Willms & Shier
Environment Aboriginal Energy Law

Direct Dial: 416 862 4830
File: 6706

By Electronic Mail & RESS Filing

August 12, 2015

Ontario Energy Board
P.O. Box. 2319
2300 Yonge Street, 27th Floor
Toronto, ON  M4P 1E4

Attention:  Kristen Walli, Board Secretary

Dear Ms. Walli:

**Re: Ontario Sustainable Energy Association's ("OSEA") Interrogatory Responses**
**Board File No. EB-2015-0029/EB-2015-0049**

Please find enclosed OSEA's Response to Interrogatories from

- Enbridge
- OGVG
- APPrO
- GEC
- VECC

Yours truly,

Joanna Vince

Encl.

cc. Nicole Risse, Executive Director, OSEA
Intervenors

Document #: 880136

**Willms & Shier Environmental Lawyers LLP – TORONTO**
4 King Street West, Suite 900, Toronto, Ontario, Canada M5H 1B6
T: 416 863 0711 F: 416 863 1938 www.willmsshier.com

**Willms & Shier Environmental Lawyers LLP – OTTAWA**
45 O'Connor Street, Suite 700, Ottawa, Ontario, Canada K1P 1A4
T: 613 761 2424 www.willmsshier.com

OSEA Response to APPrO Interrogatories

**Question #1**

Ref: Paragraph 2 and paragraph 4

Preamble: In the above references, Mr. Young indicates that he is providing expert opinion on sustainable energy opportunities and he also discusses his own experience in developing combined heat and power (CHP) projects in Ontario. APPrO would like to better understand his experience.

a) Please provide a list all of the operating CHP plants in Ontario that Mr. Young has been involved in developing and/or operating and include the size in MW, the location and the year in which it went into service, the input energy source, the annual capacity factor of each plant, and Mr. Young's ownership percentage, if any.

b) Please describe the role that Mr. Young played in developing and/or operating each of the plants identified in (a), above.

c) Please describe the commercial arrangements for the "sale" of the resulting energy outputs of each of the CHP plants.

**Response**

a) I do not operate or have any ownership percentage of any operating Combined Heat and Power (CHP) plants in Ontario. I am involved with Stoked Power Generation in the design and development of new technology for CHP systems including bio-gas equipment. Stoked Power General was selected by Sustainable Development Technology Canada to join its Natural Gas Technology Incubation Program.

b) See response a)

c) See response a)

**Question #2**

Ref: Paragraphs 9, 10, 13 and 21

Preamble: In the above references, Mr. Young speaks to greenhouse gas (GHG) emissions and Ontario's electricity sector and indicates: "*Sustainable energy approaches are critical to both energy conservation and environmental protection. Despite progress in specific areas, significant programmatic, institutional and regulatory processes and practices within many key organizations in the energy sector have had limited progress on these two matters. With respect to greenhouse gas emissions, Ontario's challenge is moving beyond phasing out coal and reducing the carbon content of applications such as heating and transportation.*"

a) Please provide, in the following chart format, the information on energy conservation and greenhouse gas emissions applicable to various programs initiatives and sectors and all supporting primary resources and documentation.

**Response**

a) The Environmental Commissioner of Ontario has the legislative authority to report on conservation results as well as progress in meeting Ontario's greenhouse gas emissions reductions. The references provided in my evidence cited the Environmental Commissioner's latest report. It is unnecessary to transcribe the data from the report into the chart form when the report is readily available to the public.

**Question 3**

Ref: (i) Paragraph 16, 18 (ii) Paragraphs 21, 22, and 27

Preamble: In Reference (i) Mr. Young notes that the electricity market is dominated by existing large central power plants. APPrO would like to better understand Mr. Young's position on gas-fired power generation.

a) Please confirm that these gas-fired power plants were developed based on, and operate in accordance with, long-term contracts between the developer and the IESO (formerly the OPA), or the Ontario Electricity Financial Corporation? If not explain.

b) Please confirm that, among other functions, gas-fired power plants provide the necessary operational back-up generation capability that is required when alternate forms of renewable energy are not available. If not confirmed, please explain.

c) In Reference ii) Mr. Young indicates the typical efficiency of electricity generation from natural gas is less than 40%.

   i. Please explain in full how Mr. Young arrived at this efficiency percentage.

   ii. Please provide all the studies of, or works on, the Ontario natural gas-fired electricity generation fleet that Mr. Young has personally worked on in order to assess the efficiency of electricity generation from natural gas in Ontario.

   iii. Please provide any and all other third party documentation and information that Mr. Young has relied on to arrive at this result.

   iv. Mr. Young states that the efficiency of CHP is "well in excess of 90 per cent". Please provide detailed calculations from both (a) an Ontario CHP plant and (b) the Ontario CHP fleet that supports this stated efficiency level. Please reconcile this statement with Exhibit H, which indicates that the overall efficiency of CHP plants range from 60-92%.

   v. Please confirm that the majority of gas-fired generation facilities in Ontario are, in fact, of a combined cycle or CHP nature or utilize waste heat for secondary power generation, to meet industrial steam or other heating requirements.

   vi. Please provide: (a) the total and average annual amount of water usage by Ontario's natural gas-fired generation fleet and (b) the total and average annual amount of water usage by Ontario's combined cycle natural gas-fired generation fleet.

   vii. Please confirm that Appendix H in Mr. Young's evidence illustrates that combined cycle power plants have overall efficiencies in the 73-90%.

   viii. Please provide the estimated capital costs and projected energy savings from converting an existing single cycle gas-fired generating facility to CHP (a) not adjacent or within 1 km of an operating industrial facility (b) adjacent to an operating industrial facility and (c) within 1 km of an operating industrial facility.

d) Please provide a map of Ontario illustrating the location of all electrical generation facilities by type.

**Response**

a) The IESO electricity production data herein indicates that Ontario's energy supply is produced by primarily large central power plants including nuclear and gas-fired power plants. Large central power plants, such as the Bruce, Pickering or Darlington nuclear power plants generate approximately 65% of the energy in the form of waste heat, which is discharged into water bodies.

Ontario Grid-Connected Electricity Production by Fuel Type 2013-2014[1]

| | Nuclear | Hydro | Coal | Gas/Oil | Wind | Biofuel | Solar |
|---|---|---|---|---|---|---|---|
| 2014 | 94.9 TWh | 37.1 TWh | 0.1 TWh | 14.8 TWh | 6.8 TWh | 0.3 TWh | 0.0185 TWh |
| 2014% | 62% | 24% | <1% | 10% | 4% | <1% | <1% |
| 2013 | 91.1 TWh | 36.1 TWh | 3.2 TWh | 18.2 TWh | 5.2 TWh | 0.2 TWh | n/a |
| 2013% | 59% | 23% | 2% | 12% | 3% | <1% | n/a |

b) Gas-fired power plants provide the type of ultra-flexible backup generation capacity that enables high penetration levels of variable renewable energy sources like wind and solar.

c)

i. Equipment manufacturers and government agencies routinely report efficiency calculations of this nature with the 40% cited at the higher end of these estimates.

ii. I have not personally worked on a study of natural gas-fired electricity generation fleet in Ontario to assess the efficiency of electricity generation. However, I will note that power generation data reported by IESO/OPA do not provide the level of detail found in other markets such as Germany or the United Kingdom. As such, omission

[1] http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx

of thermal efficiency by the IESO/OPA makes it impossible to accurately assess the efficiency level of a natural gas power plant in Ontario.

iii. Table 1-3 of the "Catalog of CHP Technologies from the U.S. EPA Combined Heat and Power Partnership"(http://www.epa.gov/chp/documents/catalog_chptech_full.pdf) provides an indication of maximum electrical efficiency range (24-41%) based on HHV of various established generation technologies. Data from the U.K. government provides additional data on electrical efficiencies (https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes).

iv. Please refer to Table 1-3 of the "Catalog of CHP Technologies from the U.S. EPA Combined Heat and Power Partnership". My assertion of higher level claims are based on virtual prototyping of proprietary microCHP technology in development where high heat utilization is possible.

v. While I know there are a number of CHP facilities in Ontario, data from IESO gives no indication of thermal efficiency of these power plants. As such I'm not in a position to comment.

vi. This data is not disclosed in the IESO data and would likely be considered commercially sensitive by those operators.

vii. Yes, so long as thermal production is consumed by the load customer.

viii. This would be highly dependent on a number of factors however the "Catalog of CHP Technologies from the U.S. EPA Combined Heat and Power Partnership" can provide a reference point.

d) It is not feasible to provide a map of <u>all</u> electrical generation facilities in Ontario and it is outside the scope of this hearing.

**Question 4**

Ref: (i) Paragraphs 24-27, (ii) Exhibit I

Preamble: In Paragraph 24-27 Mr. Young indicates that regulatory practices in Ontario have not been revised to reflect the broader societal benefits of CHP. In Paragraph 27 Mr. Young states that based on his analysis, 63.3 TWh/yr. of electricity could be saved annually by shifting away from centralized power plants in favour of CHP. The reference associated with Reference i) states that "*Based on a full conversion rate, there is potential to replace upwards of 8,000 MW of relatively low efficiency thermo electric generation capacity.*" In Reference ii) Mr. Young references efficiency information related to 'standard power plants'. APPrO would like to better understand this information.

a) Please file the reference associated with Paragraph 27 and all supporting documentation

b) Please provide the total electrical consumption in Ontario for each of the last 3 years and express the 63.3 TWh/yr. of purported potential annual savings as a percentage of the provincial total. Please also confirm that these savings are related to the replacement of 8,000 MW of low efficiency thermo electric generation capacity

c) Please provide a full copy of Mr. Young's analysis and include all major assumptions that support the claim of 63.3 TWh/yr. annual savings.

d) In Reference ii) Mr. Young references a standard power plant. Please state what Mr. Young means by a "standard power plant". Please confirm that Mr. Young's reference to a "standard power plant" is not a reference to a natural gas-fired combined cycle power plant. Please explain if this is not the case.

e) Please confirm that the efficiency estimates in Reference ii) were not developed by Mr. Young.

f) Please provide an itemization of any and all expertise that Mr. Young has in analyzing the OPA/IESO's Clean Energy Supply Agreements and early mover contracts for combined cycle natural gas-fired electricity generation.

g) Please provide a list of the Ontario "regulatory practices" that Mr. Young believes do not reflect any societal benefits.

h) Please provide Mr. Young's working definition of a "large central power plant" as stated in Paragraphs 25-27.

**Response**

a) This calculation is a high level estimation that conceptually converts all building heating systems in Ontario to building appropriate sized CHP systems and the resulting electricity production that could be achieved. Data sets for electricity were obtained from the IESO (http://www.ieso.ca/Pages/Power-Data/Supply.aspx). Building energy consumption data for Ontario Residential and Commercial/Institutional buildings was generated by Natural Resources Canada "Comprehensive Energy Use Database Query System" (http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm).

b) For the year 2012, for which this estimate applies the 63.3 TWh, represents a theoretical potential of 42% of the electricity generated in the Province. This figure is intended to be illustrative.

c) This calculation takes the total energy consumed to heat buildings in Ontario as reported by the Comprehensive Energy Use Database (reference provided above) and, adjusts for a furnace efficiency of 80% to derive a theoretical primary fuel input estimate required for space and water heating. With this understanding of potential availability of primary fuel inputs from existing use as the input source, a theoretical HHV electrical efficiency of 27% for generic CHP generation technologies (reference CHP Catalogue Table 1-3 cited above) which has been adjusted to reflect a 6% electricity savings for avoided transmission and distribution losses to arrive at an estimated 63.3TWh generation potential utilizing existing heating fuel consumption. See attached, *Linking heat and electricity in Ontario buildings to generate energy efficiency and savings*.

d) By standard power plant, I am referring to nuclear plants which dominate the Ontario electricity supply mix.

e) As cited, Exhibit I was prepared by the International District Energy Association.

f) I have not analyzed any specific commercial agreements.

g) Behind the meter CHP installations are not compensated for providing power capacity and frequency regulation services that reinforce the provincial power system. In the case of major system outages such as experienced in 2003 or as a result of severe weather (hurricanes, ice storms and flooding) such installations add local resilience to the system; a feature that is becoming more and more important, but goes unrecognized by the current market arrangements. The attached analysis, *The Grid Related Benefits of Distributed Generation* by David Engle, provides a generic summary of additional benefits.

h) My definition of a large central power plant is nuclear power plants or other facilities over 500 MW capacity that by design do not make use of low grade heat for a secondary purpose other than supporting electricity production.

**Question #5**

Ref: Exhibit G

Preamble: Mr. Young provides a publication called “Up in Smoke””. APPrO would like to better understand the information referenced in this exhibit.

a) Please confirm that this information references power generation in the United Kingdom and not Ontario.

b) Please indicate if Mr. Young conducted any of the underlying analyses that resulted in the percentages in the Exhibit. If so, please provide such detailed calculations and include all major assumptions.

**Response**

a) Yes, however the figure illustrates generating technologies that operate both in Ontario and the U.K.

b) No additional analyses were completed.

**Question #6**

Ref: Paragraphs 1-4, and Exhibit A

Preamble: In the above references, Mr. Young set out his qualifications and scope of work, which includes providing expert opinion on sustainable energy opportunities that the utilities can incorporate into their DSM plan, and identification of barriers that prevent conservation and GHG reduction.

a) Please provide any background or expertise that Mr. Young has had in relation to the Ontario integrated energy initiatives including: the 2014 Natural Gas Market Review, the Natural Gas Electricity Interface Review, the IESO/OPA conservation and demand management initiatives, and the IESO technical panel and market rule amendment process, and any supporting reports or documents that he has produced or relied upon in those matters.

b) Please provide a list all sustainable energy opportunities that you considered and rejected in light of the Ontario energy context.

**Response**

a) As a former board member of the Ontario Sustainable Energy Association, I've contributed extensively to numerous policy documents developed by OSEA and submitted to IESO/OPA either directly or through stakeholder engagements. Additionally, I have attended OPA stakeholder engagement sessions related to development of the Feed-in-Tariff program and Community Energy. In the course of my business activities I've attended numerous meetings with community based stakeholders including Commercial and Multi-Unit Residential building managers, manufacturers from different segments of the economy, electricity grid operators, and numerous community engagement activities related to siting of proposed biogas/CHP projects. In addition, I currently participate in the Sustainable Development Canada Natural Gas Technology Incubation Program.

b) The sustainable energy opportunities I considered are described in the evidence I submitted.

**Question #7**

Ref: Paragraphs 28-33

Preamble: In the above references, Mr. Young indicates that to date the Ontario approach has been focused on electricity and has not considered combined thermal and storage initiatives.

a) Please provide an itemization or any and all CHP and energy storage programs or initiatives in the province and the associated responsible authority.

**Response**

a) The following energy storage and CHP programs are currently administered by IESO/OPA:

   i. Combined Heat and Power Standard Offer Program (CHPSOP) 2.0 (http://www.powerauthority.on.ca/combined-heat-power-procurement)

   ii. IESO Energy Storage Procurement Phase II (http://www.ieso.ca/Documents/procurement/Energy-Storage/Technical-Information-Session-ESP-Phase-II.pdf)

# Linking heat and electricity in Ontario buildings to generate energy efficiency and savings

BACKGROUND

Electricity production from large central power plants has gained a dominant position in the North American Electricity landscape.

While there are several different generation technologies deployed, a key factor that should be emphasized is overall energy efficiency represented by the percentage of overall input that is utilized by the end customer.

In Ontario, 72% of electricity is generated by thermo electric power plants such as nuclear or natural gas[1], with the majority of these electricity generation facilities are not connected to heating loads despite the fact that upwards of 65% of the energy produced is in the form of heat that is in many cases wasted[2 3].

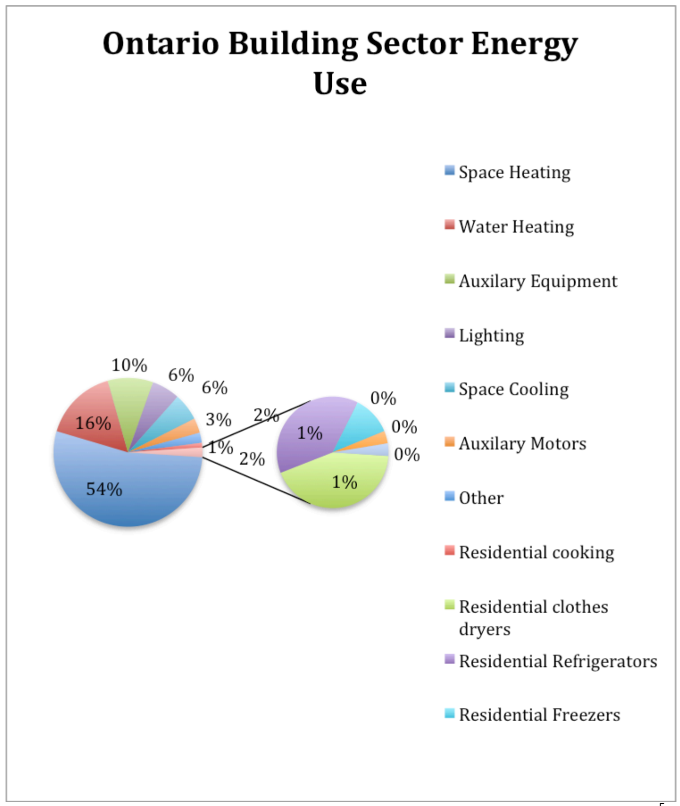
This means that while consumers are paying for electric energy they are also making an additional purchase of fuel for heating needs. This essentially results in, an unnecessary doubling of the over all energy consumption per building which can be avoided with an integrated energy management approach that pairs power production facilities with heat load customers.

If heating loads are directly linked to generation, greater efficiencies can be realized and the waste heat fraction shifting from 65% for nuclear plants down to roughly 10% with properly sized Combined Heat and Power (CHP) systems.

UNCOVERING ENERGY EFFICIENCY OPPORTUNITIES

While the Ontario Ministry of Energy places great emphasis on energy conservation measures[4] with consumers, the energy use shares for Ontario buildings suggest that emphasis be placed on the thermal needs of buildings rather than lower consumption activities such as lighting or refrigeration, which are highly emphasized in Provincial conservation initiatives.

Fig:1




Data: 2012 Natural Resources Canada Comprehensive Energy Use Database[5]

In terms of overall energy consumption, it becomes evident that while businesses may appear to be natural

1 http://www.ieso.ca/Pages/Power-Data/Supply.aspx

2 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337657/dukes5_5.xls

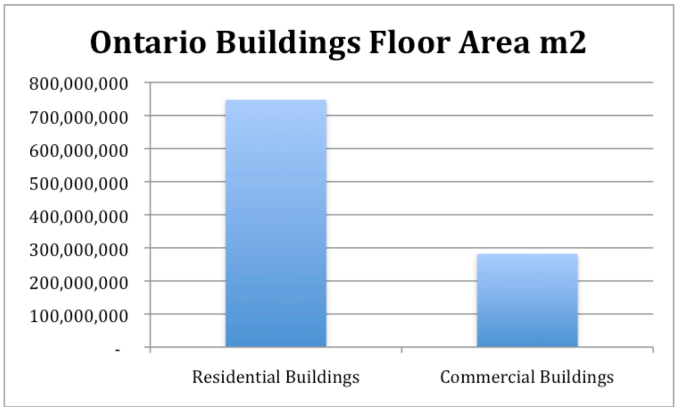
3 http://www.theguardian.com/news/datablog/2012/jul/06/energy-green-politics#data

4 https://saveonenergy.ca/Consumer/Programs/Instant-Rebates.aspx

5 http://oee.rncan.gc.ca/corporate/statistics/neud/dpa/data_e/query_system/querysystem.cfm?attr=0

adopters of energy conservation measures due to cost reductions. It is in fact the residential sector that is by far the largest consumer of energy in the provincial building segment.

Fig.2




Data: Natural Resources Canada Comprehensive Energy Use Database[6]

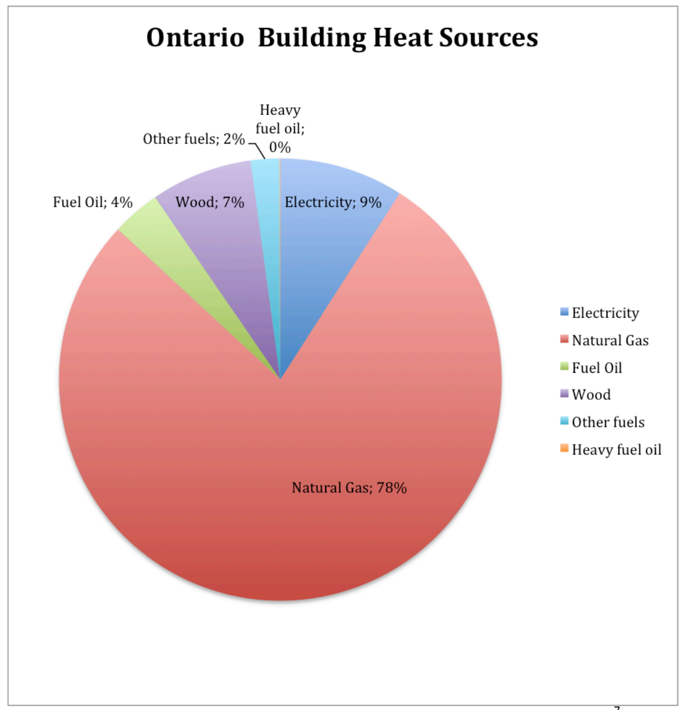
By understanding who uses energy, (fig.2) and what it's used for (fig.1), Government Policy makers will be better positioned to best develop energy conservation programs that can have the most impact.

Working under the assumption that both Policy makers and consumers have the desire either for financial or environmental reasons to become more energy efficient; it is worthwhile to explore heating needs; which is the largest energy use fraction in greater detail.

To better understand the largest energy consumption activities, an analysis of heat energy sources in figure 3 indicates 78% of the heating needs of Ontario buildings are met by natural gas with electric heating comprising only 9% of the market.

The fact that such a significant proportion of Ontario's energy consumption is already in the form of natural gas could present an opportunity to improve the energy efficiency of Ontario's electricity generating sector through a wide spread deployment of micro Combined Heat and Power (mCHP) systems rather than the significant reliance on production from inefficient thermo power plants that dump up to 65% of the energy produced as waste heat.

Fig.3




Data: Natural Resources Canada Comprehensive Energy Use Database[7]

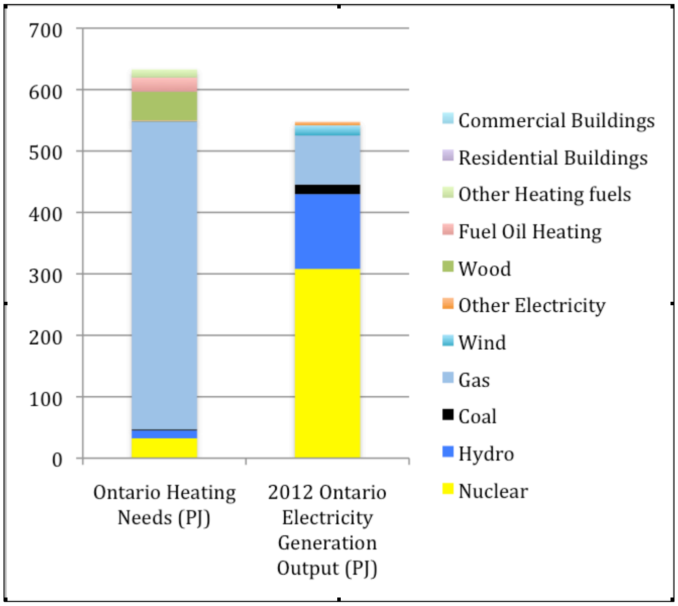
Upon examination (Fig.4), it becomes apparent that building heat in Ontarios commercial and residential building sectors consumes 115% more energy than is generated by the entire electricity sector. It is suggested that the strong demand for natural gas heating could serve to anchor a robust CHP industry in

6 http://oee.rncan.gc.ca/corporate/statistics/neud/dpa/data_e/query_system/querysystem.cfm?attr=0

7 http://oee.rncan.gc.ca/corporate/statistics/neud/dpa/data_e/query_system/querysystem.cfm?attr=0

## Linking heat and electricity in Ontario buildings to generate energy efficiency and savings

Fig.4




Ontario where heating needs for buildings serve as the basis for distributed generation with a fleet of "hyper-flexible" CHP units. Based on a full conversion rate, there is potential to replace upwards of 8,000 MW of relatively low efficiency termo electric generation capacity.

Such a rate of conversion to onsite generation and energy consumption has the potential to save consumers upwards 63.3 TWh/yr of electricity or $12.5 Billion per year.

While such an undertaking would be significant, it's estimated that the cost to do so would only require an initial capital investment that would likely be in the range range of $10 - $20 Billion for generation equipment.

Such a conversion would relieve pressure on aging central power plant infrastructure, and could potentially be accomplished at a lower cost than refurbishment of Ontario nuclear power plants.

ADDITIONAL BENEFITS of CHP deployment:

- Resilient infrastructure – Underground gaslines not as suceptable to climate related disruption.
- Energy Security
  - Multiple fuel sources with Stoked mCHP
- Deeper integration with renewable generation
  - Renewable Gas with existing distribution infrastructure
    - Hydrogen
    - Biogas
- Much more flexible than large power plants
- Energy Storage integrated into Stoked CHP
- Ability to store surplus renewable power
- Flexible ramp up of generation
- Distribution grid reinforcement

# The Grid Related Benefits of Distributed Generation

DAVID ENGLE – *Distributed Energy Journal*, January/February

“Distributed generation hurts utilities!" cry electric company engineers who believe that haphazardly sited engines threaten grid safety. The result: Prohibitively high connection charges are imposed.

"DG really helps utilities," say others, including rate-setting commissioners in California and New York in 2004, the US Department of Energy, assorted consumer advocacy groups, and the DG industry.

## Which view is right?

Perhaps there's a better question: Which side can back up its claim with compelling, reliable facts? Both sides have struggled with the complexities of quantifying potential benefits or harm and yielding solid, credible data. Both sides offer sweeping but "basically unsubstantiated" claims, observes Peter Evans, CEO of New Power Technologies (NPT) in Los Altos Hills, CA. NPT develops management solutions for the power industry. Missing from the debate, however, were methodologies for serious DG impact studies, resource optimization analysis, and comparative technology assessments. Until recently, Evans points out, no one had been able to solve puzzles like right-sizing DG resources (from the grid's standpoint), where resources should go, or what actual dollar value they would bring to the utility company.

All of this has now radically changed. During 2003–2004, NPT led a research team that produced a landmark study in nearby Silicon Valley showing these critical issues can indeed be addressed reliably—probably for the first time ever. Along with Evans and NPT, 10 other co-participants included Optimal Technologies Inc. of Benicia, CA, which provided principal optimization technology and services for the study; Cupertino Electric, which assisted in developing the system model; the Silicon Valley Manufacturing Group (SVMG); and consultancies Rita Norton & Associates, William M. Stephenson, and Roy Skinner. Funding for the study, and strong state-level encouragement, came from the Public Interest Energy Research (PIER) program within the California Energy Commission (CEC), both of which have long been major sponsors and benefactors of DG-related research and development (R&D).

To serve as a test-case system for undertaking this DG-on-grid analysis, Evans and the SVMG solicited the participation of Silicon Valley Power (SVP), a municipal network of 850 buses serving the city of Santa Clara. SVP's transmission backbones include two 115-kV main feeds, a 60-kV transmission system, and 48 or more distribution feeders of 12 kV, lightly loaded off of about 422 customer locations. That works out, Evans notes, to nearly 1,000 line segments with 106 switchable branches connecting them, 101 switchable capacitors, and six onsite generators with megawatt and megavar capability already in the mix.

## *What the Study Found*

After several months of studying grid optimization with DG sets, Evans issued his report to the CEC, from which the following summary and discussion is adapted. In essence, researchers learned that, indeed, small generators sited strategically on the distribution system would yield potentially tremendous improvements to system efficiency. Moreover, further gains and benefits would accrue to the interconnected transmission system. DG's value to both would be realized not only by the additional reserve power provided, but, even more so, from DG's ability to ease power delivery across hundreds of strained, occasionally redundant, energy-sapping distribution lines.

In any grid system, hundreds and even thousands of kilowatts are squandered in the task of moving amps across needlessly long distances squeezing through local bottlenecks and loop flows. The results: weaker voltage profiles, voltage instability, and poor power quality. Properly positioned DG can greatly reduce system congestion and curtail waste of this sort. The potential savings should readily cost-justify, and subsidize, many cogen investments.

For example, as the report notes, unstable voltage must often be boosted to maintain a sufficient minimum. But if more stable distribution system voltages could be achieved—a potential byproduct of many DG projects—it would reduce the need for wasteful over-amping.

Moreover, researchers found that system voltage stability is closely linked to optimal distribution of the system's reactive power resources, or var. What impact does DG have here? The question can now be answered using breakthrough software from Optimal Technologies called AEMPFAST (pronounced "aim-fast"). Using this tool, Evans' team evaluated and quantified both active (kilowatt and megawatt) and reactive (var and MVar) power flows and events that could lead to cost-justifiable DG sites. Evans' conclusion: "There's a lot more you can do with reactive power," he says, "from a distributed generator, toward providing system benefits."

## ***Sharing Benefits With Adopters***

What this insight also suggests is that a prospective DG adopter whose generator might provide such benefits should probably receive some kind of compensation or inducement. Optimal Technologies CEO Roland Schoettle suggests that these might come, for example, "through appropriately structured ancillary power markets, where these benefits are quantified and ranked as alternatives." DG resource optimization on a grid, he adds, "would make certain that all the lowest cost-benefit alternatives would be known and ranked" in utility management decisions, "not just the traditionally obvious ones using standard utility methods."

Schoettle's AEMPFAST also assessed SVP customer demand response measures designed for reducing system peak demand. AEMPFAST's study established that demand response, wherever onsite power is applied, has greater system benefits in certain locations within a distribution system than in others. Hence, the widely asserted "safety risk" to grid security, so often leveled at DG projects, is just the opposite of the truth: Risks are actually lowered by the presence of DG, AEMPFAST learned. Again, says

Evans, utilities "would be acting in their self-interest" by giving out carefully targeted incentives to DG adopters, especially where the result is peak-demand reduction.

Evans says other kinds of grid benefits accrue, including "all network-related, avoided, or deferred additions"; improved supply-demand margins; reduced dependence on electricity spot markets; deferred costs; reduced fuel costs; lowered emissions and related costs; and easier integration of future customer-driven onsite power projects into the grid. Lastly, with customer-owned DG in the right places, low-voltage buses can sometimes be eliminated outright.

All in all, then, grids can be "tuned up" with DG networks and made more efficient, says Evans, "by minimizing real power losses and reactive power consumption."

To illustrate, Evans notes that on a 60-kV main feeder (such as at SVP) at a transmission-to-distribution step-down point where the feeder connects to a 12-kV line (and that, in turn, to low-voltage buses), a system will typically show voltage variability. Although this isn't a problem from an engineering standpoint, he says, "It's waste, and it presents an opportunity for optimization." By carefully measuring these and assorted other losses, then determining and ranking how they'd be reduced by a customer-installed generator nearby, a grid-improvement value results. And again, in incentive terms, a portion should be rebated to the adopter.

Another example: A customer installing a 150-kW combined heat and power system might allow for eliminating a nearby low-voltage bus, or might flatten the overall voltage profile on that 12-kV line. The current would become more consistent. This would reduce wastage, thereby saving the utility something in the low four-figures each year.

DG is but one of several solutions to be applied systematically in a well-optimized grid. Others include, Evans says, "More automated remote switching, changeable topology, controllable capacitors, distribution automation, sophisticated demand-response programs," and assorted others. "That's the direction this will head to. Distributed generation is maybe the most important piece of that, but it is not the only piece."

## *Siting for Maximum Benefit*

Back, now, to the question of precisely where generators should go, and their potential dollar value. Here AEMPFAST's tools for DG-on-grid analysis are able to integrate complex interrelated functions: system security, voltage profiles, reliability, congestion, minimum loss, minimum generation cost, minimum emission, minimum maintenance, locational marginal costs, congestion mitigation, and sophisticated asset optimization. Schoettle adds that his product "is not based on the mathematical engines now prevalent," and so "does not suffer from their limitations." AEMPFAST analyzes a grid's physical condition, virtually in real time (or with only a few seconds' lag) and seeks to give system engineers best-possible resource deployment choices.

In so doing, it also ranks every component as to its net benefit, and to meeting the optimization objectives. These, says Schoettle, "can be multiple and varied, and can include both engineering and business objectives." Even very fine detail and microanalysis is possible. Evans notes that in the SVP study, "We could actually go down to line segment–by–line segment" to detect waste and to quantify savings opportunities, as well as doing the assessment device by device. Schoettle also notes that customer onsite power projects can often accomplish distribution savings and efficiencies "if located and sized optimally" to solve problems, "as well as serving the customer cost-effectively."

With these win-win criteria in mind, then, Evan's team launched the DG siting analysis. He assumed non-exporting generators that were switchable and dispatchable.

In the first what-if scenario, the DGs were limited to the light load on the feeder, meaning they could add only a maximum of 15% of the feeder power (meeting the cap under California's Rule 21 limit for expedited interconnections).

Given this input, then, AEMPFAST identified 382 customer sites where DG would help the grid significantly. The aggregated total in new generation would be optimize at 13.6 MW; that's about 36 kW per generator, totaling 3.4% of peak load.

A second what-if scenario optimized Silicon Valley Power's light feeders. California grid connection rules are more liberal here, permitting up to 60% of the adjacent load to come from non-exporting DGs. On these, Evan's group found 346 prime customer sites for onsite power, totaling 38 MW (9.7% of total peak load and about 110 kW per generator).

In AEMPFAST's number-crunching came one surprising twist: The data showed that relatively small DGs, averaging much less than 150 kW, can carry almost disproportionate impact. In fact, one of the highest-prioritized potential DG sites that AEMPFAST flagged called for a mere 7 kW to support one customer's 14-kW load. Nevertheless, this particular locale was so critical to the grid, Evans explains, that "adding capacity there would benefit the entire system."

For multiple reasons, small-footprint power projects are generally easier to position near the feeder loads than are megawatt-size ones. Likewise, smaller generators can more readily be optimally sized to match loads. "The sweet spot here," Evans says, "tends to fall somewhere between 100 and 300 kilowatts." In this size range, scores of cogeneration installations turned out to be very cost-effective for customers, especially when the analysis could assume low or subsidized up-front costs.

Next, the very best win-win deals carrying the highest value generally were found to exist near the ends of main feeders—an interesting finding in itself. By adding generation capacity there, Evans points out, "not only does it benefit the feeder, but the entire system." Generally speaking, the more remote the DG positioning, the greater the grid benefit. Less impressive but still cost-justifiable results emerge from proposed installations near existing DG plants.

In any event, location-specific analyses like these should be performed in ideal DG installations in the future, Evans and Schoettle believe. AEMPFAST does this as part of its site ranking. With the help of such tools, says Evans, "A utility can look at multiple permutations and load scenarios, multiple ways of controlling the units, identifying optimal locations, and then figuring out how far away from the optimal performance you get by using different locations."

## *Quantifying the Savings*

What's the bottom line? The Silicon Valley grid—if fully DG-optimized—could achieve an impressive 31% reduction in real power losses. Along with this would come another

30% reduction in reactive power consumption, equal to 15.203 MVar. If the recommendations churned out by AEMPFAST were actually applied, the resulting reduction in losses would come, as Evans notes, "at three times the system's average loss rate." These numbers are particularly impressive, he adds, because SVP was already relatively well designed, maintained, and operated. In more stressed-out utility environments potential savings would be much greater.

Better still, because SVP's grid interconnects with Pacific Gas & Electric's transmission system, the latter also benefits to the tune of about 5 MW gained. In dollar terms, that could easily translate into thousands of dollars per day during peak loads.

Evans sums up: "These values are significant. They can be quantified. And they are real benefits to this network." Even so, he points out, most of that value still remains with the onsite DG customer—who, after all, has hypothetically paid for it. Customer outlays yield a windfall to utilities; as a result, customers should arguably get some of it back.

## *What It Means to DG's Future*

A second NPT technology study, to be conducted in 2005 at the much larger, more complex Southern California Edison (SCE) network, will explore small-generator impact even more extensively. In scope and scale the SCE study will be nearly 20 times larger than the SVP demonstration, Evans notes. The SCE analysis will also look at DG's impact, for example, on winter peak, light load, and load-growth conditions. Research funding will come from a $5.4 million grant to Evans' firm from the CEC.

Beyond such public-private partnerships as these, various paths to a DG-optimized future are imaginable:

One possible route would be through regulatory commissions and utility rate-setting bodies. For example, Evans suggests, if a utility company sought major funding for transmission and distribution (T&D) upgrades, a panel of commissioners might require that a DG-friendly assessment first be done, at least to present an alternative. If the resulting choice came down to approving $100 million in rate hikes to pay for more wires or endorsing scores of customer-owned generators, most regulators would welcome the latter.

Or—positing a more collaborative approach—utility companies might offer financing to selected cogen adopters on a dollars-per-kilowatt-installed basis. Adopters would earn rebates by siting generators near particular buses. Deals would be subject to further terms such as kilowatt output levels, a non-exporting connection, networkability, lead lag var capability, and perhaps real-time variable controllable reactive power production. Cogen plant owners might agree to run their engines "at least 80% of the time during peak hours," Evans suggests, while also agreeing to curtail off-peak operation, or to comply with other terms that might be required. Given these grid-driven parameters, onsite power would then become a win-win-win solution for utilities, adopters, and developers.

At the state agency level, key players working to make DG-optimized grids and "ultra-networking" happen include the CEC as well as the California Independent System Operators (CAISO). The latter oversees most of the state's power transmission system, and this organization, says David Hawkins, its manager of special project engineering, "is strongly supportive of adding more distributed generation" to relieve transmission loads.

DG resources, he believes, "can provide some real benefits both for customers and for transmission load relief during times of peak loading." Widespread implementation of DG, he adds, could become "a wonderful additional tool to help us avoid having to do major customer load-shedding." Hawkins served on Evans' technical advisory committee and is also working with Optimal Technologies on critical new tools for CAISO.

But before any large-scale deployment of grid-optimized DG becomes a reality, new technology for dispatching, remote monitoring, and control systems—currently under development—must mature (Look for "DG Getting Web-Enabled" in the March/April issue of Distributed Energy). Potentially hundreds of DG assets might be networked, and to coordinate them all engineers will need ways to activate specific ones quickly and efficiently "to manage loads and avert trouble," Hawkins notes. CAISO, he adds, is now teaming up with SCE and others to implement networked, inter-communicating distributed resources on a large scale. A demonstration project currently in the offing will probably turn out to be the largest coordinated DG application ever implemented.

Money to pay for such R&D will continue to flow to worthy undertakings like these, adds Mark Rawson, CEC's policy coordinator for DG and the commission's DG integration research program manager. CEC has already contributed $100 million (mainly through PIER) to develop and advance distributed power. PIER's past investments have supported the development of cleaner-burning and lower-cost generators, among other causes. Rawson anticipates that as interconnectivity matures, the CEC will appropriately revise California's energy policy to expand the role of DG. In turn, CEC's sister agency, the California Public Utilities Commission (CPUC), will alter utility rates and policies. Here, Rawson points out that, beginning early in 2004, the CPUC was already directing state utilities "to include the implementation of DG resources in determining distribution planning." In addition, "To the extent that utilities can determine that DG would be a more cost-effective solution than a traditional utility wires solution, the utilities were directed to pursue that as well."

As for the future at Optimal, Schoettle is promoting AEMPFAST to utilities and distribution system operators to "solve previously unsolvable problems" in grid management. Various current and pending tools that Optimal is offering will make it easier, faster, and more attractive for engineers to evaluate and implement DG projects. For example, grid operators can select DG-supported remedial actions, automate their network planning and emergency control, and carry out system restoration, Schoettle says.

Summing up, Evans points out that the icons of our electrical system—big smokestack power plants and miles of high-tension lines—are more antiquated than ever "and really quaint, when you think about it." More people are beginning to realize the obsolescence and inadequacy here. Grids are poised for being phased out and replaced with an "intelligent energy infrastructure," he says, "with transmission and distribution actively managed as an integrated network." In a modern electrical future, he says, "self-healing grids" will be capable of seamlessly adjusting to demands, loads, emergencies, and outages. Loads will be made more responsive to network conditions. DG resources will be embedded into grids extensively—together with remote generation. Energy services will be better tailored to meet widely disparate customer needs. And, when it's all finished, our new infrastructure will be far less brittle and prone to outages and much more flexible, customizable, and adaptable than what we have now.

"Today," Evans says, "we're demonstrating that these things are feasible and doable—and really not even that tough." As for immediate needs, though, it's now widely accepted that several of our urban centers face serious transmission crunches. Space for expansion to meet load growth no longer exists. Adding T&D isn't viable, because costs are prohibitive or local communities raise barriers, he adds. Urban markets especially will increasingly need their generation and grid-improvement solutions to be "located much closer to the loads." DG networks "are the way to go," he says. And, because utilities stand to gain significantly from DG optimization, "let them share the benefit," he suggests. "And everyone is better off."

*La Mesa, CA–based writer* **DAVID ENGLE** *specializes in construction-related topics.*

**DE - January/February 2000**