renewable is doable

A Smarter Energy Plan for Ontario.

Analysis of Resource Potential and Scenario Assumptions

the PEMBINA institute
Sustainable Energy Solutions

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Renewable is Doable: Analysis of Resource Potential and Scenario Assumptions
Published July 2007
Printed in Canada

Editor: Randee Holmes
Layout: Paul Cobb

ISBN 1-897390-04-1

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The Pembina Institute creates sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy and environmental governance. More information about the Pembina Institute is available at http://www.pembina.org or by contacting info@pembina.org.

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The Pembina Foundation for Environmental Research and Education is a federally-registered charitable organization. The foundation supports innovative environmental research and education initiatives to increase understanding within society of the way we produce and consume energy, the impact on the environment and the consequences for communities, as well as options for the more sustainable use of energy natural resources. The Pembina Foundation contracts the Pembina Institute to deliver on this work.

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Acknowledgements

The authors would like to acknowledge the support of the EJLB Foundation and the Toronto Community Foundation.

Preface

This report is part of a study by WWF Canada and the Pembina Institute to identify electricity scenarios for Ontario that would meet future power demands without the use of nuclear power and coal, and that would generate lower emissions than the plan currently proposed by Ontario Power Authority. This report presents a review of the technical and practical potential of electricity supply and conservation measures for the province of Ontario, including an analysis and review of renewable energy sources, and the potential impact of conservation and demand management measures.

The information provided in this report was used by Portfire Associates Inc. to generate alternative electricity production and peak demand scenarios using the WADE Economic Model, a computer model developed by the World Alliance for Decentralized Energy (WADE). The results from this modelling analysis are provided in a separate report.

Green Electricity Scenarios for Ontario:

Analysis of Resource Potential and Scenario Assumptions

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Introduction

During the second half of 2006, the Ontario Power Authority (OPA) engaged in public consultation regarding its Integrated Power System Plan (IPSP). There has not been a comprehensive power system plan in Ontario in over 15 years. The completion of the IPSP will therefore be a major milestone. The results of the consultation process were rolled out as a set of eight discussion papers covering all aspects of planning the power system and culminating in a preliminary plan. Stakeholders such as WWF Canada and the Pembina Institute were invited to comment and provide feedback.

WWF Canada and the Pembina Institute are undertaking a study to develop alternatives to the IPSP scenarios that would meet Ontario power needs without the use of nuclear power or coal. These alternative scenarios would take advantage of Ontario's large untapped energy efficiency and renewable energy potential. The objective is to identify ways to reduce the environmental impact of electricity in Ontario while keeping electricity price increases in step with the environmental, climate and air quality benefits that each option provides.

The report describes four scenarios, each including conservation and demand management (CDM) and supply resources, as well as the rationale for the assumptions used in each case. Each section begins with a classification of the resource option followed by the proposed acquisitions by OPA under the preliminary IPSP. This is followed by an assessment of potential based on studies by OPA and other stakeholders. Where appropriate, deployment rates used in other jurisdictions are reviewed. Each section ends with the assumptions of deployment rates and costs used in the study scenarios.

Scenario Descriptions

Scenario 1: OPA Preliminary Plan [OPA Plan Calibration]

This scenario replicates all OPA plan acquisitions and costs as set out in the IPSP discussion papers and background data spreadsheets. CDM acquisitions are based on information provided by OPA to the Conservation Business Advisory Group in May 2007.

The purpose of the scenario was to calibrate the WADE model by reproducing the OPA preliminary plan acquisitions. The WADE model could then used to test other acquisitions strategies.

Scenario 2: A Realistic Representation of OPA Preliminary Plan [OPA Plan Updated]

This scenario provides an indication of the impact that realistic assumptions about the cost and reliability of nuclear power will have on overall plan costs and the phase-out of coal-fired generation.

The scenario bases nuclear power plant reliability on historic performance. Nuclear power plant refurbishment costs are based on those estimated in the Auditor General of Ontario's recent report for the Bruce power refurbishment project, and subsidies provided through the "stranding" of long-term debt associated with existing nuclear facilities in Ontario.

Scenario 3: Meeting Future Demands without New Nuclear Power [Soft Green]

This scenario shows that with the acquisition of OPA identified and achievable CDM, renewable energy, and combined heat and power (CHP) opportunities in Ontario, along with hydro power purchases from adjacent provinces, future power needs in Ontario can be met without any new investment in new or refurbished nuclear capacity. This scenario also results in lower greenhouse gas (GHG) emissions than the OPA preliminary plan, and a coal phase-out sooner than could be achieved using Scenario 2.

- CDM resources are acquired up to those already identified by OPA as being cost effective and achievable with modest programming — i.e., not artificially limited so as to not exceed the CDM target set in the IPSP supply mix directive.

- On-site CHP through micro-turbines in commercial and institutional facilities are increased through modest specifically targeted programs such as the recently announced standard offer.

- Wind power resources are acquired up the maximum identified by OPA that can be integrated into the grid without significant changes to grid operation or regulation.

- Solar power resources are increased to levels shown to be achievable based on the historic performance of programs (such as solar roof programs) and incentives (such as standard offer programs) established in jurisdictions comparable to Ontario.

- Bio-energy resources are increased to maximum levels identified by OPA.

- Hydroelectric capacity acquired is greater than capacity planned by OPA. Development of many projects, including large projects on the Albany River are subject to agreement with affected First Nations. If agreement could not be reached with the affected First Nations, we would substitute additional biomass capacity.

- CHP (cogeneration) and waste heat power facilities are increased to reflect industrial potential, thus displacing some future combined cycle gas power generation.

- Existing interconnections with Manitoba and Quebec and new connection capacity already under construction with these provinces is maximized to import hydropower resources.

- No nuclear refurbishments are made beyond those already committed by contract, and no new nuclear facilities are built.

- Coal gasification with carbon capture and storage is eliminated from the plan.

- No biomass or peat is used in the Atikokan facility.

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources [Deep Green]

This scenario shows that if the Province takes steps to make CDM and renewable energy the cornerstones of Ontario's future power system, natural gas use and emissions can be greatly reduced, nuclear and coal-fired power plants can be phased out more quickly, and the cost to Ontarians will not be significant when compared to the benefits of creating this secure, reliable and clean energy future.

- CDM resources, including fuel switching and CHP from micro-turbines, are acquired up to those levels identified by many studies as being cost effective and in line with achievements in other jurisdictions.

- Wind power resources are increased 50% beyond Scenario 3 and power storage is installed to integrate this additional capacity into the grid.

- The Ontario power grid is optimized around primarily decentralized power sources (thus ensuring sufficient transmission capacity for renewable energy sources), embedded power storage, smart grid control systems and a modified regulatory regime.

- After 2015, when solar photovoltaic systems are expected to become more cost competitive with other power sources, solar power resources are increased to higher deployment levels similar to those achieved in other jurisdictions that use aggressive policies.

- Bio-energy resources are increased to the levels identified by industry studies.

- Hydroelectric capacity acquired is greater than capacity planned by OPA. Development of many projects, including large projects on the Albany River are subject to agreement with affected First Nations. If agreement could not be reached with the affected First Nations, we would substitute additional biomass capacity.

- Existing interconnections with Manitoba and Quebec, and those under construction with these provinces, are supplemented with additional capacity to increase import of hydropower resources from locations where local environmental and social impacts are minimal.

- CHP (cogeneration) and waste heat power facilities are increased to reflect industrial potential, thus displacing some future combined cycle gas power generation

- No nuclear refurbishments are made beyond those already completed, and no new nuclear facilities are built.

- No coal gasification with or without carbon capture and storage is used.

- No biomass or peat is used in the Atikokan facility.

Scenario Summaries

The tables below summarize the resource capacity for the target year 2027 and the costs per kilowatt (kW) assumed for each scenario.

The remainder of this report describes the individual choices made for each resource and for each scenario based on an analysis of resource potential. Where necessary, deployment rates from other jurisdictions are used to illustrate potential in Ontario. Since many sources use 2025 as a target year, some assumptions are based on this year. In these cases additional resources were added equal to 40% of the increase between 2020 and 2025 so that all resource assumptions for the WADE modeling are for 2027.

Differences in load factors were found among the sources used. In the WADE modeling, the load factors used by OPA in the preliminary plan were used wherever possible.

Load factor relates the megawatt (MW) of installed supply capacity to the gigawatt hours per year (GWh/yr) of electricity produced by each installed MW. The peak effectiveness factor relates installed MW of each supply resource to the MW available at peak. In the case of CDM resources that reduce demand, the load factor relates the GWh/yr savings to the effective peak MW reduction achieved as a result these savings.

Supply Resources:

GWh/yr power production = 8.76 x installed MW x Load Factor
Effective peak MW = installed MW x Peak Effectiveness Factor

Demand Resources:

Effective peak MW = GWh/yr savings / 8.76 / Load factor

Table 1: Summary of Target Capacities in Four Scenarios

Summary of Scenarios 2027 Target Capacities Supply Resources = Installed Capacity (MW) CDM Resources = Peak Reduction (MW)				
	Scenario 1 OPA Plan (Calibration) (MW)	**Scenario 2 OPA Plan (Updated) (MW)**	**Scenario 3 Soft Green (MW)**	**Scenario 4 Deep Green (MW)**
Electricity Sales -TWh	187.8	187.8	187.8	187.8
Average Transmission and Distribution Losses (%)	7.67%	7.67%	7.67%	7.67%
Electricity Demand Growth Rate - %	1.26%	1.26%	1.26%	1.26%
Peak Demand - MW	34,898	34,898	34,898	34,898
Peak Demand Growth Rate - %	1.23%	1.23%	1.23%	1.23%
Peak Transmission and Distribution Losses (%)	13.86%	13.86%	13.86%	13.86%
Effective Capacity - MW	41,424	41,424	41,424	41,424
Reserve Margin	18.7%	18.7%	18.7%	18.7%
Installed Capacity - MW				
Nuclear - Existing	750	750	750	0
Nuclear - Refurbished	10,484	10,484	3,000	0
Nuclear - New	1,400	1,400	0	0
Hydro	10,095	10,095	10,793	10,793
Coal ST	0	0	0	0
Gas Combined Cycle (CCGT)	6,109	6,109	3,400	2,200
Industrial Gas Cogeneration (> 50 MW)	1,719	1,719	2,719	2,719
Oil/Gas	1,636	1,636	1,636	0
Wind Farms	5,025	5,025	10,000	15,000
Biomass & Landfill Gas (> 50 MW)	379	379	379	379
Interconnection	500	500	3,530	3,530
Storage	1,000	1,000	1,000	1,100
Gas Simple Cycle (Peaking)	750	750	400	400
Coal Gasification	250	250	0	0
Solar (Greenfield)	40	40	800	1,000
Total Central Generation - MW	40,138	40,138	38,407	37,121
CDM (Efficiency and Solar DHW)	3,712	3,712	5,638	7,500
CDM (Fuel Switching)	203	203	307	500

	Demand response, TOU Pricing & Conservation	1,458	1,458	2,129	2,500
	Industrial Gas Cogeneration (<50 MW)	878	878	878	878
	Biomass & Landfill Gas (< 50 MW)	475	475	870	870
	CDM Renewables (Onsite Wind & Hydro)	170	170	170	170
	Self Generation (CDM Cogen, Microturbines & Fuel Cells)	495	495	834	834
	Solar (Rooftop)	40	40	1,500	3,000
	Substation Peaker & CHeP	0	0	100	100
	Waste Heat Recycling	0	0	1,250	1,250
Total Decentralized Energy - MW		7,431	7,431	13,676	17,602
Total CG and DE - MW		47,569	47,569	52,083	54,723

Table 2: Supply and CDM Cost Assumptions

Supply and CDM Resource Costs ($/kW) Scenario Assumptions				
	OPA Plan (Calibration)	OPA Plan (Updated)	Soft Green	Deep Green
Nuclear - Existing	$2,845	$2,845	$2,845	$2,845
Nuclear - Refurbished	$2,845	$2,845	$2,845	$2,845
Nuclear - New	$3,400	$3,400	$3,400	$3,400
Hydro	$2,666	$2,666	$2,666	$2,666
Coal Steam Turbine	$1,840	$1,840	$1,840	$1,840
Combined Cycle Gas Turbine (CCGT)	$841	$841	$841	$841
Industrial Gas Cogeneration (> 50 MW)	$841	$841	$841	$841
Oil/Gas	$635	$635	$635	$635
Wind Farms	$1,959	$1,959	$1,959	$2,262
Biomass & Landfill Gas (> 50 MW)	$2,208	$2,208	$2,208	$2,208
Interconnection	$1	$1	$1	$1
Storage	$2,666	$2,666	$2,666	$2,666
Gas Simple Cycle (Peaking)	$635	$635	$635	$635
Coal Gasification	$2,499	$1,923	$1,923	$1,923
Solar (Greenfield)	$5,613	$5,613	$5,613	$5,613
CDM (Efficiency and Solar DHW)	$833	$833	$833	$833
CDM (Fuel Switching)	$833	$833	$833	$833
Demand response, TOU Pricing & Conservation	$833	$833	$833	$833
Industrial Gas Cogeneration (<50 MW)	$841	$841	$841	$841
Biomass & Landfill Gas (< 50 MW)	$3,200	$3,200	$3,200	$3,200
CDM Renewables (Onsite Wind & Hydro)	$2,545	$2,545	$2,545	$2,545
Self Generation (CDM Cogen, Microturbines & Fuel Cells)	$3,741	$3,741	$3,741	$3,741
Solar (Rooftop)	$5,613	$5,613	$5,613	$5,613
Substation Peaker & CHeP	$1,000	$1,000	$1,000	$1,000
Waste Heat Recycling	$1,500	$1,500	$1,500	$1,500
Note: Solar technology costs decline at 3% per year to reach $3,502/kW in 2027. Note: In the deep green scenario, the cost of wind includes storage for 5000 MW.				

Conservation and Demand Management (CDM)[1]

Classification:

OPA classifies CDM as including the following measures that reduce power consumption and peak demand beyond the customer meter:

- Conservation* — changes in "behaviour" or reductions in the demand for energy services as a result of incentives or information, or as a result of voluntary actions (natural conservation[2])
- Energy Efficiency — improvements in the efficiency of end-use technologies in response to a variety of incentives
- Demand response* — shifts in peak demand in response to incentives
- Time of use (TOU) pricing* — shifts in energy use patterns in response to pricing
- Fuel switching — shifts in end-uses like water heating and cooking from electricity to other fuels (mostly natural gas) in response to incentives
- Cogeneration — use of small scale CHP systems on the customer side of the meter with or without excess power being provided to the grid (e.g., micro-turbines or fuel cells)
- On-site renewable energy systems — production of power for electricity using end-uses and sale to the grid from small scale solar, wind, micro-hydro and wind systems operated by the customer

Those components marked with an * provide mostly peak demand reduction and do not reduce the consumption of electricity to any extent. The peak demand reduction associated with electricity savings for each of the other components (normally called the peak load factor) will vary because of the end-uses involved (see below). For example, savings in water heating from fuel switching will have a lower peak impact than savings from air conditioner equipment efficiency.

OPA Supply Mix Assumptions

In their *IPSP Discussion Paper No. 3,*[3] and in recent information provided to the OPA Conservation Business Advisory Committee, OPA consolidates the above categories into six resources and plans to acquire the amounts shown in Table 3 and Table 4 over the next 18 years. The acquisition plans include only 60% of the achievable, cost-effective potential as identified by a number of independent consultant studies (these consultant studies outlined potential based on implementation of modest CDM programming).

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[1] Most other energy utilities use the term "Demand Side Management" (DSM) to describe any program or initiative by a utility to reduce demand for power beyond the meter.

[2] Natural conservation is normally taken into account in a load forecast and not included in CDM or DSM resources. OPA take this approach.

[3] Ontario Power Authority, *IPSP Discussion Paper No 3: Conservation and Demand Management, Revised* (Toronto: OPA, 2006).

The OPA does not outline why the remaining 40% of identified potential will not be acquired, even though this identified potential is already lower than full economic potential.

Table 3: CDM Savings Projection in IPSP

GWh/yr Savings	2010	2015	2020	2025
Conservation	900	900	900	900
Efficiency	5,200	11,900	15,100	17,400
Demand Management (DM/TOU)	100	100	100	100
Fuel Switching (summer)	1,700 (200)	3,300 (300)	3,900 (500)	4,400 (500)
Self Generation/CHP	1,200	1,600	3,000	4,200
Total	9,000	17,700	23,000	27,000

Table 4: CDM Peak Reduction Projects in IPSP

Peak MW Reduction (peak load factor)	2010	2015	2020	2025
Conservation (100%)	100	100	100	100
Efficiency (56–62%)	949	2,263	3,019	3,514
Demand Management (< 1%)	874	1,077	1,233	1,313
Fuel Switching (200–400%)	49	109	151	188
Self Generation/CHP (73%)	190	256	463	646
Total (48–53%)	2,162	3,803	4,967	*5,760

*** The 2006 CDM Directive was to acquire 6,300 MW of CDM resources by 2025. However, OPA assumes that 600 MW of natural conservation will occur**.

Canadian and International Trends

In a review of international DSM and energy efficiency programs, ICF estimates that if the same results were achieved in Ontario, over 30,000 GWh/yr savings could be achieved through efficiency programs alone.[4] Many of these programs are described by the Pembina Institute in its 2006 report, *Successful Strategies for Energy Efficiency*.[5]

Studies of CDM Potential in Ontario

Besides comparisons with efficiency programs in other jurisdictions, several estimates have been made of CDM potential in Ontario using computer models (see Table 5). There was significant agreement among the studies on the sectors and end-uses that would provide the highest savings, as shown in Table 6.

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[4] ICF Consulting Toronto, *Electricity Demand in Ontario — Assessing the Conservation and Demand Management (CDM) Potential.* Prepared for the Ontario Power Authority (Toronto: ICF Consulting, 2005), 10.

[5] Alison Bailie et al., *Successful Strategies for Energy Efficiency: A Review of Approaches in Other Jurisdictions and Recommendations for Canada* (Drayton Valley, AB: The Pembina Institute, 2000).

Table 5: Energy Efficiency Potential as Identified by Various Studies

Source	Scope	GWh/yr	Peak MW
		Technical Potential — 2025	
ICF Consulting (OPA) 2005[6]	Energy efficiency only	36,600	8,200
		Economic Potential — 2025	
ICF Consulting (OPA) 2005[7]	Energy efficiency only	29,600	5,200
MKJA/Marbek (CGA) 2006[8]	EE and local cogen	38,250	
MKJA (OPA) 2006[9]	EE and local cogen	43,000	
Marbek (OPA) 2006[10]	Fuel switching only	28,264	2,082
		Achievable Potential — 2025	
Pembina Institute 2004[11]	EE / FS /solar water	*45,400	*8,650
	C/I sector cogeneration	*25,500	*4,290
ICF Consulting (OPA) 2005[12]	Energy efficiency only	28,500	4,700
MKJA/Marbek (GCA) 2006[13]	EE + some FS + cogen	20,000	
MKJA (OPA) 2006[14]	EE + some FS	24,000	
	Cogeneration	1,430	
Marbek (OPA) 2006[15]	Fuel switching only	11,855	551
Navigant (OPA) 2004[16]	Demand response		2,500 MW (10%)

*** To be achieved by 2020.**

Table 6: Sectors and End-Uses that Provide the Highest Savings Potential

GWh/yr	ICF (2015)[17]	MJKA (2025)[18]	Pembina[19] (2020)

[6] ICF Consulting, Toronto, 50
[7] ICF Consulting, Toronto, 50.
[8] MK Jaccard and Associates and Marbek Resource Consultants Ltd., *Demand Side Management Potential in Canada: Energy Efficiency Study*. Prepared for the Canadian Gas Association (Ottawa: Marbek Resource Consultants Ltd, 2006).
[9] MK Jaccard and Associates, *Modeling and Scenario Documentation* (Vancouver: MK Jaccard and Associates, 2006).
[10] Marbek Resource Consultants and Altech Environmental Consulting, *Potential for Fuel Switching to Reduce Ontario's Peak Electricity Demand* (Ottawa: Marbek Resource Consultants Ltd, 2006).
[11] Mark Winfield et al., *Power for the Future: Towards a Sustainable Electricity Supply for Ontario* (Drayton Valley, AB: Pembina Institute and Canadian Environmental Law Association, 2004).
[12] ICF Consulting Toronto.
[13] MK Jaccard and Associates and Marbek Resource Consultants Ltd., *Demand Side Management Potential in Canada: Energy Efficiency Study*. Prepared for the Canadian Gas Association (Ottawa: Marbek Resource Consultants Ltd, 2006).
[14] MK Jaccard and Associates, *Modeling and Scenario Documentation* (Vancouver: MK Jaccard and Associates, 2006).
[15] Marbek Resource Consultants and Altech Environmental Consulting, *Potential for Fuel Switching to Reduce Ontario's Peak Electricity Demand* (Ottawa: Marbek Resource Consultants Ltd, 2006).
[16] Navigant Consulting, *A Blueprint for Demand Response in Ontario* (Toronto: Navigant Consulting: Publisher, 2003).
[17] ICF Consulting Toronto.
[18] MK Jaccard and Associates, *Modeling and Scenario Documentation* (Vancouver: MK Jaccard and Associates, 2006).

Residential lighting	3,050	3,500	832
Residential space heating	1,650	530	2,884
Residential water heat	835	*1,200	*4,738
Commercial lighting	4,300	6,900	9,970
Commercial cooling	7,500	1,750	
Industrial drive-power	3,000	5,900	3,615
Industrial process heat	3,000	770	
Industrial HVAC	2,600	200	**91

*** includes fuel switching ** heating only**

These results show that there are considerably more cost effective CDM resources achievable than those that have been planned for by OPA. In fact OPA estimates that the "identified" cost effective and achievable potential is 8,655 MW but then plans to acquire only 60% (5,700 MW) of this. No reasons are given as to why they are not pursuing these resources beyond the 60% level in favour of more expensive supply side options. The OPA discusses the building of CDM capacity and the transformation of energy using markets, but has yet to demonstrate that it is serious.[20]

OPA identified achievable potential is shown in Table 7 and Table 8.

Table 7: OPA Identified Electricity Savings

GWh/yr Savings	2010	2015	2020	2025
Conservation	900	900	900	900
Efficiency	5,200	18,000	23,000	26,400
Demand Management	100	100	200	200
Fuel Switching (summer)	1,700 (200)	5,000 (500)	5,900 (700)	6,600 (800)
Self Generation/CHP	1,200	2,400	4,600	6,500
Total	9,000	26,400	34,500	40,600

Table 8: OPA Identified Peak Demand Reduction

Peak MW Reduction (peak load factor)	2010	2015	2020	2025
Conservation	100	100	100	100
Efficiency	949	3,437	4,585	5,337
Demand Management	874	1,527	1,802	1,964
Fuel Switching	49	166	229	285
Self Generation/CHP	190	389	704	980
Total	2,162	5,618	7,419	8,655

[19] Mark Winfield et al., *Power for the Future: Towards a Sustainable Electricity Supply for Ontario* (Drayton Valley, AB: Pembina Institute and Canadian Environmental Law Association, 2004).
[20] Pembina Institute, *OPA CDM Progress Report* (Drayton Valley, AB: The Pembina Institute, in preparation).

An approximate breakdown of the identified capacity of self generation and CHP can be estimated from figures contained in *IPSP Discussion Paper No. 3* — these estimations are shown in Table 9 below. It is not clear why the two totals provided by OPA for self generation (in Table 7 above, and in Table 9 below) do not match.

Table 9: OPA Identified Self Generation / CHP Potential

MW Installed	2010	2015	2020	2025
Biomass (agricultural < 100 kW)	11	24	52	52
Wind (small residential < 100 kW)	50	280	360	360
Solar (residential 1–3 kW)	30	60	90	120
Fuel Cell	0	0	0	0
CHP/Micro-turbine (< 1 MW)	32	96	161	231
Total	123	450	663	763

Scenario Assumptions

Other jurisdictions that have been successful in achieving high levels of savings through CDM programming tend to take a much more comprehensive approach than does Ontario, and have implemented a much broader series of initiatives. Ontario has the opportunity to follow the precedent of these other jurisdictions, transforming the way energy is used in the Province and achieving much higher cost effective electricity savings and peak demand reductions than is currently the case. The assumptions presented below for Scenarios 3 and 4 realize much higher CDM savings levels than those accounted for by OPA in its preliminary plan. We believe these are realistic, achievable and much more cost effective for the people of Ontario than those outlined in the current plan.

Scenario 3: Meeting Future Demand without New Nuclear Power

- Full OPA identified conservation potential (i.e., not discounted by 40%) for energy efficiency, fuel switching and demand management
- Higher estimates for CHP/micro-turbines and on-site solar PV
- OPA planned estimates for other self generation from on-site renewable energy

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- CDM, including fuel switching, self generation and CHP, increased to levels identified as cost effective and in line with achievements in other jurisdictions; solar PV deployed at rates and to levels comparable to other jurisdictions with aggressive solar policies
- The same as Scenario 2 for demand management and other self generation from on-site renewable energy

Each category of CDM is described below:

Energy Efficiency

Studies of energy efficiency programs in other jurisdictions, and those that use modeling, show that there is at least 35,000 GWh/yr (7,500 MW of peak demand reduction) of cost effective energy efficiency savings available in Ontario. The Pembina Institute study, which includes measures such as solar water heating and assumes an aggressive policy regime, estimates that 45,000 GWh/yr savings could be achieved through cost effective efficiency and fuel switching.

The Ontario Government recently announced a series of programs that could impact deployment of solar water heating in the province. Included in recent announcements are the following:

- A Retail Sales Tax exemption on all solar systems and components is available to homeowners, owners of multi-unit residential buildings and new home builders.[21]
- Homeowner Retrofit Rebates of up to $500 toward the installation of solar domestic water systems are offered as part of Homeowner Retrofits.[22]
- A zero-interest residential renewable energy loan program is being piloted by the government through two selected energy retailers (Hydro One and Enersource Hydro Mississauga). Up to 350,000 zero-interest loans will be provided to customers of these retailers, and solar thermal systems will be eligible.[23]

OPA has identified 26,000 GWh/yr savings (5,300 MW) that could be achieved by 2025 with quite modest policies, but plan to acquire only 60% of this, or 17,400 GWh/yr (3,514 MW). Over a 20-year time frame, when there is ample time to develop a CDM program infrastructure second to none, there is no reason why at least the full achievable potential for efficiency identified by OPA cannot be realized. With even more comprehensive policies implemented as part of an overall market transformation strategy by OPA and the Provincial Government, the full 35,000 GWh/y of cost effective potential could be achieved.

In our two scenarios, which include solar water heating and the use of ground source heat pumps but not fuel switching, we assume the following by 2025:

Scenario 3: Meeting Future Demand without New Nuclear Power

- 26,000 GWh/yr (5,300 MW) Energy Efficiency

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- 35,000 GWh/yr (7,500 MW) Energy Efficiency

Fuel Switching

[21] Ontario Ministry of Revenue, Refunds and Rebates, www.rev.gov.on.ca/english/refund/sesr (accessed June 26, 2007).
[22] Ontario Ministry of Energy, McGuinty Government Home Energy Retrofit and Solar Power Initiatives. www.energy.gov.on.ca/index.cfm?fuseaction=english.news&back=yes&news_id=156&backgrounder_id=122 (accessed June 26, 2007).
[23] Ibid.

Fuel switching refers to shifts in end-uses like water heating and cooking from electricity to other fuels (mostly natural gas) in response to incentives.

Only one estimate is available with respect to the achievable potential of fuel switching only. Marbek's study[24] indicates by 2025 a relatively large contribution to savings of over 11,000 GWh/yr, but a relatively small contribution to summer peak demand reduction of only 511 MW because many of the measures have higher winter impacts. The OPA uses the Marbek results as the basis for its assumptions but down rates Marbek's estimates of identified potential summer peak reduction to only 285 MW by 2025. The OPA plans to only acquire only 60% of this (i.e., 4,400 GWh/yr and 206 MW of summer peak reduction).

In our scenarios we assume the following by 2025:

<u>Scenario 3: Meeting Future Demand without New Nuclear Power</u>

- 6,600 GWh/yr savings (800 in summer) and 285 MW peak demand reduction equal to the full potential identified by OPA

<u>Scenario 4: An Electric Power Future Based Primarily on Renewable Sources</u>

- 10,000 GWh/yr (1,200 in summer) and 500 MW peak reduction based on the Marbek achievable potential study

The sum of 35,000 GWh/yr for efficiency and 10,000 GWh/yr for fuel switching for Scenario 4 is supported by the Pembina Institute *Power for the Future*[25] results that show a combined fuel switching and efficiency potential of 45,000 GWh/yr savings and 8,650 MW of peak demand reduction.

Fuel switching to natural gas does have the potential to increase GHG emissions over business as usual, but this increase can be limited or eliminated through gas demand side management programs targeting water and space heating. The Pembina Institute *Power for the Future* study showed that there was a net increase in natural gas use from fuel switching only in the commercial sector. However, the majority of this increase was due to the use of small scale micro-turbine cogeneration, which in the WADE model used in this study is estimated separately (see below). It can be assumed therefore that there would be no net increase in gas use over business as usual from fuel switching alone, and therefore no net increase in GHG emissions.

<u>Demand Management (Demand Response, TOU Pricing and Conservation)</u>

Demand Management encompasses several aspects, including:

[24] Marbek Resource Consultants and Altech Environmental Consulting, iii.
[25] Winfield et al.

- Conservation — changes in “behaviour” or reductions in the demand for energy services as a result of incentives or information, or as a result of voluntary actions (natural conservation[26])
- Demand response — shifts in peak demand in response to incentives
- Time of use (TOU) pricing — shifts in energy use patterns in response to pricing

A report by Navigant[27] suggests that a 10% reduction in peak demand can be achieved with TOU pricing and other measures. This is equal to about 2,500 MW assuming a 2025 reduced demand of 25,000 MW. This is greater than the current OPA planned MW reductions for demand response, TOU pricing and conservation combined.

Scenario 3: Meeting Future Demand without New Nuclear Power

- 2,064 MW reduction in peak demand by 2025 (including conservation provided savings of 100 MW) based on identified potential by OPA

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- 2,500 MW reduction in peak demand by 2027 for the combined three categories by 2025 for both scenarios based on Navigant estimates

CDM Cogeneration (micro-turbines/fuel cells)

Cogeneration refers to use of small scale CHP systems on the customer side of the meter with or without excess power being provided to the grid (e.g., micro-turbines or fuel cells)

The Pembina Institute *Power for the Future* study estimated that there is up to 25,500 GWh/yr cost effective potential achievable (4,300 MW) from the use of micro-turbines and other CHP systems in the commercial/institutional (C/I) sector.[28] Other studies such as the MK Jaccard and Associates report estimate a much lower potential of only 1,400 GWh/yr (235 MW).[29] OPA plans to acquire 636 MW (4,200 GWh/yr) by 2025 for all self generation including on-site renewable energy, of which about 450 MW appears to be from CHP as the contribution of small wind and hydro would be expected to be small.

Micro-turbines are an emerging opportunity and the use of a modest standing offer for power generated through CHP in the C/I sector would result in much more of the cost effective potential being realized. Ontario has recognized this by announcing a new standard offer for small cogeneration systems on June 14, 2007.[30] This of course was not

[26] Natural conservation is normally taken into account in a load forecast and not included in CDM or DSM resources. OPA take this approach.
[27] Navigant Consulting, 63.
[28] Winfield et al.
[29] MK Jaccard and Associates.
[30] The Ontario Government has instituted a Clean Energy Standard Offer Program (CESOP) that will benefit distributed small generators. Small generators (10 MW or less) will be able to access 20-year fixed contracts. Eligible project types include natural gas fuel-fired combined heat and power, by-product fuel-fired generation, and surplus energy generation (e.g., electricity from waste heat). Ontario Ministry of

taken into account in the OPA acquisition plan and therefore should result in higher contributions.

In our two scenarios we assume the following for 2025:

Scenario 3: Meeting Future Demand without New Nuclear Power

- 750 MW (6,500 GWh/yr), which is slightly greater than the OPA identified potential. This would imply good uptake of the Clean Energy Standard Offer Program (CESOP).

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- Same as Scenario 3.

See natural gas supply section (below) for estimates of industrial cogeneration, which is assumed to be outside of the CDM resource category.

CDM On-Site Renewable Power Sources

On-site renewable energy systems include the production of power for electricity using end-uses and sale to the grid from small scale solar, wind, micro-hydro and wind systems operated by the customer

OPA includes on-site renewable power sources in its self generation category. In our scenarios we have included separate distributed generation categories for micro-turbine CHP and roof-mounted solar photovoltaic (PV) (residential and commercial), leaving the remaining on-site renewable energy (RE) (small scale wind < 100 kW) as close as we can estimate to the OPA assumptions for 2025.

Scenario 3: Meeting Future Demand without New Nuclear Power

- Micro-turbine CHP – 750 MW (see above)
- Roof-mounted solar PV*: 1,500 MW – peak effectiveness factor = 100% and load factor = 11%
- Other on-site RE < 100 kW): 170 MW

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- Micro-turbine CHP: 750 MW (see above)
- Roof-mounted solar PV*: 3,000 MW with storage – effectiveness factor = 100% and load factor = 11%.
- Other on-site RE < 100 kW: 170 MW

*See solar PV section below for supporting evidence of these assumptions for roof-mounted solar PV system deployment rates.

Energy, McGuinty Government Announces North America's First Clean Energy Standard Offer Program, www.energy.gov.on.ca/index.cfm?fuseaction=english.news&body=yes&news_id=154, (accessed June 26, 2007).

Solar water heating systems are treated as an energy efficiency/conservation measure as they reduce the demand for electricity from the utility (see CDM energy efficiency category above).

Costs

OPA estimates the total resource cost of CDM resources in *IPSP Discussion Paper No. 3*.[31] The total resource cost is the sum of all costs whether paid by the user or OPA as part of CDM programs. They include the incremental cost of the efficient technology or measure over the cost of standard efficiency products, costs of alternative fuels, and costs of program delivery and administration.

The total resource cost of delivering the planned CDM potential is estimated at $4.5 billion. These programs would provide savings at 4.72 cents/kWh, and provide a peak demand reduction of 5,400 MW, or $833 per kW. The OPA does not break down the costs among the various CDM components — efficiency, fuel switching, demand response and so on.

The OPA cost analysis is applied to all identified CDM potential covered in *IPSP Discussion Paper No. 3,* so it was assumed that additional CDM resources beyond the planned 5,400 MW in Scenarios 3 and 4 could be acquired at the same $833/kW.

The planned OPA CDM resources avoid 5,900 MW of new generation resources, and therefore the avoided cost is $762 per MW. This compares to capital costs for generation technologies of $841 for natural gas Combined Cycle Gas Turbine (CCGT), $1,959 for wind, $2,666 for hydro, $2,845 to $3,400 for nuclear and $5,613 (decreasing over 20 years to $3,052) for solar. This illustrates the value of maximizing CDM potential beyond the OPA preliminary plan as shown in Scenarios 3 and 4.

[31] Ontario Power Authority, *IPSP Discussion Paper No 3*: *Conservation and Demand Management, Revised*, 32 and 91.

Natural Gas Including Cogeneration / Combined Heat and Power

Classification

OPA includes the following categories for power production from natural gas:

- Single cycle gas turbines used only for peaking
- Combined cycle gas turbines used for base load and peaking
- Industrial cogeneration (> 1 MW)
- Small scale self generation using micro-turbines or fuel cells (< 1 MW)

The last category is treated as a CDM resource and is covered in the previous section.

In our analysis we divide industrial cogeneration into two categories:
- Facilities > 50 MW that are treated as central generation
- Facilities < 50 MW that are treated as distributed generation

We also add two additional categories:
- Cogeneration facilities that use high temperature waste heat as a source for power
- Gas engine generators located at substations and institutional back up power generators — both used to provide distributed generation at peak

OPA Supply Mix Assumptions

The following Table 10 shows the additions assumed in the OPA preliminary plan between 2007 and 2027.

Table 10: Capacity Additions for Natural Gas by 2027

Type	MW
Single Cycle	743
Combined Cycle	4,866
Industrial Cogeneration < 50 MW	0
Industrial Cogeneration > 50 MW	414
Waste Heat Generation	0
Total	6,023

Estimates of Industrial Cogeneration Potential in Ontario

Several studies have attempted to identify the industrial cogeneration potential in Ontario. However, the “boundaries” of the studies are often not well defined, so it may not be clear what is being estimated in the study. There are also many anecdotal references to Ontario’s cogeneration potential as a large untapped resource. There certainly appears to be more capacity available than the 414 MW currently under development.

Technical potential studies indicate industrial cogeneration potential to be in the 13,000 to 15,000 MW range.[32, 33] One study estimates the economic potential to be in the 6,000 MW range.[34] Studies that model achievable potential, on the other hand, appear to estimate very low values with three studies estimating values to be less than 1,000 MW. This could be due to the fact that energy-economy models like Canadian Integrated Modelling System (CIMS) do not give value to the heat produced from a CHP and they base revenue on the retail price paid for power (net metering) and not the avoided cost of power.

Producing power from high temperature waste heat takes three forms: recovering exhaust heat, burning a flare gas or other opportunity fuel, and recovering pressure drop energy from gas and steam flows. The U.S. has found 64,000 MW of potential for recycling industrial waste energy and has 10,000 MW in service. Since Ontario has 4% of the peak load of the U.S., it is reasonable to multiply U.S. numbers by 4% to estimate Ontario numbers. On this basis, Ontario has a potential for 2,500 MW of waste energy recycling. Waste heat from just one source type — gas pipeline compressors — has been estimated to have the potential to produce 100 MW of power.[35]

Scenario Assumptions

Natural gas cogeneration has a smaller GHG emissions footprint per kilowatt hour than combined cycle generation since the emissions associated with the use of heat are assigned to this end-use. We have therefore chosen to displace combined cycle with cogeneration in Scenarios 3 and 4 rather than adding to OPA preliminary plan assumptions. As well as reducing emissions, this also avoids putting additional pressure on natural gas supply in Ontario, over and above business as usual.

Producing power from waste heat does not produce additional emissions. A conservative 1,250 MW of new capacity from this source was assumed for both scenarios, also displacing natural gas combined cycle capacity.

From peaking units at substations and the use of institutional back up power units, 100 MW was assumed in both scenarios to help reduce the line losses at peak times, and therefore peaking natural gas capacity.

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[32] Technical potential = 15,138 MW. Hagler Bailly Canada, AGRA Monenco and Lourie and Love Environmental Management Consulting *Potential for Cogeneration in Canada.* Prepared for Ontario Ministry of Energy Science and Technology (Toronto: Hagler Bailly Canada, 2000). Cited in Catherine Strickland and John Nyboer, *Cogeneration Potential in Canada.* Prepared for Natural Resources Canada (Vancouver: MK Jaccard and Associates, 2002), 30.

[33] Technical potential = 13,735 MW. Catherine Strickland and John Nyboer, *Cogeneration Potential in Canada.* Prepared for Natural Resources Canada (Vancouver: MK Jaccard and Associates, 2002), 30.

[34] Hagler Bailley Canada, 30.

[35] Tom Casten, Chair of Recycled Energy Development LLC, Energy Recycling, personal communication, May 21, 2007

Additional combined cycle and peaking natural gas capacity would be displaced in favour of renewable power sources. In Scenario 4, the Lennox oil/gas facility would also be shut down.

<u>Scenario 3: Meeting Future Demand without New Nuclear Power</u>

- New capacity of 1,000 MW industrial cogeneration (> 50 MW) would be added
- 1,250 MW of capacity from waste energy recycling also would be added
- 100 MW of substation peak or institutional backup generation would be made available
- 2,700 MW of combined cycle generation would not be built
- 350 MW of new peaking gas plants would not be built

<u>Scenario 4: An Electric Power Future Based Primarily on Renewable Sources</u>

- New capacity of 1,000 MW industrial cogeneration (> 50 MW) would be added
- 1,250 MW of capacity from waste energy recycling also would be added
- 100 MW of substation peak or institutional backup generation would be made available
- 3,900 MW of combined cycle generation would not be built
- 350 MW of new peaking gas plants would not be built
- The Lennox oil/gas generating facility would be shut down

Costs

The cost per kilowatt of installed industrial cogeneration used by OPA in its preliminary plan was used for all new cogeneration capacity and waste heat power generation in Scenarios 3 and 4.

Hydroelectricity (Waterpower) and Pumped Storage

Classification

Hydrolelectricity is perhaps the most predictable of all renewable energy sources. Such facilities are very efficient and generally have low maintenance costs and long lifespans.

The following terms are defined for clarity:

> *New Hydro:* waterpower development at previously undeveloped sites; also called "greenfield."
>
> *Refurbished/Upgrade:* any type of expansion or upgrade to existing hydro facilities and sites.
>
> *Pumped Generation Storage (PGS):* pumped water storage used to store off peak power produced by other generating sources that is then used to generate power through existing or new hydroelectric facilities at the storage site.

The OPA also refers to the following:

> *Near-Term Potential:* all developments, both new hydro facilities and refurbishments/upgrades, to be completed in the timeframe before 2015.
>
> *Future Potential:* all developments to be completed between 2015 and 2025. Some of the potential listed in this category is currently subject to policy commitments.
>
> *Constrained:* development at sites within parks, protected areas, areas subject to previous commitments and agreements, or otherwise restricted from development without changes to these commitments.

OPA Assumptions

There is currently over 7,700 MW of installed renewable waterpower resource capacity in Ontario.[36] The OPA plans to acquire new hydroelectric capacity of 2,283 MW by 2025 (and 2,326 MW by 2027).[37] This includes both refurbished and new capacity, as well as development of new sites in areas currently constrained.

OPA's December 2005 *Supply Mix Advice Report* recommended 1,447 MW of new hydroelectric potential in Ontario, including 500 MW of pumped storage, 385 MW of upgrades and expansions, and 562 MW at new sites. However, this 1,447 MW did not

[36] Ontario Power Authority, *IPSP Discussion Paper No 4: Supply Resources* (Toronto: OPA, 2006), 22.
[37] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating the Elements* (Toronto: OPA, 2006), 25.

include sites subject to commitments later included in the IPSP discussion papers as future potential.

The OPA, in *IPSP Discussion Paper No. 7,* lists 43 MW of new hydroelectric capacity as "committed" through procurements (but that has not yet entered service), while another 2,283 MW of new hydroelectric capacity is projected to be installed by 2025.[38] The 2,283 MW includes rehabilitation projects, efficiency upgrades, the Niagara tunnel and redevelopments such as the lower Mattagami River in the near term.

Separately, the OPA proposes the development of 1,000 MW of new pumped generation storage (PGS).[39]

OPA Estimates of Potential

In December 2005, the OPA Supply Mix Advice report outlined the potential for hydropower development in Ontario, including the potential for upgrading existing facilities' pumped storage.[40] The OPA, at this time, found that there was technical capability for 7,521 MW of new hydroelectricity, though a large portion was constrained by geography or previous land use agreements. For example, 1,501 MW was within parks, and another 4,573 MW was subject to previous commitments.[41]

In their 2006 *IPSP Discussion Paper No. 4*, the OPA outlines

- 728 MW near-term potential, generating 3,557 GWh/year
- 2,296 MW future potential, generating 7,009 GWh/year
- 1,076 MW future potential (constrained), generating 3,847 GWh/year

The near-term potential identified includes redevelopments, upgrades and a large project (450 MW) on the Mattagami River. Two Niagara area developments (Sir Adam Beck and the Niagara Tunnel) are also included in this category.[42]

The future potential category includes large developments on the Abitibi and Albany Rivers (711 MW and 860 MW, respectively), as well developments on the Mattagami and Moose Rivers (both greater than 130 MW).[43] Many of these large developments would infringe on existing policy restrictions, but are nonetheless included in the OPA IPSP Discussion Paper No. 4.

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[38] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating the Elements* (Toronto, OPA, 2006), 25.
[39] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating the Elements* (Toronto, OPA, 2006), 175.
[40] Ontario Power Authority, *Supply Mix Advice Report* (Toronto: OPA, 2005), 98.
[41] Commitments include the Northern Rivers Commitment and the Moose River Basin Commitment. Ontario Power Authority, *Supply Mix Advice Report* (Toronto: OPA, 2005), 97
[42] The 450 MW Mattagami River includes redevelopment of the existing Smoky Falls site, as well as new developments. Ontario Power Authority, *IPSP Discussion Paper No 4: Supply Resources,* 26.
[43] Ontario Power Authority. *IPSP Discussion Paper No 4: Supply Resources,* 27.

The 1,076 MW of constrained future potential consists largely of sites situated in designed parks and protected areas.

In *IPSP Discussion Paper No. 4*, three primary candidate sites for pumped storage are identified, each contributing 200 MW, 400 MW and 500 MW respectively to the peak capacity of the grid (total 1,100 MW).[44] Each of these sites have been studied and reviewed by the OPA at the pre-feasibility level; the OPA concedes that this work does not preclude the identification and development of further sites.

Stakeholder Views on Technical and Practical Development Potential

The technical potential for hydroelectricity is substantially larger than the development that would be foreseeable under most scenarios.

To illustrate the variety of reported numbers for the technical potential of hydro in Ontario, the David Suzuki Foundation presented the following table:[45]

Table 11: Various Estimates of Hydroelectric Potential in Ontario

Source	Estimated Potential (MW)
Ministry of Natural Resources	6,046
International Energy Agency (small hydro only)	2,193
Ontario Hydro (1990)	12,400
Canadian Hydro Association	5,000
Ontario Waterpower Association	1,200–2,000

The Ontario Hydro research, conducted in 1990, identified a theoretical capacity of 19,900 MW in the province; the available potential in the above table (12,400 MW) was determined by discounting the existing supply.

The Canadian Hydro Association (CHA) commissioned a study, completed by EEM Consultants (Quebec), that identified 10,270 MW of hydroelectric technical potential in Ontario.

The Ontario Waterpower Association (OWA) states on their website that there is currently 1,350 MW of potential that could be realized from redevelopment of existing sites,[46] with potential as high as 1,700 MW.[47]

These numbers were re-iterated in the Electricity Conservation and Supply Task Force 2004 report. Combining the redevelopment/upgrading potential with new development,

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[44] Ibid.
[45] David Suzuki Foundation, *Smart Generation: Powering Ontario with Renewable Energy* (Vancouver: David Suzuki Foundation, 2004), 38.
[46] Ontario Waterpower Association, Title of page or text, www.owa.ca/about.html, (Accessed June 14, 2007).
[47] Mark Winfield, *The Ontario Power Authority Supply Mix Report: A Review and Response* (Drayton Valley, AB: The Pembina Institute, 2006)

the task force found that the potential for additional waterpower capacity is 1,200–4,000 MW, with the caveat that amount actually developed depends heavily on siting and permitting processes, as well as prices.[48] The breakdown of these numbers was tabulated by the Pembina Institute.[49]

Table 12: Ontario Waterpower Potential[50]

Source	Capacity (MW)	Energy (GWh)
Known Developable Sites	200 to 300	1,000 to 1,500
Re-developments at Existing Sites	600 to 1,300 (equivalent)	2,000 to 3,000
Upgrades, Re-powering and Efficiency Improvements	200 to 400	1,000 to 1,5000
Additional Development Potential	200 to 2,000	1,000 to 10,000
TOTAL	1,200 to 4,000	5,000 to 16,000

The OWA, in a letter to the OPA dated December 15, 2006, suggests that sites recognized by the OPA as constrained — and therefore discounted for planning purposes — should be seen as future potential. The OWA notes that

> *. . . proposed legislation has provision for de-regulating portions of parks and protected areas to allow for such [hydroelectric] developments. . . . [T]here are already several permitted operating facilities within parks and protected areas.*

and,

> *. . . legislation specifically allows waterpower development within protected areas to serve First Nations socio-economic objectives.*

The OWA concludes that "at the very least" many of the hydroelectric developments discounted by the OPA should be included in the long-term potential in the first IPSP. Including hydroelectric potential that is currently constrained could add 6,073 MW of additional capacity.[51]

In October 2005, Hatch Acres completed a comprehensive report for the OWA and Ontario Ministry of Natural Resources.[52] The report concluded there was over 20,000

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[48] Electricity Conservation and Supply Task Force, *Tough Choices: Addressing Ontario's Power Needs*. Final Report to the Minister (Toronto: Electricity Conservation and Supply Task Force, 2004). 50.
[49] Winfield et al. 27.
[50] Winfield et al. 27.
[51] Includes potential within parks (1,501 MW) and potential limited by the Northern Rivers Commitment and Moose River Basin Commitment. Ontario Power Authority, *Supply Mix Advice Report*.
[52] Hatch Acres, *Evaluation and Assessment of Ontario's Waterpower Potential*. Prepared for Ontario Waterpower Association and Ontario Ministry of Natural Resources (Toronto: Hatch Acres The Energy Company, 2005).

MW of hydroelectric potential remaining in the province, including over 6,600 MW designated as "probable and/or committed" or "practical" (the latter figure includes nearly 1,235 MW of pumped storage). The report identifies only 5,368 MW of new capacity (not including storage).[53]

The report also discusses the larger development potential in northern Ontario. The Lower Albany is reported to have 2,300 MW of capacity, while other large sites on the Abitibi, Moose and Missinaibi Rivers are also considered practical. Together, these rivers could make up 3,500 MW of new capacity in Ontario. However, in addition to requiring investments in transmission capacity, these rivers are within existing policy areas and as such any development would require significant involvement from stakeholders (including First Nations) and changes in provincial policy.[54]

The 1,235 MW of probable or practical potential for pumped water storage includes the Steep Rock Mine site (four phases, each 250 MW for a total of 1,000 MW peaking capacity), and the Fourbass Lake site (providing 235 MW peaking capacity).

The following summarizes the breakdown of potential as identified in the Hatch report:

- Greenfield (probable and committed, or practical)
    - < 10 MW — total 300 MW (70 sites)
    - 10–100 MW — total 700 MW (26 sites)
    - > 100 MW — total 3,500 MW (only 14 sites)
- Redevelopment (expansion of existing sites): 440 MW
- Efficiency improvements (existing sites): 100 MW
- New powerhouses at existing dams: 180 MW
- Pumped storage: 1,235 MW
- Total within policy areas:[55] 3,917 MW
- Total within parks and protected areas: 1,000 MW

The Hatch report notes that "sites located within protected lands were not automatically placed in 'remaining sites' category."[56]

The transmission constraints outlined in the table below were used in the Hatch report to evaluate potential sites (anything outside these ranges is not included as probable, committed or practical):[57]

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[53] The report does not count within the 5,368 MW of those sites with less than three metres of head, those outside prescribed distances to transmission lines, or those deemed on preliminary analysis to be of a cost greater than $100–$120/MWh. These sites may be viable and economic in the future as economics, infrastructure and policy change.

[54] The policy areas, briefly described, are Moose River Basin ("north of Highway 11, no development beyond the Mattagami River extensions until such a time as a co-planning process has been developed, agreed to and applied by the affected First Nations") and Northern Rivers ("no development of individual sites >25 MW; sites <25 MW would be considered if proposed by or consented to by the potentially affected First Nations.") Hatch Acres, 17.

[55] Hatch Acres, 22.

[56] Hatch Acres, 16.

[57] Hatch Acres, 16.

Table 13: Transmission Constraints on Hydroelectric Development

Size of Project	Limit of Transmission Distance for Economic Feasibility
1 to 5 MW	5 km to 10 km
5 to 10 MW	10 km to 20 km
10 to 20 MW	20 km to 30 km
20 to 50 MW	30 km to 40 km
50 to 100 MW	40 km to 50 km
> 100 MW	(not a factor)

Pembina Institute and WWF Scenarios

There is a need to balance ecosystem needs and the protection of wild areas with the imperative of developing a clean, sustainable electricity supply in Ontario. We have therefore assumed that there will be no hydro development inside parks and protected areas.

Transmission capacity is another consideration in planning. A significant portion of the potential for hydroelectric development in Ontario is in northeastern and northwestern Ontario, whereas the growth in demand is concentrated in the Greater Toronto Area (GTA) and southern Ontario. Transmission infrastructure may need to be developed hand-in-hand with new hydroelectric developments in the north.

In both Scenario 3 (Soft Green) and Scenario 4 (Deep Green), we assume that 3,025 MW of capacity is added to the existing provincial capacity. This would increase the provincial hydroelectric capacity to 10,793 MW in 2027. This figure is 699 MW greater than the OPA figure primarily because we have included large hydroelectric development on the Albany River in northern Ontario. We recognize and appreciate that this development can only proceed if proposed or consented to by the affected First Nations.[58]

A capacity factor of 59.3% is assumed for new and refurbished hydro and 7% for pumped storage. An effective peak capacity of 71% of installed capacity is assumed for both new/refurbished hydro and storage in both scenarios.

Scenario 3: Meeting Future Demand without New Nuclear Power

- Total 3,025 MW additional capacity by way of new and refurbished plants. This is nearly 700 MW over and above OPA plans, and would result in a total of 10,793 MW by 2027
- 1,000 MW of pumped storage would be added

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- Additional capacity — same as Scenario 3
- 1,100 MW of pumped storage would be added

[58] If the large projects on the Albany River do not proceed, additional biomass energy could be added to the electricity grid in its place.

Costs

The same cost of $2,666 per installed megawatt of hydro used by OPA in its preliminary plan was used for all additional new and refurbished capacity added in Scenarios 3 and 4. The cost of pumped storage is assumed to be the same as for hydro facilities.

Interconnections for Imported Hydro-Electricity

Classification

The Ontario power system is connected to the transmission systems of Manitoba, Minnesota, Quebec, Michigan and New York. A total of 16 interconnection circuits provide simultaneous connection between Ontario and the systems in these other locations. Eleven interconnections (including all those with Quebec) are operated non-parallel. With these connections, a generation or load area is electrically disconnected from one system before it is connected to the other system. In summer periods, the Ontario interconnections provide a combined import capability of 2,800–4,700 MW, and a combined export capability of 3,700–5,300 MW. Winter import and export capabilities are typically higher due to higher line capabilities in colder weather. Import and export capabilities vary in actual operations due to a number of factors. Connections importing exclusively hydroelectric power are those with Manitoba (331–343 MW)[59] and Quebec (1,550 MW)[60]

The links with Manitoba and Quebec are currently being added to with a 400 MW connection with Manitoba and a 1,250 MW DC connection with Quebec.

The total capacity for importing hydroelectric power will therefore be as follows:

Manitoba: 730 MW
Quebec: 2,800 MW
Total: 3,530 MW

There is potential for a further 1,250 MW of hydropower to be imported from new facilities in Manitoba, although this would require building a new transmission line from northern Manitoba to the Sudbury area.[61]

OPA Supply Mix Assumptions

According to the IPSP, Ontario will become a net importer of 800 MW of power in 2007. This will rise to 900 MW in 2009 and then drop to 500 MW for the remainder of the plan period until 2027.[62] It is not clear where these imports will come from.

The IPSP also includes the import of 1,500 MW of dedicated hydropower, presumably from Manitoba and Quebec, but only between 2016 and 2019.

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[59] Ontario Power Authority, *IPSP Discussion Paper No 5: Transmission* (Toronto: OPA, 2006), 14
[60] Ibid., 66
[61] Ibid., 19.
[62] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating the Elements* (Toronto: OPA, 2006), 172.

The OPA preliminary plan assumes that the province's augmented transmission system will handle these imports effectively.

Technical Potential

As noted above, the maximum potential use of the Manitoba/Quebec connections (existing and under development) for the import of hydropower is 3,500 MW.

An additional 1,250 MW of capacity could come from new hydro facilities in Manitoba, but would need to include additional transmission capacity in northern Ontario. Given the recent decision to develop new hydro potential in James Bay, a second 1,250 MW DC connection with Quebec is also possible. Such a connection would also likely require additional transmission capacity in Eastern Ontario. However, optimization of the grid around a higher proportion of distributed sources such as wind, CHP and solar might free up some existing capacity.

Scenario Assumptions

<u>Scenario 3: Meeting Future Demand without New Nuclear Power</u>

- The two connections with Manitoba (800 MW) and Quebec (2,800 MW) would be used to their fullest extent throughout the plan period to import hydroelectric power

<u>Scenario 4: An Electric Power Future Based Primarily on Renewable Sources</u>

- Same as Scenario 3

Costs

The costs of acquiring power through the existing connections with Quebec are assumed to be those estimated by OPA (i.e., 8.1 cents/kWh).

Large Scale Wind Power Generation and Power Storage

Classification

- *Large Scale Wind:* All development greater than installed capacity of 10 MW.
- *Distributed Generation:* Wind generators producing 100 kW to 10 MW.[63]
- *On-Site Self Generation*: Wind development producing less than 100 kW. These systems are assumed by OPA to be part of CDM (see CDM section).

OPA Supply Mix and IPSP Assumptions for Large Scale Wind

OPA *IPSP Discussion Paper No. 7* indicates that current large scale wind capacity in Ontario is 305 MW with another 955 MW committed but not yet in service.[64] The preliminary plan would see an additional 3,764 MW of wind added by 2027 (for a total of 5,024 MW). The plan does not include new wind capacity after 2019. An average capacity factor of 27% is assumed. Effective capacity at summer peak is assumed to be 17% of installed capacity.

OPA Assessment of Potential

A report prepared for OPA by Helimax Energy Inc. in 2005 looked at projects over 10 MW in Ontario.[65] This report identified a technical potential of 628,067 MW, capable of producing 1,711 terawatts (TWh) of electricity, across the entire province. The report also identified another 46,827 MW (128 TWh) of offshore potential in the Great Lakes. Only a fraction of the total potential is south of the 50th parallel, close to the major population and energy-using sectors in Ontario, though a significant amount of this power is close to existing transmission and distribution networks.

The researchers selected and ranked 60 key sites with appropriate geographical distribution. These 60 sites would accommodate 8,191 MW at capacity factors averaging 29%, resulting in an estimated production of 20,827 gigawatt hours (GWh)/year.

For projects ranging from 50 MW to 200 MW, the anticipated timeframe for development ranged from 30 to 36 months. The installed cost for projects ranging from 20 MW to 200 MW was a high of $2,424/kW to a low of $1,959/kW for projects at the larger end of the development scale.

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[63] The OPA considers all wind development in the 100 kW to 10 MW range as distributed generation. A variety of other technologies are included together under distributed generation and on-site self generation including micro-turbines, combined heat and power (CHP) and fuel cells.

[64] According to the Canadian Wind Energy Association (CanWEA), there is currently 415 MW of installed wind capacity in Ontario, with another 955 MW proposed or under contract to come online in 2007/2008. CanWEA, Title of page or text, www.canwea.ca/Map_of_Installations.cfm (accessed June 15, 2007)

[65] Helimax Energy for OPA, *Analysis of Wind Power in Ontario* (Montreal: Helimax Energy Inc, 2005)

The OPA also referenced a study by AWS Truewind that outlined the capacity for wind development by geographical area.[66] This study found that there was potential for 8,727 MW of capacity, generating over 21,000 MWh/year.

A General Electric (GE) wind report examined grid integration issues.[67] While the overall capacity factor for wind in the province is just below 30%, the GE study found that capacity varies from an average of 17% at the summer peak to 38–42% in the winter. The GE study also addressed low-load/high-wind scenarios but suggested several ways to mitigate problems that may arise, including i) shedding wind or use controls to provide some flexibility, ii) modifying load or use storage, such as pumped water storage, iii) exporting wind power, and iv) using a flexible generation mix during low-load periods.

During the CanWEA Municipal Issues and Wind Conference (2007), the Independent Electricity System Operator (IESO) confirmed that wind power currently operating in Ontario is performing at levels in line with estimates and studies previously completed. In fact, the IESO stated that with one year experience operating 400 MW of wind, they found the following:[68]

- Overall monthly average capacity factor is 28%
- Highest monthly capacity factor is 43% (February 2007)
- Lowest monthly capacity factor is 13% (August 2006)
- Average capacity during summer peak hours is 42%.

The IESO numbers confirm the validity of the estimations used in our scenarios.

Finally, the GE paper assessed the degree of modification to the grid and regulatory regime for scenarios where up to 10,000 MW of wind was added to the Ontario power system. GE concluded that

- "in all scenarios, the incremental regulation needed to maintain current operational performance is small; this additional regulation could be handled within the current system operation framework"

and

- "for all wind scenarios, the hourly and multi-hourly incremental variability due to wind is small and not considered a major operational hurdle."

OPA *IPSP Discussion Paper No. 7* restates the conclusion of *IPSP Discussion Paper No. 4* that 5,000 MW is a "prudent" level of development over the planning period (this includes currently installed, committed and new). The report concludes that above and beyond the 4,000 MW feasible in southern Ontario, sites in northwestern and northeastern Ontario must be considered. These sites are further from large load centres, but their development will improve the geographical distribution of wind development in

[66] AWS Truewind, www.awstruewind.com (accessed June 14, 2007).
[67] General Electric Wind, *Ontario Wind Integration Study*. Prepared for Ontario Power Authority, IESO and CanWEA (City: Publisher, 2006).
[68] Tench, D. Independent Electricity System Operator (IESO). Wind Integration in Ontario. Presentation to Canadian Wind Energy Association Municipal Issues and Wind Conference. 2007.

the province. The OPA includes a limited number of northern Ontario sites in its planning. However, northern development would take place later than southern Ontario (after 2019) because north–south transmission capacity needs to be increased.[69] OPA does not include any offshore sites in its planning.

Stakeholder Views on Near-Term Potential

In their *Smart Generation* report, the David Suzuki Foundation suggested that 8,000 MW was achievable by 2012,[70] though CanWEA has targeted 6,000 MW by 2015, and "significantly more by 2025."[71] More recently, it has also suggested that 5,000 MW is achievable by 2020.[72]

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[69] North–south transmission will be enhanced at this time because of anticipated development of the Moose River Basin hydroelectric facilities.
[70] David Suzuki Foundation, 20.
[71] Canadian Wind Energy Association, *Submission to OPA Supply Mix Consultation* (Ottawa: CanWEA, 2005.
[72] David Timm, CanWEA, personal communication, Month Day. 2007.

Increasing Wind Capacity Beyond 10,000 MW

As described in the GE report, wind capacities higher than 10,000 MW would require some changes to the way the grid is operated in Ontario. Up to 10,000 MW wind integration can be achieved by, i) shedding wind or using controls to provide some flexibility, ii) modifying load or using pumped storage, iii) exporting wind power, and iv) using a flexible generation mix during low-load periods.

In many other jurisdictions, new approaches are being considered that if applied in Ontario would allow significant increases beyond 10,000 MW and lead towards a power system that is primarily based on distributed renewable energy sources:

> Power Storage
>
> Several new technologies are being tested and commercialized that could be used in conjunction with wind and other intermittent power options. By storing power produced on site and releasing it to grid as and when needed would make wind much more of a dispatchable power source and allow a predictable power output with high power quality characteristics. Storage options range from pumped storage[73] that can store power for several days to hydrogen storage,[74] flow batteries[75] and compressed air storage[76] that can store power for shorter periods.
>
> Although these storage facilities would increase the cost per MW of installed wind power, the investment will in many cases still be cost effective because of the higher value of the power produced. A recent feasibility study of an Irish wind farm showed that using storage to firm up wind generation can significantly increase the value of wind power and reduce financial risk. Storage also overcomes the problem of predicting temporal behaviour of wind farms allowing day-ahead contracts to be offered. By adding 2 MW of flow battery storage to 12

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[73] Ludington Pumped Storage discharges into Lake Michigan. Its 1,872 MW can serve 1.4 million residential customers. The site has similar topography and climate to parts of Ontario. Author, Title of page or text, www.consumersenergy.com/content/hiermenugrid.aspx?id=31 (accessed Month Day, Year).

[74] A US $2 million hydrogen-from-wind demonstration project has been launched by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) and Xcel Energy. The most significant problem they hope to solve is how to efficiently and cheaply convert the high voltage energy generated by a large wind installation to the lower voltage required by electrolysis, on a large, megawatt scale. Refocus Magazine, "Utility and US Government launch Wind to Hydrogen Facility" *Refocus Magazine,* January/February 2007. Also available online at http://www.re-focus.net/articles/biomass/prod_news/070110utility.html (accessed July 26, 2007).

[75] In the Vanadium Redox Battery (VRB), power is stored and recovered by passing this substance through an ion exchange membrane. The process is reversible, so the battery can be charged, discharged and recharged over and over almost indefinitely. Tests have confirmed that more than 10,000 charge/discharges are possible without any deterioration in efficiency. VRB Power, Frequently Asked Questions, www.vrbpower.com/technology/faqs.html, (accessed June 15, 2007).

[76] The Iowa Stored Energy Park, near Fort Dodge, Iowa, will use a pre-existing cavern to provide 200 MW storage for 100 MW wind capacity and off-peak coal, projected to be online by 2011. About the Iowa Stored Eneryg Park, http://www.isepa.com/about_isep.asp, (accessed June 15, 2007).

MW of wind capacity, capacity factors can be improved by 16%, and peak effectiveness by 78%.[77]

[77] Mark Kunz, "Flow Battery Applications with Wind Power," VRB Power Systems Inc. (paper presented at the Meeting California's Electricity Challenges through Electricity Power Storage workshop, California Energy Commission, February 24, 2005).

"Smart Grid" Control Systems

New software is being developed that makes it easier for grid operators to control a system based on distributed renewable generation sources such as solar, wind, biomass and small hydro.

A New Regulatory Regime

U.S. regulators are familiarizing themselves with the changes in the power sector regulatory regime needed to integrate more renewable energy capacity into the grid. A national teleconference was hosted by the American Council on Renewable Energy in January 2007 on the topic of "Distributed Generation and the Future of the Grid." The speakers discussed reliability and transmission issues related to connecting large numbers of distributed energy generating sources, particularly renewable sources, to local distribution networks and regional grids. Discussion topics included grid reliability and operation, interconnection, and the positions of federal and state regulators on grid access.[78]

Wind Farm Deployment Rates in Other Countries

The limiting factors for wind energy development are not technical. Deployment rates depend on a variety of factors, including transmission capacity, integration measures, regulatory and incentives policies and other socio-economic considerations (including public and community acceptance of large scale wind development).

The German experience sheds light on the potential scale and speed at which wind generation can be added to the electricity grid. Between 2000 and 2006, Germany added on average 2,416 MW of wind per year, bringing their total installed capacity from just over 6,000 MW to over 20,000 MW (see Table 14 below). This deployment rate was realized through the use of standard offers (or feed in tariffs) under the German Renewable Energy Law and other measures designed to rapidly develop wind generation as a public priority.

Table 14: Wind Power Installations in Germany

Year	Total Installed Capacity (MW)	Annual Additions (MW)
2000	6,104	—
2001	8,754	2,650
2002	11,994	3,240
2003	14,609	2,615
2004	16,629	2,020
2005	18,415	1,786
2006	20,622	2,207

[78] American Council on Renewable Energy (ACORE), Title of Page or Text, www.acore.org (accessed June 13, 2007).

Although Ontario's economy and population are smaller than that of Germany, Germany's success in creating a wind energy industry illustrates the economic and environmental benefits that Ontario stands to realize if it pursues wind development aggressively. According to the European Wind Energy Association, Germany, Denmark and Spain employ 73,800, 21,000 and 35,000 people respectively in their wind industries.[79]

Pembina Institute and WWF Scenarios

In our first green scenario (Scenario 3) we assume the maximum capacity of wind that the GE study for Ontario Hydro suggested could be installed without any major modifications to the grid or regulatory system. In our second green scenario (Scenario 4) we assume that, after 2012, power storage is incorporated into another 5,000 MW of wind capacity and the grid is optimized and regulated to manage a widely distributed power grid using techniques and software already under development in other jurisdictions.

Scenario 3: Meeting Future Demand without New Nuclear Power

- 10,000 MW would be installed by 2027 equal to the maximum capacity that can be installed without major grid modifications; an interim target of 3,000 MW by 2015 and 5,000 MW by 2020 would be appropriate
- Transmission planning and management would be slightly modified to facilitate this additional wind capacity

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- 15,000 MW of wind power could be in place by 2027, including 5,000 MW with storage capabilities; an interim target of 3,500 MW by 2015 (500 MW with storage), and 7,000 MW by 2020 (2,000 MW with storage) would be appropriate
- The grid would be optimized for distributed technology and renewable energy sources, including appropriate transmission, storage, controls and regulatory regime

The addition of storage in Scenario 4 is assumed to increase the wind farm capacity factor from 27% to 32.2% and peak availability from 17% to 30% (see above).

Costs

We have used the same cost ($/kW) for wind generation without storage as has OPA — ranging from $2,424/kW for projects less than 100 MW to $1,959/kW for projects up to 200 MW.

[79] European Wind Energy Association, Title of Page or Text, www.ewea.org/index.php?id=194 (accessed June 26, 2007).

Case studies show that the addition of sufficient storage to increase wind capacity factors and peak effectiveness by the above amounts would increase wind plant costs by 46%.[80] This cost premium has been added to the additional 5,000 MW under Scenario 4.

[80] Tapbury Management Limited et al., *VRB ESS Energy Storage System and the Development of Dispatchable Wind Turbine Output*. (Donegal, Ireland: Tapbury Management Limited, 2007), www.vrbpower.com/publications/media.html (accessed June 15, 2007).

Solar Photovoltaic Power Systems

Classification

The International Energy Agency Photovoltaic Power Systems Programme (IEA-PVPS) has four classifications for PV systems: off-grid domestic, off-grid non-domestic, grid-connected distributed, and grid-connected centralized.

Internationally, the trend for solar PV is towards grid-connected distributed systems. In Germany, of the 1,429 MW of currently installed solar PV, 97% is grid connected.

The fledging solar power industry in Canada is dominated by off-grid systems. In 2005, of the 16.75 MW of solar PV installed in Canada, 93% was off-grid (5.9 MW were for domestic systems, and 9.7 for non-domestic applications). In effect, Canada and Ontario have negligible amounts of grid-connected solar power.

The following terms are defined for clarity:

> *Greenfield:* Centralized power production facilities, typically large scale, producing power to feed directly into the grid.
>
> *Decentralized:* Electricity production at or near the point of use, irrespective of size, technology or fuel used — both off-grid and on-grid.[81]
>
> *Building Integrated Photovoltaic (BIPV):* A form of decentralized power supply where PV is typically installed on rooftops or building facades.

There is some ambiguity as to how OPA defines supply solar PV systems. Solar systems over 100 kW are considered as "supply side resources," yet OPA includes solar PV of only up to 3 kW in their "self generation from renewable energy" category of CDM.

The OPA also refers to

> *Near-Term Potential:* This category includes all developments to be completed in the timeframe before 2015.
>
> *Future Potential:* This category includes all developments to be completed in 2015–2025.

[81] This is the definition as used by the World Alliance for Decentralized Energy (WADE), www.localpower.org/deb_what.html (accessed July 23, 2007).

OPA Supply Mix Assumptions

In *IPSP Discussion Paper No. 7,* OPA details when solar supply side capacity is expected to come online in Ontario. In 2011, the first 2 MW are expected, with increasing annual installations reaching 15 MW in 2015.[82] During this period, a total of 40 MW would be installed. No new solar is planned after 2015.

OPA assumes additional solar BIPV capacity as part of their CDM self generated capacity but does not provide a breakdown by power system type (see CDM section above and estimate of potential below).

OPA Estimates of Potential

In *IPSP Discussion Paper No. 3, Revised*, the OPA establishes its proposed acquisition of solar PV for demand-side renewable energy as part of CDM programs. Based in part on consultation with the Canadian Solar Industries Association, the OPA projects that residential PV systems, assuming current programs such as the standard offer contracts continue, would contribute 30 MW every five years through to 2025.[83] In the case of solar PV, the OPA expects limited development of systems in the 200 kW to 1 MW range in Ontario,[84] and therefore assumes that 70% of all PV systems will be residential (i.e., demand side). If 70% of the total is demand side, we can then deduce that the total PV acquired would be approximately 170 MW, leaving 50 MW on the supply side. This 50 MW of supply side is also discussed in *IPSP Discussion Paper No. 4* (see below).

IPSP Discussion Paper No. 4 refers favourably to solar power, including comments describing it as "well established" and "easy to use." The discussion paper goes on to describe California's "million solar roofs" campaign, targeting 3,000 MW capacity by 2018. The OPA also refers to the success and growth of the solar PV industry in Germany and Japan. The OPA suggests that distributed solar PV would be beneficial in offsetting air conditioning load, yet sets a near-term acquisition target of only 50 MW, rising to 100 MW by the end of the planning period.[85]

IPSP Discussion Paper No. 7 backs away from an already less-than-ambitious plan of 100 MW by the end of the planning period, and instead opts to include only 40 MW of additional solar power by 2025 on the supply side. It is unclear from the reports how much additional solar PV is counted as demand side at this point, but we might assume that another 40 MW of demand side solar PV is included in OPA planning (see CDM section).[86]

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[82] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating Resources,* 175.

[83] That is, 30 MW by 2010, rising to 120 MW by 2020. This assumes 15,000 homes in each five-year time period installing 2 kW PV systems.

[84] The majority of systems are expected to be residential rooftop systems in the 1–2 kW range. Large scale solar developments are possible; these would likely be over 1 MW in size.

[85] Ontario Power Authority, *IPSP Discussion Paper No 4: Supply Resources.*

[86] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating Resources*.

Technical Potential

In a 2007 report for Environment Canada, the Pembina Institute developed estimates on the technical capacity for solar PV based on a number of sources. The study showed that in the residential sector alone, there was over 5,500 MW of potential capacity in Ontario.[87] The CANMET Energy Technology Centre — Varennes provided feedback on the methodology used for this estimate. In fact, the CANMET estimate for residential PV technical potential greatly exceeded the Pembina Institute's estimate: CANMET estimated the technical capacity of homes in Ontario to be 21,964 MW.[88]

CANMET further estimated that BIPV in Ontario could produce 20 TWh of electricity each year in the residential sector, and 6.5 TWh in the commercial/institutional sector, representing 53% and 12%, respectively, of the electricity demand in these sectors. These figures, presented at the 2006 Solar Energy Society of Canada, Inc. (SESCI) conference, used a recognized International Energy Agency methodology to estimate technical capacity. The figures are equivalent to approximately 6,300 MW at institutional/commercial buildings, and over 19,378 MW at residential buildings, resulting in a total potential of over 25,000 MW of solar power, all without including greenfield development.

The technical capacity of greenfield development is not easily defined, as it would require competition for greenfield sites between conservation, recreation, agriculture and other land uses. Other development potential (brownfield) is also not evaluated; examples in this category could include the development of solar arrays above large parking lots.

With such a high technical capacity for solar PV power, it becomes apparent that the limiting factor will likely be the deployment rate, as influenced by economics (including provincial/federal incentives) and the capacity of industry to produce and install PV. For guidance on what deployments rates are possible, we look to stakeholder recommendations as well as the history of deployment rates in jurisdictions in the U.S. and Europe.

Stakeholder Views on Solar PV Potential

In their "Sunny Days Ahead" campaign, the Canadian Solar Industries Association (CanSIA) established a 2025 target of 3,900 MW of solar PV installed on residential rooftops (plus 3 MW of commercial buildings). In their response to the OPA *Supply Mix Advice* report, CanSIA countered by suggesting the solar outlook should be increased to

[87] Alison Bailie et al. *Economic Instruments for On-Site Renewable Energy Application in the Residential/Farm Sector*. Prepared for Environment Canada by the Pembina Institute (Drayton Valley, AB: Pembina Institute, 2007).

[88] Sophie Pelland, *Memorandum to Leslie-Ann Robertson and Al Clark (Environment Canada). Re: Solar Photovoltaic Section 2.4 of the Report "Economic Instruments for On-site Renewable Energy Applications in the Residential/Farm Sector"* Internal Communication. 2007.

3,400 MW (1,200 MW each on existing and new homes, and another 1,000 MW on large commercial buildings).[89]

CanSIA later compared Canada's solar PV performance with that of other countries. If Canada were to deploy solar at rates comparable with international trends, 1,700 MW would be in place by 2025. If Canada were to catch up to international deployment rates, 16,500 MW would be in place by 2025.[90]

Finally, in 2005, CanSIA outlined a detailed plan in their report *Valuing Grid-Connected Solar Electricity: Priming the Market in Ontario* that would see market capacity grow between 2005 and 2015, with the result being 13,000 MW of installed solar PV power by 2025.

The David Suzuki Foundation *Smart Generation* report estimated the current technical capacity of residential rooftop PV at 4,181 MW (1.4 million homes with suitable solar access, each with 3 kW solar arrays).[91] Given current and projected housing growth rates, the residential capacity could grow to 7,900 MW by 2025. The same report estimated the market potential for PV at 1,263 MW by 2025, including both residential and commercial buildings.

A summary of stakeholder views on solar potential is provided in Table 15 below.

Table 15: Summary of Stakeholder Views on Solar PV Capacity

Source	Estimated Solar Capacity (MW)
Sunny Days Ahead, Canadian Solar Industries Association	3,900 (by 2025)
Smart Generation, David Suzuki Foundation	7,900 (by 2025)
Valuing Grid-Connected Solar Electricity: Priming the Market in Ontario, Canadian Solar Industries Association	13,000 (by 2025)
CanMET Energy Technology Centre — Varennes	19,378 (existing technical potential — residential) 6,300 (existing potential — commercial/institutional)

Increasing Solar PV Effectiveness

[89] Canadian Solar Industries Association, *Review of the OPA Supply Mix Advice Report: No Forecast of Sunny Days for Ontario. V2.1* (Ottawa: CanSIA, 2006).
[90] Canadian Solar Industries Association, *Putting Solar on the Grid. V1.3* (City, CanSIA, 2004).
[91] David Suzuki Foundation, 89.

Some of the solar storage technologies described in the section on wind could also be used with solar systems. For building-mounted solar PV systems, regional storage at sub-stations would be used rather than individual storage at each building. The goal would be to delay the peak output from solar PV systems to coincide with the summer peak. This lag is usually about two hours.

Deployment Rates in Other Jurisdictions

While the technical potential of BIPV in Ontario is significantly greater than what might realistically be expected to be deployed before 2025 or 2027, the exceptionally rapid growth of the industry in other countries, including Germany, Spain and Portugal, suggests that Canada could deploy a significant number of PV systems in this time frame.

In 1996, Germany installed 10 MW of solar PV. It took until 2003 before Germany had installed over 100 MW in a calendar year, but three years later (2006) the annual installed capacity had jumped to 1,150 MW. In the ten years from 1996 to 2006, Germany's total installed PV capacity jumped from 27.8 MW to over 2,500 MW. Germany's annual and cumulative PV installations over the past decade are shown in Table 16 below.[92]

Table 16: History of Solar PV Growth in Germany

Year	Installed in Calendar Year (MW)	Cumulative Installed (MW)	Growth (%)
1995	5.3	17.7	—
1996	10.1	27.8	**57.1**
1997	14.0	41.8	**50.4**
1998	12.0	53.8	**28.7**
1999	15.6	69.4	**29.0**
2000	44.3	113.7	**63.8**
2001	80	194.6	**71.2**
2002	83	278	**42.9**
2003	153	431	**55.0**
2004	363	794	**84.2**
2005	635	1,429	**80.0**
2006	1,150	2,579	**80.5**

While Germany is the leading country in terms of installed solar PV power, many other countries are greatly outpacing Canada with respect to annual installations. Some comparable countries and their annual installations of PV are shown in Table 17 below.[93]

Table 17: Annual Installations (MW) of Solar PV by Country

Country	2000	2001	2002	2003	2004	2005	2006
Australia	3.9	4.4	5.5	6.5	6.7	8.3	
Germany	44.3	80.9	83.4	153.0	363.0	635.0	1,150
Spain	3.0	3.6	4.8	6.5	10.0	20.4	

[92] International Energy Agency, *Trends in Photovoltaic Applications: Survey Report of Selected IEA Countries between 1992 and 2005.* Report IEA-PVPS T1-15 (Switzerland: IEA, 2006).
[93] Ibid.

Japan	121.6	122.6	184.0	222.8	272.4	289.9	
USA	21.5	29.0	44.4	63.0	100.8	103.0	

Pembina Institute and WWF Scenarios

Balancing economic, environmental and industry considerations, the Pembina Institute and WWF developed realistic, yet ambitious, targets for the deployment of solar PV in Ontario.

With appropriate policies and levels of support through standard offers, Ontario should be able to greatly increase the deployment of solar PV. Cost reductions expected by 2015 (see below) would also make solar PV much more cost competitive and allow reductions of standard offer premiums after that date.

<u>Scenario 3: Meeting Future Demand without New Nuclear Power</u>

- Greenfield: 800 MW
- Solar Rooftop BIPV (residential and commercial): 1,500 MW

<u>Scenario 4: An Electric Power Future Based Primarily on Renewable Sources</u>

- Greenfield: 1,000 MW
- Solar Rooftop BIPV (residential and commercial): 3,000 MW

This conservative growth in Scenario 3 allows for a modest growth of both greenfield and solar rooftop (building integrated) deployment. This growth rate is comparable with current international growth rates.[94]

Scenario 4 would see more aggressive growth in solar installations as proposed by CanSIA, ramping up after 2015 when solar PV systems are expected to drop to less than 50% of 2007 world prices. However, it is worth noting that even this growth rate does not compare with historical growth rates in leading solar PV countries such as Germany and Japan.

Costs

An RBC Capital markets report predicted that industry average installed costs would decline nearly 50% by 2011, reaching competitiveness compared to grid electricity in most regions around the world in the period between 2012 and 2015.[95]

In our scenarios we have used the OPA predicted costs until 2011 ($5,613 / MW) and the RBC predicted price of $4,400/MW until 2014, dropping to $3,000/MW by 2027.

[94] Canadian Solar Industries Association, *Putting Solar on the Grid.*
[95] Stuart Bush,.*Investing in Solar Now* (Toronto: RBC Capital Markets, 2007).

Bio-Energy Power Systems

Classification of Biomass Sources for Bio-Energy

OPA and most stakeholders, including CANBIO and BIOCAP, use the following classifications with respect to bio-energy:

Forestry sources include tree harvest residues (slash); residues from silviculture practice; diseased, insect-killed and fire-damaged trees; unused portions of annual allowable harvest cuts; black liquor, bark, sawdust and other wood waste from forest sector industries; and dedicated tree plantations.

Agriculture sources include dedicated energy crops, as well as residual and waste products. The latter includes spoiled or off-specification crops and food products, and manure from livestock operations.

Municipal (or urban) sources include municipal solid waste (MSW), fats/oils/greases from food service industries, and biosolids (sewage sludge) from wastewater treatment facilities. Methane captured from landfills (referred to as landfill gas) is also normally included as a bio-energy source.

Biomass sources can be used to produce solid fuels (pellets, chips and so on), liquid fuels (bio-oil, ethanol and bio-diesel), and gaseous fuels (anaerobically produced bio-gas, gasified biomass and landfill gas). These biofuel products can be used to produce heat, power (including heat and power) and transportation fuels.

MSW is not considered an environmentally acceptable biomass source, especially if it is directly incinerated, due to the environmental pollutants produced and the disincentives it provides for recycling and product stewardship.

OPA Supply Mix and IPSP Assumptions

The OPA categorizes biomass energy resources as, i) forestry and related industries, ii) agriculture products and by-products, and iii) municipal sources.

In *IPSP Discussion Paper No. 4,* the OPA outlines preliminary planning assumptions for biomass capacity. These assumptions are reproduced here:[96]

Table 18: Preliminary Planning Assumptions for Biomass Capacity

Sector	Planning Assumption: Electricity Generation Capacity (MW)		
	2010–2015	2016–2027	Total
Landfill Gas and MSW	100	245	345

[96] Ontario Power Authority, *IPSP Discussion Paper No 4: Supply Resources,* 59.

Forestry Sources	100	260	360
Peat*	—	200	200
Agriculture Sources	100	245	345
Total	300	950	1,250

***Peat is being considered a potential fuel for use in the existing Atikokan coal burning power station in northern Ontario.**

OPA includes peat as a biomass resource. This inclusion raises serious sustainability questions: peat has very long regeneration timelines (on the order of 1,000 years) and, therefore, as a large scale energy source cannot be considered renewable. Use of peat would also deplete carbon stocks in the boreal forest as most of the carbon is in soils and not in trees. Peat also has a very low heating value similar to lignite coal, and requires different and challenging logistical and technical solutions.

According to OPA's *IPSP Discussion Paper No. 7,* it plans to add only additional 786 MW of biomass power (only 5 MW is currently committed). This planned capacity includes 200 MW at the Atikokan facility, 185 MW from forest resources, 276 MW from agricultural sources and 120 MW from municipal sources.[97]

Stakeholder Views on Technical Potential

The David Suzuki Foundation *Smart Generation* report provided a thorough review of biomass potential in Ontario, in which they consider the total resource, the technical resource and the practical resource. The total resource is the energy content of the total quantity of biomass, regardless of environmental, technical or logistical considerations. The technical resource imposes limitations on the total resources, including technical ability to harness the energy as well as broad sustainability criteria. Lastly, the practical resource accounts for basic practical considerations, such as competition between uses of the resource.

The *Smart Generation* report finds that while the total resource of energy from biomass is nearly 850 petajoules (PJ), the practical resource is limited to 288 PJ — about one-third of the total. The breakdown provided in that report is reproduced in Table 19 below.[98]

Table 19: Overview of Biomass Resource Availability in Ontario (PJ, primary energy)

Supply Sector	Type	Total Resource	Technical Resource	Practical Resource
Forestry	Spent liquor and waste wood	377	229	83
	Bark	—	—	29
	Fuel wood	—	—	16.7
	Sawdust	—	—	13.7

[97] Ontario Power Authority, *IPSP Discussion Paper No 7: Integrating the Elements — A Preliminary Plan,* 32.
[98] David Suzuki Foundation, 58.

	Subtotal	—	—	**142.4**
Agriculture	Energy crops	103	103	103
	Field crop residues	113	64	17
	Grains and grain milling residues	99	5	5
	Livestock manure	45	19	4.8
	Subtotal	**360**	**218**	**129.8**
Organic Waste	Landfill gas	20	10	9.6
	Waste wood	4.7	4.7	3.8
	Residues from food industry	50	10	2.3
	Sewage sludge	0.8	0.6	0.4
	Biodegradable municipal waste	36	0	0
	Subtotal	**111.5**	**25.3**	**16.1**
Total		**848.5**	**445.3**	**288.3**

Stakeholder Views on Practical Development Potential

Several stakeholders have developed estimates on the potential of biomass energy in Ontario. Many of these reviews include biomass as sources of heat and transportation fuel as well. Estimates relating to electricity generation were presented in *IPSP Discussion Paper No. 4,* which are reproduced here in Table 20.[99]

Table 20: Summary of Stakeholder Views on Resource Capacity

Source	Estimate (MW)	Comments
CANBIO, 2003	1,700	Figure based on compilation of third-party estimates
Etcheverry et al. 2004 *Smart Generation* Report	2,450	All biomass projected 10–20 years into the future
The Pembina Institute and CELA, 2004	800	All biomass by 2020
Pollution Probe and Summerhill Group, 2004	480	Includes biomass, biogas and MSW

A comprehensive analysis of the supply and potential and the resources to provide both heat and power was completed in the 2004 *Smart Generation* report by the David Suzuki Foundation. The report estimates that the "practical resource" for biomass in Ontario could provide up to 14.7 TWh per year of power, equivalent to adding 2,450 MW of capacity. This breaks down as follows:

- Forest Biomass (bark, wastes) – CHP = 1,500 MW

[99] Ontario Power Authority, *IPSP Discussion Paper No 4: Supply Resources,* 59.

- Agricultural Biomass (crops, waste, manure) – CHP and anaerobic digestion = 850 MW
- Municipal biomass (food wastes, landfill, sewage) – CHP, gas and digestion = 100 MW

There are a variety of new biomass sources that are already being used in Ontario from the forest sector. Pellet production is the fastest growing source with plans to develop a pellet-based heating market in the residential sector based on the successful approaches used in Austria. Pellets are already be produced in British Columbia and New Brunswick for export to the U.S. for power production and Ontario producers hope to tap into this growing market soon.[100]

Growing trials and testing of pellets from tall prairie grasses in Ontario show that this biomass source outperforms all other agricultural crops on a carbon fixation and carbon footprint basis.[101]

On the utilization side, Abitibi Consolidated is building a 100 MW expandable in-house biomass cogeneration plant at their Fort Frances mill, and has secured 20-year contracts for supply of forest biomass from local saw mills and unsuitable lumber harvest.[102]

These developments show that that there is no shortage of biomass sources in Ontario that could be used to produce power, and that this can be done through CHP plants.

There is no need to use existing coal plants like Atikokan, which even if it used forest biomass sources instead of peat would waste over 70% of the heat produced. A far better alternative is to encourage cogeneration plants like those being built in Fort Frances to expand power output and sell into the grid. Using pellets as a fuel for cogeneration in other parts of the province — like they do in Europe using Canadian pellets — would be a much better alternative to controversial and expensive MSW incineration.

Pembina Institute and WWF Scenarios

Given the growing potential for forest and agricultural biomass sources for power production in Ontario we propose that in both green scenarios the full OPA identified potential of 1,250 MW be acquired, but without the use of coal plant conversion or MSW. Expanded cogeneration and new wood pellet plants from the forest sector would be used instead. All small scale generation would come from generation from wood pellets, agricultural crop pellets, and biogas from manure and landfill.

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[100] John Swann, (paper presented at the CanBIO Bio-energy Heat and Power Policy Workshop, Ottawa, June 25, 2007).
[101] Roger Sampson, (paper presented at the CanBIO Bio-energy Heat and Power Policy Workshop, Ottawa, June 25, 2007).
[102] Martin Kaiser, (paper presented at the CanBIO Bio-energy Heat and Power Policy Workshop, Ottawa, June 25, 2007).

Scenario 3: Meeting Future Demand without New Nuclear Power

- Bio-energy resources would be increased to 1,250 MW by the end of the planning period by 2027, the maximum level identified by OPA
- This would include 560 MW from forest resources (> 50 MW) and 690 MW from smaller scale agricultural resource and biogas plants
- The 560 MW from forest resources would not include use of the Atikokan coal plant, which would be shut down

Scenario 4: An Electric Power Future Based Primarily on Renewable Sources

- Same as Scenario 3

Costs

The costs per megawatt used by OPA for all bio-energy systems were used for both green scenarios: $2,200/MW for large scale facilities (> 50 MW) and $3,200/MW for small scale facilities.