed generators are required to produce to meet both the Ontario demand and the export demand. When the amount of energy provided by committed

generators exceeds the Ontario demand, energy price decreases caused by lower DR resource energy bids would lead to an increase in Ontario non-DR consumers' Global Adjustment charges that exceeds benefits they realize from lower energy market prices. That is, exports would realize the benefit of the lower market prices, but because Ontario consumers must cover the higher Global Adjustment charges, they would be worse off, even before paying DR resources not to consume. This is illustrated in Figure 7.

Figure 7: Sufficient condition for Net Benefits Test failure in Ontario,



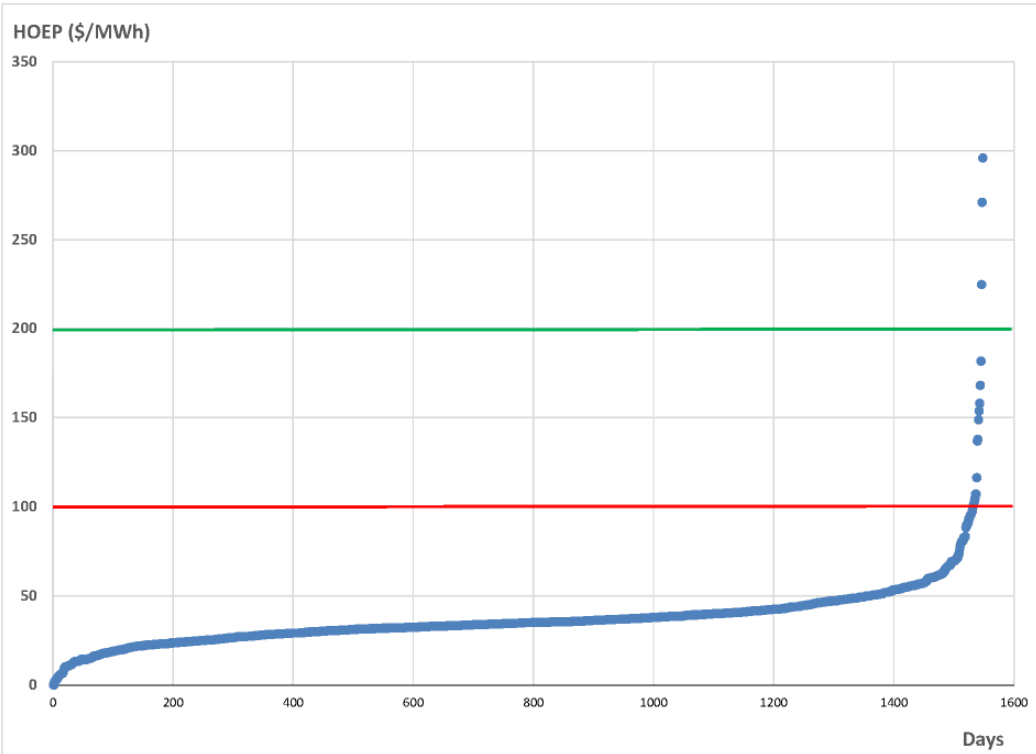
65. In Figure 7, the Ontario non-DR consumers' demand is Q^{ONT}. The difference between Q^2 and Q^{ONT} is export demand. The amount of energy produced by committed generators is Q^{COMG}, which is greater than the Ontario non-DR consumers' demand. The benefit that non-DR consumers realize from the energy price reduction is represented by the area A. However, the amount of Global Adjustment that these consumers will have to pay increases by the area A + B. Ontario non-DR consumers are made strictly worse off by compensating DR resource for economic activations. They are made worse off even before accounting for the amount they have to pay to DR resources for economic activations (the green shaded area).

C.9 Q: Have you done any analysis that could provide the OEB some guidance on the likelihood that the net benefits test would be satisfied in Ontario?

66. Yes. The IESO provided me with hourly data for the period January 1, 2018 to October 28, 2019 which is attached hereto as **Exhibit "H"**. The data included hourly HOEP and hourly quantities of Ontario non-dispatchable demand, Ontario dispatchable load demand, committed generation output, non-committed generation output, exports and imports for a total of 15,984 hours. I calculated the number of hours when output from committed generators exceeded Ontario non-dispatchable demand plus dispatchable load demand (the sufficient condition for the net benefits test to fail in Ontario). There were 14,436 hours out of 15,984 hours (90.3% of hours) in which the output of committed generators exceeded the Ontario demand between January 1, 2018 and October 28, 2019. The net benefits test would have failed in these hours.

67. In the remaining 1,548 hours (9.7% or hours) when Ontario demand was greater than the output of committed generators, I considered the likelihood that compensating DR resources for economic activations would lead to sufficient reductions in DR resources' energy bid prices to cause a decrease in the energy market price. If DR resource energy bid prices remain relatively high, then it is not likely a price decrease could occur and hence a net benefit to non-DR consumers is not possible. Figure 8 provides some insights in the number of hours that this might be possible. Figure 8 ranks the 1,548 hours between January 1, 2018 to October 28, 2019, in which Ontario demand exceeded committed generation output, from lowest HOEP to highest HOEP.

Figure 8: HOEP in hours with Ontario demand greater than committed generation Output, January 1, 2018 to October 28, 2019



68. First, DR resources must submit energy bid prices that are greater than $100/MWh. Compensating DR resources for economic activations could not have a net benefit in hours when the HOEP was less than $100/MWh because DR resource energy bid reductions could not fall below this price level. HOEP exceeded $100/MWh in only 17 of the 1,548 hours (0.106% of all hours in the data set).

69. IESO analysis found in a presentation to the Demand Response Working Group indicated the following:

> The historical contracting programs required DR energy bids to be priced at $200/MWh. Once the $200 price requirement was removed for HDR resources, the IESO observed that the majority of DR bids were priced by participants much higher than $200/MWh. This implies DR

participant's value of energy consumption is much higher than this level.[28]

70. If we consider prices above $200/MWh as the benchmark for a possible price effect, there were only 3 of the 1,548 hours (0.019% of the total hours in the data set) in which the HOEP exceed this benchmark.

71. Overall, recent historical data suggest that the net benefits test would rarely, if ever, be satisfied in Ontario (0.019% of the time).

C.10 Q: You also said that there would be additional complications for the IESO to implement the FERC net benefits test. What are the additional complications?

72. FERC Order No. 745 required the RTO/ISO's "to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[29] Essentially, the ISO and RTOs are required to use historic offer data, adjusted to reflect resource availability and fuel costs, to create a representative aggregated supply curve for a trade month.[30] This representative curve is used to determine "the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[31] The ISO and RTOs must post this threshold price on their website and update it on a monthly basis.

73. As discussed above, the IESO will require additional information to implement the net benefits test in Ontario. They will require a forecast of Ontario non-DR load, the production of committed generation and the amount of net exports. Realistically, these values will change often during the month, which makes the use of a representative

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[28] "IESO March 1 Presentation" at 7.

[29] FERC Order No. 745 at para. 4.

[30] This is described in Exhibit "G".

[31] FERC Order No. 745 at para. 4.

supply stack and a monthly price test less practical. Furthermore, applying a blunt monthly test is more likely to lead to false positives and harm to Ontario consumers given the unique conditions and relative infrequency in which the net benefits test is likely to be satisfied. The IESO would likely have to identify improvements to the way the nets benefits test is implemented in Ontario compared to the United States to limit false positives.

C.11 Q: Do you think there are any other aspects of the Ontario market that should inform a decision of whether or not to apply FERC Order No. 745 in Ontario?

74. Yes. As I outlined above, the key objective of FERC Order No. 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets."[32] The Commission stated in its Notice of Proposed Rule Making that:

> "Despite the benefits of demand response and various efforts by the Commission, ISOs and RTOs to address barriers to and compensation for demand response participation, demand response providers collectively play a small role in wholesale markets. After several years of observing demand response participation in ISO and RTO markets with different, and often evolving, demand response compensation structures, the Commission is concerned that some existing, inadequate compensation structures have hindered the development and use of demand response."[33]

75. FERC Order No. 745 further describes the types of barriers to demand response participation that concerned the Commission. These barriers primarily related to the disconnect that existed at the time between wholesale and retail prices and the lack of incentives this created for the investment in the capability to be price responsive.[34]

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[32] *Ibid* at 113.

[33] Exhibit "F" at para. 9.

[34] FERC Order No. 745. This was a point made by Commissioner Moeller on his dissenting opinion: "the lack of dynamic prices at the retail level is the primary barrier to demand response participation."

FERC Order No. 745 sought to remedy these barriers by providing DR resources additional compensation.[35]

76. However, the types of barriers to demand response the Commission was concerned with at the time of FERC Order No. 745 do not seem relevant to present day Ontario. First, as Navigant noted in a report prepared for the IESO:

> "It is important to note that Ontario is different from many U.S. jurisdiction in that many of the DR resources are wholesale market participants or large customers that are exposed to real-time electricity prices as opposed to retail prices. This means that Ontario DR customers avoid the entire real-time electricity price when curtailing and are exposed to high price spikes. When DR providers are only exposed to retail rates as they are in many U.S. jurisdictions, they are unlikely to have the same avoided cost benefit when curtailing during spikes in prices."[36]

77. Second, Ontario has already done a great deal to help DR resources recover the costs of investments needed to enable their participation in wholesale markets. As early as 2007, the IESO (formerly the OPA) recognized the capacity value of DR resources and implemented the DR3 program. The DR3 program procured DR resources through multi-year standard offer contracts that paid DR resources both an availability payment and a utilization payment. The proceeds of the availability payment could contribute in the investment in meters and control systems that would enable price responsiveness. It

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[35] *Ibid.* Commissioner Moeller in his dissenting opinion challenged the majority on this point. Commissioner Moeller stated in his dissent:

> "The Rule [FERC Order No. 745] finds that "greater uniformity in compensating demand response resources" is required and as justification for its action, references the existence of various barriers that limit the participation of demand response in the energy markets. The majority ultimately concludes that these barriers can be removed by better equipping demand response providers with the financial resources to invest in enabling technologies. This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand resources."

[36] "Navigant Report".

also helped fund investments made by load aggregators to sign-up and compensate consumers that could reduce demand upon an activation from the IESO. In 2015, the former OPA DR3 program was integrated into the IESO-administered market through a program called capacity backed demand response and through the DRA. This provided further learning for the IESO and DR resources on how demand response could respond to economic activations. DR resources were provided availability payments for providing the capacity service, which again could be used to fund investments in the technologies needed to enable demand response. These availability payments were made during a time when Ontario had more than enough capacity to meet its obligations. This means Ontario consumers paid to help remove the barriers to demand response when it did not need the capacity. Arguably, as evidenced by the number of DR resources that now participate in the DRA, Ontario has been successful in removing the types of barriers to demand response participation in the wholesale market that were the focus of FERC Order 745.

78. Third, the ICI has been very effective at stimulating demand response during peak demand periods. The Market Surveillance Panel estimates that "ICI participants reduced their consumption by 42% during peak demand conditions in 2016."[37] They do so to reduce the amount of Global Adjustment that they pay. The Panel "estimates that by reducing consumption by one megawatt during each of the five peak demand hours in 2016, a Class A consumer would have saved approximately $520,000 in Global Adjustment charges."[38] The benefit from reducing peak hour consumption are so significant, it "creates an incentive for Class A consumers to invest in new generating or storage capacity located at their facilities."[39]

[37] Exhibit "E" at 2.

[38] *Ibid* at 8.

[39] *Ibid* at 16.

C.12 Q: Are you aware of any research that demonstrates the effect that FERC Order No. 745 has had on the United States wholesale markets?

79. Yes, in the short time that I had to prepare this testimony, I conducted a non-exhaustive scan of the academic literature and reports prepared by the RTOs, ISOs and their market monitors for empirical evidence on the effects and implications of the implementation of FERC Order No. 745. I was surprised to find only a few reports or academic papers on the topic.

80. Monitoring Analytics LLC, the market monitor for PJM, prepare quarterly and annual reports on the PJM market. They dedicate a section in the reports specifically to demand response. Attached hereto as **Exhibit "I"** and **Exhibit "J"**, are the 2015 and 2019 Quarterly State of the Market Reports. The 2015 report states that FERC Order No. 745 "increased incentives to participate" in the PJM economic demand response program.[40] Figure 6-2 shows a sudden increase in both credits paid to economic demand response and economic MWh reductions starting in April 2012, when PJM implemented the Order No. 745. The 2019 report includes the same Figure 6-2, which shows the elevated levels of credits, and MWh reductions largely continued through 2019 and then subsided, although they are still above the April 2012 levels.[41]

81. The reports also provide the monthly net benefits test threshold prices. Threshold prices have never exceeded $34.07/MWh since April 2012 when PJM implemented Order No. 745.[42]

82. Steve Dahlke and Matt Prorok published a paper in the Energy Journal in 2019 that estimated the consumer savings, CO_2 emission reductions, and price effects that *could* be achieved in the MISO electricity market through the removal of regulatory and market rule barriers to market-based deployment of DR. This paper is attached hereto as **Exhibit "K"**. They argue that even after implementation of FERC Order No. 745,

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[40] Exhibit "I" at 213.

[41] Exhibit "J" at 297.

[42] *Ibid* at 300.

there continue to be barriers to DR participation in MISO and that considerable consumer savings and CO_2 emissions could be realized through the removal of the barriers. Through their analysis, they uncover a shortcoming of the FERC net benefits test. They note that DR resources that reduce their consumption in a peak hour because of an economic activation often shift their consumption to future off-peak hours. The shift in consumption increases the price in the future hours and reduces some of the benefits to non-DR resources. That is, "deploying demand response resources that pass the net benefits test in the hour they were deployed actually increased overall costs after taking into account the off-peak increase of energy."[43]

83. Kai Van Horn et al, published a paper in the Electricity Journal in October 2013 that also identified shortcomings in the net benefits test and proposed improvements to the test. This paper is attached hereto as **Exhibit "L"**. Van Horn et al, argue the failure of the net benefits tests "to integrated the impacts of transmission is a significant limitation that has unintended consequences for the total benefits which DR resources may bring to the system and for the distribution of those benefits among the buyers in the system."[44]

84. Xu Chen and Andrew N. Kleit published a paper in the Energy Journal in 2016 (attached hereto as **Exhibit "M"**) that provided empirical result to show how incentive-based DR programs can be "manipulated" to inflate customer baseline load measurement. They suggest, "policy makers in FERC, RTOs and states regulatory agencies consider the threat of manipulation when modifying DR market rules following the Supreme Court's recent upholding of the FERC Order 745."[45]

85. Finally, David Brown and David Sappington published a paper in the Journal of Regulatory Economics in 2016 that derives an optimal DR policy and uses the optimal

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[43] Exhibit "K" at 258.

[44] Exhibit "L" at 152.

[45] Exhibit "M" at 201.

policy to estimate the welfare losses that can arise under FERC Order No. 745. This paper is attached hereto as **Exhibit "N"**. They show that the implementation of Order No. 745 overcompensates DR resources and "reduces welfare well below the level secured by the optimal DR policy."[46] They argue that the policy offered by the critiques to FERC Order No. 745, to compensate DR resources the difference between LMP and the retail rate provided higher welfare than compensation at full LMP as per the FERC Order No. 745.

D. SUMMARY CONCLUSIONS

D.1 Q: Can you summarize for the Board the key findings of evidence?

86. Yes. The evidence in my testimony demonstrates the following.

87. First, the Amendments provide an equitable treatment of TCA participants. Horizontal equity requires that like people be treated alike. I show by way of example, that two identical companies, which differ only by the arbitrary placement of their meters, are treated exactly alike under the Amendment; *horizontal equity*. I then show that compensating DR resources for an economic activation provides preferential treatment to the company that operates a behind-the meter generator; *horizontal inequity*. The company that operates the behind-the-meter generator, DR Corp. is provided preferential treatment because it benefits twice when it reduces its net-demand with the IESO: first, it reduces the energy payment it makes to the IESO, and second, it receives a payment from the IESO for doing so.

88. In my opinion, applying the horizontal equity test is a more accurate way of assessing equitable treatment, than a test of functional equivalence in service provided, which is the test I understand AMPCO has asked the Board to rely on in this matter. As my example demonstrates, both DR Corp. and Gen Corp. are functionally equivalent in terms of their capability of balancing supply and demand on the IESO controlled grid;

[46] Exhibit "N" at 265.

one by reducing demand and one for producing electricity. Doing so fails to recognize that DR Corp. is effectively compensated twice for reducing demand while GEN Corp. receives no net benefit for producing electricity (i.e., it earns zero net revenue). I argue that when designing fair and efficient electricity markets, it is important to understand the underling incentives of participants.

89. Second, the Amendments do not place DR resources at a competitive disadvantage to non-committed dispatchable generators in the TCA as per AMPCO's assertion. To the contrary, pay DR resources the market price for economic activations would place non-committed-generators at a competitive disadvantage. Through examples, I show that paying DR resources the market price for an economic activation compensates them twice for their demand reduction. This double benefit would allow them to bid lower in the energy market, and offer lower capacity prices in the TCA to the disadvantage of non-committed generators. Furthermore, I demonstrate that DR resources that are Class A consumers already have a competitive advantage over non-committed generators in the TCA since they can avoid paying Global Adjustment as a capacity resource. This later point creates incentives for large-consumers to invest in behind-the-meter generation at a cost greater than the cost to operate and maintain a non-committed generator facility.

90. Third, the Amendment is consistent with the promotion of fair and equitable competition as it provides the proper incentives for DR resources to operate efficiently within the TCA and the IESO's energy market.

91. Fourth, the presence of the Global Adjustment means that the FERC net benefits test will rarely if ever be satisfied in Ontario. Furthermore, there would be significant complications for the IESO to implement the net benefits test in Ontario due to the Global Adjustment. In my opinion, the evidence shows that there is no net benefit to even further studying the merits of the application of the net benefits test in Ontario.

92. Fifth, Ontario has made significant progress towards reducing the types of barriers to DR resources that concerned the Commission at the time of FERC Order No. 745. In

my opinion, providing DR resources energy payments for economic activations is not required to overcome any legitimate barriers to DR resources, to the extent there are any remaining barriers.

93. With this I conclude my testimony.

SWORN before me at the Town of Paris, in the Province of Ontario, this 21st day of November, 2019	)	
A Commissioner for Taking Affidavits	)	**Brian Rivard**

Lauren Theresa Daniel, a Commissioner, etc.,
Province of Ontario, while a Student-at-Law.
Expires April 8, 2022.

TAB 2

Witness Statement of Dr. Brian Rivard

In my examination in chief, I intend, *inter alia*, to respond to two issues raised by Colin Anderson in his witness statement dated November 22, 2019, and further discussed by Mr. Anderson in his subsequent testimony before the Ontario Energy Board on November 25, 2019.

1. **Issue 1:** Does the analysis change when a DR resources does not have behind-the-meter ("BTM") generation?

Response:

The purpose of the examples in my affidavit (as revised November 21, 2019) was to show that the Amendments are consistent with the principle of horizontal equity and by this principle, the Amendments are not discriminatory.

Horizontal equity requires that individuals or corporations that are alike in all relevant respects are treated the same. The examples show how two companies, that are identical in all relevant respects (both demand and supply), and that differ only by the arbitrary placement of a meter, would be compensated the same under the Amendments. This is consistent with horizontal equity. By extension, when the DR resource receives an energy payment (the market price) to curtail demand, the DR resource receives preferable treatment. This is inconsistent with horizontal equity.

Mr. Anderson assumes a different situation in which a DR resource does not have a BTM generator to supply its own demand. This sets up a comparison of two different individuals: a DR resource without a BTM generator to a generator. This comparison requires consideration of the principle of vertical equity, which states that individuals that differ in relevant respects should often be treated differently. The challenge for evaluating what is vertically equitable is in determining a principled basis for the differential treatment. I propose that a constructive way to think about this is to understand what the purpose of the TCA is and hence to evaluate the differential treatment of different participants in the auction against this purpose. The purpose of the TCA as stated in the evidence is to promote or enhance competition and efficiency to the benefit of Ontario consumers.

I offer the following example to show how the Amendments are consistent with the promotion of fair and efficient competition. Attached are Figure 1.A' and 1.B' that illustrate implications on efficiency and competition. The example shows that if a DR resource and a Generation resource each needed to recover a $1,000 fixed avoidable cost in order to be available, the Amendments result in an outcome that is efficient. Both are incented to offer in the capacity auction at a price that just recovers this cost. By this principle, it is vertically equitable.

If instead, DR Resources are paid the market price to reduce demand, then they are incented to lower their bid price to the point where it is indifferent between consuming or being paid not to consume (i.e., $75/MWh). In this scenario, the DR resource forgoes some productive value from consumption, equal to the difference between what it is willing to pay, $150/MWh and the market price it would pay $100/MWh (i.e., $50/MWh) in order to receive a payment of $100/MWh. This would be inefficient from a societal standpoint because the value to society from producing the good ($150/MWh) is greater than cost to society to produce the electricity needed to produce the good ($100/MWh). Paying the DR resource therefore induces inefficiency. Furthermore, it provides the DR resources a competitive advantage in the TCA against a generator that has the same avoidable cost. By this standard, paying DR resources the market price when activated is vertically inequitable.

2. **Issue 2:** Mr. Anderson states:

> Dr. Rivard suggests that providing a DR resource with capacity payments rewards it twice for the same demand reduction if the resource also participates in the Industrial Conservation Initiative (ICI) peak reduction program. Dr. Rivard is mistaken about this. If a DR resource reduces load for the purposes of reducing its peak for ICI calculations, that reduction would by definition be unavailable to the market and the IESO would thus claw back availability payments for the period during which the resource was not available at a 2:1 ratio.

Response:

Mr. Anderson is correct to say that if a DR resource intentionally ignores its obligation under the TCA to benefit from the ICI program, it is subject to a daily Availability Charge for the hours in the day that it was not available to meet its obligation. The Availability Charge is equal to the daily unavailable MWh times the daily availability payment divided by the number of hours in the day the DR resource was obligated to be available. In the peak demand months, this charge is doubled. So, for example, assume the DR resource was obligated to make 1 MW of demand reduction available in 9 hours in a day during a peak month, and the TCA auction provided a daily availability payment of $230/ MW- day (the TCA capacity clearing price). If the DR resource decided that it was in its financial interest to not meet its TCA obligation for the entire day in order to instead benefit from the ICI and avoid the Global Adjustment, it would be subject to an Availability Charge equal to:

Availability Charge = Unavailable MWh x Hourly Availability Payment x Factor of 2

= (1MW x 9hrs) x (($230/MWh – day)/9 hrs) x 2

= $460

However, this does not change the conclusion illustrated in Figure 4 of my affidavit. In all other days, the DR resource would receive an Availability Payment if it makes itself available, that can be used to offset the fixed avoidable cost of being available to reduce system demand. It would have the double incentive to incur the fixed avoided cost because it would allow it to avoid the Global Adjustment charge (which alone covers the $1,000 fixed avoided cost), and it would receive an Availability Payment in all hours that it chose to make itself available. This provides an advantage to the DR resource over the Generation resources, since the Generation resource can only apply the Availability Payment to cover its $1,000 fixed avoided cost.

Figure 1.A': No Energy Payments for DR Resources

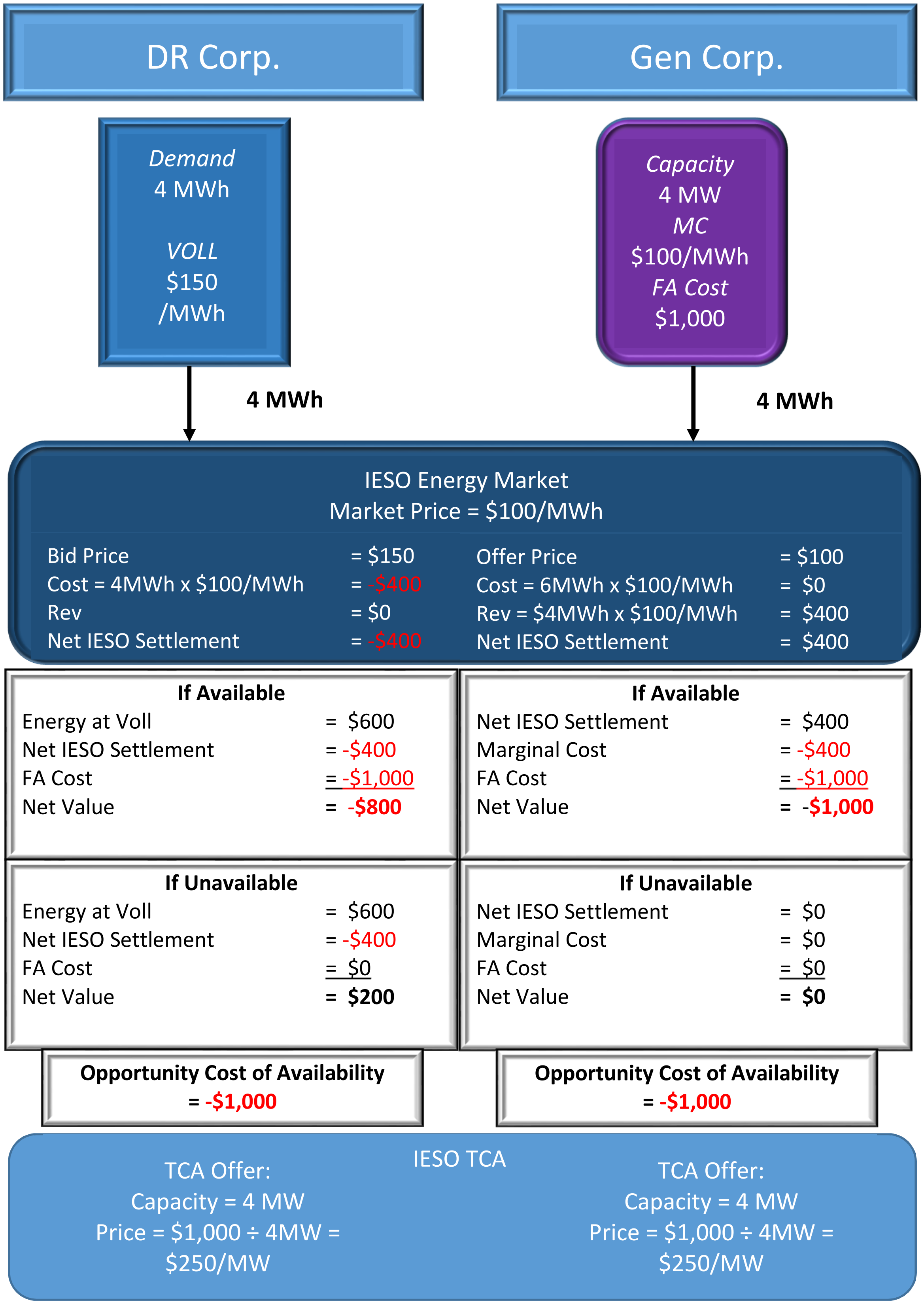

Figure 1.B’: Energy Payments for DR Resources