Association of Major Power Consumers of Ontario

OEB Staff Compendium

Panel 2 – London Economics International

Examination in Chief

EB-2019-0242

November 25, 2019

OEB Staff Compendium for EB-2019-0242 Oral Hearing

Index

TAB 1

FORM A

Proceeding: EB-2019-0242

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is AJ Goulding (*name*). I live at Toronto (*city*), in the province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of OEB staff (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date November 8th, 2019

Signature

FORM A

Proceeding: EB-2019-0242..........

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Adam Hariri ....(*name*). I live at Toronto .... (*city*), in the province .... (*province/state*) of Ontario ....

2. I have been engaged by or on behalf of OEB staff .... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

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Date November 8th, 2019..........

Adam

Signature

TAB 2

Curriculum Vitae

A.J. GOULDING

President, London Economics International LLC

LONDON ECONOMICS

KEY QUALIFICATIONS:

In his role as president of London Economics International LLC, A.J. Goulding manages a growing international consulting firm focused on finance, economic, and strategic consulting to the energy and infrastructure industries. In addition to serving as a sector expert in electricity and gas markets, his responsibilities include project management, marketing, budget and financial control, and recruiting. A.J. also serves as an Adjunct Associate Professor at Columbia University, where he teaches a course on electricity market design and regulatory economics while also supervising graduate workshops.

With over twenty years of experience in evolving electricity and natural gas markets, A.J.'s diverse background enables him to work effectively in both emerging markets and OECD countries. In North America, A.J. has been articulate in describing market relationships between wholesale power marketers, merchant plants, aggregators, and the existing investor owned utilities. In emerging markets, A.J. has considerable experience dealing with the challenges of mixed private and public ownership, difficulties in creating credit-worthy distribution and retail entities, and the realities of line losses, unreliable fuel deliveries, and politicized labor relations.

A.J. began his career performing natural gas market analysis for the ICF Resources subsidiary of ICF Kaiser International. Later, he lived for two years in New Delhi, India, where he advised the United States Agency for International Development (USAID) on electric power sector restructuring in India. He continued his work on India while pursuing his MA at Columbia University, leading to the publication of an article on Indian privatization. Simultaneously, he researched the process of power sector reform in Pakistan, contrasting it with the Indian experience. Upon completion of his MA, A.J. served as business development associate for Citizens Power LLC, a top ten US wholesale power marketer. He then moved to London Economics, where he has held roles of progressively increasing responsibility.

EDUCATION:

Earlham College, Richmond, Indiana, B.A. in Economics, 1991. College honors, scholar-athlete, public service graduate fellowship.

Columbia University, New York, New York, M.A. in International Business, 1997. Foreign Language and Area Studies fellowship, Cordier prize.

EMPLOYMENT RECORD:

From: 1996 **To:** present
Employer: *London Economics International LLC, United States*
President (July 1999 to present), Senior Consultant (January 1998 to July 1999), Summer Associate (June 1996 to August 1996)

From: September 2003 **To:** present
Employer: *Columbia University*
Adjunct Associate Professor (2014 to present), Adjunct Assistant Professor (2003-2014)

From: 1997 **To:** 1997
Employer: *Citizens Power LLC; Boston, MA*
Associate

From: 1994 **To:** 1995
Employer: *USAID; New Delhi, India*
Energy Consultant

From: 1991 **To:** 1993
Employer: *ICF Resources, Inc.; Fairfax, VA*
Analyst

SAMPLE PROJECT EXPERIENCE:

The projects briefly described below are typical of the work A.J. has performed throughout his career at London Economics, Citizens Power, USAID/India, and ICF Resources. A.J. also serves as an adjunct professor at Columbia University, where he teaches a course in electricity market design.

Electricity and Natural Gas Asset Valuation and Transaction Advisory Work

- ***Member of OEB's Advisory Committee on Innovation:*** AJ, as LEI's President, was selected to serve on the Ontario Energy Board ("OEB")'s Advisory Committee on Innovation, to assist the OEB in sharpening its focus on enhancing efficiency, cost effectiveness, innovation and value for electricity customers. The Committee, reporting directly to the Chair of the OEB, focused on identifying actions that a regulator can take that will support and enable cost effective innovation, grid modernization, and consumer choice to help inform regulatory policy development. The Committee's overarching goal was to support the OEB's embarkment on a process that would evaluate whether and how best to adapt regulation in order to keep pace with an evolving sector.

- ***analyzed cost implications of Ontario's Green Energy Act:*** on behalf of the Official Opposition in Ontario, analyzed the cost implications of the government proposed 2009 Green Energy Act. This included costing of the feed in tariff program, interconnection costs, conservation and demand management initiatives and the implementation of the smart grid. The company presented key results in a press conference

- ***led Ontario gas LDC performance-based ratemaking project:*** LEI was engaged by Union Gas to review Union's proposed 2014 to 2018 incentive ratemaking ("IR") plan as presented to stakeholders on April 29th, 2013 and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, Union particularly requested LEI to examine approaches to a set list of ratemaking parameters: productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism ("ESM"), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas ("UFG"), and service quality indicators ("SQIs") and how they are measured. LEI was subsequently requested by Union to provide comments on Union's draft Settlement Agreement

- ***submission to Ontario LTEP consultations regarding value of capacity imports:*** On behalf of a large Canadian hydropower generator, LEI analyzed the potential economic benefits of the export of capacity and energy from Quebec to Ontario. The engagement included a review of the treatment of imports in capacity markets in the Northeast, an examination of the impact on capacity prices of imports, and a discussion of the reliability benefits that long term contracts for capacity imports provide. In addition, LEI discussed how Ontario can create a level playing field for clean energy imports relative to other potential future sources of supply in Ontario

- ***due diligence support associated with the evaluation of the possible acquisition of a minority stake in a major Ontario transmission and distribution company:*** LEI prepared reports and analysis which contributed to the analytic framework for this proposed transaction, including analysis of the regulatory framework, review of impact of PBR on revenues, strategic issues, and the potential for revenue growth

- ***impact of Ontario market changes on industrial consumers:*** for association of large power consumers in Ontario, assessed market trends and future entry and exit scenarios to determine long term price dynamics in the face of changes in government deregulation policies

- ***valuation of Ontario generating plants, including assessment of regional electricity markets:*** organized and implemented major modeling effort to determine potential value of generation stations in Ontario. Assessed impact of transmission constraints and restructuring efforts in neighboring markets on future wholesale market prices

- ***revenues to hydro portfolio in Ontario:*** for a large North American industrial company, A.J. led the creation of a market study and report underlying the issuance of income trust securities. Tasks included multiple scenario analysis of merchant revenues, review of ancillary services revenues, and an examination of the Ontario hybrid market structure

- ***assessment of role of peaking plant in Ontario power sector:*** for Ontario government body, performed extensive scenario analysis to determine extent to which peaking plant should be a part of future procurement plans in the province; this analysis included assessment of revenues from ancillary services and of optionality

- ***price forecasts in key Canadian markets and associated export zones:*** provided long term electricity price forecasts in multiple engagements for key Canadian markets, including Alberta, British Columbia, and Ontario, as well as related export markets such as New York, Midwest ISO, and PJM. Results used by clients for obtaining financing and assessing contract pricing

- ***valuation of integrated IOUs:*** coordinated evaluation effort for acquisition of Southeastern US utility and of Ontario municipal electric utility; tasks included assessment of impact of PBR, calculation of difference in profits from generation portfolio under ratebase versus in open market, and analysis of ratebase settlement

- ***transmission review in Canada:*** LEI was hired by a French consulting firm to provide commentary insights on the state of the transmission and distribution market in a number of Canadian provinces including Alberta, Ontario, British Columbia, Manitoba, Saskatchewan and Quebec

- ***led Alberta performance review:*** LEI was engaged to perform an assessment of the Alberta Energy Framework, which encompasses the wholesale generation market, retail market, agencies, transmission planning, access and distribution, as well as the operations of the Alberta Interconnected Electricity System. The analysis included both qualitative and quantitative components

- ***conducted overview of hydro-dominated market:*** LEI was hired to provide an understanding of the dynamics underpinning hydro-dominated power markets as opposed to thermal systems. As part of this project, LEI reviewed in details the dynamics and key drivers of energy markets in a sample of Latin America countries including Colombia, Panama, Brazil and Chile. Colombia was the point of focus of the report, in this respect LEI compared and contrast several aspects of the Colombian markets to other jurisdictions and created a scoring card to evaluate Colombia against similar jurisdictions.

- ***evaluated peaker units in New England:*** London Economics International LLC ("LEI") was retained to evaluate the economics of constructing peaking units in two possible existing New England hydro facilities. Specifically, LEI conducted an analysis on existing peaker technologies, the permits required, and determined how much investment would be justified to make the project economic.

- ***evaluated cost economics of installing energy storage technologies at existing hydro power plants in Massachusetts and New York:*** The analysis was conducted in three phases – phase 1 consisted of literature reviews and primary information collection (from manufacturers and service providers) on the available types of energy storage technologies and associated fixed and variable costs. Phase 2 consisted of an economic cost-benefit analysis of the least cost storage technologies to understand the viability of the investment. Phase 3 consisted of developing comprehensive criteria for selecting the energy storage manufacturer/service provider and presenting implementation recommendations.

- ***conducted PJM price forecasting:*** London Economics International LLC ("LEI") was retained to provide forecasted energy and capacity prices as well as supply curves for a plant located in PJM's SWMAAC region

- ***market briefing on renewables in El Salvador:*** LEI was engaged by a private equity firm focused on small-scale renewable energy projects considering expanding into South America to develop a market briefing on El Salvador, focused on the challenges and opportunities in developing small hydro projects in the country

- ***cost benefits analysis of US transmission line:*** for a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible

- ***review of RRO in Alberta:*** London Economics International LLC ("LEI") was asked by ENMAX Energy Corporation ("EEC") to review EEC's request for continuation of the practice of earning a fixed margin associated with expenses incurred as a result of operation of the Regulated Rate Option ("RRO"). For the client, LEI reviewed the settled practice in Alberta, investigated the risk of operating the RRO, and calculated an indicative range of margin for EEC

- ***review of risk management practices:*** LEI was engaged by the client to review its risk management practices and provide meaningful insights with regards to the risk management related issues. Analysis included quantification of the magnitude and probability of risks being faced, as well as research into the best practices of other similar organizations

- ***conducted Independent Evaluation review:*** LEI provided advisory services to assist the OPA in evaluations of applications made to the Aboriginal Renewable Energy Fund ("AREF") and the Aboriginal Transmission Fund ("ATF"). LEI provided advice and analysis related to the technical, financial and regulatory viability of each proposed project

- ***conducted a report on net metering programs in New Hampshire and New York:*** for a private equity power sector investor, LEI conducted a report on net metering programs to determine if the client's facilities would qualify. Project work included determining load at the sites, examination of net metering in the applicable regions, assessment of potential solar installation, exploration of installation options to determine which would be most suitable, and analyzing potential returns

- ***assessment of small hydro properties:*** as part of a retainer agreement with a growing private equity firm focused on the roll-up of small hydro properties, LEI performed a variety of supporting activities, including examination of forward markets, review of PPAs, assessment of renewable energy policies, and strategic analysis

- ***review of North American hydro assets:*** LEI was engaged by a large Canadian hydro generator to evaluate the potential renewable premium associated with its hydro assets in North America. LEI developed an economic model to project legacy Renewable Energy Certificate ("REC") prices in New York and New England. LEI also provided alternative methodologies such as projecting the premium based on forecasted carbon allowance prices and analyzing potential sales to large corporations on a voluntary basis

- ***analyzed current and future dynamics in the British Columbia power markets for of British Columbia power producers:*** topics analyzed included costs of independent power producers ("IPPs") relative to BC Hydro, uncertainty around future demand levels in BC, implications of moving away from use of Critical Water Year analysis in planning, risks and uncertainties regarding import availability, and the overall macroeconomic contributions of IPPs. LEI also analyzed the provincial government's Review of BC Hydro and provided an assessment

- ***valuation of distribution company in Bolivia:*** LEI provided inputs into the valuation of a Bolivian distribution company, including developing the cost of capital; assessing demand, cost, and tariff forecasts; and reviewing the overall cash flow model. LEI also reviewed the company's historical performance relative to efficiency and performance targets

- ***wrote paper on investments by electric and natural gas utilities:*** LEI authored a paper on the successes and failures associated with international investment by electric and natural gas utilities for a major Japanese utility. The paper focused on the activities of over forty companies, both within North America and internationally

- ***European power market analysis:*** LEI worked with one of North America's largest independent operator of power generation facilities to develop a comprehensive analysis of central European power markets including price forecasts and renewable energy policies. As part of its client's efforts to acquire a portfolio of hydroelectric power generating facilities, LEI's team developed a medium-term price forecast, stress tested critical assumptions, and provided detailed insight into federal and state renewable energy policies

- ***developed several forecasts of the long-term Alberta electricity power pool prices (2010 to 2030) based on different market parameters and build decisions:*** the forecast also made special note of the effect on the market, if any, of the following conditions: (i) greenhouse gas legislation; (ii) increase in unconventional (shale) natural gas production; (iii) effect of the enactment of Bill 50; and (iv) effect on the market by external jurisdictions

- ***market analysis for a client interested in purchasing a portfolio of global generation assets:*** in this project, the LEI team, led by AJ, provided a market analysis of California, Mexico, and the Philippines. This market analysis included the following aspects: description of portfolio assets in the jurisdiction, supply/demand balance in the jurisdiction, regulatory framework, contract description and impact of competition on specific portfolio assets in the jurisdiction, indicative position of target asset on supply curve presently and in the future, impact of climate change and other environmental regulations, observations from material in dataroom, review of pool price projections, and remarks about the jurisdiction. In addition, LEI performed a 20-year price forecast for these markets, which was delivered in a spreadsheet form and incorporated into the management presentation

- ***review of business plans for hydrokinetics technology company:*** for start up hydrokinetics technology company, LEI reviewed business plans and applicability of technology worldwide. Tasks included commenting on strategic plan, advising board members on the evolution of renewable energy markets worldwide, and assessing US Federal Energy Regulatory Commission polices towards hydrokinetic projects

- ***due diligence and valuation of engineering consulting firm:*** for a Middle Eastern investment fund, A.J. led the evaluation of the acquisition of an engineering consulting firm with offices in the US, Europe, and the Middle East focused on the power sector; the project included creation of a pro forma for the business, evaluation of business prospects and strategy, and an examination of the relevant economic conditions and their impact on value

- ***assessment of plant pro formas and underlying market environment in six Asian countries:*** for leveraged buyout of major global IPP developer, assessed plant financial models, state of reform efforts, and potential for unbundling in Bangladesh, China, India, Philippines, Thailand, and Turkey

- ***valuation of Singapore generating asset:*** on behalf of a large Asian generating company, provided revenue forecasts from spot, retail, and vesting contracts for successful acquisition of Singapore generator Analysis included review of repowering options, assessment of regulatory evolution, assessing the relevant cost of capital, and potential for strategic behavior; A.J. later performed a similar exercise for a second Asian generating company also seeking to purchase a similar set of assets in Singapore, as well as subsequently assisting in analysis associated with refinancing of the acquisition performed by initial client

- ***modeling future Japanese electricity market dynamics:*** for a leading Japanese financial institution, led workshop and directed the creation of an interactive model of the Japanese electric power sector. Issues addressed included quantification of plant asset values under various market scenarios, an assessment of the potential for stranded costs, review of debt coverage ratios, and exploration of the evolution of transmission assets

- ***advised Japanese company on potential US power sector acquisitions:*** reviewed project economics for multiple acquisition targets of Japanese investor. Tasks included providing long term revenue forecasts, reviewing motivations of sellers, providing insights on the associated market, and examining the role of hedge funds and private equity

- ***examination of markets and generation asset values in Mexico, Philippines, and California:*** assisted Asian IPP in assessing generating assets in Mexico and Philippines, as well as export potential from Mexican plants to the US; mandate included developing long run marginal cost forecasts for Philippines and Mexico, and providing detailed dispatch modeling of the California market

- ***valuation of generation and distribution assets in Philippines and the Caribbean:*** provided detailed analysis of regulatory trends in the Philippines and in selected Caribbean countries. Used regulatory filings, PPAs, and public information to develop a value for generation and distribution assets in these markets. Advised potential buyer on relative risk in each country examined, including country risk, regulatory risk, and fuel supply and load growth issues

- ***power price forecast for Balkans:*** to support potential bid to acquire nuclear station in Bulgaria, led team forecasting revenues from future spot power market sales. Issues included treatment of carbon emission credits, extent of regional integration, and availability of existing transmission capacity

- ***revenue forecast and financing advisory for renewables acquisition:*** for newly established private equity firm, managed acquisition process for small hydro and biomass site. Process included revenue forecasting, negotiating term sheets with banks, obtaining quotes for power purchase agreements, reviewing operating agreements, and overseeing all aspects of transaction process

- ***prices for merchant generators and IPPs:*** provided expert opinion on the extent to which value of a generating station could change over a 12 to 18 month period, based on historical analysis of price changes for individual generation assets as well as for generation asset portfolios

- ***biomass investment evaluation:*** on behalf of growing private equity investor, performed extensive analysis of economics of restart of several biomass plants in California and elsewhere. Tasks included PPA review, examination of permits, assisting in arranging financing, and examination of California market dynamics

- ***advised on purchase of small hydro station:*** for a newly established hydro-focused private equity investor, valued and performed regulatory review associated with successful purchase of a small hydro facility in Maine. Tasks including creating pro forma, reviewing material contracts, negotiating purchase and sale agreement, hiring operator, and monitoring ongoing performance

- ***bid for New York City gas and oil fired stations:*** for a major financial institution, A.J. led a team of analysts in examining potential future revenues for a portfolio of peaking plants in New York City. Assignment included using proprietary models to forecast future capacity and energy revenues, and the application of real option techniques to determine value of plant flexibility

- ***bid for PJM coal-fired power station:*** worked closely with private equity fund in creating deal team, preparing first round bid, and valuation of facility, including coal supply, environmental compliance, site options, and forecast of future revenues; helped to develop second round bid, including assisting in arranging financing and risk management

- ***collateralized debt obligations ("CDOs"):*** led projects associated with detailed statistical analysis of the underlying economics of CDOs associated with distressed debt in the power sector, and with examining whether such a CDO could have been launched in the wake of the Enron collapse

- ***valuation of New England based generation portfolio:*** worked with potential acquirer of New England's largest generation portfolio to determine the costs of ongoing obligations associated with the portfolio, provide an understanding of long term market dynamics, and assess value of overall portfolio, including revenue forecasts and review of market rules

- ***valuation and regulation of LNG facilities:*** assessed potential for combination of strategically situated LNG facility with US wholesale power marketer; for separate client, advised on third party access requirements for LNG facilities in the US and relevance to potential regulatory changes in Japan

- ***assessment of value of coal station contracts circa year 2000:*** developed analysis of value of contracts to bear costs and benefits associated with output from coal fired power stations in Alberta. Engagement involved considering only information known as of 2000, for inclusion in tax litigation case. Created pro forma valuation of the contracts as of 2000, including forecast costs and revenues, as well as opining on the appropriate cost of capital to be used

- ***revenues to wind generators in Alberta:*** A.J. led the examination of merchant revenues to a portfolio of existing and under construction wind generators in the province of Alberta. Tasks included review of market design issues, 20 year scenario analysis for merchant revenues, review of contract terms and conditions, and an examination of the potential for additional revenues from the sale of emissions reduction credits and renewable energy certificates. Deliverables included market study supporting issuance of income trust units

- ***developed price trends, in conjunction with the valuation of several Colombian power plants:*** LEI also provided an evaluation of the Colombian market, an overview of modeling methodologies and assumptions, and modeling results. The modeling results included forecast spot market prices, plant dispatch and revenues (energy and capacity), under a variety of scenarios

- ***conducted tariff review for Ente Nacional Regulador de la Electricidad ("ENRE"):*** the Argentine regulatory authority for the electricity sector (ENRE) awarded a contract for a tariff review of Edenor, a large utility serving the northern portion of Buenos Aires to a consortium led by LEI. The engagement entailed evaluating the performance of Edenor in the 1992-2002 tariff period; advising ENRE on international best-practice design of distribution tariffs; proposing a tariff setting methodology for the 2002-2007 tariff period; providing technical assistance in the analysis of information presented to ENRE by Edenor; proposing tariffs for the 2002-2007 tariff period; and assisting ENRE during public hearings on the proposed tariffs. The consortium proposed that tariffs be set via an RPI-X approach employing Data Envelopment Analysis (DEA) for establishment of the X-factor

- ***revenue forecasting in Nicaragua:*** LEI developed revenue forecasts for two generating companies (GeCsa and GeOsa) being auctioned by the Nicaraguan government as part of the privatization of the country's electric power industry. The revenue forecasting was conducted in three stages: a production cost-based spot price and dispatch forecasting stage, a contracts valuation stage, and a Monte Carlo Simulation stage. Out Monte Carlo simulation quantified the impacts of hydrological and fuel price variation on the values GeCsa and GeOsa

- ***advised on bid strategy for Mexican IPP:*** LEI assisted a large foreign utility in its bid strategy for acquisition of generating assets in international jurisdictions (across North America, Europe, and Asia). The LEI team led the market analysis for assets located in Mexico; more specifically, LEI analyzed a series of macroeconomic risks (including political, economic, and regulatory risks) likely to impact operations of the assets in the long run, performed a full due diligence review of the targeted assets, and developed forecast of the Mexican wholesale spot energy prices in order to determine future profitability of the assets.

Power, Gas, and Infrastructure Sector Business Development and Strategy

- ***conducted workshop on generation reliability standard review in Malaysia:*** LEI held a two-day workshop on Generation Reliability Standard Review Seminar for TNB in Kuala Lumpur, Malaysia. The topics included: Malaysia reliability standard policy overview, jurisdiction review on reliability indices and benchmarking Malaysia's reliability standard against other countries, inter-play between government agencies in formulating the reliability standard, lessons learned from other counties, incorporating renewable energy, interconnection and distributed generation in calculating reliability indices, input parameter to derive the value of reliability indices, and lesson learned from LOLE studies from other jurisdictions.

- ***performed a peer-group analysis of Independent Power Producers ("IPPs") in the US market:*** LEI presented research to Osaka Gas with insights on the key economic, financial and strategic factors contributing to growth of mid-sized companies in the US merchant generation market. LEI identified nine categories of IPPs in the US merchant market and defined a subset of companies to be considered as the peer-group of Osaka Gas. For the peer-group, LEI reviewed key success criteria of each company including business focus, leadership, growth strategy and financial performance. LEI presented three peer-group companies as case studies to highlight examples of successful players in the US IPP market. Overall, LEI highlighted the implications that current market trends and key success factors of Osaka's peer-group would have on the company's future growth strategy in the US market.

- ***conducted water pricing in California:*** London Economics International LLC ("LEI") was retained to conduct a 30-year price curve for Metropolitan Water District of Southern California ("MET Water") in relation to a potential acquisition of a proposed desalination plant in California. The desalination plant's water rate specified in the draft Term Sheet of the Water Purchase Agreement is based on MET Water's prices plus avoidable charge, subsidy, and a premium. LEI reviewed the regulatory arrangements of MET Water, supply-demand dynamics in Southern California, and water pricing mechanisms used by MET Water. LEI also assessed the different key drivers for each component of the MET Water price. Lastly, LEI created a cost of service model and projected the MET Water prices for the next 30 years.

- ***study on transmission and distribution:*** LEI collaborated with SratOrg, a French consultancy on the development of strategic recommendations for market penetration in the US transmission and distribution markets . As part of this work, LEI and StratOrg performed a detailed analysis of the US market structure, identifying key market players and recent development, as well as barriers of entry and market opportunities for a prospective European investor. LEI travelled to Paris for an internal workshop session with Stratorg and actively participated in the final presentation of the team findings before the client's top managers.

- ***advisory services on the development of a 75 MW hydroelectric power plant in Cameroon:*** under a USTDA contract, AJ Goulding acted as a Senior Energy Market Specialist in the LEI portion of the work for a consortium to provide financial and technical advisory assistance to the Ministry of Energy and Water Resources of the Government of Cameroon with respect to the development of a 75 MW hydroelectric power plant at Bini à Warak. Specific tasks included review of Cameroon's existing regulatory system, regional market demand analysis and assessment of developmental impact of the project

- ***business development opportunities in India:*** for UK electricity and mining conglomerate, provided detailed assessment of opportunities in construction of integrated mining and mine-mouth power stations and in distribution of electricity

- ***assessment of US natural gas storage business:*** for a large Japanese gas utility, examined trends in regulation and investment in the US natural gas storage business. Engagement included comparison of natural gas storage business risks to that of IPP investment

- ***European renewables investment strategy:*** on behalf of a global power and real estate investment company, reviewed policies towards renewable energy in Europe and individual European companies, as well as available assets, sites, and investment climate

- ***distressed asset acquisition strategy:*** advised a major Japanese utility on entry strategies to the US market, including performing a workshop on due diligence, US regional market analysis, and asset valuation; arranging for introductions to major asset sellers, potential investment partners, and advisors; and creating a screening methodology and database of potential acquisition targets

- ***unbundling of French state-owned vertically integrated monopoly:*** worked with leading French electricity generator and supplier to examine how to create independent profit and loss statement for its generation assets, benchmark performance against expectations, and separate revenues from plant operations from those gained through trading

- ***renewables value chain investment analysis:*** for Dutch foundation based in Switzerland, examined macro trends associated with renewable energy in several major global economies, including the global supply chain from component manufacturers to installation to operation. Objective was to determine where on the renewables value chain the most profitable opportunities could be found

- *workshop on performance-based ratemaking strategy:* for first stand-alone transmission company in North America, conducted day long workshop on issues associated with PBR, including the types of PBR and which one is most appropriate for what type of company, the sources of efficiency gains observed in other transmission companies worldwide, and the impact of performance standards on profitability and flexibility

- *global generation investment strategy:* for a major Canadian generation company, used modern portfolio theory to identify combination of asset classes and geographic locations which would result in optimal risk-reward combination for generator given its core competencies. Deliverables included interactive model to be used by generator staff on an ongoing basis

- *development of regulatory and financing strategy for transco:* for first stand-alone transmission company in North America, evaluated key transaction parameters, assessed allowed ROE, proposed strategy for attaining favorable incentive rates, and helped to identify potential cost savings

Regulatory Economics

- *Ontario electricity market paper:* on behalf of a respected Canadian think tank, LEI provided an assessment of the ways in which the Ontario electricity sector could be improved to increase economic efficiency and reduce costs for consumers over the long run

- *assessed potential cost of Ontario Green Energy Act:* explored costs of Green Energy Act, including feed in tariff provisions, grid connection funding, institutional development, loss of local control, and stakeholder mandates

- *cost of capital for regulated generating assets:* provided expert testimony on behalf of the Ontario Energy Board regarding risk factors associated with Ontario Power Generating's prescribed assets, as well as creating a risk-return continuum on which power sector assets could be placed

- *incentive-based contract design:* for Ontario Power Authority, advised on provisions of power purchase agreement associated with incentives for optimization of production in peak periods for hydro facility owned by a major generator

- *upstream capability to deliver conservation and demand management:* for Ontario Power Authority, performed examination of capabilities of Ontario to provide necessary inputs to assure that Ontario meets is conservation and demand management targets; report incorporated into Integrated Power System Plan submission to OEB

- *regulation of generation in Ontario:* for Ontario Energy Board, A.J. authored paper described the ways in which legacy assets of Ontario Power Generation could be regulated, including incentive regulation and a set of regulatory contracts. Deliverables included providing technical advisory during public workshop

- *potential for regulation of retail market auctions:* for Ontario Energy Board, A.J. led engagement to review practice of regulatory oversight of load auctions to serve default supply across North America

- *examination of contracting processes in Ontario:* on behalf of the Ontario Power Authority, met with over 50 stakeholder groups to determine potential ways in which contracting process for new supply could be improved. Engagement included assessing practices in other jurisdictions and review of standard offer processes

- *provided a briefing for Alberta's Minister of Energy:* briefings consisted of two 90 minute presentations – the first was a review of the Alberta Retail Market, and the second was a wholesale market review of ERCOT, Australia, Singapore, UK and Ontario

- *supported client's transmission FBR reopener application:* in particular, the client wanted LEI to provide an independent opinion on their argument (i) to amend the G factor calculation to eliminate the G-factor lag effective January 1, 2011 and (ii) to reduce EPC's current X factor of 1.2% to 0.0%. LEI provided support throughout the whole litigation proceeding by responding to information requests which involved additional research and analysis, including synthesis of publications on recent technological advances in electricity transmission sector, and updating the Ontario LDCs TFP model to ten years

- *2nd generation PBR in Ontario:* led Cdn. $1.5 million engagement focusing on design of second generation PBR in Ontario. Key components include estimating total factor productivity (TFP), determining appropriateness of yardstick competition, analyzing demand-side management programs in the context of PBR, and examining service quality indicators

- *market power concerns in Ontario:* determined concentration ratios for existing configuration of generation plant, developed set of recommended portfolios to minimize market power across all timeslots in hourly market in preparation for divestiture or other market power mitigation mechanisms

- *supported Manitoba cost of service review:* London Economics International LLC ("LEI") was retained by Christian Monnin Law Corporation, at the request of Manitoba Public Utilities Board, to represent the interests of small commercial customers in its review of Manitoba Hydro's cost of service review

- *supported setting of Nova Scotia Performance Standards:* LEI was engaged by the Nova Scotia Regulatory Authority – the Nova Scotia Utility and Regulatory Board (NS UARB) to assist in setting performance standards for NSPI in respect of reliability, response to adverse weather conditions, and customer service for Nova Scotia

- *conducted NYC entities capacity portfolio analysis:* For a large Canadian hydropower generator, LEI performed a review and analysis of the capacity portfolio of several entities operating within New York City

- ***served as Ukraine Electricity Tariff Expert:*** As part of a team hired by the Anti-Crisis Energy Group of the Cabinet of Ministers of Ukraine, LEI was tasked with identifying opportunities to streamline and enhance procedures used to set tariffs and prices for electricity produced. LEI performed an extensive literature review of the Ukrainian electricity market, assessed the current tariff-setting regulations and procedures and carried out in-person interviews with stakeholders. LEI wrote a briefing memo on the Ukrainian market and a recommendations paper in line with its scope of work. The recommendations were incorporated into an Energy Resiliency Plan that would aid decision-making to the Cabinet of Ministers and the Verkhovna Rada

- ***Conducted 2015 Review of Non-Energy Margin***: London Economics International LLC ("LEI") was asked by ENMAX Energy Corporation ("EEC") to review EEC's proposed non-energy return/risk margin associated with expenses incurred as a result of operation of the Regulated Rate Option ("RRO"). For the client, LEI reviewed the settled practice in Alberta, recent proposed changes providing for an all-inclusive return margin, and calculated an indicative range of margin for EEC.

- ***overview of Colombia market and revenue forecasts for target assets:*** LEI was hired by an electric operator for the purposes of valuing a portfolio of generating assets in Colombia. LEI's scope of work consists of a comprehensive review of the Colombia energy market (including fuel and power market drivers), describe in details the functioning of both wholesale power market and firm energy market (capacity market), develop forecasts of spot prices in order to derive expected revenues for the portfolio. Colombia being a hydro dominated system, as part of its modeling exercise, LEI ran a Monte Carlo simulation to develop a series of probabilities associated with generation profiles of Colombia's hydro resources to reflect the impact of weather conditions and water inflows on hydropower plants' output. LEI summarized its research and modeling results in a final report that was presented to lenders and other interested parties

- ***conducted analysis of Nova Scotia electricity systems:*** LEI was retained by Nova Scotia Department of Energy ("NS DOE") to perform analysis of the organization and governance of electricity systems both cross-jurisdictionally and within the province of Nova Scotia. The scope of work was divided into two main phases: (i) Review of international best practices and lessons learned; and (ii) Translation of best practices and lessons learned into best fit for NS

- ***assessed consistency of proposed Clean Energy Standard with existing Alberta electricity market design characteristics:*** Paper included discussion of potential additional program attributes, indicative cost assessment, impact on investment and reliability, and assessment of further required research

- ***assisted generator in hydro development strategy:*** assisted Alberta generator on strategy related to new large scale hydro development, including justification as inflation hedge for potential pension fund investors, integration into competitive market while maintaining ability to finance, and other strategic and regulatory support

- ***conducted IBR workshop in Malaysia:*** LEI was retained by the largest electric utility company in Malaysia to conduct a workshop on incentive-based ratemaking ("IBR"). The topics for the workshop include theoretical conceptual overview of IBR regulatory framework, key elements of comprehensive IBR regimes, best practices of IBR in various jurisdictions, timing and framework in other jurisdictions, how to convince regulators and stakeholders, identifying barriers to successful implementation of the IBR, and moving from first to second generation IBR, to name a few.

- ***developed a transmission cost causation study for the Alberta Electric System Operator ("AESO"):*** the study will be used for the determination of the AESO's Demand Transmission Service Rate DTS, and is expected to be filed with AESO's 2014 tariff application to the Alberta Utilities Commission ("AUC"). The study is intended to cover four main topics: (i) Functionalization of Capital Costs; (ii) Functionalization of Operating & Maintenance ("O&M") costs; (iii) Classification of Bulk and Regional System Costs; and (iv) Implementation Considerations

- ***conducted review of gas transmission sector in the US:*** for a European economic advisory firm, LEI reviewed the US gas transmission sector focusing on its regulatory structure. Tasks included researching the regulatory approach, legal framework, allowed capital costs and incentive mechanisms of the US gas industry

- ***review of rate of permitted return in Hong Kong:*** for the Hong Kong Government, LEI reviewed the rate base and the rate of permitted return for the power companies in Hong Kong under the Scheme of Control Agreements. This required reviewing the alternatives to using Average Net Fixed Assets as the rate base, examining the assumptions used and methodology to calculate the WACC of power companies, updating the indicative range for the permitted rate of return, and recommending changes to existing rates of return by identifying new international best practices

- ***reviewed the US gas transmission sector focusing on its regulatory structure:*** on behalf of a European economic advisory firm, an LEI team, led by AJ, reviewed the US gas transmission sector. Tasks included researching the regulatory approach, legal framework, allowed capital costs, and incentive mechanisms of the US gas transmission industry. Analysis focused on US Federal Energy Regulatory Commission ("FERC") regulatory proceedings, as well as state commission findings, related to allowed returns, capital investment requirements, and treatment of capacity

- ***developed financial, commercial, and regulatory framework, in addition to drafting an investment strategy and model for Saudi clean energy institution:*** deliverables included: (i) A master plan on how to develop renewable and atomic energies based on local value chains in Saudi Arabia; (ii) An economic framework to create a favorable environment in order to follow this master plan; (iii) An investment strategy to make use of KSA resources and available funds in an efficient way; (iv) A multitude of international case studies to avoid costly mistakes in the future and to know when to adopt; (v) A final report on 'National Policy for Investment in Alternative Energy Sources'; and (vi) Two 'sales pitch' documents for submittal to the King's Supreme Council and for the financial community

- ***advised Jordan regulator:*** advised the regulator on the weighted average cost of capital and optimal capital structure for Jordan's three distribution companies: EDCO, IDECO and JEPCO. The recommended optimal capital structure was consistent with targeted debt service and interest coverage ratios in line with the rating methodology for distribution companies from the global credit rating agencies. Work also included identifying salient risk factors for the distribution companies, identifying appropriate local and international metrics and benchmarks, developing a usable cost of capital model, and providing training workshops for local staff

- ***drafting National Renewable Energy Plan for Saudi Arabia:*** on behalf of the regulator, developed proposal for renewable energy plan for Saudi Arabia, including assessment of procurement methods, new institutions required, and determination of resource eligibility

- ***rate design for water and wastewater services in Saudi Arabia:*** on behalf of utility serving industrial areas in the Kingdom, examined appropriate regulatory structure and recommended approach to establishing new regulatory body, including composition of regulator, incentive structure, and tariff modeling

- ***design of wheeling tariff and pilot program for Saudi Arabia:*** for Saudi regulator, developed proposed plan for wheeling of power in Saudi Arabia, including proposed pilot program, assessment of impact on incumbent, relative economics of wheeling versus the industrial tariff, and review of associated commercial and regulatory issues

- ***tariff design for Kingdom of Saudi Arabia:*** led engagement with international team assessing tariff design, modeling, and electricity market evolution in Saudi Arabia; engagement resulted in a revised tariff system, including performance based rates, tolling agreements for generation, and an open access tariff. Included holding workshops for regulator in explaining cost of capital, tariff design, and other regulatory issues

- ***Electricity Industry Restructuring Plan for Saudi Arabia:*** A.J. developed the blueprint for industry restructuring in Saudi Arabia, including unbundling of the current monopoly vertically integrated utility, introduction of wholesale competition, and creation of a Single Buyer

- ***developed regulatory incentives in Jordan:*** examined regulatory framework in Jordan, with particular focus on creating specific regulatory incentives for distribution companies to optimize their operational expenses. Proposals envision move away from cost of service regime to incentive based structure benefiting customers and shareholders

- ***global regulatory review:*** assisted private equity player in assessing electricity markets in Eastern Europe, Turkey, Asia, and Latin America to determine potential regulatory and market issues associated with proposed purchase of diverse portfolio of generation, distribution, natural gas pipeline, and retail fuels businesses

- ***assessed retail margin review for generator in India:*** reviewed retail margins on electricity sales worldwide, in order to provide Indian generator insight with regards to appropriate retail margins that could be charged to selected customers in one Indian jurisdiction.

Engagement involved review of case studies of electricity retail margins around the world, including the US, UK, and Australia. In addition, retail margins in other industries were reviewed, along with the progression of margins as an industry progresses from infancy to maturity

- ***institutional development for IPP promotion:*** contributed to Indian private power promotion efforts through technical assistance program to state electricity boards, central government agencies, and private firms, with particular emphasis on role of PURPA in creating US IPP industry

- ***bagasse cogeneration:*** worked extensively with Indian sugar mills, equipment suppliers, government investment promotion agencies, and state electricity boards to develop cost-effective targeted loan and technical assistance program to promote bagasse cogeneration

- ***barriers to introduction of new coal combustion technologies in emerging markets:*** served as liaison between India's National Thermal Power Corporation (NTPC) and US research institutions to assess ways to adapt US coal combustion technologies to Indian conditions

- ***recommendations for next Scheme of Control in Hong Kong:*** worked with the Hong Kong government to develop a series of recommendations regarding appropriate allowed returns, calculation of asset base, prevention of over-investment, and rate stability

- ***lessons from North American experience for Chinese regulators and grid companies:*** for a set of Chinese state-owned companies, including grid operators, the nuclear operating company, and provincial power companies, London Economics International LLC prepared a series of detailed briefings on developments in electricity market design worldwide, with a particular emphasis on lessons from the North American experience. This experience was then used to highlight the various alternatives for market design in China, and the potential outcomes

- ***implications of restructuring the Japanese power sector:*** for a major Japanese development bank, we analyzed the impact of proposed reforms on a Japanese transmission and generation company, including the potential for stranded costs, opportunities for expansion of transmission, and future tariff setting regimes. The engagement included extensive training of the development bank's staff, as well as the creation of a working model of the Japanese power sector

- ***preparing appropriate framework for private investment in Romanian distribution sector:*** on behalf of a private client, worked with Romanian regulators to develop a consensus on approaches to capital recovery, PBR application, performance standards, supply cost-pass through, and cost of capital. These elements served as preconditions for the private investor's participation in the privatization process

- ***arguments for retaining vertical integration:*** for large French utility, reviewed cases worldwide in which during liberalization incumbents were allowed to remain active across the value chain, including retail. Our work included an assessment of the minimum competition enhancing measures regulators may require in order for the utility to continue operating in all or most of its traditional supply chain activities

- *implications of performance based ratemaking (PBR) in the Caribbean:* for a privately owned integrated electric company based on a well developed Caribbean island, directed strategic analysis of implications of PBR, suggested approach to regulators, and provided indicative benchmarking analysis

- *review of stranded cost settlement and default supply pricing:* prepared support for regulatory filing in Pennsylvania assessing benefits to customers from a proposal to extend recovery period for competitive transition charge while extending fixing price for default supply

- *assessment of changes in market power for a FERC Section 203 filing:* in connection with a proposed combination of generation portfolios, developed testimony concerning the change in market concentration as a result of the transaction, including an assessment of changes in HHIs under various market definitions

- *review of durability of gas franchises in the face of competition:* reviewed state regulator decisions and FERC rulings regarding sanctity of natural gas distribution franchises, assessed relevance in the face of deregulation of gas markets

- *market response to tax credit:* performed in-depth analysis of impact of Section 29 tax credit for non-conventional fuels production on supply and price response in US southwestern gas markets

- *economic efficiency effects of retail market design:* for major US electricity retailer, analyzed various forms of retail electricity competition and default service parameters and compared them to retail/wholesale structure in other industries to determine welfare effects

- *design of incentive rate structure for Alberta utility:* for a large metropolitan Alberta utility, A.J. advised on design of a proposed incentive based rate structure, including a multi-year term, operating cost incentive structure, and earnings sharing mechanism. Deliverables aided in development of regulatory filings and included testimony before the Alberta Utilities Board

- *critiquing and improving electricity market structure in Alberta:* for market institutions and regulators in the Canadian province of Alberta, performed extensive analysis of current industry market structure, including role of Power Pool, Transmission Administrator, Market Surveillance Administrator, the Scheduling Coordinator, and the Balancing Pool. Directed detailed analysis of market power issues associated with divestiture of specific assets and advised on particular market rules to ameliorate strategic behavior

- *recommendations regarding market power mitigation and retail market design:* in two separate engagements, advised the Government of Alberta on alternatives for rate designs for small customers and on measures to monitor, measure, and ameliorate market power;

both engagements included extensive modeling of Alberta wholesale market and of retail supply tariffs

- *evaluation of rates across Canada:* reviewed rates charged to final consumers across Canada and identified distortions in rate design across provinces; performed modeling to adjust for distortions; developed appropriate calculations to appropriately compare rates across jurisdictions

- *resource adequacy mechanisms for Alberta:* worked with generators association to assess alternative approaches to assuring resource adequacy. Reviewed mechanisms for capacity and default supply procurement worldwide, developed alternatives for Alberta, and engaged in intensive stakeholder consultation

- *strategic implications of US deregulation:* performed in-depth study of the impact of unbundling in the US on the fundamental economics of the electric power industry at all points on the value chain; identified regional investment opportunities congruent with these dynamics

- *Regulatory review of power markets for Chilean client:* at the request of a major Chilean generating company, LEI performed a detailed review of the regulatory regimes of four restructured power markets (California, Colombia, Nord Pool, and Spain), as well as an analysis of the current Chilean regulatory regime and the changes to that regime that the regulator has proposed. The review addressed the positions of all stakeholders, with a particular focus on the implications of various types of market design on generators

Written and oral expert testimony

Note: expert testimony was also a component of some projects listed above, particularly regulatory projects for Ontario Power Authority, Ontario Energy Board, and involving incentive rates in Alberta.

- *conservation and demand management (C&DM) in Ontario:* wrote testimony related to the alternative ratemaking approaches available regarding C&DM; addressed innovative alternatives and compared and contrasted various schemes in the Ontario context

- *review of valuation metrics used in conjunction with tax payment challenge for an Alberta generator:* assessed the appropriateness of valuations utilized to determine depreciation deductions related to the acquisition of a coal-fired generating station. Engagement also required creating forecasts that would have been appropriate at the time the acquisition was made several years previously, as well as calculating asset values using multiple valuation approaches. Multiple forecasting tools were used. Engagement included developing critiques of work by opposing expert witnesses

- *examination of Swiss electricity market:* for a US financial institution, A.J. reviewed the development of the Swiss electricity market and specifically the position of hydro stations within that market. Analysis included a discussion of the factors that influence the value of hydro stations, presence of foreign owners in the Swiss electricity market, and use of post-tax cash flow to evaluate potential investments

- ***analysis of potential customer impacts due to holding company acquisition of merchant generator:*** discussed ways in which customer rates would be impacted by potential credit rating downgrades of regulated subsidiaries due to holding company parent's acquisition of merchant generator; engagement included examination of impact on default supply as well as reliability

- ***assessment and valuation of quantum merit claims:*** for advisor and developer of biomass facilities, provided expert opinion on value of services provided based on industry knowledge, review of correspondence, and experience providing or commissioning similar services

- ***review of Dutch electricity market regulatory dynamics:*** in a case before the US Federal Court of Claims related to economic substance, provided understanding of how Dutch electricity market was structured in the mid-1990s, how it was expected to evolve, and how it did actually evolve. Issues addressed included market structure, regulation, role of non-utility investors, and role of private and international investors

- ***valuation of PPAs associated with IPPs in Thailand:*** as an expert witness in an arbitration case, A.J. quantified the change in value resulting from modifications to several PPAs associated with a power project in Thailand. Engagement included review of PPAs, evaluation of Thai power sector restructuring process, extensive modeling of financial aspects of PPAs, and assessment of financing alternatives; client won on all claims

PUBLICATIONS:

Goulding, AJ and Stella Jhang. "Secretary Perry's Grid Resiliency Pricing Rule: On Market Interventions and Minimizing the Damage." Columbia University. SIPA – Center on Global Energy Policy. October 2017.

Goulding, AJ. "Railroads, Utilities and Free Parking: What the Evolution of Transport Monopolies Tells Us About the Power Network of the Future." Columbia University. SIPA – Center on Global Energy Policy. November 2016.

Goulding, A.J. "A New Blueprint for Ontario's Electricity Market." C.D. Howe Institute. Commentary No. 389. September 2013.

Goulding, A.J. and Serkan Bahçeci. "Stand-by rate design: Current issues and possible innovations." *Electricity Journal*, June 2007, pp 87 – 96.

Goulding, A.J. and Bridgett Neely. "Picture of a Stalled Competitive Model" *Public Utilities Fortnightly*, February 2005, pp 35 - 42.

Goulding, A.J. and Bridgett Neely. "Acceding to Succeed" *Public Utilities Fortnightly*, July 2004.

Goulding, A.J. "Let's Get This Party Started: Why Ontario needs a competitive market" *Public Utilities Fortnightly*, May 2004, pp 16 - 20.

Goulding, A.J. and Nazli Z. Uludere. "Uncovering the *true value* in merchant generation" *Electricity Journal*, May 2004, pp 49-58.

Goulding, A.J. "On the Brink: Avoiding a Canadian California" *Public Utilities Fortnightly*, February 5, 2003.

Goulding, A.J., Julia Frayer, Jeffrey Waller. "X Marks the Spot: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly*, July 15, 2001.

Goulding, A.J., Julia Frayer, Nazli Z. Uludere. "Dancing with Goliath: Prospects After the Breakup of Ontario Hydro" *Public Utilities Fortnightly*, March 1, 2001.

Goulding, A.J., Carlos Rufin, and Greg Swinand. "Role of Vibrant Retail Electricity Markets in Assuring that Wholesale Power Markets Operate Effectively." *Electricity Journal*, December 1999.

Adamson, Seabron and A.J. Goulding. "The ABCs of Market Power Mitigation: Use of Auctioned Biddable Contracts to Enhance Competition in Generation Markets." *Electricity Journal*, March 1999.

Goulding, A.J. "Retreating from the Commanding Heights: Privatization in an Indian Context." Columbia University: *Journal of International Affairs*, Winter 1997, pp. 581-612.

Hass, Mark R. and A.J. Goulding. "Impact of Section 29 Tax Credits on Unconventional Gas Development and Gas Markets." Society of Petroleum Engineers: SPE 24889, presented at 67th Annual Technical Conference, Washington, DC, October 6, 1992.

SPEAKING ENGAGEMENTS:

"Considerations for policymakers regarding capacity mechanism design." Speaker, Independent Power Producers Society of Alberta ("IPPSA"). Calgary, Alberta, Canada. July 17th, 2017.

"Future Models for Utility Ownership and Regulation in Hawaii." Speaker, VERGE Hawaii: Asia Pacific Clean Energy Summit. Hilton Hawaiian Village, Honolulu, Hawaii, US. June 20th, 2017.

"Capacity Market Review: Workshop #2." Speaker, Independent Power Producers Society of Alberta ("IPPSA"). Calgary, Alberta, Canada. June 14th, 2017.

"Capacity Market Review: Workshop #1." Speaker, Independent Power Producers Society of Alberta ("IPPSA"). Calgary, Alberta, Canada. May 18th, 2017.

"Distributed Energy Resources: Regulatory Framework and Ratemaking Considerations." Speaker, CAMPUT Annual Conference 2017's CEA's Regulatory Innovation Task Group. Vancouver, British Columbia, Canada. May 10th, 2017.

"From Theory to Practice: Disruptive Technologies, Innovation and the Future of the Utility." Panelist, Northwind Professional Institute 13th Annual Electricity Invitational Forum, Langdon Hall, Cambridge, Ontario, Canada. January 27th, 2017.

"Ontario's Electricity Sector: Does the Current Institutional Framework Serve the Public Interest? Is it Times for Ontario to Consider a Fundamental Redesign?" Discussion

Leader, Northwind Professional Institute 11th Annual Electricity Invitational Forum, Langdon Hall, Cambridge, Ontario, Canada. January 30th, 2015.

"What's Next for Ontario's Electricity Market?" Panelist, C.D. Howe Institute Roundtable, Toronto, Ontario, Canada. September 16th, 2014.

"Prices and Costs, Why Rates Don't Tell the Whole Story" Speaker, Making Markets Work Symposium – Manning Centre, Calgary, Alberta, Canada. June 25th, 2014.

"Examining the Future Structure of Ontario's Electricity Market: Should Ontario Incorporate a Capacity Market or Alternative Structural Framework?" Panelist, Ontario Power Conference, Toronto, Ontario, Canada. April 15th, 2014.

"Electricity Prices – Economics, Public Policy, Technologies and Affordability" Panelist, CCRE Energy Leaders Roundtable, Hockley Valley Resort, Orangeville, Ontario, Canada. March 27th, 2014.

"Priorities for enhancing Ontario's electricity market: What direction forward?" Panelist, APPrO, Toronto, Ontario, Canada. November 20th, 2013.

"Evolving Regulation in Ontario: Best Practices from Other Jurisdictions" Panelist, Ontario Energy Association's ENERGYCONFERENCE13, Toronto, Ontario, Canada. September 11th, 2013.

"Points to consider when valuing hydro in the US" Speaker, HydroVision 2013, Denver, Colorado, US. July 26th, 2013.

"Pricing Power in Ontario: Perspectives and Competitive Analysis on the Future Direction of Ontario Electricity Rates" Panelist, Ontario Power, Toronto, Ontario, Canada. April 17th, 2013.

"Why Alberta* is *Still Standing" Panelist, Independent Power Producers Society of Alberta's 19th Annual Conference – Last Market Standing?, Alberta, Canada. March 11th, 2013.

"Market Evolution in the context of the EMF and the post-election environment" Panel Moderator, Association of Power Producers of Ontario, Toronto, Ontario, Canada. November 16th, 2011.

"Green Energy Economics" Panelist, Electricity Distributors Association's ENERCOM, Toronto, Ontario, Canada. March 30th, 2011.

"Projected Supply-Demand Balance in Ontario: A Call to Inaction" Speaker, APPrO, Toronto, Ontario, Canada. November 18th, 2010.

"Changes in electricity policy: what will it cost?" Speaker, 2010 Ontario Energy Association Annual Conference, Niagara Falls, Ontario, Canada. September 21st, 2010.

"Energy Infrastructure Spending" Debate Panelist, Canadian Association of Members of Public Utility Tribunals (CAMPUT), Montreal, Ontario, Canada. May 5th, 2010.

"Strategic implications of the Ontario Green Energy Act" Presentation to Ontario Energy Association Green Energy and Conservation Joint Sector Committee, Toronto, Ontario, Canada. June 24th, 2009.

"Strategic implications of evolution of North American utilities sector in response to environmental initiatives" Presentation to Mitsui Canada Leadership Forum, Toronto, Ontario, Canada. June 17th, 2009.

"Making retail competition work in electricity" Speaker, Illinois Commerce Commission Retail Competition Workshop, Chicago, Illinois, US. October 2nd, 2006.

"Gods and monsters: the role of the Ontario Power Authority in Ontario's hybrid market" Speaker, Ontario Energy Association annual conference, Niagara Falls, Ontario, Canada. September 14th, 2005.

"Transmission investment in today's power markets: key considerations" Presentation to the Wyoming Infrastructure Authority, Casper, Wyoming, US. May 26th, 2005.

"The true cost of power: comparing rates for power across Canada" Speaker, Independent Power Producers Society of Alberta conference, Banff, Alberta, Canada. March 15th, 2005.

"Key considerations with regards to resource adequacy mechanisms in Alberta." Speaker, Independent Power Producers Society of Alberta luncheon, Calgary, Alberta, Canada. November 3rd, 2004.

"Finding the silver lining: investment opportunities in Canadian power markets" Speaker, 2004 Canada Power Conference, Toronto, Ontario, Canada. September 30th, 2004.

"Adding value for the shareholder: Managing small utilities in a period of regulatory change." Speaker, Ontario Electricity Distributors Association, London, Ontario, Canada. June 8th, 2004.

"Case studies in electricity market design: learning from experience." Guest lecturer, Columbia University Center for Energy and Marine Policy graduate program, International Energy Systems and Business Structures class, New York, New York, US. April 8th, 2003.

"'The grass is always greener' vs. 'All of your eggs in one basket': investment outlook for California and foreign markets." Speaker, Platt's Global Power Markets Conference, New Orleans, Louisiana, US. March 31st, 2003.

"Transmission congestion, valuation, and investment issues in the region surrounding Ontario." Speaker, Canadian Institute conference on Inter-jurisdictional Power Transactions, Toronto, Ontario, Canada. April 8th, 2002.

"Update on new generation development in Alberta." Speaker, Canadian Institute Conference on Managing Electricity Price Volatility in Alberta, Calgary, Alberta, Canada. February 27th, 2002.

'The Alberta market structure and implications of structural change." Speaker, Insight Conferences Alberta Power Summit, Calgary, Alberta, Canada. February 22nd, 2002.

"Implications for developers of key aspects of competing Midwest ISO designs." Speaker, INFOCAST conference on Maximizing the Value of QFs and IPPs, Orlando, Florida, US. February 1st, 2001.

"Risk and rewards from PBR for US utilities: lessons from overseas." Speaker, UTECH 2000 conference, St. Petersburg, Florida, US. November 30th, 2000.

"Dancing with Goliath: increasing competition in Ontario wholesale generation market." Speaker, Canadian Independent Power conference, Toronto, Ontario, Canada. November 27th, 2000.

"Asset valuation in evolving global power markets." Speaker and case study facilitator, World Bank conference on Emerging Issues in the Power Sector, Washington, DC, US. April 19th-21st, 2000.

"Overseas exposure: is it worth the risk?" Speaker at Global Power Markets Conference, organized by Global Power Report and McGraw-Hill, New Orleans, Louisiana, US. April 16th -19th , 2000.

"Profiting from retail: challenges for MEUs." Speaker at conference on buying and selling electric utilities in Canada, organized by IBC USA conferences, Toronto, Ontario, Canada. November 15th-17th, 1999.

"Assessing the US electricity market and evaluating US targets." Facilitator for workshop on US acquisition opportunities for European energy firms, organized by IIR Limited, London, England. February 9th-11th, 1999.

Curriculum Vitae

Adam Hariri

Senior Consultant, London Economics International LLC

LONDON ECONOMICS

KEY QUALIFICATIONS:

Adam joined LEI in May of 2014. Since then has worked on a number of engagements covering North American markets. The majority of Adam's work experience has been in the Ontario, Alberta, and New York markets, and includes conducting an industry productivity study for a large Ontario generator, as well as evaluating the economic viability of two separate transmission projects in the New York State. He is also LEI's primary Ontario market modeller. Prior to his employment at LEI, Adam worked briefly in audit and consulting roles at Deloitte and Touche Middle East.

Adam completed his Master's in Economics at the University of Waterloo, and is a CFA charterholder.

EDUCATION:

University of Waterloo, Waterloo, Ontario, B.A. in Economics and Political Science, 2012.

University of Waterloo, Waterloo, Ontario, M.A. in Economics, 2014.

SAMPLE PROJECT EXPERIENCE:

- ***Review of electricity regulation in Newfoundland and Labrador:*** LEI was engaged by the Commission of Inquiry Respecting the Muskrat Falls Project to serve as an expert to the Inquiry in Newfoundland and Labrador. LEI's scope of work consisted of preparing a report addressing the following topics: a comparison of Newfoundland and Labrador's electricity regulation system relative to other jurisdictions across Canada; assessing the system's ability to deal with challenges stemming from interconnection, including energy marketing; exploring the province's energy policy; recommending changes to the province's electricity pricing model; and assessing the potential role for renewable energy generation expansion.

- ***Assessment of self-supply alternatives in Alberta:*** LEI was engaged by an industrial client in Alberta that was considering the addition of on-site gas peakers. LEI's scope of work consisted of identifying potential technology type candidates that would suit the client's needs, reviewing historical and projected site loads, developing a status quo estimation for the cost of delivered power rates, and finally creating a relative economic model that compared the use of on-site generation against the status quo.

- ***Price curve analysis:*** LEI was retained by a large generator as part of an asset sale to assess the suitability of its price curve included in their financial model, as well as qualitative considerations, primarily for the NYISO, Ontario, ISO-NE, PJM and MISO markets. LEI's assessment entailed providing a general commentary on the outlook for each market, an assessment of the suitability of the long-term prices in the relevant markets, and provision of relevant regulatory/political context as part of the outlook.

- ***Review of investment opportunities in the Middle East power sector:*** LEI was retained by a private middle eastern company in relation to developing a comprehensive study with a road map and implementation plan for its entrance in the Saudi and regional power sector. The key objective of this engagement was to determine where best the company should be positioned in the power generation ecosystem in the Kingdom of Saudi Arabia and the region, to create capacity and value. The assessment evaluated opportunities along the power sector value chain and across the following energy types: conventional, renewables (including hydro, wind, solar, geothermal and biomass), and nuclear.

- ***Analysis of potential implications with Ontario moving to nodal pricing***: As part of the IESO's energy-related market renewal efforts, LEI was engaged by a large utility to review the IESO's new and historical nodal pricing consultations, and assessed Ontario's differences between historical nodal and settlement prices, internal transmission constraints, inter-jurisdictional trade paths and potential wheel through transactions. A final paper presented LEI's analysis of potential impacts of nodal pricing and transmission constraints in Ontario on trading with a neighboring jurisdiction.

- ***Reviewed Manitoba cost of service methodology:*** LEI was retained by Hill Sokalski Walsh Olson ("HSWO") to provide independent evidence to assist the Manitoba Public Utilities Board ("PUB") in understanding the views and positions of the general service small and general service medium ("GSS/GSM") customers in Manitoba Hydro's 2017/18 & 2018/19 general rate application ("GRA") proceeding. In a PUB letter dated September 15, 2017, the scope of LEI's role was expanded to include key issues for the Keystone Agricultural Producers ("KAP"). LEI's analysis included the impact of the proposed rate increases of GSS, GSM and agricultural ratepayers, Manitoba Hydro's capital plan, and a review of the utility's operating efficiencies and service quality.

- ***Assessment of thermal generation assets in Canada:*** behalf of a private equity fund, LEI conducted an assessment of the re-contracting environment for gas plants in two Canadian provinces over the next 15 years. The engagement focused on reviewing the historic contracting of gas/thermal assets, the relevant political and regulatory context and outlook with respect to carbon targets and emissions performance standards, the need for gas plants as part of the supply mix, locational value in alleviating congestion and valuation of energy, capacity, ancillary service and export revenue streams.

- ***Resource adequacy market institutions workshop:*** LEI presented at IPPSA-sponsored workshops in Alberta findings on resource adequacy market institutions, specifically focusing on the installed capacity and locational installed capacity markets in the US. The workshops involved jurisdictional reviews of capacity mechanisms in PJM, ISO New England, NYISO, and MISO, issues facing the capacity mechanisms in those markets, as well as their relevance to Alberta.

- ***Risk assessment and capital structure review for Canadian gas distribution company:*** LEI was engaged by a large Canadian gas distributor to conduct an independent capital structure review to assess the reasonableness of their current common equity component. The project included completing an assessment of its business and financial risk profile compared to the last assessment that was reviewed by the regulator, completing an assessment of its business and financial risk compared to other comparable Canadian and U.S. utilities, estimating the cost of equity for groups of comparable risk utilities, examining information on average utility actual and allowed capital structures, comparing cost of equity estimates and information on average utility capital structures to its proposed cost of equity and capital structure, and, providing recommendations on the appropriate common equity level for the utility.

- ***Measuring delivered cost of electricity across Canadian provinces:*** Adam was part of a team that estimated and compared the delivered cost of electricity for all Canadian provinces over the 2011-2015 timeframe. In addition, LEI also forecasted how the delivered cost of electricity in Alberta could develop over the next fifteen years (2017-2031) under the Climate Leadership Plan ("CLP"). LEI forecasted energy, transmission, and distribution rate components, using three modeling scenarios in addition to a Base Case, evaluating different assumptions for renewable investments, demand levels, and reserve margin targets.

- ***Analysis into potential transmission development opportunities in New York:*** LEI was retained to conduct a mini-workshop on five proposed transmission projects in the US and Mexico. As part of this engagement, LEI reviewed the historical hourly energy prices and annual capacity prices at their sink and source locations to determine the magnitude of historical arbitrage opportunity, and discuss market developments that may impact the energy and capacity price arbitrage opportunity. Adam led the analysis for transmission projects based in New York.

- ***Industry TFP study for hydroelectric assets:*** LEI performed an industry productivity study on OPG's prescribed hydroelectric assets as part of the OEB mandate on implementing incentive ratemaking. Adam's role on this project included the addition of peers to the industry group, modeling and analyzing the industry productivity values, drafting the report which was submitted to the OEB.

- ***Cost-benefit assessment of New York transmission project:*** LEI was retained by a coalition of community groups and officials to investigate the costs and benefits of proposed transmission line projects across New York State. The study included reviewing the proposed projects from each of the applicants to identify key characteristics of each project, as well as modeling the current New York markets to assess the need for new transmission infrastructure.

TAB 3

Demand response programs in selected US markets

prepared for the Ontario Energy Board staff by London Economics International LLC ("LEI")

November 8th, 2019

Federal Energy Regulatory Commission ("FERC") Order 745 established that demand response resources participating in organized wholesale energy markets (day-ahead and real-time) would be compensated through the payment of the locational marginal price for curtailing their load if dispatched. However, Order 745 did not directly impact the majority of demand response resources participating in programs administered by the two US Independent System Operators ("ISO") and one Regional Transmission Organization ("RTO") that LEI reviewed, as these demand-side resources tended to serve more as capacity providers. Demand response resources as capacity providers make up the majority of demand-side participation in the ISO and RTO programs that LEI reviewed, and capacity payments make up the bulk of their total compensation (although additional payments are made if these resources are actually activated). In contrast, the total dispatch of demand response resources through ISO and RTO programs reviewed by LEI was low, as were revenues associated with dispatch.

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1 LEI scope of work

London Economics International LLC ("LEI") was retained to assist Ontario Energy Board ("OEB") staff by providing context around demand response ("DR") resource participation in a selection of US markets at the Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") level, as well as the applicability of Federal Energy Regulatory Commission ("FERC") Order 745 to programs offered by these markets.

LEI's scope of work included the provision of a summary of Order 745 and its scope, as well as the net benefits test methodology. The research was to focus on how DR resources are compensated in US markets, including consideration for energy, capacity or other kinds of payments. OEB staff also asked LEI to identify key contextual differences between the Ontario electricity sector and the US electricity markets subject to FERC Order 745. Other key areas to be described included how load customers participate in the respective electricity markets, how the energy they consume is priced, and how US markets reconcile wholesale market dispatchability with fixed retail rates.

2 Executive summary

FERC Order 745 relates to the compensation of DR resources participating in organized wholesale energy markets (day-ahead and real-time). Order 745 requires that DR resources participating in these markets be compensated through the payment of the locational marginal price ("LMP") for curtailing their load if dispatched.[1] In Order 745, the Commission identified a number of barriers to entry for DR resources, which included a disconnect between the price that load pays to consume and the wholesale price in any one hour (e.g. load paying rates that are less dynamic than actual wholesale prices on an hourly basis). Payment of the LMP to DR was therefore meant, at least in part, to address this disconnect between wholesale and retail rates. Order 745 is not concerned with DR participation in capacity markets, compensation in ancillary services markets, DR programs administered at the state/utility level, nor ISO- and RTO-level programs administered for reliability or emergency conditions.

In responding to the questions posed by the OEB, LEI focused on ISO- and RTO-level programs in three markets: PJM, ISO-NE, and NYISO. A summary of selected information around these programs, participation, as well as system-wide peak demand and load (for context), are presented in Figure 1.

Figure 1. Summary of demand response programs and information by ISO/RTO

ISO/RTO	NYISO					ISO-NE			PJM			Ontario
Demand side resource program	Special Case Resource	Emergency Demand Response Program	Day Ahead Demand Response Program	Demand-Side Ancillary Services Program	System-wide data	Passive	Active	System-wide data	Emergency/ pre-emergency	Economic	System-wide data	DR Auction
Can participate in market as and receive compensation for:	Capacity[a]	Emergency[a]	Energy	Operating reserves and regulation services		Capacity	Capacity, energy, operating reserve		Capacity[a]	Energy, operating reserves		Capacity
Considered dispatchable by ISO?	No	No	Yes	Yes		No	Yes		No	Yes		
Does Order 745 apply?	No	No	Yes	Yes		No	Yes		No	Yes		
2018 enrollment/ participation (MW)	1,309	18	0	116.5[b]		2,580.1[c]	365.7[c]		8,946	2,512		550.4*
2018 dispatch (GWh)[d]			0				18.1[e]			49.186[f]		
2018 peak demand (MW)					31,861			26,024			147,042	23,240
2018 load (GWh)					161,114			123,306			791,093	137,400

[a] can also receive activation payments; [b] capability over the May to October 2018 period; [c] capacity supply obligation for August 2018; [d] DR dispatched through these programs; [e] day-ahead dispatch for June to December 2018; [e] in day-ahead and real-time; * For Summer 2018 commitment period. DR procured through the auction take two forms, virtual and physical. Virtual resources, which are non-dispatchable, made up 407 MW of cleared capacity; 31.4 MW of physical resources were non-dispatchable and 112 MW were dispatchable. Dispatchable loads in Ontario can also provide and receive compensation for the provision of operating reserves.

[1] LMPs differentiate the price of electricity at each production and consumption node on the system, based on locational supply and demand conditions as well as congestion and losses. This contrasts with the current system in Ontario which has a single system-wide market clearing price.

In PJM and NYISO, DR programs are currently broken down into economic (energy and ancillary services, dispatchable) and reliability/emergency (capacity, non-dispatchable). The majority of DR in these two markets participate on the capacity side, in programs that Order 745 does not apply to.[2] Additionally, actual dispatch of economic DR on the energy side is extremely low. Noteworthy, however, is that DR participating on the capacity side can receive payments (in $/MWh) if actually activated (e.g. during an emergency or reliability event).

ISO-NE's structure differs from PJM and NYISO, in that its groupings are broken down into two 'demand resources' (also referred to as demand response). 'Passive demand resources' are non-dispatchable, and can only provide capacity. 'Active demand resources' are dispatchable, and active resources with a capacity obligation have must-offer rules in the energy market. Because of this, most active DR in the energy market submits at or close to the offer cap. Most demand-side capacity is provided by passive resources, and active demand resources are dispatched at very low levels in the energy market. Order 745 only applies to active demand resources.

While the three US markets do distinguish between dispatchable and non-dispatchable resources, there are some differences compared to the Ontario context. For PJM and NYISO, DR resources in emergency/reliability programs are non-dispatchable from the RTO/ISO's perspective as they are activated outside of the RTO/ISO's dispatch system (e.g. manual activation), even though these resources reduce their load upon instruction from the RTO/ISO given adequate lead time. In ISO-NE, non-dispatchable resources cannot reduce their load in response to dispatch instructions. In contrast, LEI's understanding is that dispatchability of DR in the Ontario context is centered around whether the resource can respond to 5-minute schedules from the IESO.

As most DR resources participate on the capacity side, and actual dispatch on the energy side for those that participate in these programs is quite low, compensation for demand response participating in these RTO/ISO programs is mostly related to capacity payments, as can be seen in Figure 2 (all dollar values shown in this report are in US terms unless otherwise noted). Ancillary service payments for those demand-side resources that are capable of providing them can often form the next largest revenue stream, although this is low in aggregate. Payment from dispatch in the energy markets for demand response resources is also quite low, as are activation payments for reliability and emergency-related programs in NYISO and PJM.

Figure 2. Demand response resource revenues in ISO-NE and PJM ($ million)

Market	Capacity	Energy	Ancillary Services
PJM	$577.1	$2.9	$6.1
ISO-NE	$89.0	$3.6	n/a

Note: ISO-NE shows three-year average demand response revenues from 2012 to 2014; similar data for more recent years was not readily available, but as capacity prices have risen in ISO-NE, capacity would most likely make up a large proportion of total revenues. PJM shows three-year average total demand response revenues from 2016 to 2018. Comparable data for NYISO was not readily available.
Sources: ISO-NE's Annual Market Reports, PJM's state of the market reports.

[2] "… the Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions." Source: FERC. *Demand Response Compensation in Organized Wholesale Energy Markets [Docket No. RM10-17-000; Order No. 745].* Issued March 15, 2011.

3 Overview of FERC Order 745

The Federal Energy Regulatory Commission ("FERC") Order 745 amended regulation under the *Federal Power Act* in relation to the compensation of demand response ("DR") resources participating in organized wholesale energy markets (i.e. day-ahead and real time markets) administered by ISOs or RTOs. According to Order 745, demand response resources participating in organized wholesale energy markets **must** be compensated when providing services to the energy market at the market price for energy (the locational marginal price or "LMP"), but **only** when the following two conditions are met:

1. the DR resource has the capability to balance supply and demand as an alternative to a generation resource; and
2. the dispatch of that DR resource, and the payment of LMP for this dispatch, is cost-effective as determined by the 'net benefits test'.[3]

3.1 What Order 745 applies to

According to information contained in Order 745, demand response can generally take the following two forms:

1. customers reduce demand by responding to retail rates that are based on wholesale prices; and
2. customers provide demand response that acts as a resource in organized wholesale energy markets to balance supply and demand (the focus of this proceeding).

> *"**Demand response** means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy"*
>
> *"**Demand response resource** means a resource capable of providing demand response"*
>
> Definitions contained in Order 745

Order 745 only applies to demand response resources participating in day-ahead or real-time energy markets administered by US ISOs or RTOs, that can balance the system through load reduction when dispatched, with this load reduction being compared to an expected level of consumption and undertaken in response to price signals.[4] The FERC Order[5] therefore applies to DR resources that can be viewed similar to generation resources, and as discussed in FERC Order 745-A (and originally covered in FERC Order 719), such DR resources must be "technically capable of providing the ancillary service" and "submit a bid under the generally-applicable bidding rules."[6]

[3] FERC. *Demand Response Compensation in Organized Wholesale Energy Markets [Docket No. RM10-17-000; Order No. 745].* Issued March 15, 2011.

[4] Ibid.

[5] Usage of 'the FERC Order' in LEI's report refers to Order 745.

[6] FERC. *Order No. 745-A: Order on Rehearing and Clarification*. Issued December 15, 2011.

The FERC Order **does not** apply to:

- **state-level efforts**, including state and/or utility retail-level price-responsive demand initiatives based on dynamic and time-differentiated retail prices and utility investments in demand response enabling technologies;
- DR participating in RTO and ISO programs administered for **reliability or emergency** conditions;
- compensation in **ancillary services** markets (which the FERC has addressed elsewhere); and
- **capacity** markets.[7]

3.2 Net benefits test

A DR resource participating in a wholesale energy market would theoretically be dispatched when it is the incremental resource with the lowest bid. However, under certain situations, dispatching this DR resource could result in a higher cost per unit for all remaining load (compared to a situation where the next-lowest-bid incremental resource was dispatched), and therefore dispatching the DR resource would not be cost-effective.[8] In an attempt to deal with such situations, Order 745 requires each RTO and ISO to implement and perform a **net benefits test**, to determine whether the dispatch of a demand response resource is cost-effective.

3.2.1 Generalized approach

According to FERC, a DR resource can be considered cost-effective compared to alternative generation resources under the conditions that:

- LMP is reduced (due to the dispatch of the DR resource) and the remaining market load achieves cost savings due to this LMP reduction; and
- the cost savings from dispatching the DR resource are greater than the total cost to consumers for paying the DR resource the LMP, as well as the effect of the reduction in load paying for the purchased supply resources.

To establish cost-effectiveness, a price threshold must therefore be estimated, where the overall benefit from the LMP reduction due to the DR resource dispatch is greater than the cost of dispatching that DR resource, and a net benefit occurs. With this in mind, Order 745 requires each RTO and ISO to approximate conditions under which it is cost-effective for demand resources to be dispatched and receive the LMP. More specifically, ISOs and RTOs were directed to approximate, updated on a monthly basis, the "*threshold price corresponding to the point along the supply stack at 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.*"[9] This

[7] As some US RTOs and ISOs do not have capacity markets, and for those that do DR resources are not always obligated or able to participate in wholesale energy markets.

[8] This potential result is referred to as the 'billing unit effect' of dispatching DR.

[9] In Order 745, the FERC acknowledges that this monthly price threshold method may be less precise than a more dynamic approach that integrates a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs, but also acknowledges that modification to ISO and RTO dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term.

approximation would be done through analysis based on historical data and updates for condition changes (e.g. supply-side availability and fuel prices).

3.2.2 Net benefits test methodology

Conceptually, the net benefits test methodology requires RTOs and ISOs to calculate the pricing point on the supply curve where price elasticity of supply changes from greater than one to less than one (i.e. the point where percent changes in the prices result in same percent changes of supply).

An RTO/ISO's typical approach in determining the net benefits test price levels involves six steps as shown in the Figure 3 below.

Figure 3. Methodology to determine the Net Benefits Test price

Steps	Details
Step 1	Retrieve generation offers from the corresponding month of a previous year (reference month)
Step 2	Apply fuel cost adjustment (year-on-year change by using futures price of fuel and average spot price of fuel in a reference month) to the portion of the offers that typically represents fuel costs
Step 3	Build daily supply curves for the month
Step 4	Build monthly average supply curve
Step 5	Use non-linear least squares estimation technique to calculate an equation that smooths the supply curve
Step 6	Calculate the price level at which the elasticity is equal to 1

Source: *PJM Manual 11: Energy & Ancillary Services Market Operations, Section 10: Overview of the Demand Resource Participation*. Dec 20, 2018

An intuitive way to view the net benefits test ("NBT") is that it enables determination of the price level where the cost of the next generating unit after the DR is not high enough to offset the billing unit effect of the demand response resource dispatch would have on the remaining load. Figure 4 demonstrates the billing unit effect of DR and the circumstances when:

- the dispatch of DR resources results in net benefit to consumers (Scenario 3, when the next marginal generating unit is sufficiently more expensive than the DR resource to offset the billing unit effect of reduced load paying for supply);
- such dispatch would result in net costs to consumers (Scenario 1, because the next marginal generating unit's cost is too close to the DR's offer and does not offset the increased cost of electricity per MWh of load); and
- when there is a zero net benefit from dispatching the DR resources, i.e. the price point target of the Net Benefits Test (Scenario 2).

Figure 4. Illustrative application of net benefits test

			Scenario 1		Scenario 2		Scenario 3	
			MWh	LMP, $/MWh	MWh	LMP, $/MWh	MWh	LMP, $/MWh
Demand	Regular load		10,000		10,000		10,000	
	DR load		100		100		100	
Supply	Suppliers A - R		9,000	$ 50	9,000	$ 50	9,000	$ 50
	Supplier S		800	$ 60	800	$ 60	800	$ 60
	Supplier T		100	$ 70	100	$ 70	100	$ 70
	Supplier U		100	$ 100	100	$ 100	100	$ 100
	DR resource		**100**	**$ 1,000**	**100**	**$ 1,000**	**100**	**$ 1,000**
	Supplier V		100	$ 1,001	100	$ 1,062	100	$ 1,100
			No DR deployment	DR deployment	No DR deployment	DR deployment	No DR deployment	DR deployment
Cost of supply	Suppliers A - R	= 9,000 MWh * $50	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
	Supplier S	= 800 MWh * $60	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000
	Supplier T	= 100 MWh * $70	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000
	Supplier U	= 100 MWh * $100	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
	DR resource	**= 100 MWh * $1,000**	**$ -**	**$ 100,000**	**$ -**	**$ 100,000**	**$ -**	**$ 100,000**
	Supplier V	= 100 MWh * LMP	$ 100,100	$ -	$ 106,200	$ -	$ 110,000	$ -
	Total cost of supply for the hour ($)		$ 615,100	$ 615,000	$ 621,200	$ 615,000	$ 625,000	$ 615,000
	Total load to be supplied in the hour (MWh)		10,100	10,000	10,100	10,000	10,100	10,000
	Zonal price for the hour, i.e. cost of electricity paid by load ($/MWh)		**$ 60.90 <**	**$ 61.50**	**$ 61.50 =**	**$ 61.50**	**$ 61.88 >**	**$ 61.50**

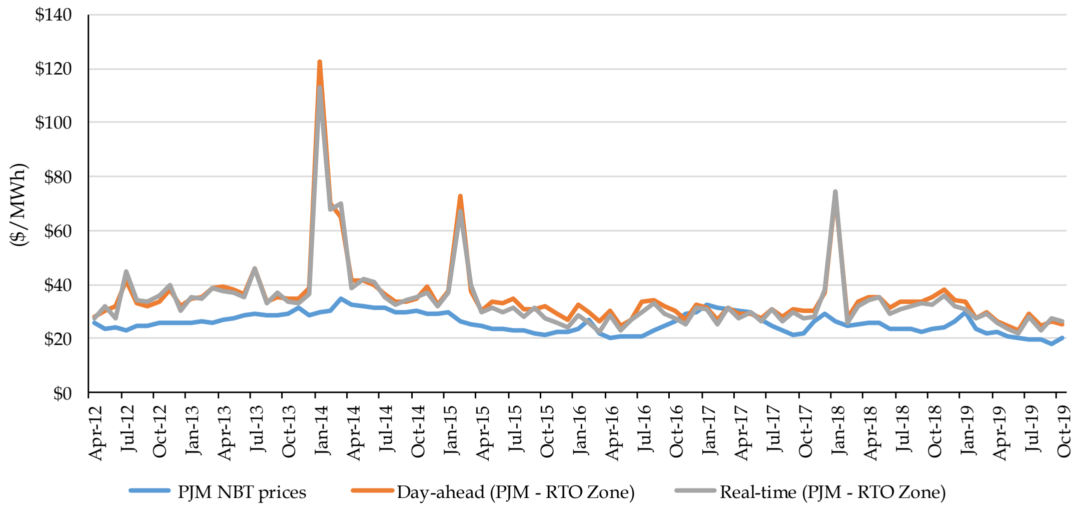
Source: *LEI calculations based on FERC Order 745*

Using PJM as an example, Figure 5 presents for illustrative purposes PJM's monthly NBT prices from April 2012 to October 2019, along with the monthly average prices for PJM – RTO Zone (this chart is illustrative as the test is actually applied to each applicable zone on an hourly basis). Dispatched DR resources are paid LMP times MWh of reduced load only for the hours where the applicable zonal LMP is greater than or equal to the month's NBT price.[10] Based on this figure, real-time and day-ahead prices were almost always higher than PJM's NBT price, and it is likely that across the RTO in most months, on average, DR resources were economic to dispatch

[10] PJM Manual 28: Operating Agreement Accounting," § 11.2.2 Economic Load Response Program, Rev. 81 (Oct. 25, 2018).

(assuming, of course, that monthly PJM – RTO Zone prices are representative of hourly zonal prices).

Figure 5. NBT prices versus real-time and day-ahead prices in PJM



Source: PJM. *Historical results of net benefits test calculations; Energy Velocity*

3.3 Wholesale – retail disconnect

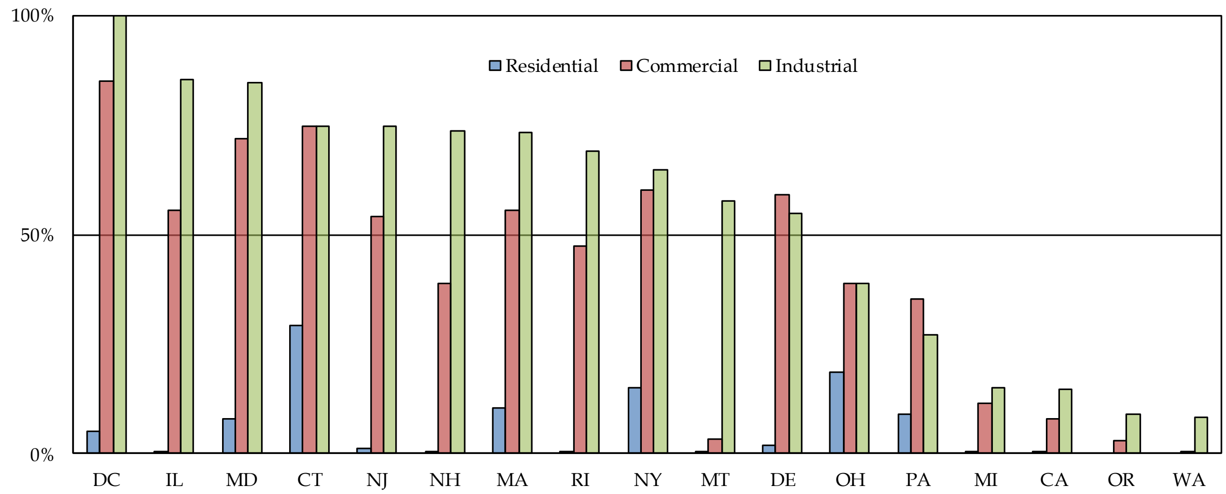
Wholesale electricity prices are dynamic. When retail customers pay for their consumption based on rates that do not reflect volatile potentially higher electricity prices in a given hour, for the hour in which their consumption occurs, this leads to a disconnect. For example, as customers on fixed price retail contracts are not impacted by the wholesale electricity cost for a given hour in which they are consuming, they are not incentivized to reduce consumption in the hours where large wholesale price spikes occur. As this was one of the key issues in the FERC proceeding, this section covers some of the matters around this disconnect. First, context around the retail choice situation in the US prior to the FERC Order is provided in Section 3.3.1. Then, discussion of the disconnect between retail rates and wholesale prices from within Order 745 appears in Section 3.3.2.

3.3.1 Contextual background: Retail choice situation in the US prior to the FERC Order

In the US, FERC's authority is at the wholesale market level (e.g. NYISO, PJM, ISO-NE), while the sale of electricity to end users ("retail") and their associated rates ("retail rates") are outside of FERC's jurisdiction. Retail rate design and retail electricity choice (i.e. allowing end-use customers to buy electricity from competitive retail suppliers instead of a default provider) falls under state-level jurisdiction. The demand response issue therefore creates additional layers of administrative complexity, as it encompasses both the retail and wholesale level.

According to the US Energy Information Administration ("EIA"), in 2010 (the year before FERC Order 745), 17 states and the District of Columbia had adopted electric retail choice programs. As shown in Figure 6, although residential participation in competitive retail (i.e. choosing a retail provider other than their default) was low, commercial and industrial participation was much more active, with a number of states mostly in the geographic Northeastern US (and part of either ISO-NE, NYISO, and PJM) having a majority of retail load served by competitive suppliers.

Figure 6. % of retail sales from competitive suppliers by state and customer class (2010)



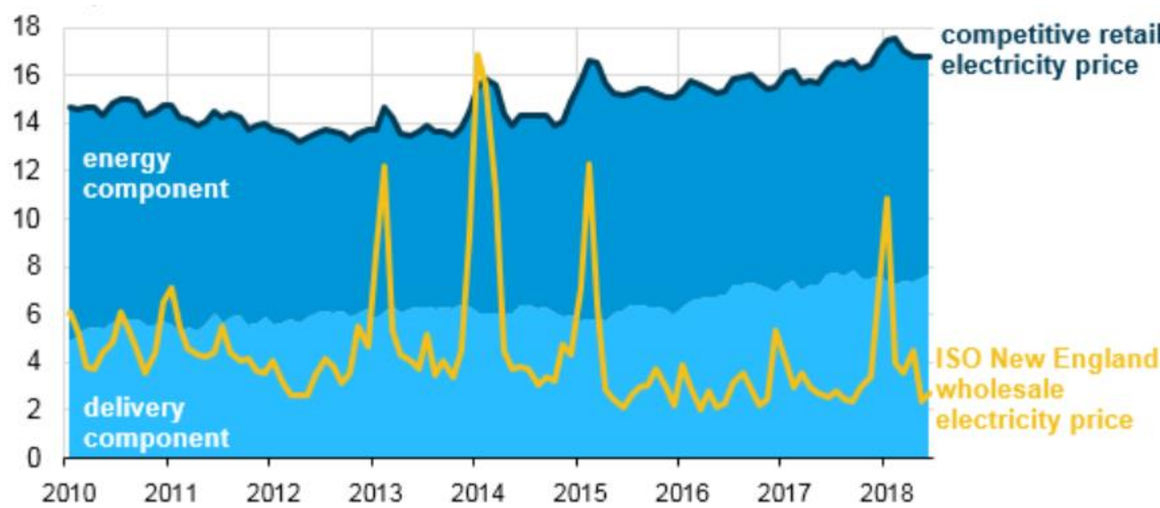
Notes: Texas is not shown since "participation is mandated" for all customers served by investor-owned utilities located within ERCOT, but according to the EIA around 60% of all customers (residential, commercial, and industrial) buy electricity from competitive retailers; Maine had retail choice, but is not included because of "reporting issues"; the District of Columbia only had one industrial customer.
Sources: US EIA. *State electric retail choice programs are popular with commercial and industrial customers*. May 14, 2012; US EIA Form EIA-861 data for 2010.

While there is a linkage between participation in a wholesale market and allowance of retail electricity choice, it is not direct; some states that are part of restructured wholesale markets do not have full retail choice, while other states that have retail choice may not be part of wholesale markets.[11] For example, although Georgia is not part of an organized wholesale market, retail electricity choice is available for large industrial and commercial customers, and according to the Southern Company CEO, around 40% to 50% of Georgia Power (the largest provider in the state) industrial and commercial load is subject to the utility's real-time pricing schedule.[12]

Within states that are both part of a wholesale market and allow retail electricity choice, there can still be a disconnect between the retail rates and the wholesale price volatility at the hourly and even monthly level. This can be seen in Figure 7, which shows the monthly competitive retail rates (with the energy component in the dark shaded blue) along with the monthly wholesale price in ISO-NE from 2010 to 2018. While the energy component of competitive retail rates is mostly higher than wholesale prices, periods of large price spikes in the wholesale market do not cause price spikes in the retail rates of close to the same magnitude.

[11] US National Renewable Energy Laboratory. *An Introduction to Retail Electricity Choice in the United States*. August 2017.
[12] S&P Global. *Hot temperatures, heavy loads drive Southern Company earnings growth*. October 30, 2019.

Figure 7. Monthly competitive retail and wholesale electricity prices in NE (¢/kWh)



Taken directly from: US EIA. *New England's competitive electricity markets lead to less price volatility*. October 31, 2018.

Issues around wholesale and retail rates were a key part of Order 745 (discussed in the upcoming Section 3.3.2). Even before Order 745 however, some US ISOs and RTOs had already implemented rules around the compensation of demand response resources participating at the wholesale level, to deal with the issue of wholesale – retail disconnect. For example, from November 2007 until March 2012 PJM compensated economic DR based on the difference between the LMP and the generation and transmission portions of the retail price. According to PJM, this "LMP-G&T" structure was developed precisely to "foster customers with fixed retail prices to reduce load when wholesale prices were high", as "without a price signal, retail customers have minimal financial motivation to reduce or shift their load since it may not result in a reduction in electricity costs for the customer."[13]

3.3.2 Discussion within Order 745 of the wholesale – retail disconnect and perceived barriers to DR

This section isolates some of the arguments made in Order 745 and Order 745-A related to retail rates, the disconnect between these rates and wholesale prices, and the impact this disconnect had on the Commission's decision.[14]

One of the main arguments against Order 745 as established related to the full payment of LMP to dispatched DR. An alternative suggestion, made by a number of parties and supported by FERC Commissioner Moeller in his dissenting view, was to subtract the cost associated with the avoided load from LMP (LMP minus G, with G referring to the generation component of retail

[13] PJM Interconnection. *2012 Economic Demand Response Performance Report: Analysis of Economic DR participation in the PJM wholesale energy market after the implementation of Order 745*. March 25, 2013.

[14] The focus here is only on certain aspects of the retail discussion contained in Order 745 and Order 745-A, and is not intended to be a comprehensive exposition of every question that arose with respect to the FERC proceeding.

rates). The argument in favour of this approach was that paying full LMP could result in over-payment as DR resources both avoid paying G and receive the LMP for dispatched load curtailments. Without the G offset, the payments fail to account for savings associated with the DR resource responding to curtailment.[15]

The Commission noted that incorporation of retail rates into wholesale payments made to dispatched DR resources would be "perhaps feasible" but would "create practical difficulties for a number of parties, including state commissions and ISOs and RTOs." The Commission ultimately disagreed with this LMP minus G position, in part because arguments in its favour "fail to acknowledge the market imperfections caused by the existing barriers to demand response."[16]

> *"Paying LMP to demand resources will help address the lack of a direct connection between wholesale and retail prices and the lack of dynamic retail prices by providing those customers that can respond to price signals with the accurate market price signal for such response."*
>
> Order 745-A

Some of the barriers that the Commission identified include a lack of direct connection between wholesale and retail prices, and a lack of dynamic retail prices (retail prices that change as the marginal wholesale costs change). According to the Commission, this demonstrates that customers "do not have the ability to respond to the often volatile price changes in the wholesale market and demonstrate the need for including demand response as part of wholesale market design." It is under these circumstances the Commission found that, in order to establish just and reasonable prices, demand response that can participate in the wholesale market should be paid the marginal value of its contribution. Given the barriers, the payment of LMP is "appropriate as it represents the value of the contribution of demand to the market during those periods in which demand response provides net benefits."[17]

[15] FERC. *Demand Response Compensation in Organized Wholesale Energy Markets [Docket No. RM10-17-000; Order No. 745].* Issued March 15, 2011.

[16] Ibid.

[17] FERC. *Order No. 745-A: Order on Rehearing and Clarification*. Issued December 15, 2011.

4 Demand response in selected US markets

This section covers two US ISOs and one RTO: PJM, ISO-New England, and New York ISO, all of which are in reasonable proximity to Ontario. All three of these ISOs (hereafter the term ISO should be assumed to encompass PJM as well) have both energy and capacity markets. Compensation from the energy market is paid in $/MWh terms (for utilization), while compensation from the capacity market is paid in $/kW-month or $/MW-day terms (for reservation, which pays resources for their availability to be utilized if needed). The demand response programs in these three ISOs, and the revenue streams available to them, are first covered in: Section 4.1 for PJM; Section 4.2 for NYISO; and Section 4.3 for ISO-NE. Once a background into the demand response programs in these three ISOs has been established, cross-cutting analysis and observations are presented in Section 4.4.

4.1 PJM

Currently there are two main categories of demand response programs in PJM, and one new category that becomes effective in 2020:

- economic DR;
- emergency DR; and
- (new category) Price Responsive Demand ("PRD").

The ***economic DR*** can participate in:

- energy markets (day-ahead and real-time);
- ancillary services:
    - day ahead scheduling reserve (30 minutes);
    - synchronized reserves (10 minutes); and
    - regulation.

The economic DR bids on a voluntary basis into real-time and day-ahead energy markets, and if it clears the market, it is to be dispatched along with generating resources, and as such its curtailment (when cleared in the marketplace) is termed as "dispatchable curtailment." Energy payments to economic DR resources are paid by loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[18]

The ***emergency DR*** includes both emergency and pre-emergency DR resources, and the registration options include:

- load management capacity only resources;

[18] PJM Manual 28: Operating Agreement Accounting," § 11.2.2 Economic Load Response Program, Rev. 81 (Oct. 25, 2018).

- load management capacity and energy resources; and
- emergency energy only DR resources.

DR resources under the first two registration options can be curtailed in emergency conditions (further details below) on a mandatory basis, while emergency energy only DR resources can be curtailed only on a voluntary basis.

DR resources under the load management capacity-only registration are paid the capacity prices, and when activated are not paid energy payments. Only 1.2% of DR load management resources were registered as capacity-only for the 2018/19 delivery year.[19] The remaining two (load management capacity and energy, and emergency energy only) allow DR resources to get paid the higher of the "minimum dispatch price" or LMP for when they are curtailed. The minimum dispatch prices are set once for the delivery year. The energy payment for curtailment is the minimum dispatch price or LMP, whichever is higher and is calculated on a $/MWh basis, plus shutdown costs, which are one time payments for each curtailment instance per nominated MW. For delivery year 2018/2019, only 7.2% of nominated capacity for resources had minimum dispatch prices below $1,100, as can be seen in Figure 8. The majority of nominated capacity (53.4%) had minimum dispatch prices at or close to the maximum price ($1,849).

Figure 8. Distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices: 2018/2019 delivery year

Range of minimum dispatch price ($/MWh)	Locations	Percent of total (%)	Nominated MW (ICAP)	Percent of total
$0 - $1,100	383	2.8%	637.5	7.2%
$1,100 - $1,275	2,235	16.4%	3,069.9	34.6%
$1,275 - $1,550	325	2.4%	380.6	4.3%
$1,550 - $1,849	10,695	78.4%	4,776.1	53.9%
Total	**13,638**	**100.0%**	**8,864.1**	**100.0%**

Source: Monitoring Analytics LLC. *2018 PJM State of the Market Report,* March 14, 2019

A **DR resource may be registered as either** program participant (**economic DR** or **emergency DR**) **or both**, depending on circumstances and eligibility.[20]

PRD is an annual capacity resource nominated by a PRD provider (e.g. a Load Serving Entity or "LSE"). The customer load behind PRD must be on dynamic retail rates and a PRD provider must have capability to remotely reduce load at customer locations. There are no capacity market payments as PRD reduces the capacity that must be purchased by an LSE, and thus reduces the LSE's capacity payments (additionally, there are no energy payments for activation). Instead the

[19] *Monitoring Analytics. 2018 State of the Market Report for PJM: Section 6 – Demand Response.*
[20] PJM End Use Customer Factsheet. *Demand Response and Why It's Important*.

PRD provider receives a Daily PRD Credit,[21] which is applied to the LSE's Locational Reliability Charge (capacity payments).[22] PRD meets its obligation when LMPs are at or above the price threshold specified in its PRD plan and only when PJM declares a maximum emergency event, i.e. when emergency/pre-emergency DR resources and emergency energy DR sources are fully utilized and additional load reductions are required ("Deploy All Resources" emergency action in Figure 10 covered later). PRD is a new product that first cleared the Reliability Pricing Model ("RPM", the name of PJM's capacity market) for the 2020/2021 delivery year. Figure 9 compares different DR programs for dispatch requirements and sources of revenue.

Figure 9. PJM DR programs

	Economic DR	Emergency and pre-emergency DR			Price Responsive Demand
		Load management capacity only	**Load management full (capacity and energy*)**	**Emergency energy* only**	
Can be compensated for	Energy, ancillary services	Capacity only	Capacity and Energy*	Energy* only	Capacity only
Capacity market participation	No	RPM	RPM	No	RPM
Curtailment type	Dispatched curtailment	Mandatory curtailment	Mandatory curtailment	Voluntary curtailment	Price threshold specified in PRD plan
Capacity payments	No	RPM clearing price	RPM clearing price	No	Avoided capacity costs
Energy payments	Full LMP	No energy payments for activation	Higher of ***minimum dispatch price*** or LMP (paid for declared Emergency Event mandatory curtailment)	Higher of ***minimum dispatch price*** or LMP (paid only for voluntary curtailment)	No energy payment for activation

*Energy payments when activated
Source: Monitoring Analytics LLC. *2018 PJM State of the Market Report.* March 14, 2019.

4.1.1 DR deployment in PJM

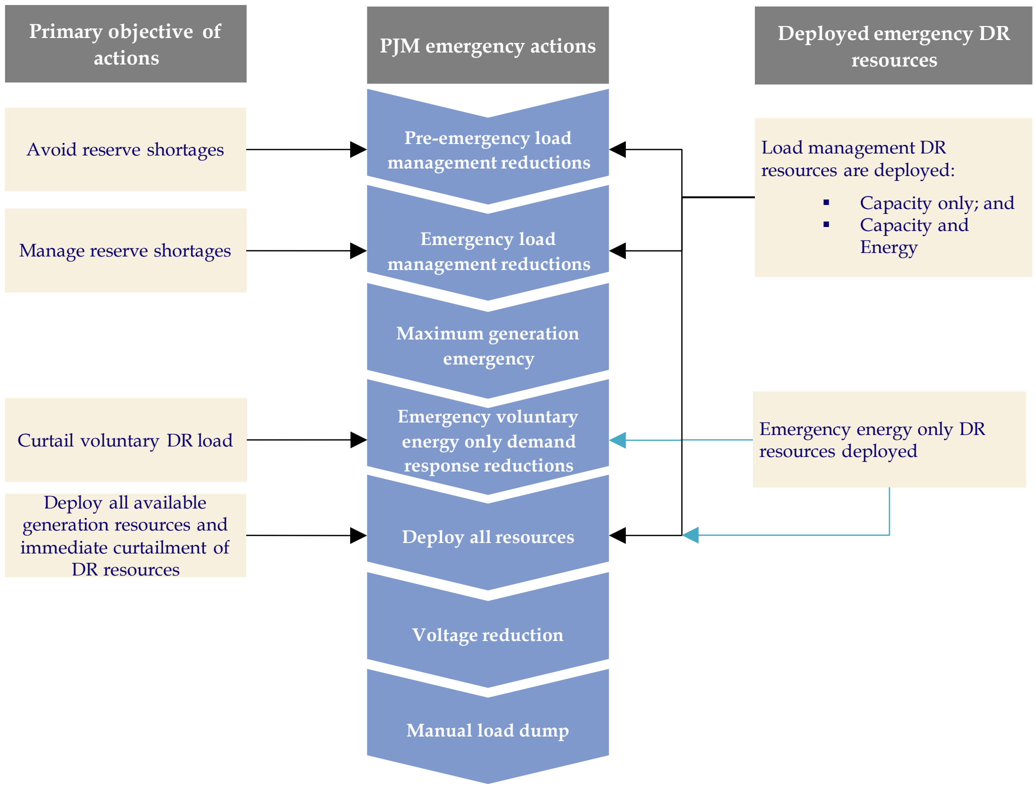
The economic DR resources are deployed along with generation resources in the energy markets, both real-time and day-ahead, i.e. dispatched curtailment.

The emergency DR resources are deployed in the order of severity of emergency conditions. There are seven actions that PJM can take in emergency conditions, and emergency DR is

[21] Daily PRD Credit is a product of final zonal capacity prices (in $/MW-day) and PRD nominal value (in MW).
[22] Locational Reliability Charge ($/day) is equal to the Unforced Capacity Obligation (in MW) of the LSE multiplied by the final zonal capacity price (in $/MW-day). After the Daily PRD Credit is applied, the LSE owes Net Load Charge ($/day), i.e. Locational Reliability Charge minus Daily PRD Credit.

deployed in four of these. The actual sequence of PJM actions may vary and can be implemented in any order that is required. Figure 10 shows PJM's emergency actions (in nominal order of severity), types of emergency DR deployed along with the corresponding objectives of the actions that are applicable to DR.

Figure 10. Current emergency actions and DR deployment in PJM



Source: PJM. *Demand Response Overview*. October 8, 2019

4.1.2 DR statistics in PJM

Since 2010, enrollment in economic DR programs in PJM has fluctuated but stayed above 2,000 MW, while enrollment in emergency DR programs also fluctuated but stayed above 8,000 MW. Combined, these resources accounted for between 6% and 9% of PJM's peak demand between 2012 and 2018 (based on unique DR capacity, as resources can be registered as both emergency and economic DR). Figure 11 shows enrollment statistics over the 2010 to 2018 timeframe.

Figure 11. DR enrollment MW statistics (2010-2018)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Economic DR program	2,441	2,252	2,204	2,660	2,955	3,456	2,597	2,269	2,512
Emergency DR (emergency and pre-emergency)	1,091	3,091	8,552	8,967	9,360	11,635	8,749	9,123	8,946
Emergency Interruptible Load for Reliability	7,961	8,731	*discountinued - - -*						
Total unique DR capacity	n/a	n/a	8,781	9,901	10,437	12,952	9,836	9,520	9,294
Total DR capacity as percent of PJM peak demand			6%	6%	7%	9%	6%	7%	6%
PJM peak demand	136,465	158,016	154,344	157,508	141,673	143,697	152,177	142,387	147,042
PJM installed capacity	154,074	170,481	173,414	183,095	183,724	177,683	182,449	183,882	185,952

Notes: ATSI transmission zone was integrated into PJM in 2011, accounting for the majority of increase in peak demand and installed capacity from 2010 to 2011; installed capacity refers to average offered capacity as reported by the Independent Market Monitor; Emergency Interruptible Load for Reliability was discontinued in 2012 and merged with the Emergency DR program; PJM's DR activity reports did not report unique DR capacity for 2010 and 2011.

Source: Monitoring Analytics LLC. *2010-2018 PJM State of the Market Reports;* PJM. *2010-2018 Demand Response Operations: Markets Activity Reports*

Among the sources of revenue for DR resources in PJM, capacity market payments remain by far the largest, accounting for on average 95% of all DR resource revenues over the 2010 to 2018 timeframe. Emergency energy revenues have been the second largest source of revenues over this period, averaging 2.3%, but there have been no emergency energy revenues reported in annual data from 2015 to 2018. DR revenues in PJM are discussed in greater detail in Section 4.4.3.[23]

Economic DR is paid the energy market price (LMPs) when its offers clear the energy markets alongside generation resources: real time and day-ahead. The combined revenues of the economic DR averaged $6.4 million annually (or 1.1% of all DR resource revenues) from 2010 to 2018 for reducing demand by an average of 92,104 MWh annually. Economic DR reductions (in MWh) and revenues over the 2010 to 2018 timeframe are provided in Figure 12.

Figure 12. Economic DR reductions and revenues

	2010	2011	2012	2013	2014	2015	2016	2017	2018
MWh reduction in real-time market	60,522	17,161	85,210	77,360	93,546	87,469	53,503	41,801	33,384
MWh reduction in day-ahead market	13,548	237	59,810	56,593	52,755	33,659	26,714	19,865	15,802
Total MWh reduction	**74,070**	**17,398**	**145,020**	**133,953**	**146,301**	**121,128**	**80,217**	**61,666**	**49,186**
Revenue, real-time market, $ mln	2.7	2.0	5.5	4.6	10.6	5.8	2.4	1.8	1.7
Revenue, day-ahead market, $ mln	0.4	0.0	3.8	4.1	7.2	2.2	1.0	0.8	0.9
Total revenues, $ mln	**3.1**	**2.0**	**9.3**	**8.7**	**17.8**	**8.0**	**3.4**	**2.6**	**2.6**

Source: PJM. 2010-2018 *Demand Response Operations: Markets Activity Reports*

[23]Monitoring Analytics. *2010-2018 PJM State of the Market Reports*

Key takeaways from these programs: PJM

FERC Order 745 only applies to DR participating in PJM's economic program, but actual dispatch of DR resources under this program has been low. The majority of DR participating in PJM programs fall under emergency-based programs (not the subject of the FERC Order). Under these programs, the vast majority of DR resources would receive activation payments ($/MWh) if required to reduce their load by PJM in an emergency/pre-emergency situation. However, here too emergency events are not common, and there have been no emergency energy payments since 2015. Capacity payments are by far the main source of revenues for DR resources in PJM.

4.2 New York ISO

NYISO demand response programs currently include reliability- and economic-based demand response programs.[24]

Reliability-based demand response programs compensate load reduction during periods when the grid is expected to see stress in high-demand periods, such as in anticipation of reserve margin shortages or during extreme weather events. NYISO has two such programs, the Special Case Resource ("SCR") program and the Emergency Demand Response Program ("EDRP").[25] These resources are not capable of responding to real-time NYISO directions, and these programs were not directly impacted by Order 745, as it "does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions."[26]

Economic-based demand response programs involve load reduction being offered into the NYISO markets directly. Currently, there are two such programs, the Day Ahead Demand Response Program ("DADRP") and the Demand-Side Ancillary Services Program ("DSASP"). According to the NYISO, the issuance of Order 745 impacted these two programs.

Selected characteristics of these four DR programs are presented in Figure 13. According to the NYISO, participants may participate simultaneously in one reliability- and one economic-based demand response program.[27] Once the NYISO's dispatchable Distributed Energy Resource participation model is implemented, the NYISO intends to retire these two economic-based programs, with resources that currently participate in the DADRP and DSASP transitioning to participation as dispatchable DERs (while the two reliability-based DR programs will remain).[28]

[24] NYISO Website. Demand Response. <https://www.nyiso.com/demand-response>

[25] EDRPs and SCRs participate through Curtailment Service Providers and Responsible Interface Parties ("RIP") respectively, which serve as the interface between the NYISO and the resources. Source: NYISO. *2018 Annual Report on Demand Response Programs*

[26] FERC Order 745

[27] NYISO. *NYISO Demand Response Programs: Frequently Asked Questions (FAQs) for Prospective Resources*. September 12, 2018.

[28] NYISO. *Distributed Energy Resources Market Design Concept Proposal*. December 2017.

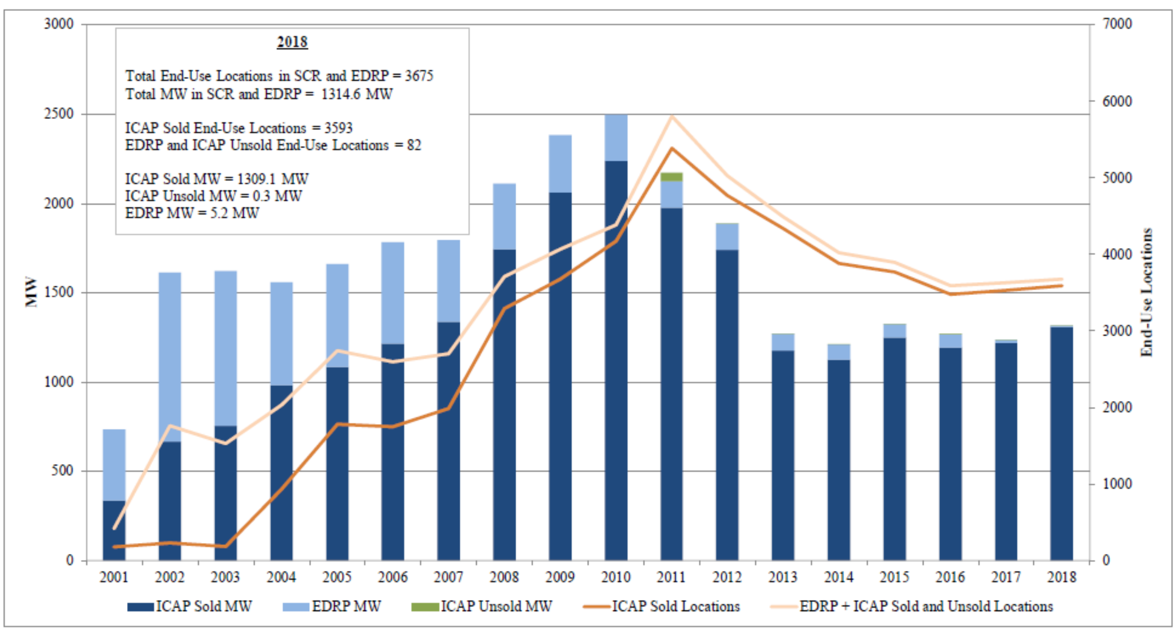
Figure 13. NYISO's DR programs

Type	DR Program	Dispatchable?	Performance obligation	2018 participation (MW)	Directly impacted by Order 745?
Reliability	**SCR**	No, manually activated	Mandatory for NYISO reliability event	1,309	No
Reliability	**EDRP**	No, manually activated	Voluntary for NYISO reliability event	5	No
Economic	**DSASP**	Yes	Mandatory if scheduled	*	Yes
Economic	**DADRP**	Yes	Mandatory if scheduled	**	Yes

*DSASPs represented 116.5 MW of capability over the May to October 2018 period, and provided on average over 100 MW of 10-minute spinning reserve over the entire 2018 period (nearly 15% of the 10-m spinning reserve requirement).
**No bidding activity
Sources: NYISO. *NYISO Demand Response Programs: Frequently Asked Questions (FAQs) for Prospective Resources*. September 12, 2018; Potomac Economics. *2018 State of the Market Report for the New York ISO Markets*. May 2019; NYISO. *2018 Annual Report on Demand Response Programs*.

As is visible in Figure 14, capacity enrolled in the two reliability programs has grown since 2001, (SCR shown in the darker blue column, EDRP shown in the lighter blue column). In 2003, participation in the EDRP and the SCR program became mutually exclusive (i.e. resources could no longer participate in both), leading to a reduction in participating MWs in the EDRP program. A large drop in SCR capacity and locations can be seen starting from 2010, which according to the NYISO was at least in part due to changes in market rules related to estimation of DR capability under peak conditions (moving in 2011 from a methodology based on average peak monthly demand, to average coincident load).[29]

Figure 14. Enrollment in NYISO reliability programs by MW and number of locations (2001-18)



Source: Taken directly from NYISO's *2018 Annual Report on Demand Response Programs*

[29] NYISO's Report on Demand Response Programs for 2011, 2013, and 2018.

Payment for operation in the different DR programs consists of: [30]

- **EDRP:** a voluntary curtailment program, where resources are paid the higher of \$500/MWh or the real-time LMP if they choose to curtail when called upon by the NYISO.
- **SCR:** can participate in the NYISO capacity market. Resources can sell their capacity, and are obligated to reduce their load when deployed.[31] In such an event, they are also paid the higher of their strike price (which can go up to \$500/MWh) or the real-time LMP. In 2018, EDRP and SCR were activated on three days (between 480 and 495 MW) to prevent potential capacity deficits in New York City.
- **DADRP**: can participate in the NYISO day-ahead market, and are paid the same market clearing prices as generators. However, **there has been no bidding activity in this program between 2011 and 2018** (based on last full-year state of the market report for 2018).
- **DSASP:** can participate in the NYISO ancillary services market (operating reserves and regulation services), are paid the same market clearing prices as generators, and receive the real-time LMP if actually dispatched.

Key takeaways from these programs: NYISO

FERC Order 745 only applies to DR participating in NYISO's economic programs (DADRP and DSASP). No resources have bid into NYISO's economic DADRP program between 2011 and 2018. The vast majority of NYISO's DR resources participate in reliability programs (specifically the SCR) which are not the subject of the FERC Order. They receive capacity payments for their availability and activation payments if actually deployed (in \$/MWh terms). However, actual activation of SCRs is low, and the capacity market remains their main source of revenues.

4.3 ISO-New England

ISO-NE has two general groupings for demand-side resources:

1. active (**dispatchable**) demand resources (also referred to as demand response resources or active demand response resources); and
2. passive (**non-dispatchable**) demand resources (also referred to as passive demand response resources).

Active demand resources are activated upon dispatch instruction from ISO-NE, through for example ramping down on-site consumption or activating on-site generation. These resources are fully integrated into the wholesale market, and can participate in the day-ahead and real-time energy markets (dispatch is determined economically based on their offers), as well as the

[30] Sources: Potomac Economics. *2018 State of the Market Report for the New York ISO Markets*. May 2019; NYISO. *2018 Annual Report on Demand Response Programs*

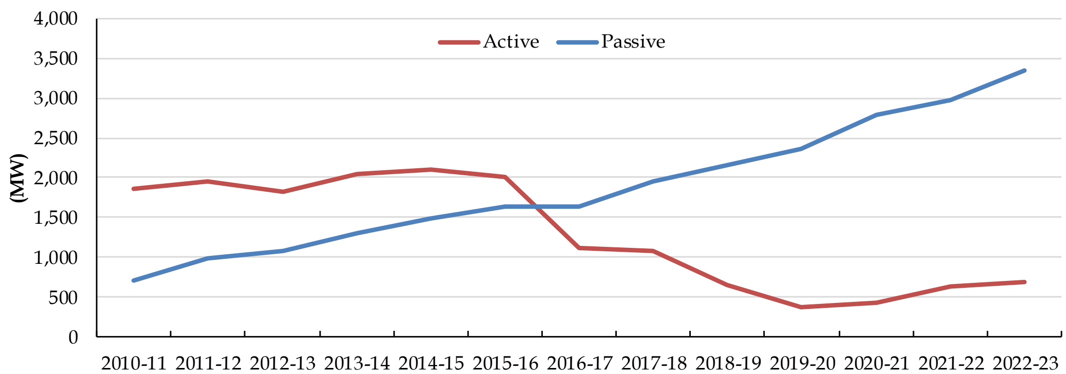
[31] Load reduction for SCRs is mandatory provided the NYISO gives notification a day before the event and two hours before the event. Source: NYISO. NYISO Demand Response Programs: *Frequently Asked Questions (FAQs) for Prospective Resources*. September 12, 2018.

operating reserve ("OR") markets. Active demand with capacity supply obligations ("CSO") also participate in the Forward Capacity Market ("FCM") as active demand capacity resources ("ADCR").[32, 33]

Passive demand resources reduce their consumption during predetermined periods. Examples of passive demand resources include energy efficiency and passive distributed generation (e.g. distributed solar). These resources differ structurally from the reliability- and emergency-based demand response resources in NIYSO and PJM, in that they cannot reduce their load upon instruction from the ISO. While passive demand resources have been fully integrated into the Forward Capacity Market,[34] they are **not eligible** to participate in energy or ancillary services markets.[35]

Passive demand resources make up the bulk of total demand resource participation in the New England Forward Capacity Auction ("FCA"), as shown in Figure 15. Passive demand resources have grown significantly since the 2010-2011 FCA commitment period, driven mainly by state-sponsored energy efficiency programs, while active demand resources have declined noticeably.

Figure 15. FCA capacity of passive and active demand response by commitment period



Source: ISO New England. *NEPOOL Participants Committee Reports: September 2019.* September 13, 2019

[32] To participate in the FCM, one or more demand response resources are mapped into ADCRs, which holds the CSO. ADCRs have a "must offer" obligation whereby they are required to offer into energy markets all physically available capacity up to their CSO. Source: ISO-NE. *2018 Annual Markets Report*. May 23, 2019.

[33] ISO New England. About Demand Resources. <https://www.iso-ne.com/markets-operations/markets/demand-resources/about>

[34] Passive DR resources that can participate in the FCM are on-peak and seasonal resources. On-peak resources offer their reduced consumption during peak hours, while seasonal resources offer reduced consumption during periods of specific months.

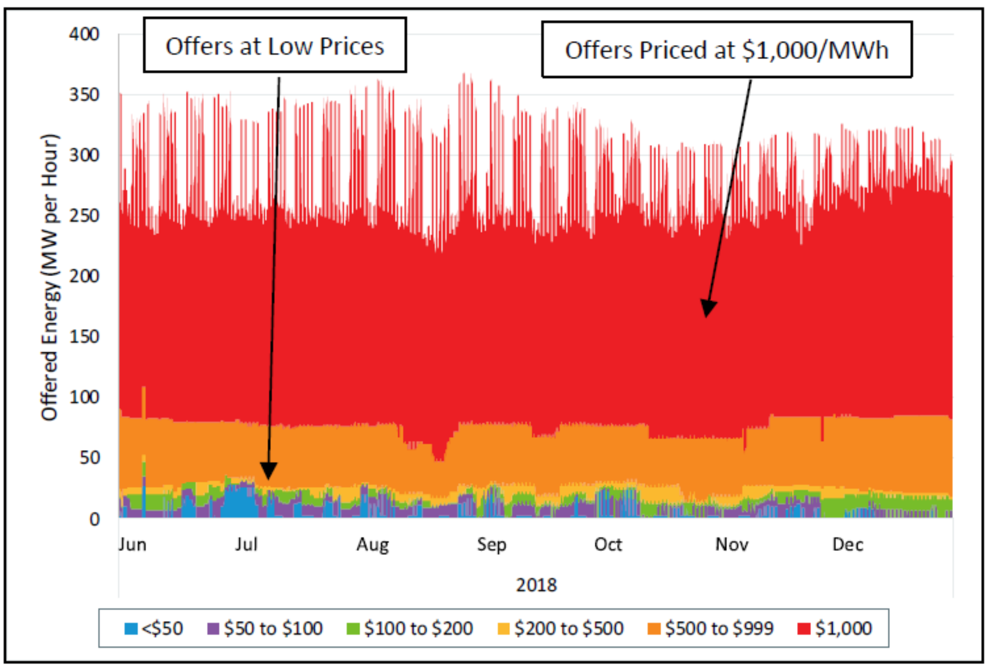
[35] Source: ISO New England. "About Demand Resources". <https://www.iso-ne.com/markets-operations/markets/demand-resources/about>

From the June to December 2018 period,[36] around 350 MW of active demand resources participated in ISO-NE's wholesale energy markets (day-ahead and real-time). In terms of pricing, on average:[37]

- 72% of offered capacity was priced at the energy market cap ($1,000/MWh); and
- 7% of offered capacity was priced in the 'lower-priced tier' of $200/MWh or less, and did not exceed 20% of offered demand reduction capacity in any hour.

As according to ISO-NE only lower-priced tiers ($200/MWh or less) have a "reasonable likelihood of being dispatched in the day-ahead energy market," active demand resources participating in the wholesale energy market were dispatched at low levels and functioned predominantly as "capacity deficiency resources." From June to December 2018, the highest hourly amount of DR dispatched in the day-ahead market was 31.2 MW, and averaged just 7.7 MW in the hours when they were dispatched (which was 46% of hours over this period). This can be seen in Figure 16 (which shows the total DR resource participation in the day-ahead energy market along with their offers) and Figure 17 (which shows the total DR resource participation in the day-ahead energy market, the amount dispatched, and the corresponding day-ahead prices).[38]

Figure 16. DR resource offers in day-ahead energy market



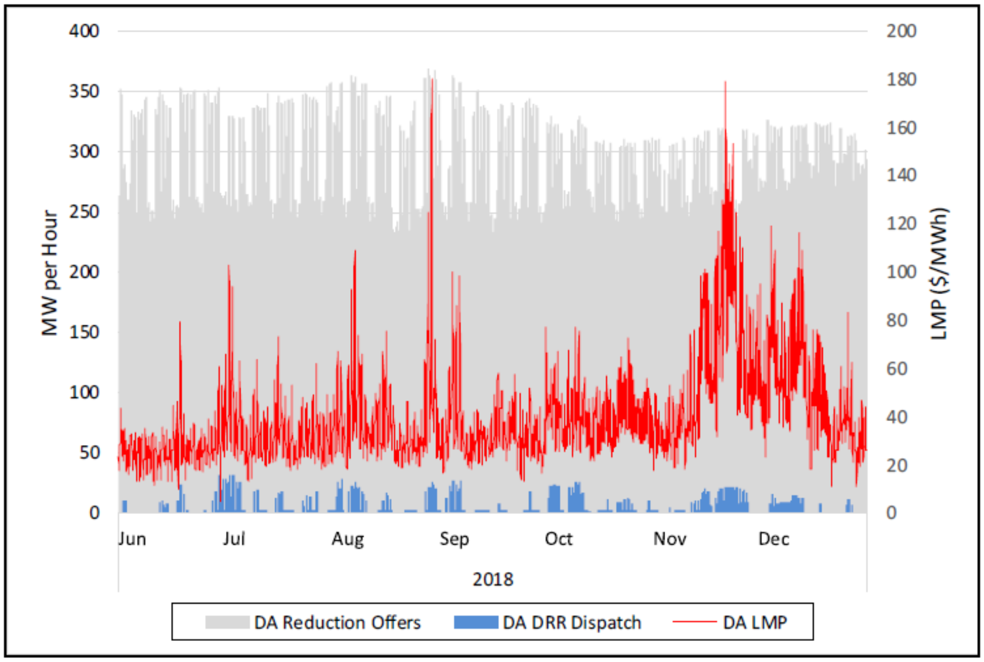
See source and note in Figure 17

[36] Demand response resources were fully integrated into the wholesale energy market on June 1st 2018, in compliance with Order 745, and DR resources with a CSO now have must-offer rules in the energy market. Prior to this, while DR resources were capable of actively participating in wholesale energy markets, most chose not to, and instead participated as emergence response resources providing dispatchability during capacity deficiency events. However, their behaviour in 2018 after their full integration into the energy markets did not change, most continued to serve as capacity deficiency resources (i.e. bidding at the offer cap in the energy markets).

[37] ISO-NE. *2018 Annual Markets Report*. May 23, 2019.

[38] Ibid.

Figure 17. DR resource dispatch in day-ahead energy market



Note: According to ISO-NE, real-time energy market dispatch would be similar to the day-ahead dispatch, with the exception of a single capacity scarcity period on September 3rd.
Figures taken directly from: ISO-NE. *2018 Annual Markets Report*. May 23, 2019.

Key takeaways from these programs: ISO-NE

FERC Order 745 only applies to active demand resources. Active demand resources with CSOs have must-offer rules in the energy market, leading most active DR resources to bid into the energy market at or around the offer cap. Actual dispatch of active demand resources is therefore low, and the capacity market remains their main source of revenues. Passive demand resources, which make up the majority of ISO-NE's total demand resources, are not the subject of the FERC Order.

4.4 Cross-cutting analysis

4.4.1 Applicability of Order 745 to the DR resource programs covered

FERC Order 745 relates to DR resources that participate in organized wholesale energy markets (real-time and day-ahead). It applies to those resources that are capable of balancing supply and demand as an alternative to generation through reducing load upon dispatch instructions (received in-market). The FERC Order also discusses that such DR resources must be technically capable of providing ancillary services, and states that it does not apply to DR participating in programs administered for reliability and emergency conditions.

For demand-side resources in the ISO programs LEI reviewed, the FERC Order therefore **only applies to those DR resources that are considered dispatchable from the ISO's perspective**.

These would be DR participating in economic programs run by PJM and NYISO, and active DR in ISO-NE.

The FERC Order **does not apply to DR** participating in ISO programs, **that from the perspective of the ISOs, are considered non-dispatchable**. These include: passive DR in ISO-NE; the SCR and EDRP in NYISO; and the emergency and pre-emergency DR resources in PJM. These 'non-dispatchable' resources, which the FERC Order does not apply to, make up the majority of total demand-side resources in each of the three markets reviewed. Figure 18 provides a summary of the covered programs and the applicability of Order 745.

Figure 18. Dispatchability of selected DR resources and applicability of Order 745

ISO	NYISO				ISO-NE		PJM	
Demand side resource program	SCR	EDRP	DADRP	DSASP	Passive	Active	Emergency/ pre-emergency	Economic
Considered dispatchable by ISO?	No	No	Yes	Yes	No	Yes	No	Yes
Does Order 745 apply?	No	No	Yes	Yes	No	Yes	No	Yes

4.4.2 Instances of Order 745 energy payments as the only source of DR compensation

The question of whether situations occur in which energy payments are the only source of DR compensation can be looked at from the perspective of actual load being dispatched by the respective ISOs, which is what Order 745 is focused on. From this perspective, because dispatch of DRs under any circumstance is infrequent, we can infer that situations when DR only receives an energy payment would be even more rare.

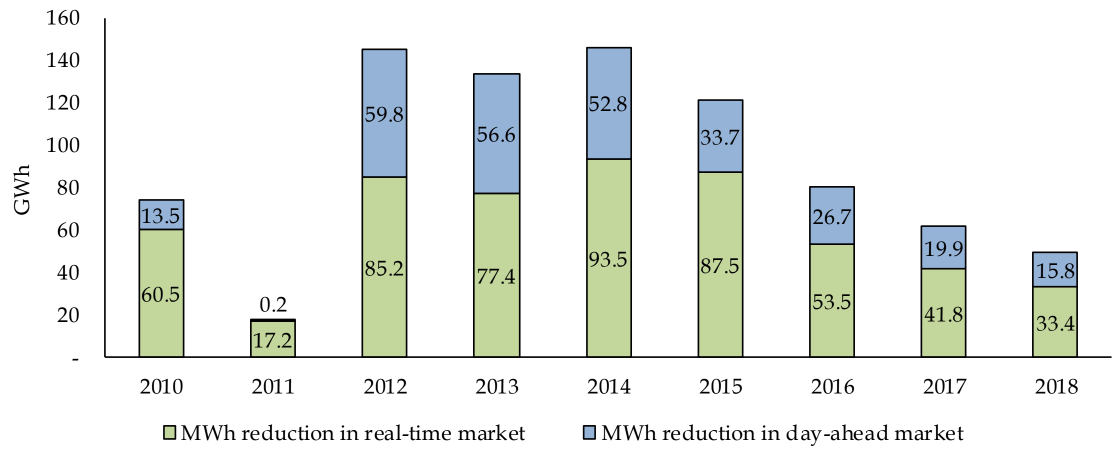
Based on the ISO programs for the US markets reviewed by LEI, and data LEI was able to gather:

- for NYISO, as stated previously, there has been no bidding activity between 2011 and 2018 (i.e. no offers submitted in the program);
- for ISO-NE, in the 46% of hours when DR was dispatched in the day-ahead market over the June to December 2018 period, it averaged just 7.7 MW per hour (and was not dispatched in the remaining 54% of hours), implying a total DR dispatch of around 18.1 GWh in the day-ahead market over this timeframe (with real-time energy market dispatch generally being similar to day-ahead dispatch according to ISO-NE); [39] and
- in PJM, dispatch (i.e. load reduction) of economic DR in 2018 was around 33.4 GWh in the real-time market and around 15.8 GWh in the day-ahead market (these figures are additive), which is very low as a proportion of total load (791 TWh in 2018). Day-ahead

[39] ISO New England. *2018 Annual Markets Report*. May 23, 2019.

and real-time dispatch of economic DR for the historical period from 2010 to 2018 is shown in Figure 19.[40]

Figure 19. Real-time and day-ahead reductions to economic DR in PJM



Source: Monitoring Analytics LLC. *2010-2018 PJM State of the Market Reports*

Based on this information and the information on revenues to be covered in Section 4.4.3, it is not common for DR resources eligible to participate in ISO energy markets to only participate in ISO energy markets. The provision of capacity, and compensation from this provision, has tended to be the focus for DR resources in these markets.

4.4.3 DR resource revenue streams

DR resources participating in ISO programs for the US markets reviewed by LEI are compensated through different revenue streams, as shown in Figure 20.

Figure 20. ISO programs and markets available through the programs

ISO	NYISO				ISO-NE		PJM	
Demand side resource program	SCR	EDRP	DADRP	DSASP	Passive	Active	Emergency/ pre-emergency	Economic
Can participate in market as	Capacity*	Emergency*	Energy	OR and regulation services	Capacity	Capacity, energy, OR	Capacity*	Energy, OR

*can also receive activation payments

Capacity-related payments, or payments related to their load being made available for reduction (not the actual activation of this load reduction), are their main source of revenues. Ancillary services (operating reserves and regulation in certain markets) are another source of revenues

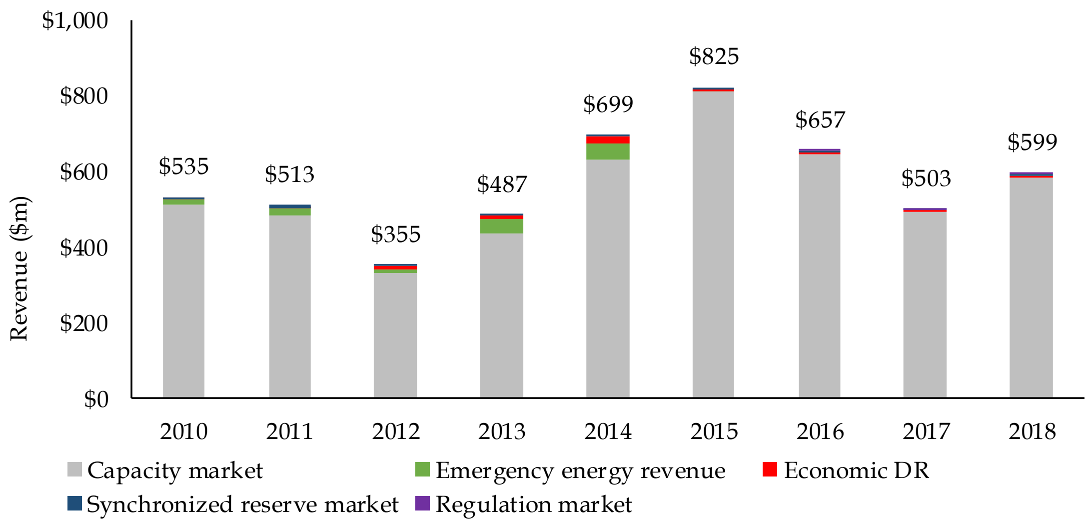
[40] An alternative approach would be to look at the difference between total unique DR capacity and total emergency DR capacity in PJM (shown in Figure 11), which would give an indication of the amount of DR capacity that participates as only economic. In 2018, this difference was 348 MW, which was just 3.7% PJM's total unique DR capacity.

made available to dispatchable DR resources. Energy market revenues are available to dispatchable DR resources participating in ISO-run markets. Compensation for activation of non-economic DRs also occurs in NYISO and PJM (reliability and emergency/pre-emergency DRs in these two markets respectively).

In terms of actual compensation, as mentioned previously, for NYISO economic demand response hasn't been dispatched through the DADRP between 2011 and 2018. Additionally, SCR and EDRP resources only saw three event-related activations in 2018, and total payment for these activations was $2.3 million.[41] In ISO-NE, total energy market payments to DR resources over the June to December 2018 period were $2.8 million. For reference, based on the CSO of demand response resources over that same period and the capacity price of $9.55/kW-month, total implied revenues for demand response resources over the June to December 2018 period were $197.6 million (broken down into $23.9 million for active resources and $173.6 million for passive resources).[42]

Information from PJM provides more granular breakdowns over longer periods of time. As shown in Figure 21, capacity payments have historically made up by far the largest portion of revenues for DR resources. In 2018, capacity market revenues for DR resources were $587 million, compared to total DR revenues of $598.6 million (i.e. 98.1% of total revenues were related to capacity). The remainder was made up of revenues from ancillary services (regulation and synchronized reserves) which totaled $9 million in 2018, and energy market revenues for economic demand response which totaled $2.6 million. There were no emergency energy revenues in 2018 (payments to emergency and pre-emergency demand response during a load management event).

Figure 21. PJM demand response revenues by market ($ million)



Source: Monitoring Analytics. *2018 State of the Market Report for PJM: Section 6 – Demand Response.*

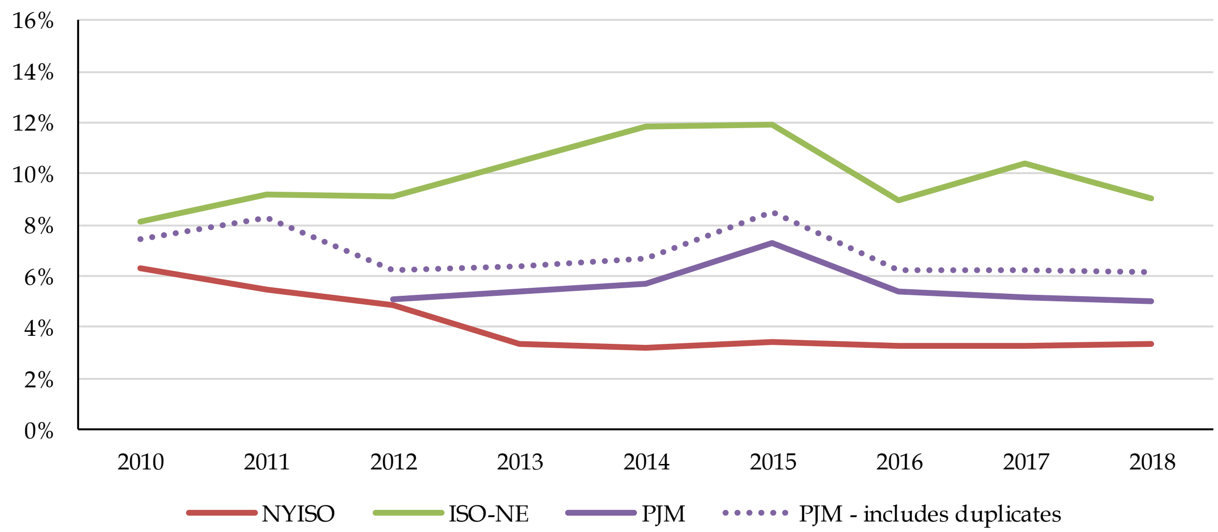
[41] NYISO. *2018 Annual Report on Demand Response Programs*

[42] LEI estimate for illustrative purposes, based on the CSOs from ISO-NE's NEPOOL Participants Committee Reports for the months of June to December 2018, and the capacity market clearing price for FCA 9.

4.4.4 DR resource capacity and revenues relative to the total system

Figure 22 shows total demand response capacity relative to total installed generating capacity in each of the three markets. Total demand response in the three markets has not increased substantially since 2010, and NYISO has seen a noticeable decline in this ratio, due mostly to the drop in SCR capacity as discussed in Section 4.2. Still, DR procured through the various programs covered previously serve an important role through the provision of capacity during scarcity, reliability, and emergency events.

Figure 22. Demand response relative to installed generating capacity

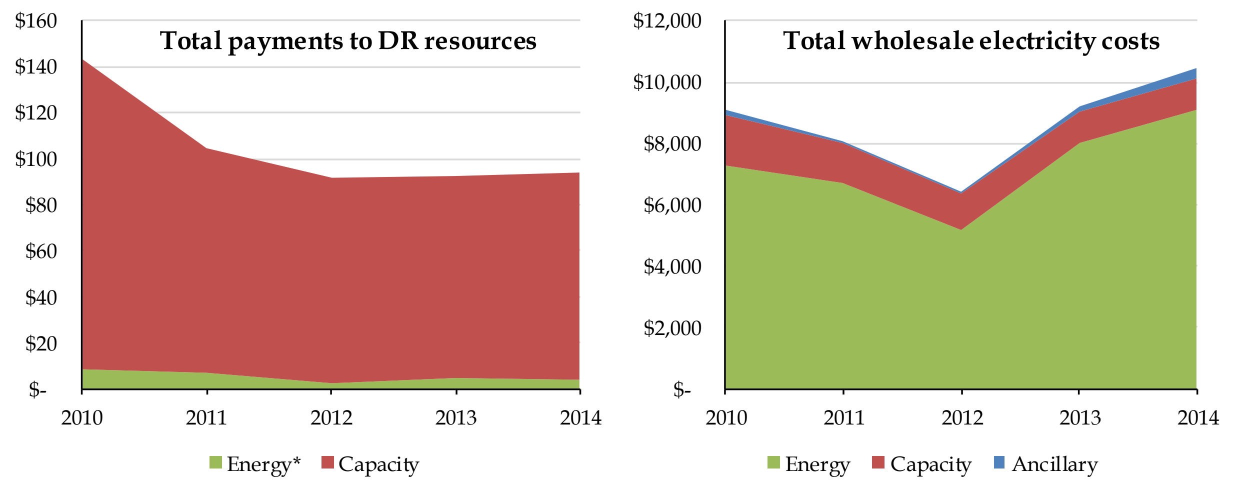


Demand response shown: NYISO shows the sum of EDRP and SCR ICAP; ISO-NE shows sum of active and passive resources with CSOs for commitment periods starting in 2010/2011; for PJM the solid line uses unique DR capacity. As PJM's DR activity reports did not report unique DR capacity for 2010 and 2011, the dotted line uses the sum of economic and emergency DR. This approach double-counts those resources that participate on both the emergency and economic side, but gives a visual indication of the trend over the 2010 to 2018 timeframe.
Installed capacity: NYISO shows summer capacity; ISO-NE shows capacity based on seasonal claimed capability
Sources: ISO-NE's CELT reports, ISO-NE's NEPOOL Participants Committee Reports, NYISO's annual reports on demand response programs, PJM's state of the market reports.

The importance of DR as a capacity resource specifically can be illustrated by looking at the total revenue breakdown between energy and capacity for DR, versus total system costs for energy and capacity. To this end, Figure 23 shows total payments made to demand response resources (consisting of energy and capacity) and total system costs for energy, capacity, and ancillary services in ISO-NE from 2010 to 2014 based on information contained in ISO-NE's Annual Market Reports (annual market reports from 2015 onwards stopped reporting the information on total payments made to demand resources). Similarly, Figure 24 shows payments made to demand response resources (consisting of economic energy, emergency energy, ancillary services, and capacity, as also shown in Figure 21) and total system costs for energy, capacity, and ancillary services in PJM.

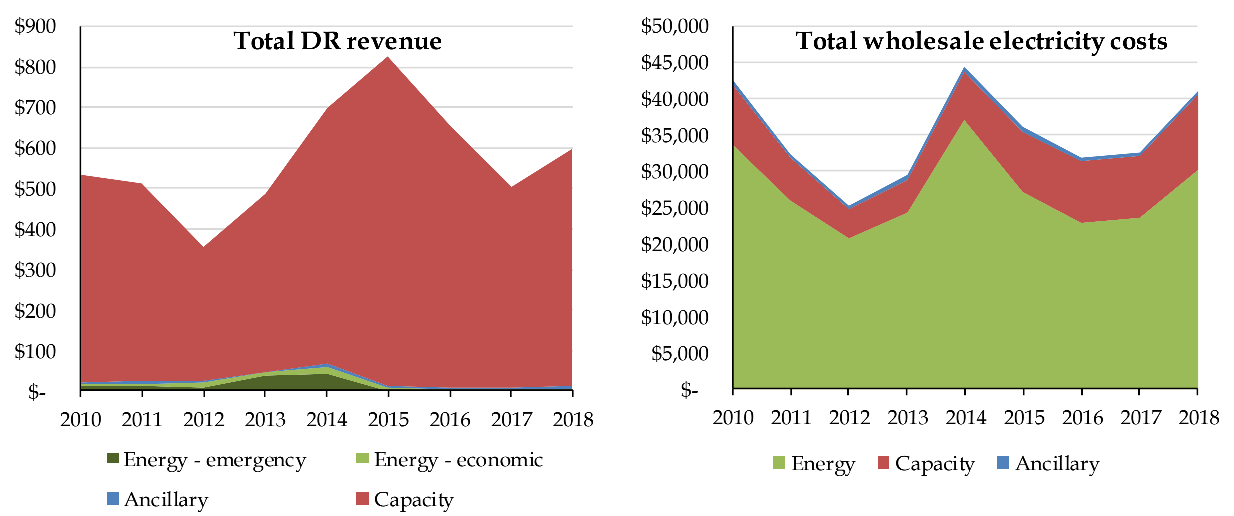
Based on these figures, and as discussed in Section 4.4.3, it is clear that **capacity payments make up the vast majority of compensation for demand response resources**, while payments for their activation or dispatch are a very small proportion of their total revenues (on average 5% of total payments to DR resources in ISO-NE and 3% in PJM using this data). This is in stark contrast with total system costs, which are majority energy-related in these two markets (84% energy in ISO-NE and 78% in PJM).

Figure 23. Total payments to DR and total wholesale electricity costs in ISO-NE ($ million)



* Energy values shown consist of the Day-Ahead Load Response Program, Transitional Price-Responsive Demand program, and the Real-Time Price-Response Program.
Sources: ISO-NE Annual Markets Reports for 2010 to 2014; ISO-NE. *2018 Report of the Consumer Liaison Group*. March 12, 2019

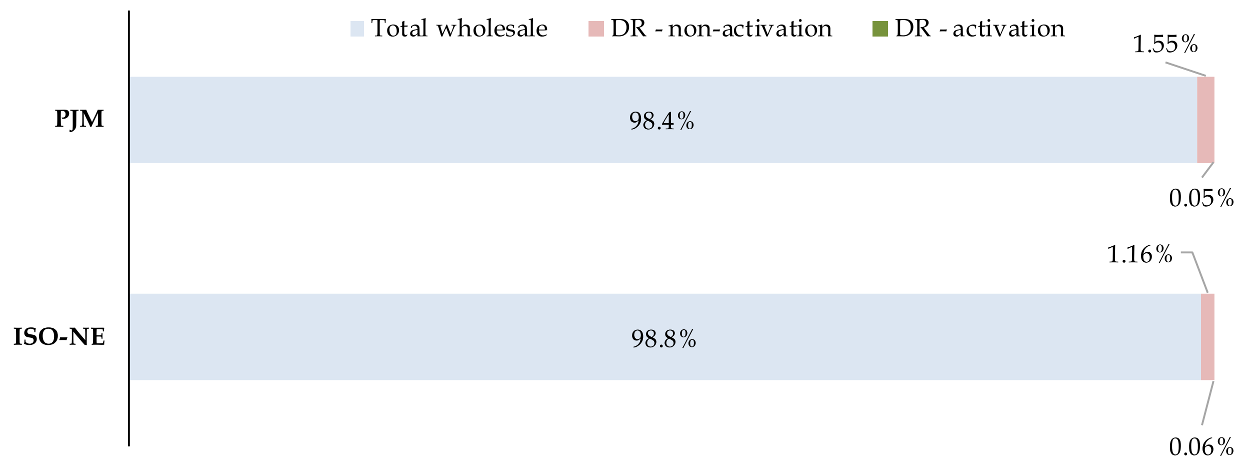
Figure 24. DR and total wholesale system revenues in PJM ($ million)



Sources: Monitoring Analytics LLC. *2010-2018 PJM State of the Market Reports*

It is also clear that **total revenues earned by DR resources are a very small proportion of total system commodity-related costs** (energy, capacity, and ancillary services). This is illustrated in Figure 25, which show the percentage of total costs that are attributable to wholesale electricity costs and the percentage attributable to just DR resources, based on the average of data shown in Figure 23 and Figure 24. DR here is broken down into those related to activation (both energy and emergency), and those related to non-activation (capacity in ISO-NE, capacity and ancillary services in PJM). Total DR payments made up around 1.2% of wholesale electricity costs in ISO-NE between 2010 and 2014, and 1.6% in PJM between 2010 and 2018. Activation-related DR payments were a fraction of this fraction, at only 0.06% of wholesale electricity costs in ISO-NE and 0.05% in PJM.

Figure 25. Total payments made to DR relative to total wholesale payments (%)



Sources: See Figure 23 and Figure 24

4.4.5 Degree of connection between energy payments for DR activations and capacity markets

While, as discussed previously, both the total revenues and total dispatch/activation from participation on the energy side directly or through emergency/reliability activations is low, there is still a **strong practical linkage** in these markets between participation on the capacity side and payments for activation or dispatch.

Most DR resources in the markets reviewed by LEI **participate through the provision of capacity**, in emergency or reliability-related programs in PJM and NYISO, and as active DR in ISO-NE. In NYISO and PJM, although Order 745 does not apply to these programs, when resources that participate in them are called upon to curtail, they are paid (in $/MWh terms) for this curtailment.[43] This activation payment is therefore directly linked to participation on the capacity side.

In ISO-NE, active DR with capacity obligations have must-offer rules in the energy market, therefore energy market participation is directly linked to capacity participation for DR resources in New England.

[43] In PJM, a small fraction of emergency and pre-emergency demand response is registered as capacity only, meaning they do not get payments for activation. There was 1.8% of emergency and pre-emergency demand response registered as capacity-only for the 2017/2018 delivery year, and 1.2% for the 2018/2019 delivery year. Source: Monitoring Analytics. *2018 State of the Market Report for PJM: Section 6 – Demand Response*.

Symbiotic nature of energy and capacity payments

Theoretically, a market participant's bid into the capacity market will reflect the residual revenue need that is required after all other sources of revenue or cost reductions have been considered. In the case of load, there are two potential 'revenue' sources: payments, if allowed, at LMP or some other level when dispatched, and the cost avoided by not operating. Note that failure to operate is not "free"; the cost to load of not operating in the period is equal to its lost profit for the period when it has been dispatched plus any shut down and restart costs. In a functioning market, the capacity payment would be expected to equal the desired revenue minus expected activation payments (at LMP or some other level) minus expected avoided costs. Allowing for an activation payment would not necessarily increase consumer costs; rather, it would shift the means by which they are paid out, and delineate between the "reservation payment" embodied in the capacity payment and the "utilization payment" embedded in the activation payment.

5 Contextual differences between Ontario and the markets covered

Starting with an overview of demand response procured by the IESO in Ontario, this section covers at a high level some of the differences between the three US markets discussed in this report and Ontario related to: differences in dispatchability from the ISO perspective; the amount of demand response in these markets procured at the ISO level; differences in total commodity costs; and structural considerations.

5.1 Demand response in Ontario

Demand response in Ontario takes two forms, dispatchable loads and Hourly Demand Response ("HDR") resources.

According to the IESO, **dispatchable loads** are those large consumers that actively participate in the energy market. Dispatchable loads submit bids into the energy market, and if prices exceed their bid, these loads will receive dispatch instructions to reduce consumption. Settlement price for dispatchable loads is the 5-minute Market Clearing Price ("MCP").[44]

Dispatchable loads:

- are not paid the MCP for this load reduction, but do avoid paying the MCP on the portion of load that was reduced;
- can participate in the IESO's capacity auctions;
- are able to offer and receive payments for operating reserves; and
- may receive Congestion Management Settlement Credits under certain conditions.[45]

HDR resources are those demand response resources that cannot respond to 5-minute schedules from the IESO (non-dispatchable).

Within the current Demand Response Auction ("DRA"), demand response market participants must be registered as either dispatchable loads or HDR resources. These resources fulfill their capacity obligations by making cleared capacity available in the energy market, through submission of bids that are greater than $100 and less than $2,000.[46] Activation of both dispatchable loads and HDRs can therefore occur in market, but these resources are not paid for reducing their consumption if activated.[47] Demand response resources that clear the auction

[44] Non-dispatchable loads are those that are not able to respond to 5-minute signal. Non-dispatchable loads cannot offer operating reserves, and settlement prices for these loads is the HOEP. Source: IESO. *Quick Takes - Dispatchable Loads*. April 2017; IESO Website. Real-time Energy Market. <http://www.ieso.ca/sector-participants/market-operations/markets-and-related-programs/real-time-energy-market>

[45] Sources: IESO. *Quick Takes - Dispatchable Loads.* April 2017.

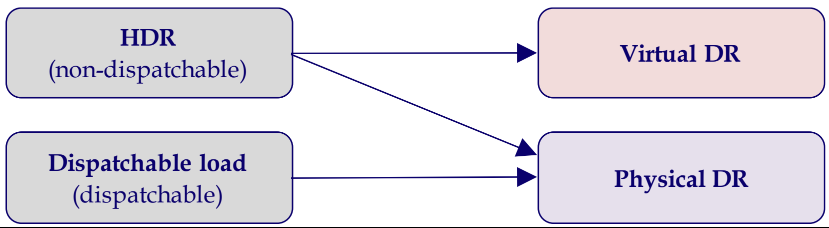
[46] Based on availability window for when the DR resource is expected to be available to provide demand response. The availability window is hours between 12:00 and 21:00 for the summer obligation commitment period, and 16:00 and 21:00 for the winter period, for business days. Sources: IESO. *Introduction to the Demand Response Auction*. May 2017; IESO. *Market Manual 12: Capacity Auctions - Part 12.0: Capacity Auctions - Issue 7.0*. October 15, 2019.

[47] Out-of-market activation can also occur for HDRs, under emergency or test situations. Source: *IESO. Energy Payments for Economic Activation of DR Resources.* October 10, 2019.

receive compensation for being available (through $/MW-day term payments) regardless of whether or not they are activated.

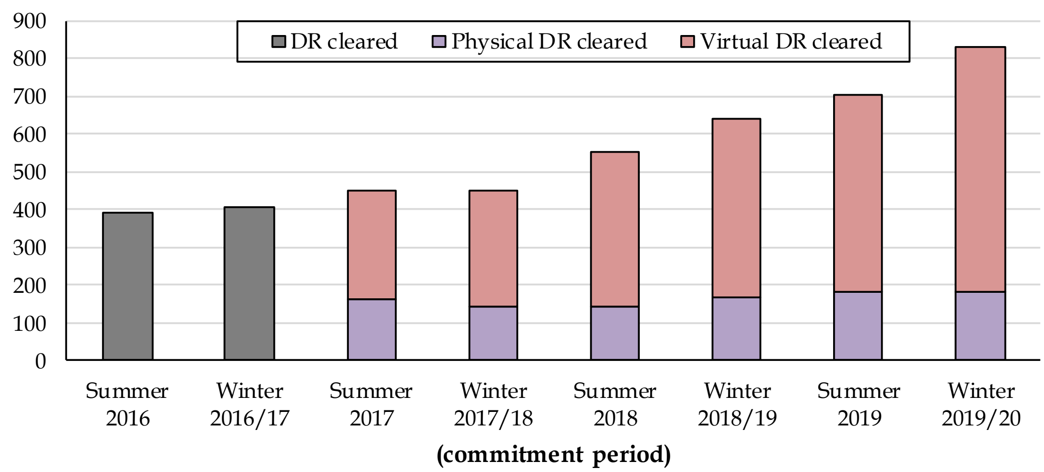
Cleared capacity within the auction is broken down into physical and virtual demand response. Physical DR resources are those that have IESO-registered revenue metering, while virtual DR resources are those that do not. All dispatchable loads are physical resources, and all virtual resources are HDRs, but HDRs can also be physical resources.[48] The linkage between physical/virtual and dispatchable loads/HDRs is shown visually in Figure 26.

Figure 26. Linkage between physical/virtual resources and dispatchable loads/HDRs



As shown in Figure 27, the amount of capacity procured through the DRA has grown since its first commitment period in 2016. Breakdowns for cleared capacity between virtual and physical DR were reported from the summer 2017 commitment period onwards. Based on this, it is also clear that most DR resources procured through the auction are HDRs (as all virtual resources are HDRs).[49]

Figure 27. DR auction cleared capacity (MW)



Note: breakdowns between physical and virtual DR capacity were reported from the summer 2017 period onwards
Sources: IESO Demand Response Auction Post-Auction Summary Reports

[48] IESO response to OEB interrogatories under case EB-2019-0242 filed on November 6, 2019.
[49] Further, according to the IESO for the Winter 2018/19 commitment period 112 MW of physical DR was dispatchable load, and for the Summer 2018 commitment period 137 MW of physical DR was dispatchable load (with physical HDR capacity at 31.4 MW for both these commitment periods). Source: IESO response to OEB interrogatories under case EB-2019-0242 filed on November 6, 2019.

Although full data on utilization of DR resources was not readily available, according to an IESO presentation in 2016 activation of dispatchable load resources procured through the DR auction totaled just 1,431 MWh.[50] Further, according to the IESO HDRs have only been economically activated once (in July 2019 for a three hour period) since the introduction of the DRA, and dispatchable loads have been dispatched less than 1% of time over the same timeframe.[51]

5.2 Differences between load dispatchability in Ontario as compared to the US markets

For the demand-side resources in ISO programs LEI reviewed, dispatchability of the resource is centered around the ability of the ISO to schedule the resource in-market, based on economic considerations (resource dispatchability by program is summarized in Figure 28). Dispatchable resources are scheduled economically and in-market, while non-dispatchable resources, if activated, are done so in anticipation of emergency or reliability events and scheduled manually (out-of-market and not 'economically dispatched'). In contrast, LEI's understanding is that dispatchability of DR in the Ontario context is centered around whether the resource can respond to 5-minute schedules from the IESO; HDRs, while 'non-dispatchable', can still be economically activated in-market.

Figure 28. Dispatchability of selected demand response resources from ISO perspective

ISO	NYISO				ISO-NE		PJM		Ontario	
Demand side resource	SCR	EDRP	DADRP	DSASP	Passive	Active	Emergency/ pre-emergency	Economic	HDR	Dispatchable load
Considered dispatchable by ISO?	No	No	Yes	Yes	No	Yes	No	Yes	No	Yes

In ISO-NE, demand-side resources include "passive" resources (including energy efficiency) that can participate in the capacity market by providing on-peak and seasonal load reduction. However, this load reduction is provided across multiple hours, and is non-dispatchable from the ISO's perspective as load cannot be reduced in response to a dispatch instruction. DR resources in ISO-NE, referred to as active DR, are dispatchable from the ISO's perspective, as they are energy market participants and reduce their load when economically dispatched by the ISO.

For the NYISO, DR programs include reliability- and economic-based demand response programs. Reliability (SCR and EDRP) resources are non-dispatchable from the ISO's perspective, and, although they have the capability to reduce their load with adequate lead-time from the ISO, they must be **manually activated** by the ISO based on expectations of reliability events (i.e. not part of NYISO's dispatch algorithm).[52] Resources participating in economic-based demand response programs in NYISO (e.g. DADRP) are considered dispatchable as they are active

[50] IESO. *Demand Response Working Group: Notification and Activation of Hourly DR Resources*. May 11, 2017.

[51] IESO response to OEB interrogatories under case EB-2019-0242 filed on November 6, 2019.

[52] Manual activation uses load and generation forecasts, as well as forecasts of transmission availability, to determine whether a reliability DR resource may be needed in order to maintain reliability. As this is a manual activation based on forecasted conditions, it is less efficient than an automated commitment and dispatch in the wholesale market. Source: NYISO. *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets*. January 2017.

participants in the NYISO's energy markets. These resources determine when they participate through supply offers, and are scheduled by the ISO and dispatched when they are 'economic'.

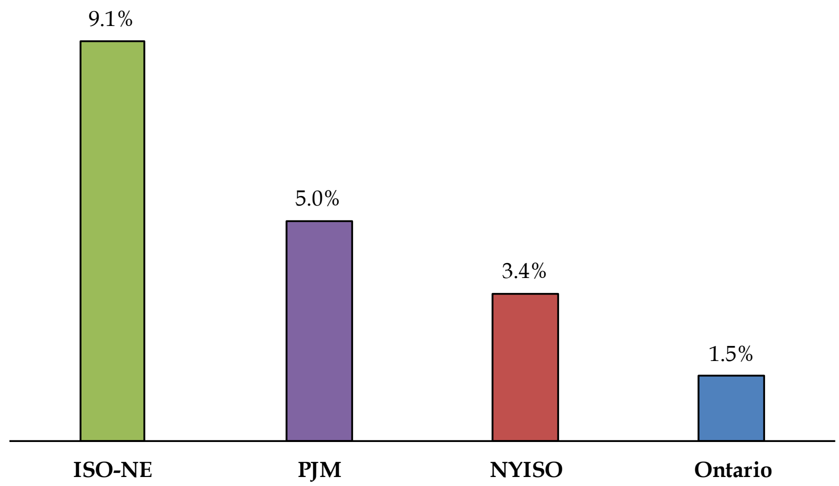
PJM currently has two broad categories of DR resources: economic DR and emergency DR. The economic DR participates in energy markets (real-time and day-ahead) on a voluntary basis, and when it clears the market, it is committed and dispatched by PJM. The reductions achieved through the deployment of the economic DR are known as dispatched curtailment. The emergency DR, on the other hand, are not dispatchable directly by PJM. When these resources are needed (as pre-emergency or emergency load reduction), PJM contacts these resources via email/web portal or telephone to curtail the load. This type of curtailment is known as mandatory curtailment. Once these sources of DR are exhausted, PJM may call on emergency energy only DR resources, but their curtailment is voluntary.

In the IESO market, dispatchable and non-dispatchable DR resources participating in the auction make their cleared capacity available in the energy market through submission of bids above $100 and below $2,000. Activation for **both** dispatchable and non-dispatchable DR resources can therefore occur in market, through the ISO's dispatch. This is in contrast to the other markets reviewed by LEI, where non-dispatchable resources either cannot reduce their loads even with instruction (e.g. passive resources in ISO-NE), or are activated by the ISOs but out-of-market (e.g. SCR in NYISO).

5.3 Comparing Ontario's DR resource supply to other markets

Total demand response resources relative to total installed generating capacity in 2018 for each of the three US markets is shown in Figure 29, along with Ontario's demand response resources procured through the DRA (see figure note for what is included). ISO-NE's demand response resources are made up mostly of passive resources, PJM's demand response resources are mostly emergency (non-dispatchable), and Ontario's are mostly HDRs; NYISO's demand response in this figure only includes reliability-based resources, as there was no bidding activity in the DADRP in 2018. For the three US markets, DR relative to total installed capacity was between 3.4% and 9.1% in 2018; Ontario's DR procured through the DR auction was below this range, at 1.5% for 2018.

Figure 29. Demand response relative to installed generating capacity (2018)



Demand response shown: NYISO shows the sum of EDRP and SCR ICAP; ISO-NE shows sum of active and passive resources with CSOs for commitment period 2018/2019; PJM is sum of economic and emergency DR; Ontario uses demand response capacity from the Summer 2018 DR auction.
Sources: See sources from Figure 22 and Figure 27; IESO's December 2018 Reliability Outlook

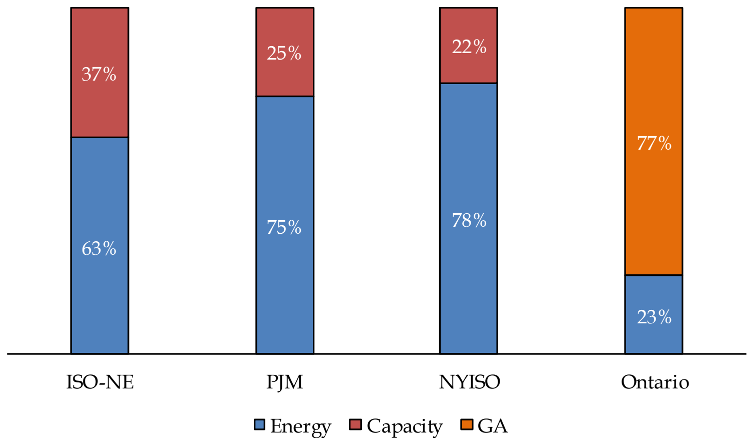
An alternative metric for consideration is DR capacity as a percentage of peak load, which averaged 5.6% across **all** US ISOs and RTOs in 2017 (and is depressed by the lack of DR participation in Southwest Power Pool);[53] again, Ontario is below this average at 2.4% for 2018. Worth re-emphasizing however, and as discussed in Section 4 and Section 5.1, based on data LEI could gather actual utilization of DR resources has been minimal in all markets reviewed when compared to total load, and DR resources in the US markets are compensated primarily for their provision of capacity.

5.4 Impact of the Global Adjustment

Total system costs for energy and capacity in the three US markets, and for wholesale energy and the Global Adjustment ("GA") in Ontario, are shown in Figure 30 (for 2018). In the three US markets covered by LEI in this report, the energy component made up the bulk of total costs, ranging from 63% in ISO-NE to 78% in NYISO. In contrast, Ontario's wholesale energy component constituted only 23% of the combined total wholesale energy and GA. The main component, the GA, relates to a number of items including regulated and long-term contracted generation, and captures aspects related to capacity, as well as internalized Renewable Energy Credits (in contrast to the three US markets, which have standalone renewable energy compensation products at the state-level), among others.

[53] FERC Staff Report. *2018 Assessment of Demand Response and Advanced Metering*. November 2018.

Figure 30. Total system costs for energy and capacity/GA (2018)



Notes: NYISO system costs estimated by LEI using regional average all-in prices and regional load data; energy costs for Ontario estimated using weighted average Hourly Ontario Energy Price ("HOEP") and Ontario market demand. Total costs shown are: $9.6 billion for ISO-NE; $40.5 billion for PJM; $8.3 billion for NYISO; and Canadian $14.5 billion for Ontario. For reference, when included, AS made up between 1.5% and 2% of total system costs for energy/capacity/AS in the three US markets for 2018.
Sources: ISO-NE's 2018 Report of the Consumer Liaison Group; NYISO's 2018 State of the Market report and 2019 Gold Book; PJM's 2018 State of the Market report; IESO monthly market report for December 2018 and IESO year-end data for 2018.

While not part of the DRA program, larger customers in Ontario can be eligible to participate in the Industrial Conservation Initiative ("ICI"). The ICI is a powerful demand response tool that incentivizes qualified customers to reduce their load at peak periods through lower Global Adjustment ("GA") costs (which as visible from Figure 30 are the largest portion of commodity costs in Ontario).[54] The ICI is estimated to have reduced peak demand in Ontario by around 1,300 MW in 2016 and 1,400 MW in 2017 (similar data for 2018 was not readily available, although participation in the ICI has grown from 20% of Ontario's annual consumption in 2016 to 29% in 2018).[55, 56]

5.5 Distinctions and implications

As discussed in Section 3.3.2, in the US the FERC has jurisdiction over the wholesale markets, states have jurisdiction over the retail situation, and ISOs and RTOs can span multiple states.

Whereas Ontario was able to simultaneously develop its wholesale and retail markets, in the US, given this split between federal and state jurisdictions, state retail market designs were developed over a different timeframe from wholesale market designs, without substantial coordination.

[54] As they pay for the Global Adjustment based on their percentage contribution to the top five peak demand hours in Ontario over a 12-month period.
[55] Peak demand reduction estimate for 2016 taken from the IESO's Industrial Conservation Initiative Backgrounder (August 2019); estimate for 2017 taken from the Q1 2019 Ontario Energy Report.
[56] Based on consumption by customer class from the IESO's "GA components plus costs and consumption by customer class" datasheet.

The existence of multi-state ISOs, state-level regulators, and the FERC mean there are additional actors attempting to address potentially overlapping issues (in this case demand response) that are not present in Ontario. For example, the presence of multi-state ISOs means that states may have additional DR programs which may or may not complement those at the ISO level.

Based on the demand response resource programs in the three US markets LEI reviewed, the following conclusions can be drawn:

- DR resources serve primarily by the provision of capacity (in terms of total resource participation);
- when they have access to both capacity- and 'energy'-related compensation, capacity revenues still form the bulk of their revenues; and
- compensation for dispatch of economic DR resources or activation of emergency/reliability resources is the common approach; but the actual dispatch (in aggregate) of economic DR resources is low and activation of emergency/reliability resources is very infrequent (meaning, again, that actual dispatch or activation is a very small proportion of revenues for most DR resources).

Ontario has several key differences from US ISOs:

- a number of states in the geographic Northeast (including most states in PJM, ISO-NE, and NYISO) allow retail electricity choice, with Load Serving Entities being more prevalent, a large portion of industrial and commercial load being served by competitive suppliers, and greater access to competitive fixed-price contracts or hedging without the use of physical assets;
- demand response procured through the IESO's DRA in Ontario is presently a smaller share of capacity and peak than in other markets. Additionally, this auction is still in its early stages of development (compared to the other three markets), and procurement is limited to a small proportion of Ontario's total capacity;
- the fact that over 90% of all generation in the province is under regulated rates or contracted impacts the price signal provided by the HOEP and increases the influence of the GA on bills to final consumers; and
- although fewer DR resources are procured through the IESO's auctions compared to the US ISOs, outside of the DRA, the incentives embedded within the ICI provide significant avoided costs for those Class A customers capable of curtailing their loads during critical peak periods (with around 29% of load being Class A in 2018).

Overall, when assessing compensation mechanisms for DR, the impact on the transparency of the energy price signal needs to be considered, balanced against the practical reality that across the three US markets covered in this report DR is rarely activated, and receives the bulk of its revenue from capacity-like mechanisms.

6 Appendix A: List of acronyms

ADCR	Active Demand Capacity Resources
CA	California
CELT	CELT and Transmission
CEO	Chief Executive Officer
CSO	Capacity Supply Obligations
CT	Connecticut
DADRP	Day Ahead Demand Response Program
DASR	Day Ahead Scheduling Reserve
DC	District of Columbia
DE	Delaware
DER(s)	Distributed Energy Resource(s)
DR	Demand Response
DRA	Demand Response Auction
DSASP	Demand-Side Ancillary Services Program
EDRP	Emergency Demand Response Program
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FAQs	Frequently Asked Questions
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
GA	Global Adjustment
GWh	Gigawatt-hours
HDR	Hourly Demand Response
HOEP	Hourly Ontario Energy Price
ICAP	Installed Capacity
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IL	Illinois
ISO(s)	Independent System Operator(s)
ISO-NE	ISO-New England
kW	Kilowatt
LEI	London Economics International LLC
LLC	Limited Liability Company
LMP	Locational Marginal Price
LSE	Load Serving Entity
MA	Massachusetts
MCP	Market Clearing Price
MD	Maryland
MI	Michigan

MT	Montana
MW	Megawatt
MWh	Megawatt-hour
NBT	Net Benefits Test
NEPOOL	New England Power Pool
NH	New Hampshire
NJ	New Jersey
NY	New York
NYISO	New York ISO
OEB	Ontario Energy Board
OH	Ohio
OR	Operating Reserve
OR	Oregon
PA	Pennsylvania
PRD	Price Responsive Demand
RI	Rhode Island
RTO(s)	Regional Transmission Organization(s)
SCR	Special Case Resource
WA	Washington

7 Appendix B: List of works cited

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TAB 4

LEI responses to interrogatories

Responses to interrogatories prepared for the Ontario Energy Board staff by London Economics International LLC ("LEI")

November 20th, 2019

Table of contents

Table of figures

1 Interrogatories to LEI from Kingston Cogen Limited Partnership

1.1 KCLP-1

Interrogatory

Reference: LEI Report, section 3.2.2, pp. 9-10

Preamble: FERC Order No. 745 at paragraph 49 describes "the billing unit effect of dispatching demand response resources" as:

> "*…when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost effective purchase from the customers' standpoint.*"

Footnote 119 of FERC Order No. 745 provides an example to illustrate:

> "*As a simple example, assume a market of 100 MW, with a current LMP of $50/MWh without demand response, and an LMP of $40/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be $4,000 with demand response compared to the previous $5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would decrease from $50/MWh to $42.11/MWh ($4,000/95). Therefore, the payment of LMP to demand resources is cost-effective.*"

The LEI Report states that Figure 4 demonstrates the billing unit effect of DR under three separate conditions. Scenario 2 demonstrates the billing unit effect of DR and the circumstances when there is a zero net benefit from dispatching the DR Resources, i.e. the price point of the target of the net benefits test.

Questions:

(a) In Scenario 2, when there is no DR deployment, can you please confirm:
   i. When the LMP is determined, where total load to be supplied (Regular Load and DR load) is equal to 10,100 MWh, which is the total amount supplied?
   ii. When the offer price of Supplier V is $1,062/MWh, whether it is the marginal price-setting supplier, and hence the LMP is $1,062/MWh?
   iii. As per the simple example provided by the Commission, if the average price paid by each customer is $1,062/MWh, and total payments by load to generators would be equal to the LMP multiplied by total load supplied (i.e., $1,062/MWh x 10,100 MWh = $10,726,200).

(b) In Scenario 2, when there is DR deployment, can you please confirm:
   i. When the bid price of the DR resource is $1,000 MWh, the DR resource is the marginal price setting resource and hence the LMP is $1,000?
   ii. Whether the remaining load benefits pays generators the amount of $10,000,000, which is derived as the LMP times total load (i.e., $1,000/MWh x 10,000 MWh = $10,000,000)?

iii. Whether the amount the remaining load must pay to DR resources is $100,000, which is derived as $1,000 MWh x 100 MWh?
iv. As per the simple example provided by the Commission, total payments by the remaining load to generators and DR resources would by the sum of what they pay generators plus the amount that they pay the DR resource, which is equal to $10,000,000 + $100,000 = $10,100,000, and that the average price paid by the remaining load customer is $1,010/MWh?

(c) In Scenario 2, when there is DR deployment, can you please confirm:
i. Whether the bid price of the DR resource is $1,000 MWh, the DR resource is the marginal price setting resource and hence the LMP is $1,000?
ii. Whether the remaining load benefits from the lower LMP and pays generators the amount of $10,000,000?
iii. Whether the amount the remaining load must pay to DR resources is $100,000?
iv. As per the simple example provided by the Commission, total payments by the remaining load to generators and DR resources would by the sum of what they pay generators plus the amount that they pay the DR resource, which is equal to $10,100,100 and that the average price paid by the remaining load customer is $1,010/MWh?

(d) Do you agree that contrary to what Scenario 2 claims to demonstrate, this is not a zero net benefit scenario as contemplated by FERC Order 745 but instead a net benefit scenario?

(e) Do you agree that your calculation of the net benefits test and billing unit effect is different from the Commissioners definition?

<u>Response</u>

Figure 4 of LEI's report was meant to show hypothetical billing unit effects under an illustrative scenario where suppliers receive different prices applicable to their nodes, while load pays the load-weighted zonal average price. In LEI's Figure 4, Suppliers A-R, S, T, and U, are meant to exist at individual nodal points, while Supplier V and DR resource are at the same node. Under this illustrative scenario, suppliers are receiving their applicable nodal prices based on their supply, and load is paying the load-weighted average price.

Figure 4 should be interpreted with the above context in mind. As covered in the first question to LEI from KCLP (KCLP-1), when all suppliers receive the same price as 'Supplier V' or 'DR resource', dispatching the DR resource over Supplier V in LEI's Scenario 2 would be cost-effective.

1.2 KCLP-2

Interrogatory

Reference: LEI Report, section 3.2.2, pp. 10-11

Preamble: The LEI Report states that Figure 5 presents for illustrative purposes PJM's monthly NBT prices from April 2012 to October 2019, along with the monthly average prices for PJM – RTO Zone. It states that the chart is illustrative as the test is actually applied to each applicable zone on an hourly basis.

Questions:

(a) Can you confirm that the net benefits test price threshold in PJM is calculated monthly using a system-wide monthly supply curve that is smoothed using non-linear estimation techniques?
(b) Can you confirm that this singular system-wide threshold is compared to the various locational marginal prices (LMPs) on an hourly basis to determine DR resources are eligible for compensation?
(c) In your opinion, are there any shortcomings of applying this system-wide threshold to hourly LMPs for determining a net benefit to consumers from compensating DR resources?
(d) Would you recommend the same approach be applied to Ontario? If yes, why and if no, why not?

Response

(a) As laid out in PJM's *Manual 11: Energy & Ancillary Services Market Operations, Revision: 107,* Section 10.3.1 (effective September 26, 2019), the aggregate supply curve for PJM is smoothed using a non-linear least squares estimation technique.

(b) The system-wide threshold is compared to applicable LMPs; this can be on an hourly basis (e.g. in the case of the day-ahead market) or on a five-minute basis (e.g. in the case of the real-time market).

(c) Yes. Comparing the LMPs to a system-wide threshold poses a degree of administrative burden on market institutions, while potentially oversimplifying net benefit calculations given the possible diversity in how load to customers is priced and the nature of their financial hedges, among other factors.

(d) No. We do not believe that Order 745 is relevant to the specifics of the Ontario market. Any test developed for Ontario should at a minimum take into account Ontario-specific conditions, including the Global Adjustment and how it is recovered, as well as more generally how supply is priced to various types of load in Ontario and over what time period, and the expected evolution of the Ontario market.

1.3 KCLP-3

Interrogatory

Reference: LEI Report, Section 3, Pages 7-14

The Affidavit of Brian Rivard dated Nov 8, 2019 (the "Rivard Affidavit"), Paragraphs 53-57

Preamble: At section 3 (pages 7-14) of the LEI Report, LEI provides an overview of FERC Order 745 and the net benefits test.

At paragraphs 53-57 of the Rivard Affidavit, Mr. Rivard provides a summary of the FERC Order 745 and the net benefits test.

Questions:

(a) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's overview of FERC Order 745 and the net benefits test. If LEI generally agrees with Mr. Rivard, please confirm this.
(b) If LEI disagrees with any aspect of Mr. Rivard's overview, please explain the basis of this disagreement.

Response:

LEI broadly agrees with Dr. Rivard's brief description of FERC Order 745 provided in Paragraph 53, and agrees that the contents in Paragraph 54 and 55 are consistent with LEI's understanding. LEI does not disagree with the information contained in Paragraph 56, but believes it would be more appropriate to refer to "remaining load" rather than "non-DR consumers." For the contents in Paragraph 57 related to FERC Order 745, LEI would characterize the net benefits test as seeking to avoid situations where dispatching DR may result in higher costs per unit for remaining load, rather than to "maximize the benefits to non-DR participants."

1.4 KCLP-4

Interrogatory

Reference: LEI Report, Section 3, Pages 7-14

Rivard Affidavit, Paragraphs 56-58

Preamble: At section 3 (pages 7-14) of the LEI Report, LEI provides an overview of FERC Order 745 and the net benefits test.

At paragraphs 56-58 of the Rivard Affidavit, Mr. Rivard draws a distinction between the net benefits test and economic efficiency.

Questions:

(a) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's assessment of the net benefits test and economic efficiency. If LEI generally agrees with Mr. Rivard, please confirm this.
(b) If LEI disagrees with any aspect of Mr. Rivard's assessment, please explain the basis of this disagreement.
(c) Based its research conducted, has LEI formed an opinion regarding the economic impacts of providing energy payments to DR resources? If yes, please state the opinion.
(d) Is LEI of the opinion that providing energy payments to DR resources could lead to economically inefficient outcomes both during the TCA, and in the event that a DR resource is dispatched? Please explain.

Response

(a) LEI's disagreement with the assessment of the net benefits test lies primarily with regards to its relevance to the Ontario situation. With regards to economic efficiency, LEI's concern is with regards to the fidelity of the price signal and the need for a more nuanced approach to the concept of horizontal equity.

However, LEI agrees that any consideration of whether and how market rules are developed to incorporate an activation payment must take into account the incentives Class A customers receive under the ICI to adjust their consumption.

(b) LEI believes that the discussion of horizontal equity is over-simplified. Fossil generators are not expected to guess how many times they will operate and at what fuel price, and to incorporate those assumptions into their capacity bids because they will not be paid an energy price when run. While the theoretical premise is that generators will reduce their capacity bids by the margin above fuel costs that they expect to achieve, generators do expect to receive at least their short run marginal costs when dispatched, and configure their bids accordingly.

A framework in which DR receives only capacity payments but no activation payments will drive DR participants to set high activation price thresholds. This may dull the effectiveness of the price signal at relatively high price periods (such as periods when the market price is high, but remains below the DR activation threshold). Short run costs of activation include process wastage (for example disposing of unfinished and unfinishable products) and staff inefficiencies; allowing compensation for these costs rather than expecting companies to factor them in to their activation threshold (i.e. the price trigger at which load would be curtailed) is more consistent with horizontal equity in that it is equivalent to generators being paid for fuel and other short run variable operating costs through their energy bids.

(c) Given the short time period in which to develop its analysis and respond, LEI's opinions are preliminary and subject to change. With that caveat in mind, LEI's views are as follows:

Based on the markets and programs LEI reviewed in its report, actual activation of DR resources has been relatively limited, and DR resource revenues from this activation have also been limited (as compared DR capacity revenues, see Section 4.4 of LEI's report). This implies that, from a practical perspective, the benefit or harm arising from whether DR resources are provided energy payments may not be material in the near term.

LEI's understanding is that the IESO's proposed design is the subject of this proceeding and alternative approaches are not within the scope of the case. Nevertheless, LEI believes that, conceptually, there is merit in separating the reservation payment embodied in a capacity payment from an activation payment which occurs when the resource is actually deployed. In such a market design, bidders into the capacity auction need not consider the frequency of deployment or build in a risk premium when submitting their capacity bid. Were market rules devised which allowed a two part bid from DR resources in which they set forth both their required activation payment and the activation price threshold, DR resources would receive a payment, and their DR activation bids would reflect both the benefit of avoiding a cost and the cash payment required to address specific costs of activation. LEI believes that such an approach would result in greater variation of DR activation bids leading to a more robust price signal. LEI also notes that behavior responses to avoidance of cost versus those to receipt of a benefit may differ; creating a hybrid of the two may produce more economically efficient outcomes.

(d) LEI believes that any assessment of economic efficiency needs to be based on the specific market rules being applied, and the period of time being analyzed. Furthermore, the fact that something ***could*** happen does not mean that it ***will*** happen; analysis needs to take into account probability, frequency, the degree of harm, safeguards, and net benefits before coming to a determination.

1.5 KCLP-5

Interrogatory

Reference: LEI Report, Section 4, pages 15-32, Rivard Affidavit, Paragraphs 79-85

Preamble: At section 4 (pages 15-32) of the LEI Report, LEI provides an overview of how DR resources are compensated in PJM, ISO-NE and NYSIO.

At paragraphs 79-85 of the Rivard Affidavit, Mr. Rivard provides a summary of the results of a non-exhaustive scan of the academic literature and reports prepared by the RTOs, ISOs and the market monitors for empirical evidence on the effects and implications of the implementation of FERC Order No. 745.

Questions:

(a) Does LEI agree that Mr. Rivard's summary contained at paragraphs 79-85 of the Rivard Affidavit is complimentary to the research and analysis completed at pages 15-32 of the LEI Report?

(b) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's summary of the results of his non-exhaustive scan of academic literature and reports. If LEI generally agrees with Mr. Rivard's summary, please confirm this.

(c) If LEI disagrees with any aspect of Mr. Rivard's summary, please explain the basis of this disagreement.

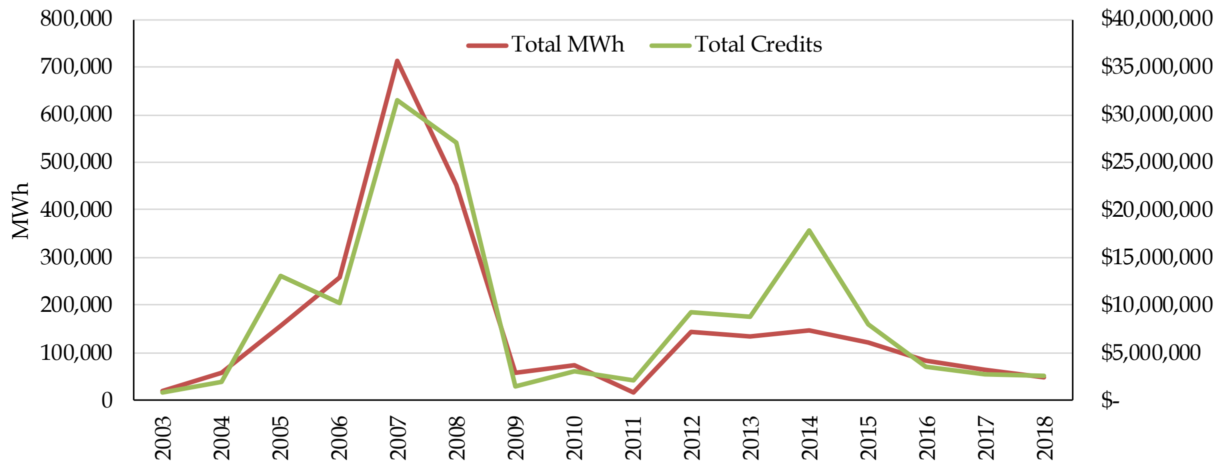
Response

Although LEI sees very little overlap between Section 4 of its report and Paragraphs 79-85 of Dr. Rivard's Affidavit, they can be viewed as complementary. Section 4 of LEI's report was intended to provide an overview of DR participating in programs administered by a selection of US ISOs/RTOs (including those programs to which FERC Order 745 does not apply) and provide some cross-cutting observations, relying primarily on information from the ISOs/RTOs themselves. Paragraphs 79-85 of Dr. Rivard's Affidavit provides a non-exhaustive scan of research on the effects FERC Order 745 has had on wholesale markets, and is focused largely on academic studies. LEI's disagreement is not with regards to Dr. Rivard's summary but rather with regards to the relevance of the articles to Ontario.

Paragraph 80 of Dr. Rivard's Affidavit and Section 4 of LEI's report both reference PJM State of the Market Reports for information on payments made to and dispatch of DR resources. As noted in Paragraph 80 of Dr. Rivard's Affidavit, monthly data from 2010 to 2019 shows an increase in economic demand response reductions and credits in PJM after FERC Order 745 was implemented (April 2012, as compared to the months before FERC Order 745 was implemented).

As discussed in Section 4 of LEI's report, considering the size of the PJM market, these credits and reductions are a very small proportion of total DR revenues and PJM's total load. In addition to information contained in Section 4, LEI notes that extending the historic period further back would show that total credits and DR reductions were noticeably higher in 2007 and 2008 as compared to the period from 2012 onwards, which can be seen in Figure 1.

Figure 1. Annual economic program credits and MWh (2002-2018)



Sources: data from 2002 to 2009 relies on Table 6-4 from the 2013 *State of the Market Report for PJM: Section 6 – Demand Response;* data from 2010 to 2018 relies on Table 6-4 from the 2018 *State of the Market Report for PJM: Section 6 – Demand Response.*

1.6 KCLP-6

Interrogatory

Reference: LEI Report, Section 5, pages 33-39, Rivard Affidavit, Paragraphs 58-71

Preamble: At Section 5.4 (pages 37-38) of the LEI Report, LEI identifies the impact of Global Adjustment in Ontario, which according to Figure 30 accounts for 77% of the total electricity wholesale costs (excluding transmission and distribution costs) in Ontario.

At paragraphs 58-71 of the Rivard Affidavit, Mr. Rivard provides an analysis of the impact of Global Adjustment on the calculation of the net benefits test in Ontario.

(a) Does LEI agree with Mr. Rivard that 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 in Ontario?
(b) Does LEI agree with Mr. Rivard that as a result of the Global Adjustment, the net benefits test will be satisfied less frequently (if ever) than in the US markets?
(c) With specific reference to paragraphs 58-71 and Figures 5, 6 and 7 of the Rivard Affidavit, please explain whether LEI generally agrees or disagrees with Mr. Rivard's analytic approach and Mr. Rivard's findings?

Response

(a) Yes; however, as Ontario is not under FERC jurisdiction, and the market framework has significant differences, the test is not relevant.

(b) LEI does not believe that the net benefits test as configured for US markets is appropriate for developing market rules in Ontario. Due to the generally inverse correlation between Ontario wholesale market prices and the Global Adjustment, there are some changes to Ontario market rules which could improve transparency and change wholesale price outcomes without having an immediate bill impact. However, such rule changes could still incentivize changes to investment and operating behavior which over the long run would still provide benefits to consumers.

(c) Because LEI questions whether the net benefits test as configured for US markets is relevant to Ontario, LEI regards the analysis as largely academic. LEI nonetheless has the following observations:

1. The analysis is largely static; it does not assess how the behavior of various market players would change as a result of the changes in market conditions.
2. Using historical data is a beginning, rather than an end, to the analysis; consideration of future changes in price dynamics is helpful in exploring the impact on final consumers.
3. Changes that impact even a very small number of overall hours may nonetheless be worthwhile, to the extent that they improve the value of the price signal during super-peak hours.

4. The analysis may be targeted at the wrong question: a better question is, under what circumstances would providing energy payments to demand response be beneficial for Ontario, and what tests should be designed to confirm that those circumstances prevail at the time?
5. LEI believes that Ontario should pursue a pragmatic approach based on sustained incremental improvements to market rules, which where appropriate is substantiated by dispatch modeling and scenario analysis.

1.7 KCLP-7

<u>Interrogatory</u>

<u>Reference:</u> LEI Report

Rivard Affidavit

<u>Preamble:</u> The preceding questions asked very specific questions to explore the similarities and differences between the LEI Report and the Rivard Affidavit.

<u>Questions:</u>

(a) Are there any other areas of similarities or differences as between the LEI Report and the Rivard Affidavit that you would like to identify for the OEB?

<u>Response</u>

The two reports differ in the scope provided to their authors.

The LEI report was focused on describing FERC Order 745, conditions in US wholesale and retail markets, and contextual similarities and differences between Ontario and the US. LEI was not asked to develop conclusions with regards to how a net benefits test could be properly designed for Ontario, or whether any particular party would be harmed through any specific configuration of an IESO market rule.

By contrast, Dr. Rivard was asked to offer his “independent views on the economic merit of AMPCO’s position in this proceeding”.

2 Interrogatories to LEI from the School Energy Coalition

2.1 SEC-OEBStaff-1

<u>Interrogatory</u>

[KingstonCoGen, Evidence of Brian Rivard, para. 53-85] Please provide LEI's views on Mr. Rivard's evidence regarding the application of FERC Order No. 745 to Ontario.

<u>Response</u>

Please see LEI's responses to the KCLP interrogatories, and the following interrogatories specifically: KCLP-2 (d), KCLP-4, KCLP-5, and KCLP-6.