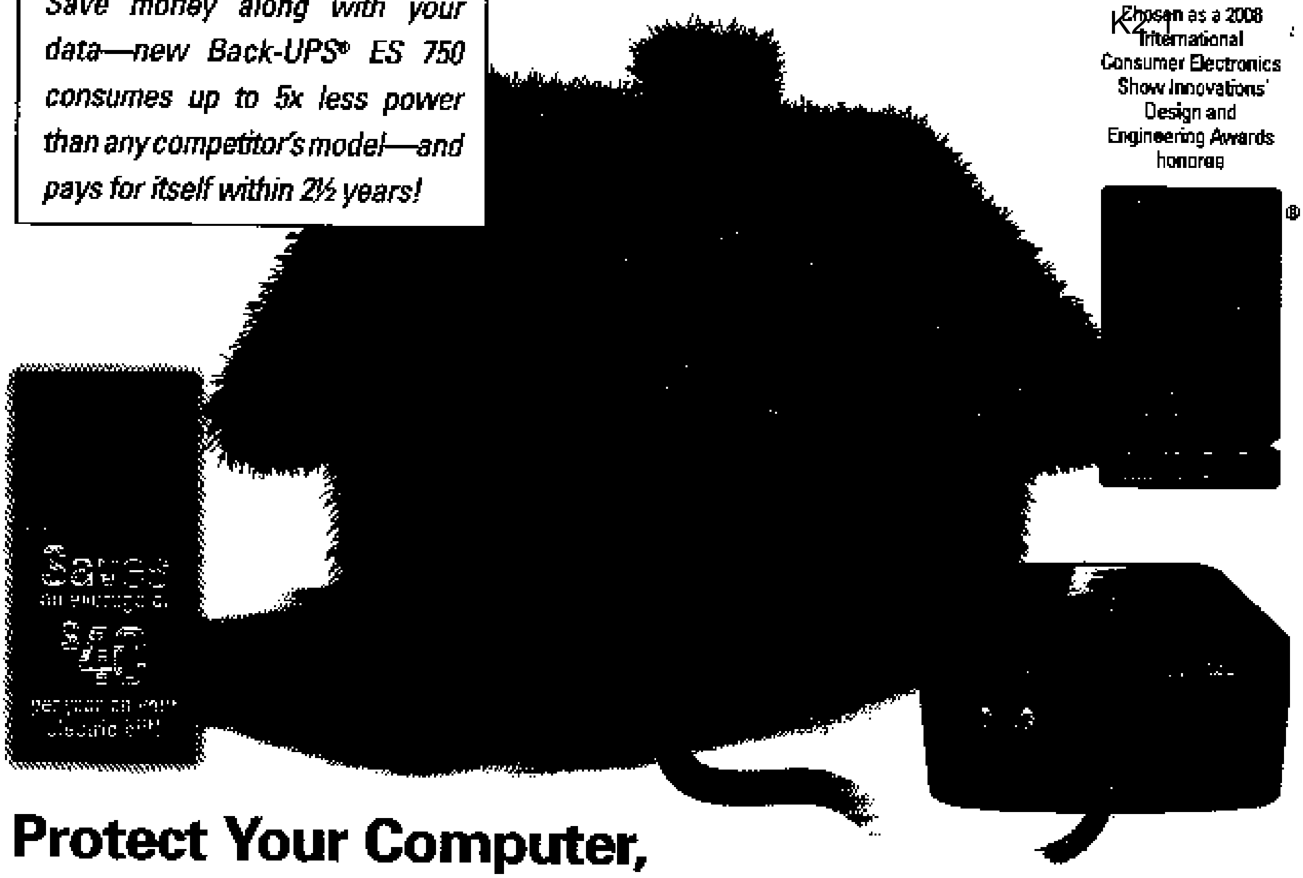
Avoidable Planned Capacity (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Proxy Nuclear							700	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Kitchener-Waterloo SCGT	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
GTA SCGT			550	550	550	550	550	550	550	550	550	550	550	550	550	550
NUG Replacement (CCGT)		165	165	469	469	469	469	469	469	469	469	469	469	469	469	469
Unspecified Proxy Gas (SCGT)							250	250	250	250	250	250	250	250	250	650
Total	450	615	1,165	1,469	1,469	1,469	2,419	3,119	3,119	3,119	3,119	3,119	3,119	3,119	3,119	3,519

Save money along with your data—new Back-UPS® ES 750 consumes up to 5x less power than any competitor's model—and pays for itself within 2½ years!



Protect Your Computer, the Environment, and Your Wallet

New Back-UPS® ES 750 five times more efficient than competitors' models

Computer users have long relied on APC Back-UPS® technology to save their data. Now Back-UPS units help you save the planet as well.

New features on the most popular desktop UPS in the world are designed to minimize environmental impact while maximizing efficiency. The Back-UPS ES 750 now consumes up to five times less power in normal operation than competitors' models. That's good news for the environment—and your pocketbook. On average, the unit will pay for itself within two and a half years through savings on utility bills.

Money-saving "green" features

The Back-UPS ES 750 features one "master" and three "controlled" outlets. The master outlet senses the amount of current drawn by the device plugged into it, which is usually a computer. When the computer goes into sleep mode or is turned off, the master outlet automatically shuts off power to the three controlled outlets. Equipment plugged into the controlled outlets—printers, speakers, etc.—normally consumes electricity even when the computer is powered down. By cutting power to these "dark loads," the Back-UPS ES 750 can provide savings of up to $40 per year compared with competitors' models.

Additional "green" features include:

- A high-frequency design, which uses less copper and other raw materials and reduces the product's overall dimensions, making it more efficient to ship, package, etc.
- Compliance with Restriction of Hazardous Substances (RoHS) guidelines, so the unit conforms to strict regulations to make it more environmentally friendly at the end of its life
- Recycled packaging materials, instead of styrofoam, which minimize environmental impact.

Same benefits, same price

Best of all, the Back-UPS ES 750 adds these energy-efficient features but remains the same price. With the highest VA available in the Back-UPS ES family, it provides battery backup power to ride you through short- and medium-length power outages; safeguards your equipment from damaging surges and spikes traveling along your utility, coax cable, and phone lines; and includes our award-winning auto-shutdown software.

For more information on the energy-efficient features of the Back-UPS ES 750, go to *www.apc.com/products*

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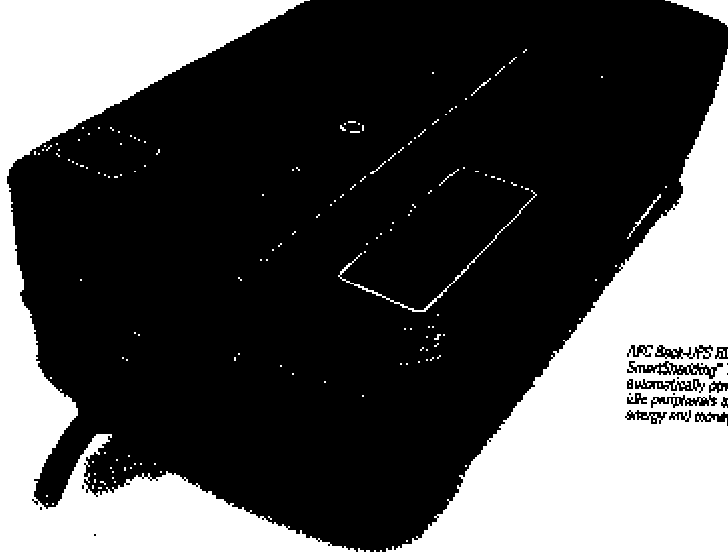
Protects your computer, the environment, and your wallet.



APC Back-UPS ES750G with SmartShedding™ Technology automatically powers down idle peripherals to save energy and money

Saves
an average of
$40

Get the most energy efficient desktop battery backup yet.

Let's protect what's important

What's in your computer? Photos, music, personal files, financial data, broadband access, videos, and more. Your computer has never been more important, and yet it has never been at higher risk for damaging power surges and other disturbances.

So like most people, you need to protect your assets. But like most people, you'd also like to protect the environment. With our new energy conscious products, you can do both. Energy efficient by design, our new smart products protect the power going in your computer, at a cost that is quickly offset by big energy savings. How? Not only do the new Back-UPS ES® and SurgeArrest® use power very wisely, they also boast a master/controlled outlets feature, which automatically powers down idle devices to conserve energy.

APC power protection products are available at:

CDW · STAPLES · Office DEPOT

"The pricetag on the new UPS is $99.99. While I'm not in the habit of endorsing products in this blog, if you're in the market for a workstation-class UPS, why not opt for the greener option?"

– Heather Clancy
ZDNet.com

In fact, while protecting your power supply, we're up to 5 times more energy efficient than any other solution. By saving you $40 a year in energy costs, our Back-UPS ES pays for itself in 2 short years. The high frequency, low copper design has a smaller transformer and environmental footprint. Even the packaging has been carefully selected and manufactured to maximize use of recycled materials and minimize waste.

In this world, every decision you make counts. So protect your power with a battery backup that works to protect the environment. It conserves power, it pays for itself, and it's backed by APC's 20-plus years of legendary reliability. For more information on this or our other great products, or for information about environmentally responsible disposal of your old battery, visit *www.apc.com*

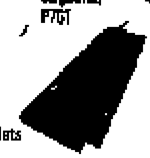
Energy Efficient Solutions for Every Level of Protection:

Surge Protection

Starting at $34

Guaranteed protection from surges, spikes, and lightning.

SurgeArrest® P7GT



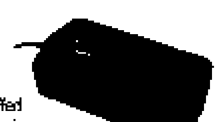
7 outlets, Phone/Fax/Modem Protection, Master/Controlled Outlets

Battery Back-UPS®

Starting at $99

Our most energy efficient backup for home computers.

Back-UPS® ES 750G



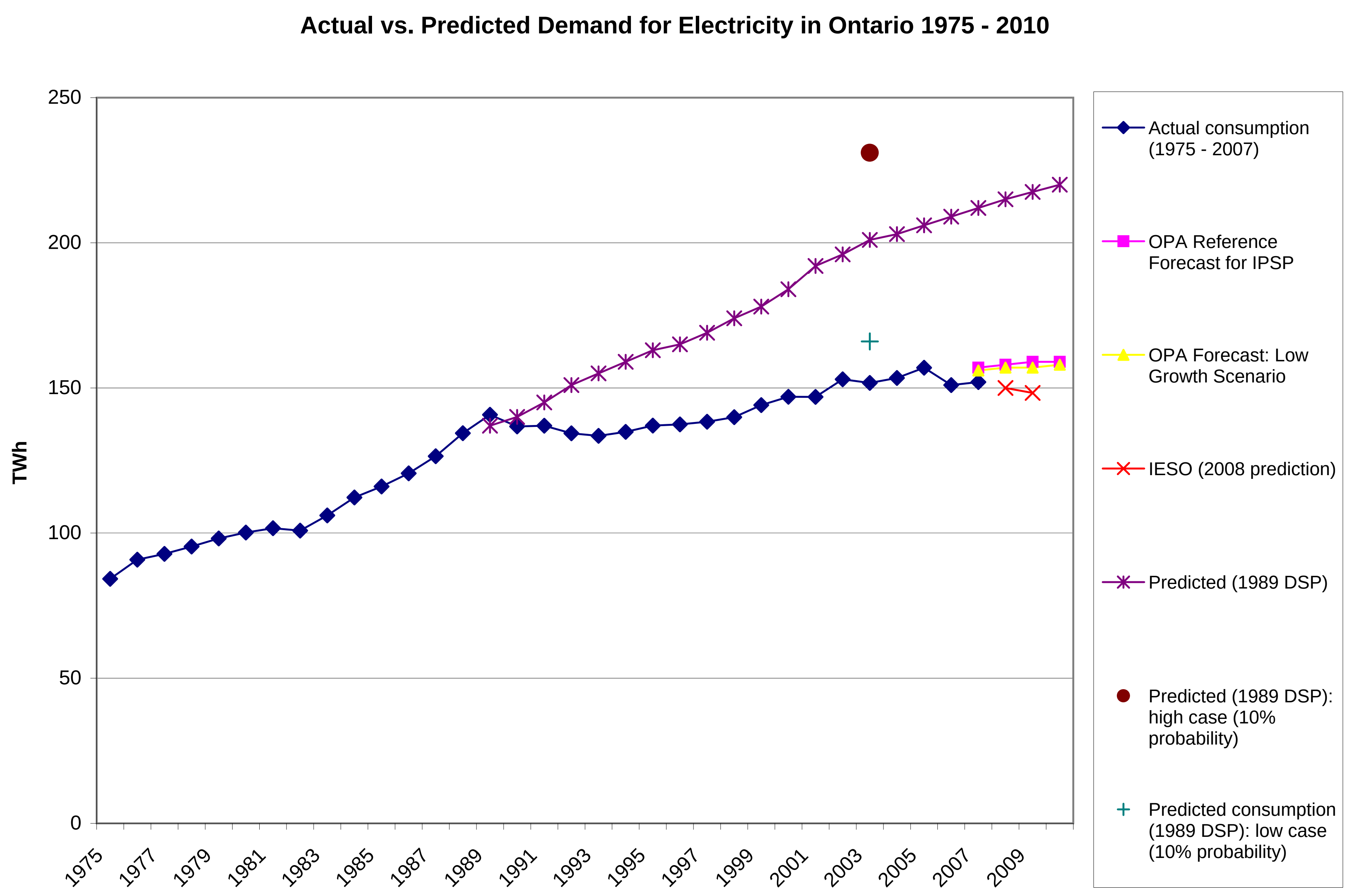
10 outlets, DSL and Coax protection, Master/Controlled Outlets, High Frequency Design, 70 minutes of runtime[1]

APC can help with your other power protection needs. Visit apc.com to see our complete line of innovative products.

Enter to Win a Back-UPS® ES 750G! (a $99.99 Value)

1. Go to *www.apc.com/promo*
2. Enter the key code from the blue box on the back of this magazine
3. Click on "Back-UPS ES 750G Giveaway"

APC Legendary Reliability®


Actual vs. Predicted Demand for Electricity in Ontario 1975 - 2010
TWh
250
200
150
100
50
0
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
Actual consumption (1975 - 2007)
OPA Reference Forecast for IPSP
OPA Forecast: Low Growth Scenario
IESO (2008 prediction)
Predicted (1989 DSP)
Predicted (1989 DSP): high case (10% probability)
Predicted consumption (1989 DSP): low case (10% probability)

A responsible energy plan begins here.

OntariosGreenFuture.ca

Ontario energy planners say the province should invest $26.5 billion in new nuclear reactors. But their estimate of the cost of these new nuclear units is less than half of what Moody's Investor Services, one of the world's most respected credit rating companies, says the real cost will be,

Lowball estimates and ballooning real costs are nothing new for nuclear projects in Ontario. For more than 20 years, the nuclear industry has been promising to deliver nuclear power projects on time and on budget in Ontario, but it has never delivered on this promise. As a result, Ontario Hydro's massive nuclear debt — $20 billion — was handed over to Ontario ratepayers to be paid off with a special surcharge on their monthly hydro bill.

Just recently, privately owned Bruce Power — which has leased the publicly owned Bruce Nuclear Station — admitted that costs on its latest retrofit project are already $350-$650 million over budget and the units are still not producing a single kilowatt of electricity. And Ontario ratepayers are once again on the hook for a big chunk of this bill.

Ontario simply cannot afford to continue to allow nuclear costs to spiral out of control. Companies such as Bruce Power and Ontario Power Generation that are proposing costly new nuclear generating projects must no longer be allowed to reach into our pockets to cover their cost overruns.

No renewable power project, even if it is run by a community co-op or a First Nation, is allowed to pass on capital cost overruns to ratepayers or taxpayers. Companies building natural gas-fired power plants also have to play by these rules.

It is time to end the special treatment for nuclear projects. It is time for Ontario to pass a **Nuclear Cost Responsibility Act** that makes it illegal for nuclear capital cost overruns to be passed on to ratepayers or taxpayers. Nuclear companies should be responsible for all excess costs, just as renewable and natural gas companies are now. They should also face strict financial penalties for late projects, just as renewable and natural gas generators do now. We must level the playing field between nuclear power and other lower cost, lower risk electricity sources.

Support a sensible energy plan for Ontario. Support reducing the demand for electricity through well-funded energy efficiency programs and developing clean renewable energy sources *before* spending more public money on nuclear projects. Support a responsible power plan that eliminates subsidies for nuclear cost overruns and uses the savings to fund the development of clean energy solutions.

Support an energy plan that will deliver clean, low-impact power in the most efficient way possible.
Visit **www.OntariosGreenFuture.ca** to find out more.

Nuclear is no deal

Nuclear project	What they said it would cost	What it really cost
Darlington Nuclear Station	$4 billion	$14.3 billion
Pickering A Unit 4 refurbishment	$457 million	$1.25 billion
Pickering A Unit 1 refurbishment	$213 million	$1.016 billion
Bruce A Units 3 and 4 refurbishment	$375 million	$750 million
Bruce A Units 1 and 2 refurbishment (ongoing)	$2.75 billion	Current estimate: $3.1 to $3.4 billion

Other special subsidies for nuclear power

Taxpayers are not only on the hook for nuclear cost overruns, we also give nuclear power operators subsidies that are not available to any other power producer:

Radioactive waste disposal costs. The Nuclear Waste Management Organization estimates these costs will be more than $20 billion for *existing* waste. Taxpayers will foot a major share of this bill, including 100% of any costs over $10 billion.

Nuclear Liability Costs: No private insurer will insure a nuclear plant against a major accident. Therefore, the government artificially limits the liability of nuclear plant operators to $75 million — a token sum that will be dwarfed by the real costs of even a modest accident.

Nuclear plant decommissioning: Ontario's electricity consumers and taxpayers are responsible for 100% of the costs of taking apart and disposing of the nuclear reactors run by privately owned Bruce Power.

Nuclear a costly response to climate change

Nuclear plants are extremely costly and take a long time to plan and build (10-15 years). Given our need for action on climate change today, this makes them a poor climate solution. They are also the most expensive option for displacing greenhouse gas (GHG) emissions from coal plants. To dispace a tonne of coal-plant GHGs would cost:

$4.11 with an efficient natural gas fired plant

$18.85 with a wind turbine

$29.76 with a Candu 6 nuclear unit

Join the call for a responsible energy plan. Go to:

www.OntariosGreenFuture.ca

to learn more, sign a petition calling on the government to close the nuclear cost loopholes, and for ways that you can help spread the word about a better approach.

This information provided by:

ONTARIO CLEAN AIR ALLIANCE

The Ontario Clean Air Alliance is a coalition of health and environmental organizations, faith communities, municipalities, utilities, unions, corporations and individuals working for cleaner air through a coal phase-out and a shift to a renewable electricity future.

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416-926-1907 x245
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PUBLIC

REPORT

IESO Operability Review of OPA's Integrated Power System Plan

Issue 2.0

Advice to Reader

The study results in this report are based on information made available to the IESO at the time the assessment was carried out and the assumptions set out in the report. The IESO assumes no responsibility for the accuracy or completeness of such information or the conformity of actual events to the assumptions. Furthermore, the results and conclusions are subject to further consideration due to changes to this information or assumptions, or to additional information that may become available in the future.

The performance expectations of power system facilities were determined based on typical assumptions used in power system planning studies. The actual performance of these facilities during real-time operations will depend on actual system conditions, including ambient temperature, wind speed and facilities loading, and may be higher or lower than those stated in this study.

The IESO assumes no responsibility to any third party for any use it makes of this report.

Document ID	IESO_REP_0411
Document Name	IESO Operability Assessment of the OPA's Integrated Power System Plan
Issue	Issue 2.0
Reason for Issue	Second Issue
Effective Date	April 21, 2008

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Reference (Paragraph and Section)	Description of Change
Section 3	Clarified assumptions in response to questions received from market participants.

Executive Summary

The electricity infrastructure of the future as envisioned by the Integrated Power System Plan represents the most significant transformation of Ontario's electricity sector since the incorporation of nuclear generation. Many of the proposed supply options have significantly different operating characteristics from the current generation fleet – and some of the proposed projects, such as intermittent and embedded generation are outside the IESO's traditional dispatch authority and monitoring. Also, increased conservation and demand management programs will create new daily, weekly and annual load patterns. These much needed initiatives must be incorporated into the routine operation of the system such that reliability is maintained throughout their implementation.

The IESO is accountable for managing the operation of the electricity system so that supply is reliably and efficiently delivered to the people of Ontario, and has carried out this task since its inception. Drawing on its experience and expertise, the IESO is well positioned to assess any operability issues and to develop any new or evolved operational and market processes needed to support the changing infrastructure going forward.

Operability is a measure of whether the proposed supply mix from the IPSP can be reasonably coordinated through unit commitment decisions and real-time dispatch to follow the ever-varying load profile through both high and low demand conditions, while constantly meeting all operating standards, such as operating with sufficient operating reserves.

The IESO has assessed the operability of the IPSP and concluded that it provides sufficient flexibility to meet future system needs. Current market mechanisms and control actions will allow the IESO to reliably operate the system described in the IPSP.

This report represents just the first step in addressing future operability. Assessments will be on-going for two reasons:

- System operability is directly related to the infrastructure of the day. This operability assessment involved many assumptions about in-service dates for new generators, implementation timetables and results for conservation and demand response programs. The IESO will update this assessment for material changes to any assumptions, particularly in-service milestones, which can have an impact on operability.

- The currently available information provides a reasonable representation of hourly outcomes in the future. However, like other system operators, to date Ontario has limited actual experience with the combined impacts of significant amounts of wind generation, embedded generation and demand management. As the future is realized greater detail will be incorporated to examine intra-hour operability, local area impacts, and to achieve minute-to-minute coordination. The IESO expects that these more detailed operational requirements will be addressed through mechanisms such as the connection assessment process as each project moves from the proposal stage to reality, and with the benefit of actual experience. As their penetration increases, future operations planning will capture their impact.

The IESO's operability assessment also reinforced a number of opportunities to improve transparency and efficiency in the operation of the power system and electricity market as the province moves forward with the IPSP. The IESO and its stakeholders should continue to evolve current operating processes and market incentives to capture these benefits, and the IESO has started initiatives to address these opportunities on several fronts. These efforts include a stakeholder initiative to address market design issues related to operability, and a new industry-wide examination of smart grid technologies and other non-traditional solutions to facilitate greater consumer involvement in solving future operational challenges.

– End of Section –

1. Introduction and Purpose

The IESO directs the operation of Ontario's bulk electricity system, balancing demand and supply of electricity on a second-to second basis to meet the electricity needs of over 12 million Ontarians. It does this by administering the competitive wholesale electricity market, which involves, among other things, collecting offers from suppliers and bids from purchasers to determine the market price of electricity that reflects current conditions across the province. This price, in turn, helps to drive market efficiencies and participant behaviour to assist in solving reliability issues.

The IESO is also involved in planning and assessment of future conditions of the electricity system. Through various assessments, the IESO ensures that sufficient generation and transmission resources are available to satisfy the needs of Ontario's consumers and respond to unforeseen contingencies, both now and in the future. These assessments include:

- Near-term and mid-term adequacy assessments of generating resources and transmission system status
- Contingency planning for major outages or disruptions to power supply;
- The need for market evolution initiatives to enhance the efficiency of the market and encourage market-based solutions to managing reliability.

Given the IESO's role in overseeing the reliable operation of Ontario's electricity market and power system, it assisted the OPA in several areas of IPSP study. Support was given in the form of several system impact assessments, preliminary assessments, and planning study reports based on the forecast transmission and resource expansions contained in the IPSP.

This report is an independent assessment of the IPSP's operability. Operability is a measure of whether the proposed supply mix from the IPSP can be reasonably coordinated through unit commitment decisions and real-time dispatch to follow the ever-varying load profile through both high and low demand conditions, while meeting all operating standards.

The analysis is based on preliminary IPSP hourly data submitted to the IESO by the OPA, which includes Ontario demand, conservation[1] , scheduled intertie imports and exports, generator availability, and generation schedules. The simulated data was compiled by the OPA using cost-based dispatch as an approximation of market outcomes to determine generation output, costs and economic transactions between interconnected areas for each hour in the simulation period (2010 - 2026).

[1] OPA conservation programs include demand management, demand response, customer generation, fuel switching and efficiency programs.

The criteria used to determine the operability of the IPSP includes the ability of the future supply mix to:

- Provide sufficient load following capability
- Manage surplus baseload generation conditions
- Serve Ontario demand during high demand conditions
- Meet operating reserve requirements

The IESO will continuously monitor IPSP implementation and update the assessment for material changes to any assumptions, particularly in-service milestones, which can have an impact on operability.

– End of Section –

2. Generation and Supply Mix Summary

This section provides a summary of Ontario's forecasted generating capacity, its evolving composition, based on fuel type, and an overview of the proposed supply mix changes. The generation summary is based on simulated schedules provided by OPA for every year between 2010 and 2014, and every second year between 2016 and 2026.

The OPA simulations produced an hourly available capacity value for each major generating station/resource in Ontario. The highest hourly value for the year for each resource was summed to produce the annual totals. Results are lower than could be achieved by summing the nameplate capacity of the affected resources as the capacity maximums used by the simulations reflect operational capacity limits.

2.1 Generation

Table 1 shows the simulated hourly maximum capability of each resource in each year, grouped by fuel type. These values do not represent either coincident peak-hour production quantities or installed capacity values, as they are simulations of actual hourly outputs which are subject to normal outages and de-ratings. As such, they provide practical maximum production levels for the various sources in any year.

	2010	2011	2012	2013	2014	2016	2018	2020	2022	2024	2026
Nuclear	11,379	11,379	12,919	12,403	12,403	10,242	10,572	10,941	12,923	13,804	13,804
Gas/Oil	9,338	9,690	10,696	11,576	12,112	11,986	11,540	11,012	10,350	10,352	10,349
Renewables	8,689	9,307	9,347	9,713	10,181	10,868	11,369	12,922	13,473	13,477	13,683
Conservation	2,911	3,342	3,762	4,170	4,570	5,153	5,658	6,040	6,453	6,849	7,329
Coal	6,343	4,893	3,928	3,443	3,232	-	-	-	-	-	-
Interconnections	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
Other	88	88	149	189	229	457	483	525	525	525	525
TOTAL	39,999	39,949	42,051	42,744	43,977	39,955	40,872	42,690	44,973	46,255	46,940

Table 1: Annual Generation Capacity Based on Preliminary IPSP Data Provided by OPA

2.2 Supply Mix Changes

The changes in the proposed supply mix from 2010 through to 2026 are:

- Phase-out of all coal-fired generation by the end of 2014
- A significant increase in reliance on conservation and demand management with the implementation of the OPA's conservation programs
- Growth of wind generation in Ontario's generation portfolio
- Increase in biomass and gas-fuelled generation
- Refurbishment of 16 nuclear units as well as addition of two new units
- Production from contracted non-utility generation (NUG) units that is consistent with the IPSP assumptions
- General reduction in the proportion of manoeuvrable generation in Ontario's generating fleet

– End of Section –

3. Assumptions

The IESO's analysis was performed using production data provided by the OPA. As such, the data reflects the many assumptions used in the IPSP. The IESO did not modify any IPSP assumptions. Hence, the analysis is based on the following:

- New resources and the transmission capability necessary to support the OPA's simulated hourly schedules were assumed in service, as indicated in the IPSP.
- Non-utility generator (NUG) outputs were consistent with IPSP assumptions and were provided to the IESO in the OPA's simulated hourly schedules.
- The energy and capacity schedules provided by the OPA respected normal operational limitations on the associated resources. These limitations include forced and planned outages, daily energy limits, and the need for hydroelectric units to run during periods of freshet.

The IESO was required to make certain assumptions to accurately interpret the simulated data and produce meaningful operating conditions:

- Existing generation resources were assumed to have ramping and operating characteristics similar to those they currently exhibit in the IESO-administered markets.
- Generation resources not yet in service were assumed to have ramping and operating characteristics similar to existing resources of the same technology type. Some operating parameters such as minimum load point were adjusted in proportion to nameplate capacity.
- It was assumed that ramping and operating characteristics did not appreciably degrade over the life of the plant and were held constant for the entire study period.
- Ontario's operating reserve requirement was assumed to be constant throughout the entire study period as no new generating unit in the OPA simulated schedules exceeded the size of today's largest resource. Any future increase in operating reserve requirements will be addressed within the IESO's Connection Assessment and Approval processes.
- Using voluntary regional reserve sharing programs, which can reduce operating reserve requirements, was not considered for this analysis.
- The operability benefits of currently registered dispatchable loads or NUGs that have elected to operate as dispatchable generation in today's IESO-administered markets were not considered in the simulated schedules. However, they were used in the analysis as a viable control action.

– End of Section –

4. Hourly Load Following

Load following capability is a measure of the dispatchable resources' ability to be effectively dispatched to follow the fluctuations of consumer demand and overall system needs. The OPA submitted hourly data to the IESO for its analysis. The study of inter-hour load following capability used these hourly schedules by employing a methodology developed through the IESO's Stakeholder Engagement Program[2] that analyzed historical load following requirements. The hourly schedules include generation, Ontario demand, imports and exports, and the results of conservation programs.

The IESO assessment focused on the most critical days - the days with the highest hourly peak demand and highest hourly positive load following requirement (LFR)[3] of each season for each year of study. Where shortfalls were observed during these critical days, the analysis evaluated existing market mechanisms and control actions to determine whether a more optimized dispatch than provided by the OPA schedules could have resolved the shortfall. The assessment revealed that all the identified load following shortfalls could be successfully addressed through the current dispatch methodology. Table 2 summarizes the results of this analysis.

4.1 Hourly Load Following Analysis (2010-2016)

The first five years of the analysis, from 2010-2016, are the critical period, during which there is a profound transformation of the resource mix. During this period all of the coal-fired plants will be replaced with gas-fired units, hydroelectric, wind and conservation programs. In addition, a number of nuclear units are expected to be removed from operation for refurbishment. Over the 2010-2014 period, five of 40 days studied (12.5%) showed load following shortfalls, though all were successfully resolved by applying the unit commitment, curtailing exports and constraining-off dispatchable loads.

4.2 Hourly Load Following Analysis (2017-2026)

The second interval of the analysis was limited to every second year. This period saw the completion of all planned nuclear refurbishments, as well as the commissioning of two new nuclear units. Additionally there was continued growth in conservation programs, wind generation and several new hydroelectric units. The only reduction in the resource capacity over the period was due to an assumed further retirement of NUGs.

[2] "Stakeholder Engagement #38 – Load Following Standard", http://www.ieso.ca/imoweb/consult/consult_se38.asp

[3] The hourly load following requirement is the calculated change in demand requirement between one hour and the next.

As shown in Table 2, during the later interval of study, the frequency of critical days with seemingly insufficient load following increased to 10 of 48 days (20.8%). With the increase, several days required more actions then were needed in the previous period to overcome shortfalls.

In addition to such actions as unit commitment, curtailment of exports, and constraining off of dispatchable loads, further imports and outage management were needed to resolve shortfalls.

Year	2010	2011	2012	2013	2014	2016	2018	2020	2022	2024	2026
Winter Max LFR	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Spring Max LFR	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Summer Max LFR	🔴[1,2]	🔴[1,2]	🟢	🔴[1,2]	🟢	🔴[1,2,3]	🔴[1,2,3]	🔴[1,2]	🔴[1,2,3]	🟢	🟢
Fall Max LFR	🟢	🟢	🟢	🟢	🟢	🟢	🔴[1,2,3]	🟢	🟢	🟢	🟢
Winter Peak Demand	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Spring Peak Demand	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Summer Peak Demand	🟢	🔴[1]	🟢	🟢	🟢	🔴[1,2]	🔴[1,2]	🔴[1,2]	🟢	🟢	🔴[1,2,3]
Fall Peak Demand	🔴[1]	🟢	🟢	🟢	🟢	🔴[1,2]	🟢	🟢	🟢	🟢	🟢

1 - Resolved through market scheduling and commitment of fossil units
2 - Resolved through market not scheduling exports and/or dispatchable load
3 – Requires additional measures to satisfy reserve requirement (i.e. additional imports, management of scheduled outages)

🟢 - Sufficient Load Following Capability (73 of 88)

🔴 - Insufficient Load Following Capability that would be managed through dispatch of the market (15 of 88)

Table 2: Results of Critical Days (2010-2026)

4.3 Unit Commitment

In today's operation, the market utilizes two programs to commit generation units:

- The Day-Ahead Commitment Process (DACP) provides a generator with day-ahead certainty in covering their start up costs, including the incremental operating and maintenance costs associated with the start up.
- The Spare Generation On Line (SGOL) program allows generators to commit to a start three hours out of real-time operation and covers the fuel costs associated with the start up.

Both programs schedule units to their minimum load points and allow them to meet the technical characteristics of the unit through a minimum runtime. This positions the units so they will be able to ramp to meet market dispatch.

In the OPA simulated schedules, hourly load following capability shortfalls often occurred when internal generation resources were scheduled at low energy output so they would be available to provide operating reserve. This positioning of the units at low output, left them operating in a range of poor ramping capability. In these cases, the future potential of a load following shortfall is not a concern, as it will be mitigated by using of one of the unit commitment processes discussed above.

4.4 Dispatchable Load

In today's IESO-administered markets, dispatchable loads provide ramping services on the same basis as generators. In the analysis, shortfalls in hourly load following capability were significantly mitigated by dispatching these resources, particularly during summer periods. This is consistent with experience in the summer of 2005, when the dispatch of dispatchable load allowed for more effective use of energy-limited hydroelectric resources during challenging operating conditions. The analysis shows the continued value of dispatchable demand in the market.

4.5 Other Market Actions

Where unit commitment and dispatch of dispatchable loads was unlikely to resolve hourly shortfalls in load following capability, other actions were evaluated for effectiveness. Generally these events occurred in the summer, during periods of high demand and challenging operating conditions which typically included periods of operating reserve shortfalls. These types of conditions send market price signals that cause market participants to reschedule planned outages and elect not to export.

All shortfalls in hourly load following that remained after using the unit commitment process and the dispatch of dispatchable loads could be resolved through a combination of outage management (provided to the IESO through the OPA's hourly availability schedules) and curtailment of exports (provided through the hourly export schedules). It is expected that should such shortfalls actually develop, normal market price signals would be sufficient to drive these outcomes without intervention by the IESO.

– End of Section –

5. Intra-Hour Load Following and Dispatch Issues

The IESO balances supply and demand through its direction of dispatchable resources, which will continue throughout the on-going evolution of Ontario's generating fleet. Although this report indicates, at least on an hourly basis, that there is sufficient flexibility to successfully operate using the proposed resources mix, challenges remain. Load following capability on a more granular level than hourly blocks of time is required if the proposed resource mix is to achieve true operability.

Figure 1 shows the gradual increase in the proportion of generation outside the dispatch control of the IESO or normally unavailable for dispatch and a corresponding decrease in dispatchable generation able to respond to 5-minute dispatch.

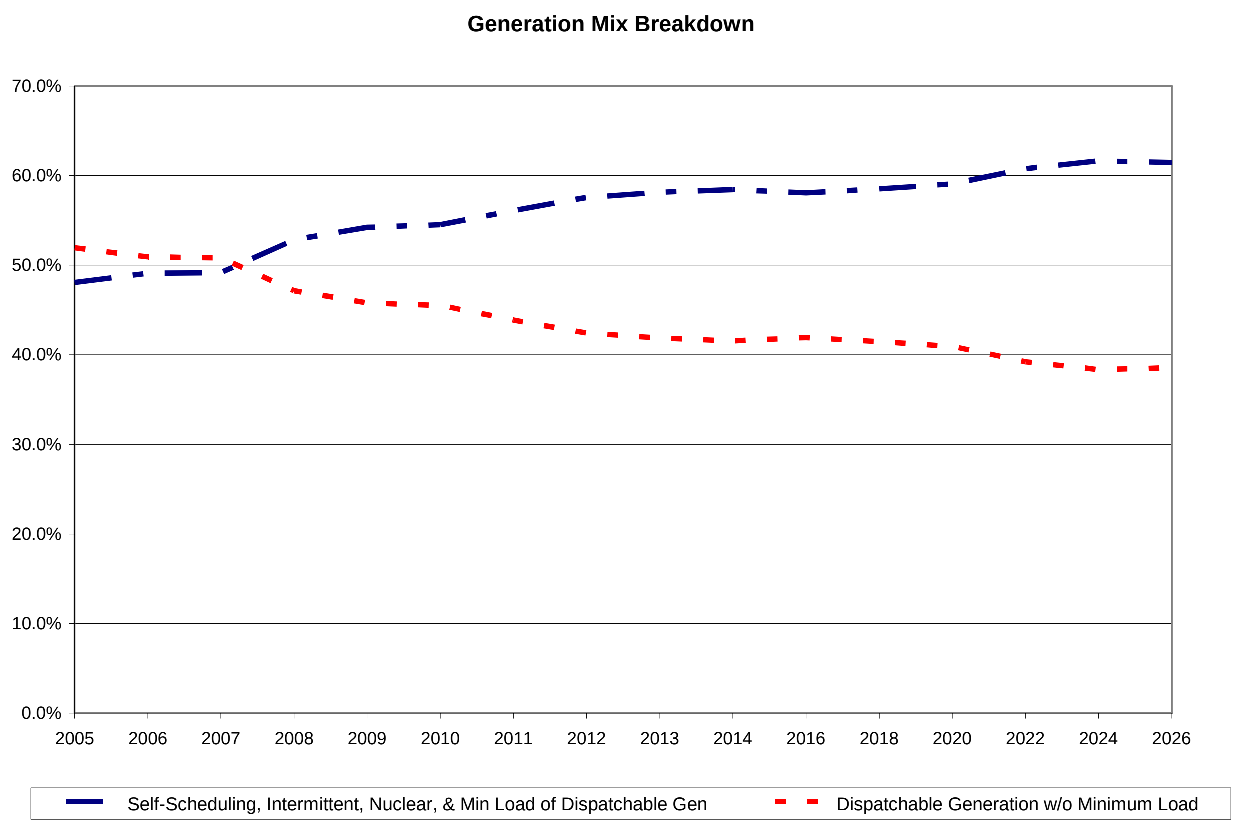

Figure 1: Generation Availability for Dispatch

5.1 Wind Generation

In 2006 the IESO participated in a study of the impact of wind power penetration on the operation of the IESO- controlled grid and the IESO-administered markets. This GE Truewind study(16) was sponsored by CANWEA, the Ontario Power Authority and the IESO. The study indicated that there is a 16% probability that the output of wind generation will change over the next ten-minute interval by more than 10%. The probability of a 20% change over 10 minutes was predicted to be negligible. The IESO has been monitoring wind production since the fall of 2006 and has found that this study value is consistent with operational experience. There is approximately 500 MW of currently installed wind capacity. As the size of the wind fleet increases as shown by the data in the IPSP, the IESO will have to consider its impact on flexible generation and the need for additional intra-hour load following services.

5.2 Dispatch Issues

The hourly data provided by the OPA did not allow an explicit analysis of the 5-minute dispatch effect on the future flexible generation pool. It is reasonable to assume that dispatch volatility is unlikely to reduce from current levels, in the absence of any further mitigation. For example, throughout the study period, in 20% of the hours, hydroelectric generation volumes changed by more than 500 MW. As slower moving thermal and gas units try to respond to these changes, other fast-moving resources must ramp to make up the difference, exposing them to significant dispatch volatility.

The IESO recognizes stakeholder concerns in this area and has implemented various programs to mitigate the dispatch volatility of load following units, but concerns remain. In order to maintain the availability rate of the dispatchable resources presented in the IPSP, the IESO and its stakeholders must continue to address the impact of dispatch issues on flexible generation. These efforts will ensure that the market maintains sufficient drivers to guarantee reliable and efficient load following and dispatch capability.

– End of Section –

6. Surplus Baseload Generation

Surplus baseload generation (SBG) is an over-generation condition that occurs when Ontario's electricity production from baseload facilities such as nuclear and must-run hydroelectric units is greater than market demand.

Surplus baseload generation periods are typically the result of low demand and can be exacerbated by:

- Spring freshet, when hydroelectric stations cannot lower generation output
- The inability of neighbouring jurisdictions to absorb surplus energy in the form of exports
- High production from intermittent resources such as wind generation

Often these events can be foreseen in the planning timeframe. However, sometimes events such as unexpectedly high production of intermittent resources (i.e. under-forecasting from participants) or low export levels to adjacent areas can lead to surplus generation conditions in real-time.

Currently, surplus baseload generation occurs only a few times a year. In the planning timeframe, the IESO's reliability publications send signals to the market to take actions such as rescheduling outages to take advantage of these conditions. Closer to real-time operation, participants may respond to forecast surplus baseload generation by increasing the Ontario demand for electricity or scheduling additional exports during times of very low price signals.

The IPSP includes increases in conservation, which will have a lowering affect on the demand for electricity across the day, and increases in intermittent and embedded generation, both of which can increase the supply even at low demand periods. For these reasons, the frequency, magnitude, and duration of surplus baseload conditions is likely to increase in the future.

Analysis of the OPA data indicated that management of surplus baseload generation in the simulated schedules relied on significant amounts of exports. If these exports failed to materialize in real-time, the IESO would have to take other control actions to maintain reliability. In order to mimic operational conditions, a number of assumptions were made with respect to the schedules provided by the OPA:

- The maximum export schedule considered was capped at 1000 MW**.** This is based on the historical export volumes seen during overnight operation, and during the infrequent surplus baseload generation conditions seen over the last few years. This is consistent with current IESO practice (limited reliance on intertie transactions for reliability planning).

- All thermal generation, gas fired generation, and dispatchable hydroelectric resources were dispatched-off to mitigate surplus conditions, which reflects current practice
- An allowance of 100 MW of surplus baseload generation was considered acceptable in the analysis, as this amount can realistically be managed by generation under contract to provide Automatic Generation Control

6.1 Results of Surplus Baseload Generation Analysis

Surplus baseload generation can be managed through actual operation of the market and its attendant price signals. For example, recent experiences with surplus baseload generation due to export failures resulted in negative Ontario energy market prices, with a significant increase in exports in response. Such prices can be expected during the surplus events seen in the study period. This should encourage domestic consumer response and attract exports beyond the level assumed in the study.

Under existing market rules, the IESO only considers the curtailment of wind resources when all market mechanisms are exhausted, including the reduction in output of nuclear units. The significant amount of surplus baseload generation hours left after dispatching down all thermal, gas and dispatchable hydroelectric units during the periods from 2012-2014 and 2022-2026, led the IESO to analyze the effectiveness of curtailing wind resources. Curtailment of wind and other intermittent resources can be an effective approach when the dispatch down (or complete shut down) of a nuclear unit can lead to reliability concerns in future hours. The effectiveness of wind generation curtailment can be seen by comparing the number of hours of surplus baseload generation under the two columns of Table 3.

Year	Number of hours of Surplus Baseload Generation (no gas, thermal or dispatchable hydroelectric generation in service)	Hours remaining after further action of curtailing wind resources
2010	59 of 8760 Hours	25 of 8760 Hours
2011	115 of 8760 Hours	64 of 8760 Hours
2012	781 of 8784 Hours	435 of 8784 Hours
2013	754 of 8760 Hours	343 of 8760 Hours
2014	788 of 8760 Hours	282 of 8760 Hours
2016	88 of 8784 Hours	3 of 8784 Hours
2018	116 of 8760 Hours	14 of 8760 Hours
2020	140 of 8784 Hours	6 of 8784 Hours
2022	580 of 8760 Hours	114 of 8760 Hours
2024	891 of 8784 Hours	193 of 8784 Hours
2026	857 of 8760 Hours	236 of 8760 Hours

Table 3: Surplus Baseload Generation Results

Reducing a nuclear unit's output can lead to it being unavailable to generate for up to three days. The analysis assumed the worst case for a reduction of a nuclear unit, i.e. the reduction resulted in the unit poisoning out[4], leaving it entirely unavailable for 72 hours. Therefore, before a unit was shut down in the analysis to resolve surplus baseload generation concerns, a verification step was taken to ensure that the remaining available generation could meet Ontario's peak demand over the period required to return the nuclear generator to service.

Given the flexibility of thermal and gas units, any resulting generation shortfalls during the peak hours were resolved by increasing these generators' schedules. Recognizing the possibility of thermal and gas units being on maintenance outage during the extended periods of low demand expected with surplus baseload conditions, a limitation was imposed on the increase to thermal and gas schedules. This limit was set to the larger of the maximum amount scheduled in the previous 24-hour period or 2,000 MW (conservative value based on estimates of fossil and gas availability). Where replacement energy was not available, Table 4 reported these as unresolved hours of surplus baseload generation.

Year	# of Nuclear Unit Shutdowns	# of SBG periods resolved by nuclear shutdown	Remaining SBG Hours
2010	5	4	0
2011	9	7	6
2012	77	36	47
2013	52	31	1
2014	39	25	6
2016	2	1	0
2018	4	4	3
2020	2	1	4
2022	23	16	2
2024	36	26	16
2026	42	25	28

Table 4: Nuclear Unit Shutdowns to Resolve SBG Events

Table 4 lists the results of the analysis that used nuclear generation to reduce unresolved hours of surplus baseload generation. The table includes:

- The number of unit-shutdowns that were required over the entire year,
- The number of surplus periods, lasting 3 days or more, where nuclear unit shutdowns were used to resolve the condition
- The remaining number of surplus condition hours, which could not be resolved through nuclear shutdown, due to insufficient replacement generation for upcoming demand.

Although not considered, the number of surplus baseload generation hours could be further reduced through the use of shallow manoeuvres of nuclear units. Shallow manoeuvres allow

[4] Term "poisoning out" refers to the situation where a nuclear unit reduces reactor power to a level where it can no longer sustain the chain reaction and must shutdown. This occurs when its normal reactor regulating devices cannot overcome the build-up of neutron absorbing isotopes that takes place after a significant power reduction.

nuclear units to partially reduce, without poisoning out and result in a limited restriction on their total subsequent output. Such manoeuvres could limit the impacts to the market by reducing the need for complete shutdown of a nuclear unit and the associated cost of replacement energy.

6.2 Other SBG Management Requirements

With a shrinking proportion of dispatchable generation for load following purposes, fossil and gas generation will be called on to provide energy as a result of peaking demand and fluctuations created by intermittent generators. Non-quick start units will need to be efficiently committed to address load following and operating reserve requirements, and must also be able to shut down during anticipated surplus baseload generation conditions. Committed generators need to respect the technical requirements of units such as minimum load, minimum run-time, maximum number of starts per day, and minimum turnaround time, which could require some generators to continue to operate through the night, potentially adding to the SBG likelihood. The IESO and stakeholders will have to continue their efforts to improve unit commitment processes and to create the market signals and incentives to encourage flexibility in these generators.

The IPSP indicates a forecasted growth of embedded/distributed generation. Embedded generators are generators that are connected to a distribution system or are connected "behind the meter" of an industrial facility. When located close to distribution load centres, these resources can provide benefits to the electricity system by reducing losses, and can often contribute to reduced load on transmission facilities. These generators are not currently monitored by IESO, nor under its dispatch control. This could result in less than optimal management of surplus baseload generation conditions. With the appropriate procedural and technological changes, embedded generation has the potential to enhance operability during periods of surplus baseload generation as well during normal conditions. These changes could include real-time monitoring, availability for dispatch (under specific conditions), appropriate communication protocols, and exposure to effective market signals.

– End of Section –

7. Adequacy Overview

The OPA data was also analyzed for adequacy to assess periods where energy was not served or there were operating reserve shortfalls.

7.1 Periods of Energy Not Served

Energy not served refers to an under-generation condition that occurs when there is insufficient generation to meet Ontario demand. In determining whether an energy not served condition existed for the analysis, a shortfall of 100 MW was considered acceptable, as this amount can realistically be managed by generation under contract to provide Automatic Generation Control. There were no instances of insufficient energy to meet Ontario demand over the entire study period of 2008 to 2026.

7.2 Shortfalls in Operating Reserve

The IESO's operating reserve requirement is based on Northeast Power Coordinating Council Operating Reserve criteria and is roughly equal to one and one-half times the largest single contingency loss. This amount would increase if larger capacity generation units or single-element based contingencies than those presently in service were to materialize. The IPSP preliminary data provided to the IESO does not currently include larger generators or single contingencies than currently exist.

The OPA simulation results did not specifically model all options available to the IESO in meeting operating reserve requirements, and hence at times generated more exports than would actually occur. As a result, when analysing the ability of the Plan to provide sufficient operating reserve, the simulation data resulted in occasional periods of operating reserve shortfalls. During actual operation of the IESO-administered markets, such exports would not be scheduled in the pre-dispatch timeframe, or would be made recallable if the shortfall developed in real-time. In addition, the IESO- administered markets currently have over 600 MW of dispatchable load, which provides a significant amount of operating reserve to the market.

The incidence of operating reserve shortfalls becomes negligible when the market-driven export behaviour and the availability of dispatchable load to provide operating reserve is considered, as shown in Table 5.

Year	IPSP Simulated Schedule After considering Non-Scheduled Exports & Dispatchable Loads
2010	0 of 8760 Hours
2011	0 of 8760 Hours
2012	0 of 8784 Hours
2013	0 of 8760 Hours
2014	0 of 8760 Hours
2016	2 of 8784 Hours
2018	3 of 8760 Hours
2020	1 of 8784 Hours
2022	0 of 8760 Hours
2024	0 of 8784 Hours
2026	1 of 8760 Hours

Table 5: Frequency of Insufficient Operating Reserve

– End of Section –

8. Conclusions and Recommendations for Future Action

The IESO has assessed the operability of the IPSP and concluded that it provides sufficient flexibility to meet future system needs. Current market mechanisms and control actions will allow the IESO to reliably operate the system described in the IPSP.

8.1 Recommendations for Future Action

The assessment identified several opportunities, and in many instances reinforced current IESO initiatives to improve transparency and efficiency in the operation of the power system and electricity market. The IESO and its stakeholders should continue to evolve current operating processes and market incentives to capture these benefits. The IESO has begun initiatives to address these opportunities on several fronts, and will ensure the following are addressed:

Reliability Starts and Unit Commitment – Efficient scheduling of thermal units has been shown to facilitate optimal load following capability. With future reductions in fleet load following capability and the likelihood of increased surplus baseload generation conditions, current commitment programs should be maintained and evolved to meet the needs of the proposed supply mix.

Dispatch Volatility and Load Following - In order to maintain the availability rate of the dispatchable resources presented in the IPSP, the IESO and its stakeholders must continue to address the impact of dispatch volatility on flexible generation. These efforts will ensure that the market maintains sufficient drivers to guarantee reliable and efficient load following and dispatch capability.

Load Following Service (incentives for capability) – Given the shrinking portion of manoeuvrable generation in Ontario’s fleet of generators, load following capability will be a generating commodity that will increase in value to the market. Market incentives should be investigated to determine if additional drivers are needed for new generators and loads to provide load following services.

Mid-Hour Intertie Scheduling – In order to implement the growing magnitude of intertie activity seen in the IPSP simulation data, the IESO should develop an intertie protocol that allows for more frequent scheduling that the current hourly practice. This would serve two purposes: to limit the load following required to accommodate changing intertie schedules, and to allow intertie scheduling to be used as a source of load following in a manner more granular nature than currently available.

Conservation and Demand Management Measures –The continuation and expansion of dispatchable load programs and smart grid technologies should be encouraged as these measures improve operability under all conditions.

Visibility and Control of Embedded Generation – The IESO should work with stakeholders to investigate incorporating increased visibility and control of embedded generation to enhance operability during periods of surplus baseload generation and assist in load following.

Generation Curtailment Options to Manage Surplus Baseload Generation – The future holds an increased likelihood of surplus baseload generation. The current practice of shutting down nuclear units to manage extreme surpluses carries significant risk. As a result, the IESO should perform a review of the prioritization and impact of current generation manoeuvring/shutdowns to manage surplus baseload generation conditions.

Regional Reserve Sharing – The IESO should continue to participate in reserve sharing programs that allow for portions of operating reserve to be shared between neighbouring jurisdictions. These programs reduce the associated costs and effectively free-up manoeuvrable generation for other services such as load following.

– End of Section –

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The Economic Impacts of the August 2003 Blackout

Prepared by the Electricity Consumers Resource Council (ELCON) - February 9, 2004

This paper summarizes recent efforts to quantify the total economic costs of the August 2003 Blackout. These estimates are shown to be consistent with post-blackout surveys of affected manufacturers and businesses. The paper concludes with examples of impacts to major industries and attempts to put a face on the economic consequences of this unfortunate debacle.

The August 14, 2003 Blackout started shortly after 4 PM EDT and resulted in the loss of 61,800 MW of electric load that served more than 50 million people. The footprint of the blackout on both sides of the US-Canadian border includes large urban centers that are heavily industrialized and important financial centers (*e.g.,* New York City and Toronto). Nearly half the Canadian economy is located in Ontario and was affected by the blackout. Service in the affected states and provinces was gradually restored with most areas fully restored within two days although parts of Ontario experienced rolling blackouts for more than a week before full power was restored.[1]

Other major North American blackouts in 1965 and 1977, and the 2000-2001 California Electricity Crisis, produced a sizable library of studies and analyses of the direct and indirect economic costs of power outages on regional economies. Based on the much-studied 1977 New York City blackout, ICF Consulting estimated the total economic cost of the August 2003 blackout to be between $7 and $10 billion.[2] These figures are based on estimates of direct costs per kWh of the power outage (*e.g.,* losses due to food spoilage, lost production and overtime wages) and indirect costs due to the secondary effects of the direct costs.[3] According to ICF, the estimates are corroborated by more recent simulation studies of potential outages in California.

Anderson Economic Group (AEG) estimates the likely total cost to be between $4.5 and $8.2 billion with a mid-point of $6.4 billion. This includes $4.2 billion in lost income to workers and investors, $15 to $100 million in extra costs to government agencies (*e.g.,* due to overtime and emergency service costs), $1 to $2 billion in costs to the affected utilities, and between $380 and $940 million in costs associated with lost or spoiled commodities.[4]

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[1] U.S.-Canada Power System Outage Task Force, *Causes of the August 14th Blackout: Interim Report,* November 2003, p. 1; James McCarten, CNEWS, December 31, 2003

[2] ICF Consulting, "The Economic Cost of the Blackout: An Issue Paper on the Northeastern Blackout, August 14, 2003."

[3] *Impact Assessment of the 1977 New York City Blackout*, SCI Project 5236-100, Final Report, Prepared for the U.S. Department of Energy, July 1978, pp. 2-4.

[4] Anderson, Patrick L. and Ilhan K, Geckil, "Northeast Blackout Likely to Reduce US Earnings by $6.4 Billion," AEG Working Paper 2003-2, August 19, 2003

The U.S. Department of Energy (DOE) has published a total cost estimate of about $6 billion.[5] This number is the most frequently cited cost estimate in press coverage of the blackout.

In a separate study completed shortly after August 14, the Ohio Manufacturers' Association (OMA) estimated the direct costs of the blackout on Ohio manufacturers to be $1.08 billion.[6] Some 12,300 manufacturing companies in the state (representing approximately 55% of the manufacturers in Ohio) were impacted with an average estimated direct cost of nearly $88,000 each. All companies reporting indicated that the blackout caused a "complete shutdown in operations." The average duration of a plant shutdown was 36 hours. Over a third of the companies reported that the outage also disrupted deliveries from suppliers and deliveries to customers. The study was based on a survey of OMA members and the results have a sampling error of plus or minus 5%.

The OMA study noted that other indirect costs also resulted from the blackout, including:

1. The diversion of significant amounts of capital investment from new job-producing investments to blackout protection systems; and
2. Lower bottom lines resulting from lost production will reduce the value of those companies' securities.

The OMA results are consistent with the ICF and AEG estimates given that the Ohio study only captures impacts on the manufacturing sector and not commercial or public sector costs. The blackout affected parts of eight states and the Canadian province of Ontario. The OMA survey confirms that the event's economic cost is reasonably measured in the "billions" of dollars.

A second post-blackout study underway by CrainTech (a business news publisher), Case Western Reserve University's Center for Regional Economic Issues and Mirifex Systems LLC has produced some preliminary results based on a survey of businesses in Ohio, New York, Pennsylvania, Michigan, Wisconsin and Southern Canada. These findings include:[7]

1. A quarter of the businesses surveyed (24%) lost more than $50,000 per hour of downtime (*i.e.,* $400,000 for an 8-hour day). And 4% of the businesses lost more than $1 million for each hour of downtime.

[5] "Transforming the Grid to Revolutionize Electric Power in North America," Bill Parks, U.S. Department of Energy, Edison Electric Institute's Fall 2003 Transmission, Distribution and Metering Conference, October 13, 2003

[6] Ohio Manufacturers' Association, August 29, 2003

[7] Mirifex Systems LLC, Case Western Reserve University and CrainTech, November 5, 2003

2. Almost 11% of firms say the blackout will affect their decision-making with regards to either growth at the current location or relocation to another.

The Detroit Regional Chamber estimated the financial loss to the Detroit region resulting from the blackout will reach $220 million. The Chamber collaborated with the University of Michigan's Institute of Labor and Industrial Relations in the analysis.[8]

An important indirect—and impossible to quantify—cost of the blackout was the "cascading" consequences on regions outside of the blackout footprint created by manufacturers' *just-in-time* (JIT) production scheduling. Delivery times for parts and materials to assembly plants are timed to meet scheduled production and thus minimize or eliminate the cost of inventory.

From a public policy perspective—in the U.S. or Canada—it really does not matter if the total economic damages are $4 billion, $6 or $10 billion, or anywhere in between. The point is that this type of event is unconscionable to the extent that a single utility's failure to properly trim trees is deemed the "root cause" of the August 14 Blackout.

Nonetheless, until a more comprehensive analysis of the 2003 Blackout is performed, the AEG and ICF estimates are reasonable placeholder values. However, any subsequent study will likely produce cost estimates with the same order of magnitude given the results of recent post-blackout surveys.

Examples of Impacts on Specific Industries

The remainder of this paper is a compilation of reported impacts on specific facilities of manufacturing companies and other organizations. This information is based on trade press or media coverage of the blackout unless otherwise noted. This is not a comprehensive survey but the results are illustrative of the serious consequences of a blackout on North American industry.

Motor Vehicle & Automotive Parts Industries

At least 70 auto and parts plants and several offices were shutdown by the August 14 Blackout, idling over 100,000 workers.[9]

General Motors Corporation reported that the blackout affected approximately 47,000 employees at 19 manufacturing facilities and three parts warehouses in Michigan, Ohio and Ontario.[10]

[8] Transmission & Distribution World, October 1, 2003

[9] Detroit Free Press, August 16, 2003

[10] General Motors Corporation, August 18, 2003

The **Ford Motor Company** reported that 23 of Ford's 44 plants in North America were shutdown, as were numerous office, engineering and product development facilities in southeastern Michigan. Other facilities were affected by disruptions in parts supply lines.[11] At Ford's casting plant in Brook Park, Ohio, the outage caused molten metal to cool and solidify inside one of the plant's furnaces. The company reported that a week would be required to clean and rebuild the furnace.[12]

The North American operating units of **DaimlerChrysler AG**, lost production at 14 of its 31 plants. Six of those plants were assembly plants with paint shops. All the vehicles that were moving through the paint shop at the time of the outage had to be scrapped. The company reported that, in total, 10,000 vehicles had to be scrapped.[13]

The **Honda Motor Company** reported that its Canadian assembly plant in Alliston, Ontario, was shutdown as a result of the blackout.[14]

Auto suppliers **Lear Corporation**, **ArvinMeritor Inc.**, and **Delphi Corporation** had facilities that were affected by the blackout, including Delphi's huge Flint East manufacturing complex.[15]

Three **Neff-Perkins Company** manufacturing plants, located in Lake, Geauga, and Ashtabula counties, Ohio, lost production from 4:10 pm on August 14 until 7:00AM on August 15. The company also shut down certain presses and air conditioning in the office areas to comply with the local utility's request to cut back power consumption.[16] Neff-Perkins is a manufacturer of custom-molded rubber and plastic parts for the automotive and controls industries.

Petroleum Refineries

The blackout affected at least eight oil refineries in the U.S. and Canada. The loss of production at the damaged refineries threatened a gasoline shortage in the Detroit Metropolitan Area, creating the potential for a broader energy emergency. As a result the Governor of Michigan issued two Declarations of Energy Emergency on August 22 that, in part, suspended certain air quality regulations that might have exacerbated a gasoline shortage.[17]

[11] Ford Motor Company, August 17, 2003

[12] Cleveland Plain Dealer, August 16, 2003

[13] Detroit Free Press, August 22, 2003

[14] Detroit News, August 15, 2003

[15] Detroit News, August 19, 2003; Plant Engineering Magazine, "How One Plant Survived the Blackout," November 1, 2003

[16] Andy Budd, Controller, Neff-Perkins Company, August 15, 2003

[17] Michigan PSC Report on August 14th Blackout, November 2003, p. 74

Affected refineries and their production capacities included:

- **Marathon Oil Corporation** – 76,000 barrels per day (bpd) at Detroit, Michigan[18]
- **BP PLC** – 160,000 bpd at Toledo, Ohio[19]
- **Sunoco Inc** – 140,000 bpd at Toledo, Ohio. The refinery also produces cumene feedstock for the company's phenol plant in Frankford, Pennsylvania.[20]
- **Imperial Oil Ltd.** – Two refineries: 119,000 barrels per day at Sarnia, Ontario, 118,000 bpd at Nanticoke, Ontario.[21]
- **Petro-Canada** – 90,000 bpd at Oakville, Ontario. [22]
- **Shell Canada Ltd.** – 75,000 bpd refinery at Sarnia, Ontario.[23]
- **Suncor Energy Inc.** – 70,000 bpd at Sarnia, Ontario.[24]

The main pipeline network for Canadian oil shipments to the U.S. Midwest and southern Ontario—operated by **Enbridge Inc**.—was also crippled by the blackout. Much of the 2 million bpd system, the world's longest for crude oil and petroleum products shipments, was shut down east of Lake Superior. Enbridge reported that it was forced to cut volumes moving to its terminal at Superior, Wisconsin, from Alberta to prevent overfilling storage tanks.[25]

The blackout was responsible for triggering emergency shutdown procedures at the **Marathon Oil Corporation**'s Marathon Ashland refinery about 10 miles south of Detroit. During those procedures, a carbon monoxide boiler failed to shut down properly, causing a small explosion and the release of a mixture of hydrocarbons and steam. As a pre-cautionary measure, police evacuated a one-mile strip around the 183-acre complex and forced hundreds of residents to seek shelter elsewhere. The Marathon refinery can process 76,000 barrels of crude oil per day into a variety of petroleum products. Approximately half the production from the refinery is gasoline designed to meet the air quality requirements in southeastern Michigan. Full production was not restored at the refinery until eight days after the onset of the outage. During

[18] Houston Business Journal, August 18, 2003

[19] Id.

[20] Chemical Week, August 20, 2003

[21] Standard & Poor's Utilities & Perspectives, August 25, 2003, Vol. 12, No. 34, page 11.

[22] Id.

[23] Id.

[24] Id.

[25] Reuters, August 18, 2003

that time the company was unable to deliver to the local market approximately 500,000 barrels of gasoline and other products.[26]

Steel Industry

United States Steel's Great Lakes Works, the company's second largest plant, resumed production on August 18, four days after the country's worst blackout knocked the plant off line. U.S. Steel is the largest integrated steel maker in the country. The Great Lakes Works is located in Ecorse and River Rouge, Michigan.[27]

Rouge Industries Inc. reported that its huge Dearborn, Michigan, plant was completely shutdown for 24 hours with only limited power for several days thereafter. The company lost the equivalent of four days' worth of production.[28]

The **International Steel Group Inc.** reported that its Cleveland Works was shut down by the blackout and did not restart steel production until four days later. When the plant lost power, 1,250 tons of molten iron had to be dumped into two slag pits along the west bank of the Cuyahoga River. ISG said that the plant suffered some damage as a result of the outage.[29]

AK Steel Corporation's Manfield, Ohio, facility lost power at 4:15 PM on the day of the blackout. The plant's melt shop had six heats of steel in process, all of which were lost. Also in Manfield, **Bunting Bearings Corporation**, a manufacturer of bronze, plastic, powdered metal and aluminum bearings and solid bars, could not cast for four days. [30]

BCS Cuyahoga LLC reported that its Cleveland plant was shutdown until August 18. When the power failed, plant personnel had to manually fill the water-cooling jackets on the reheat furnaces to prevent damage.[31]

An explosion and fire caused significant damage to **Republic Engineered Products**' No. 3 Blast Furnace in Lorain, Ohio, as a result of the blackout. No one was injured due to the explosion. Within 15 to 30 minutes after the outage began, the plant lost the ability to cool the iron inside the furnace and the molten metal burned through the side of the structure and started spilling inside the building. Several fires erupted sending an orange-gray plume of smoke that was visible throughout the city. Company officials refused to allow firefighters on the premise, but the company's workers were able to successfully contain the fires. The company announced that it expected to

[26] Michigan PSC Report on August 14th Blackout, pp. 81-82

[27] Pittsburgh Business Times, August 18, 2003

[28] American Metal Market, August 19, 2003

[29] Id.; Cleveland Plain Dealer, August 16, 2003

[30] Metal Industry News, September 2003

[31] Id.

resume production at Lorain by the middle of September.[32] Republic is North America's leading producer of special bar quality (SBQ) steel. On October 6, 2003, Republic announced that it had been forced to file for protection under Chapter 11 of the U.S. Bankruptcy laws. It cited the August 14 explosion and fire at Lorain as a contributing factor.[33]

Nucor-Auburn, the merchant bar mini-mill in Auburn, New York, operated by **Nucor Corporation**, shut down its rolling mill and melt shop during the outage. Operations were resumed the following week.[34]

Steelmaker **Dofasco Inc.**, the largest single-site consumer of electricity in Ontario, was affected both by the blackout and requests from the Independent Market Operator (IMO) to curb consumption to facilitate power restoration in the province. The plant, located in Hamilton, Ontario, experienced a fire that resulted in a damaged Coke Plant when power was interrupted on August 14. Other Canadian steel mills that were affected are: **Algoma Steel Inc.,** an integrated steel producer based in Sault Ste. Marie, Ontario; **Stelco Inc**., Canada's largest steel producer, with integrated mills in Hamilton and Nanticoke, Ontario; and two mills operated by **Gerdau AmeriSteel Corporation** in Whitby and Cambridge, Ontario.[35]

Chemical Industry

Over thirty chemical, petrochemical and oil refining facilities are located in the "Chemical Valley" area near Sarnia, Ontario. All the plants suffered some form of outage resulting in the flaring of products at most of the facilities. Massive clouds of black smoke were visible throughout the area. Estimates of the cost to producers in the Valley range from $10 to $20 million per hour of outage.[36]

Nova Chemicals Corporation reported that plant outages resulting from the August 14 Blackout reduced third-quarter earnings by $10 million or 12 cents per share. The power outage hit production at its Corunna, Moore Township, Sarnia, and Sti. Clair River, Ontario, and Painesville, Ohio, facilities. Nova stated that it lost a total of 150 million pounds of ethylene and co-products, polyethylene (PE), styrene and expandable polystyrene (EPS) production by the time its facilities returned to normal. The company declared *force majeure* on ethylene co-product deliveries from Corunna. Nova restarted

[32] Cleveland Plain Dealer, August 15, 2003; Association for Iron & Steel Technology, August 16 and August 28, 2003

[33] Republic Engineered Products LLC, October 6, 2003

[34] American Metal Market, August 19, 2003

[35] Id.

[36] Detroit Free Press, August 15, 2003

its ethylene plant at Corunna and its styrene plant at Sarnia, as well as portions of its Moore Township complex about a week after the outage began.[37]

DuPont reported that all five plants in Ontario were downed by the blackout. The company produces nylon and nylon intermediates at Kingston and Maitland, specialty polymers at Sarnia, polyethylene films at Whitby, and automotive finishes at Ajax. Three DuPont facilities in the U.S. were also affected by the blackout. DuPont said that sodium and lithium production at Niagara Falls and operations in Buffalo, NY, where Corian® solid surfaces and Tedlar® PVF film are manufactured, were shut down on Thursday, August 14, but were back to full power by Thursday night. Its automotive finishes facility in Mount Clemens, Michigan, suffered a complete outage but started to receive power a day later.[38] The facility at Kingston, Ontario, was down for more than a week.[39]

Bayer Canada reported that the blackout idled butyl rubber and nitrile butyl rubber operations in Sarnia, Ontario.[40]

BASF reported that its large polymers facility in Wyandotte, Michigan, was shut down as a result of the blackout.[41] BASF Wyandotte operations is a leading producer of plastics and the world's second largest producer of vitamins.

Dow Chemical's chemicals and plastics operation in Sarnia, Ontario, was shut down on August 14 and was not able to restart production until the following Monday, August 18. The company produces polystyrene, polyethylene, interpolymers and acrylic latex at the site. Dow also reported that its industrial biotechnology facility, **DowPharma**, in Stony Brook, NY, was affected by the blackout.[42]

BP reported that disruptions to its petrochemical production were limited to its 140-million lbs/year butanediol plant in Lima, Ohio. The plant was restarted the day after the blackout started.[43]

Imperial Oil Ltd., a subsidiary of **ExxonMobil**, reported that its aromatics and polyethylene production at its Samia, Ontario, site was disrupted.[44]

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[37] Chemical Week, August 27, 2003

[38] Chemical Week, August 20, 2003

[39] Chemical Week, August 27, 2003; Chemical & Engineering News, August 25, 2003

[40] Chemical Market Reporter, September 1, 2003

[41] Chemical & Engineering News, August 25, 2003

[42] Chemical Week, August 20, 2003; Chemical & Engineering News, August 25, 2003

[43] Id.

[44] Id.

Merck & Co.'s pharmaceutical operations in Rahway, New Jersey, were interrupted by the blackout.[45]

Chlor-alkali producers **Olin Corporation** and **Occidental Chemical Company** shutdown their respective plants at Niagara Falls, NY, because of the blackout but were able to restart the plants by Saturday, August 16.[46]

Approximately ten **Praxair, Inc.** air separation plants in Connecticut, Michigan, New Jersey, New York, Ohio and Pennsylvania, as well as three in Ontario, Canada, were out of service as a result of the regional electricity failure at 4:11 p.m. on August 14, 2003. All plants either returned to service when power was restored or temporarily remained off-line at the request of the local utility on Friday and Saturday. Praxair plant operations and logistics responded to the sudden power outage safely and successfully. The North American Logistics Center in Tonawanda, NY, took steps to shift product deliveries to customers in the affected area.

Linde Gas' air separation plant in Bozrah, Connecticut, was interrupted most of the day Friday, August 15, and into Saturday because of the power outages elsewhere in the state and regions in ISO-New England.[47]

Other Impacts on Industry and the Commercial and Public Sectors

Alcan Inc., the world's second largest aluminum producer, reported that its cold-rolling plant in Kingston, Ontario, was shutdown by the blackout.[48]

Revere Copper Products Inc., in Rome, New York, lost copper and alloy production as a result of the blackout.[49] The plant facilities include melting, casting, hot rolling, cold rolling extrusion, bar making and testing equipment.

Paper-maker **Domtar Inc.** shutdown its pulp mill in Espanola, Ontario, and a paper mill in Cornwall, Ontario, as a result of the blackout. Forestry company **Tembec Inc.** shutdown sawmills in Timmins,Cochrane, Huntsville and Hearst, Ontario, a pulp mill in Smooth Rock Falls, Ontario, and a newsprint mill in Kapuskasing.[50]

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[45] Chemical & Engineering News, August 25, 2003

[46] Id.

[47] Mike Kovach, US Linde Gas, August 18, 2003

[48] The Globe and Mail, August 16, 2003

[49] Metal Industry News, September 2003

[50] The Globe and Mail, August 16, 2003

The **National City Corporation** reported that across the bank's six-state franchise, approximately 174 branches were closed due to the power situation: 30 in Ohio, 134 in Detroit, Michigan and 10 in Pennsylvania.[51]

Kroger Company, the largest U.S. supermarket chain, reported that 60 of its stores were without power as a result of the August Blackout. Most of the stores were in Michigan.[52]

The **Associated Food Dealers of Michigan** estimates that over $50 million in perishable foods were lost due to the lack of refrigeration caused by the blackout.[53]

Local telephone service was also jeopardized by energy emergency created by the blackout. **SBC**, the dominant carrier in Michigan, requested assistance from Michigan's State Emergency Operations Center (SEOC) to locate supplemental supplies of petroleum liquids to assure the continued operation of the local telephone system. This fuel was needed for both standby generators and company vehicles to allow travel to remote locations to assure continued operation of telephone equipment.[54]

Duane Reade Inc., the largest drug store chain in the metropolitan New York City area, reported that the August 14th Blackout forced the closure of all of the company's 237 stores. The company estimates that as a result of the interruption, lost sales totaled approximately $3.3 million.[55]

Airports were closed in Toronto, Newark, New York, Detroit, Cleveland, Montreal, Ottawa, Islip, Syracuse, Buffalo, Rochester, Erie, and Hamilton.[56]

The **New York City** comptroller's office estimated that losses topped $1 billion, including $800 million in gross city product. The figure includes $250 million in frozen and perishable food that had to be dumped. The Restaurant Association calculated that the city's 22,000 restaurants lost between $75 and $100 million in wasted food and lost business. Broadway lost approximately $1 million because of cancelled performances.[57] New York City's mayor estimated that the city would pay almost $10 million in overtime related to the outage.[58]

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[51] National City Corporation, August 15, 2003

[52] Detroit Free Press, August 16, 2003

[53] PRNewswire, August 18, 2003

[54] Michigan PSC Report on August 14th Blackout, November 2003, p. 75

[55] Duane Reade, August 22, 2003

[56] Toronto Star, August 16, 2003

[57] Associated Press, August 21, 2003, reported at www.smh.com.

[58] Gotham Gazette