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A Smarter Energy Plan for Ontario.

Analysis and Scenario Modelling of the Ontario Power System

Marc Godin
Portfire Associates • July 2007

In partnership with:
Emerging Energy Options WADE Canada

Report Presented to:

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Manager, Climate Change Campaign
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Executive Summary

This report presents the result of the analysis and scenario modelling of the Ontario Power System. Most of the information used as input was provided by the Ontario Power Authority (OPA) in its Supply Mix Advice and in its Integrated Power System Plan (IPSP).

The first task was to calibrate the numerical model by reproducing the OPA Preliminary Plan as presented. The analysis used a numerical model of the Ontario Power System constructed in 2006 using the WADE Model (World Alliance for Decentralized Energy). The WADE Model is an economic model that compares the performance of Central Generation (CG) and Decentralized Energy (DE) in meeting future electricity demand growth. The Model allows planners to calculate the economic and environmental impacts of different generation choices. An emphasis on transmission and distribution network capital requirements differentiates the model's approach from other energy economics analyses.

With a calibrated model in hand, the second task was to update the calibration run with recent information and develop a critical assessment. In effect, this was a sensitivity analysis of the Preliminary Plan by using realistic assumptions particularly with respect to the performance and cost of Ontario's current and proposed nuclear power plants.

The third task was to use the updated Preliminary Plan to explore the impact, costs and environmental benefits of adopting strategies that would increase the penetration in Ontario of technologies with low environmental footprint, such as conservation and demand management (CDM), solar, wind, hydro, storage, cogeneration, and waste heat recycling with emphasis on distributed generation because of its potential for avoiding some of the investments in transmission and distribution infrastructure and associated line losses. This resulted in two illustrative scenarios: "Soft Green" and "Deep Green".

It should be noted that these illustrative scenarios are predominantly based on OPA inputs, many of which are not critically analysed in this study and are deserving of further appraisal.

Costs

Table 1 and Figure 1 show total capital costs on an as spent basis (not NPV) over the 20 year study period for all four model runs. Capital costs include the upfront investments required to build new generation capacity, as well as the associated transmission and distribution infrastructure. Due to the manner in which CDM costs were presented by the OPA, capital costs in Table 1 and Figure 1 include all CDM costs (including delivery and societal costs) on a present value basis.

When the Preliminary Plan is updated with realistic assumptions, total capital costs are increased by 12%. However, these costs are reduced by 4% in the Soft Green Scenario, mostly due to a more aggressive deployment of CDM technologies. The Deep Green scenario results in 13% higher total capital costs as compared to the Updated Preliminary Plan because of its higher content of solar and wind technologies. Higher capital costs do not necessarily mean higher total costs as there may be offsetting ongoing reductions in fuel and operating costs as is the case when CDM, solar and wind displace nuclear and coal.

Table 1 - Total Capital Expenditures from 2007 to 2027 - $ billion				
	OPA Plan (Calibration)	**OPA Plan (Updated)**	**Soft Green**	**Deep Green**
Generation	64.6	70.2	69.3	84.5
Transmission	10.7	12.5	11.7	12.9
Distribution	26.3	30.7	28.2	31.1
Total	**101.5**	**113.3**	**109.1**	**128.4**

The allocation of total capital costs by category of generation technology is provided by Table 2 and Figure 2. The OPA Preliminary Plan (calibration run and updated) favour nuclear energy. By contrast, the green scenarios emphasize renewable energy technologies and significantly increase investment in CDM.

Table 2 - Total Capital Costs by Generation Technology ($ billion)				
	OPA Plan (Calibration)	**OPA Plan (Updated)**	**Soft Green**	**Deep Green**
Nuclear	$33.8	$34.6	$9.8	$0.0
Coal Gasification	$0.6	$0.5	$0.0	$0.0
Natural Gas, Cogeneration and Self Generation	$6.7	$11.0	$6.7	$5.6
Renewable Energy	$19.3	$19.8	$46.4	$70.3
Conservation and Demand Management	$4.1	$4.2	$6.5	$8.5
Transmission and Distribution	$36.9	$43.1	$39.8	$43.9
Total	**$101.5**	**$113.3**	**$109.1**	**$128.4**

Table 3 and Figure 3 provide details for the cost of delivered electricity in 2027. The cost of delivered electricity includes amortization and return on investment for generation, transmission and distribution capital costs, operations and maintenance costs, fuel cost and a $15/tonne charge for the CO_2 emissions of generation facilities where applicable.

The Updated model run of the Preliminary Plan increases delivered cost by 17%. However, the Soft Green scenario decreases this cost by approximately 11% and returns it to a level similar to the calibration run. The Deep Green scenario results in an 8% higher cost as compared to Soft Green but 4% lower than the Updated run. While the cost for generation is higher with Deep Green, cost reductions are provided by fuel and operations & maintenance savings.

Table 3 - Total Delivered Electricity Cost in 2027 - ¢/kWh				
	OPA Plan (Calibration)	**OPA Plan (Updated)**	**Soft Green**	**Deep Green**
Generation Capital	5.49	6.51	6.16	7.06
Fuel	0.63	0.93	0.47	0.37
Operation & Maintenance	1.31	1.24	1.00	0.92
CO_2	0.04	0.10	0.03	0.02
Transmission	0.98	1.14	0.93	0.98
Distribution	2.10	2.46	2.40	2.54
Total	**10.55**	**12.37**	**10.99**	**11.88**

Environmental

Table 4 and Figures 4 and 5 show CO_2 emissions for all model runs. One limitation of the WADE Model is that only air emissions directly related to combustion are calculated. This is in contrast to the approach chosen by the OPA which includes life cycle GHG emissions in addition to water, land and other environmental impact.

Annual CO_2 emissions in 2027 climb under the Updated Preliminary Plan because natural gas facilities are deployed to compensate for the lower amount of electricity generated by nuclear plants. In addition, the total amount of CO_2 emissions over the 20 year study period jumps by 34% because the retirement of Ontario's coal-fired facilities is delayed by 2 years.

Table 4 - CO_2 from Coal, Gas and Oil				
	OPA Plan (Calibration)	**OPA Plan (Updated)**	**Soft Green**	**Deep Green**
In 2027 (million tonnes per year)	8.49	13.80	8.02	6.82
From 2007 to 2027 (million tonnes)	286	383	192	178

The Soft Green scenario offers significant reductions in CO_2 emissions as compared to the Updated scenario and the calibration run because the total amount of natural gas fired facilities is reduced in favour of higher capacities of CDM, wind and solar technologies. In addition, the phase-out of coal-fired facilities is accelerated by one year as compared to the Preliminary Plan. The Deep Green scenario increases the penetration of CDM, wind and solar beyond OPA expectations, resulting in a further displacement of natural gas facilities and additional reductions in CO_2 emissions. The conservative one year acceleration of the coal shut down could be improved upon if CDM and renewable deployment rates are enhanced but only a one year acceleration was assumed in the runs.

The environmental impact of nuclear generation is considered in Table 5 and Figures 6 and 7. The amount of electricity generated by nuclear facilities is a proxy indicator for the amount of radioactive waste and level of risk associated with nuclear power.

The Updated Preliminary Plan generates less nuclear electricity because of the lower reliability and load factor assumptions, as compared to the calibration run. The Soft Green model run results in significantly lower levels of nuclear electricity because no new nuclear facility is constructed or refurbished beyond existing commitments. Less nuclear electricity is produced and it is replaced by green technologies such as solar, wind and CDM. The Deep Green scenario goes further by illustrating the impact of cancelling commitments and retiring all existing facilities by 2027[1].

Table 5 - Nuclear Electricity (2007 to 2027) - TWh

	OPA Plan (Calibration)	OPA Plan (Updated)	Soft Green	Deep Green
In 2027 (TWh)	91.4	77.3	26.2	0.0
From 2007 to 2027 (TWh)	1,851	1,646	1,167	969

Soft and Deep Green not only result in reduced GHG emissions, but also greatly reduce the environmental, safety and security risks associated with dependency on nuclear power, including the generation of radioactive waste fuel. This analysis and modelling work is however limited in terms of assessment of environmental impacts. The model only estimates atmospheric impacts and other types of impacts, such as water pollution and waste generation are not fully accounted for.

Conclusion

This work demonstrated that the Ontario power system may be simulated with independent computer modelling tools using data provided by the OPA and other public sources. This allowed for a critical review of the current Preliminary Plan and the identification of strategies that would reduce the environmental impact of power production including CO_2 emissions and nuclear waste, emissions and associated risks.

[1] Details of any potential contract penalties were not available for inclusion.

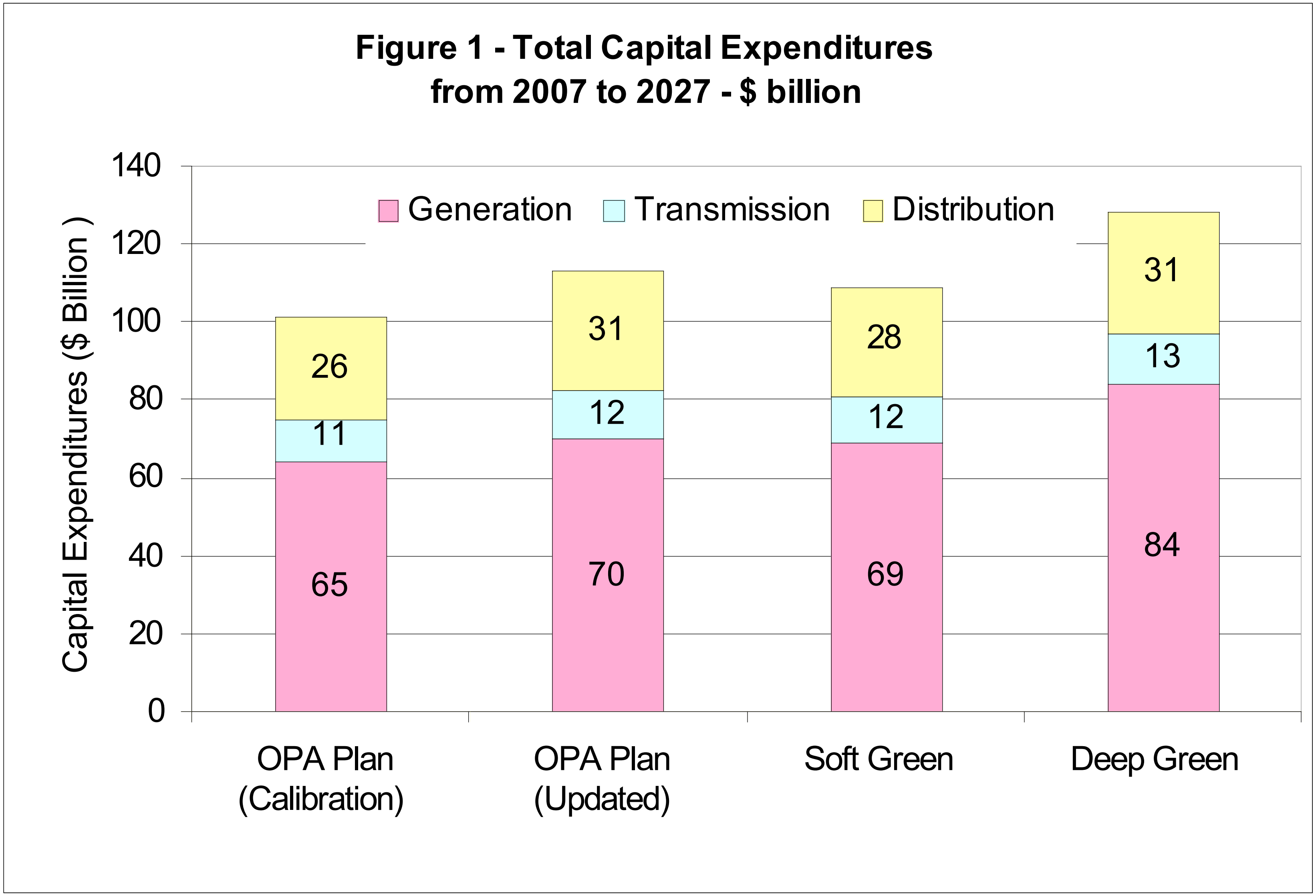
Figure 1 - Total Capital Expenditures
from 2007 to 2027 - $ billion
Capital Expenditures ($ Billion)
140
120
100
80
60
40
20
0
Generation
Transmission
Distribution
26
11
65
31
12
70
28
12
69
31
13
84
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green

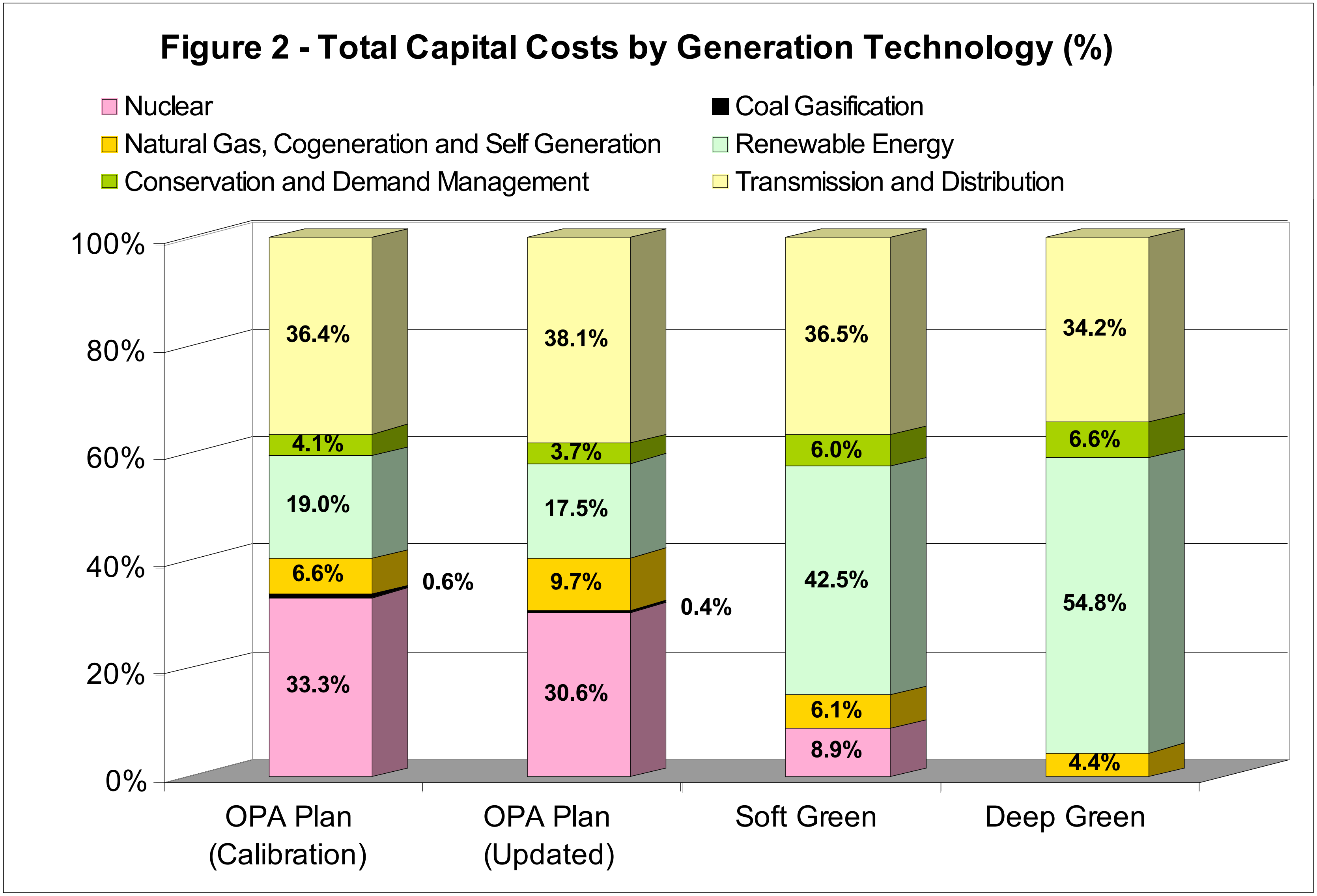
Figure 2 - Total Capital Costs by Generation Technology (%)
Nuclear
Coal Gasification
Natural Gas, Cogeneration and Self Generation
Renewable Energy
Conservation and Demand Management
Transmission and Distribution
100%
80%
60%
40%
20%
0%
36.4%
4.1%
19.0%
6.6%
0.6%
33.3%
38.1%
3.7%
17.5%
9.7%
0.4%
30.6%
36.5%
6.0%
42.5%
6.1%
8.9%
34.2%
6.6%
54.8%
4.4%
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green

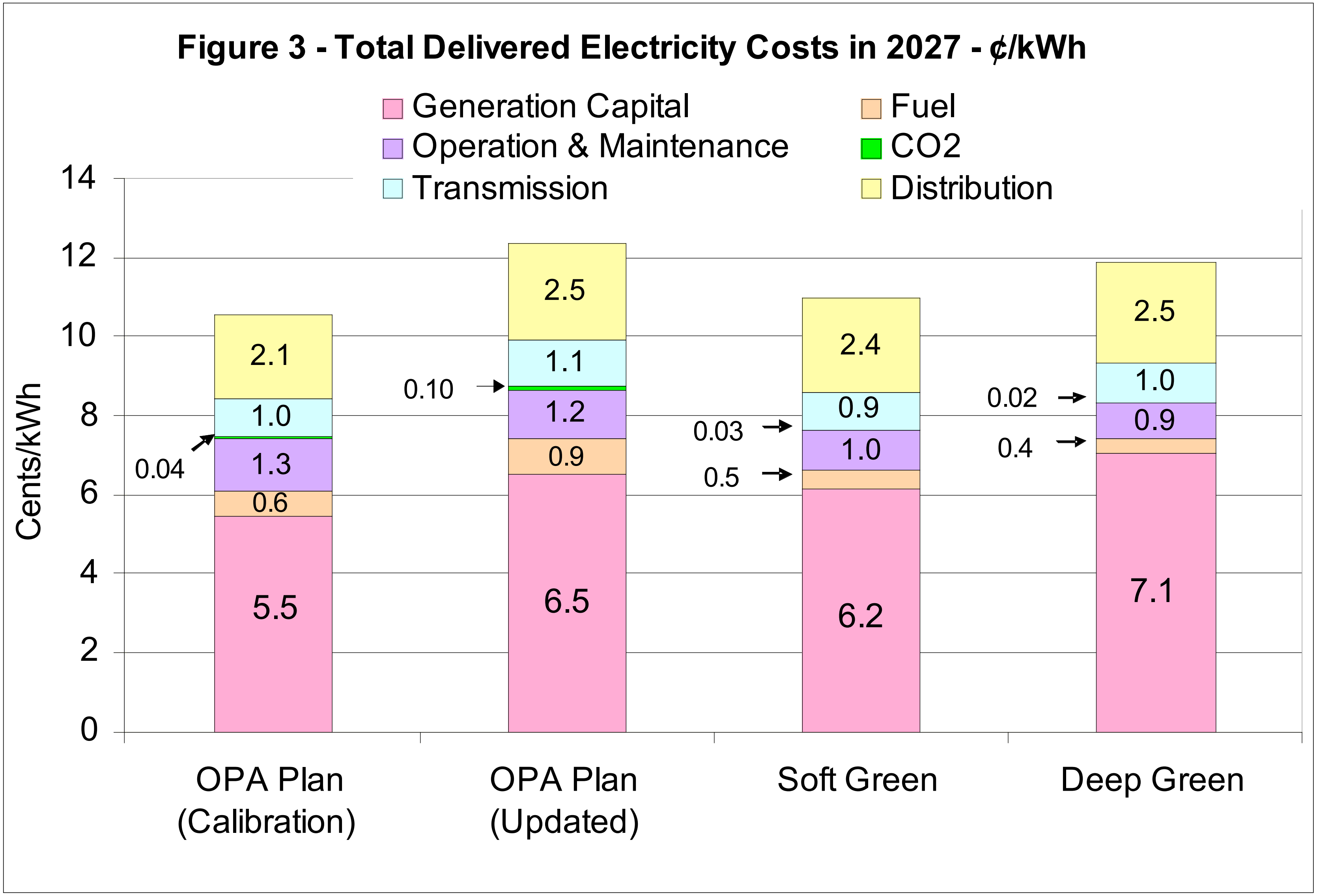
Figure 3 - Total Delivered Electricity Costs in 2027 - ¢/kWh
Generation Capital
Fuel
Operation & Maintenance
CO2
Transmission
Distribution
Cents/kWh
14
12
10
8
6
4
2
0
2.1
1.0
0.04
1.3
0.6
5.5
2.5
1.1
0.10
1.2
0.9
6.5
2.4
0.9
0.03
1.0
0.5
6.2
2.5
1.0
0.02
0.9
0.4
7.1
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green

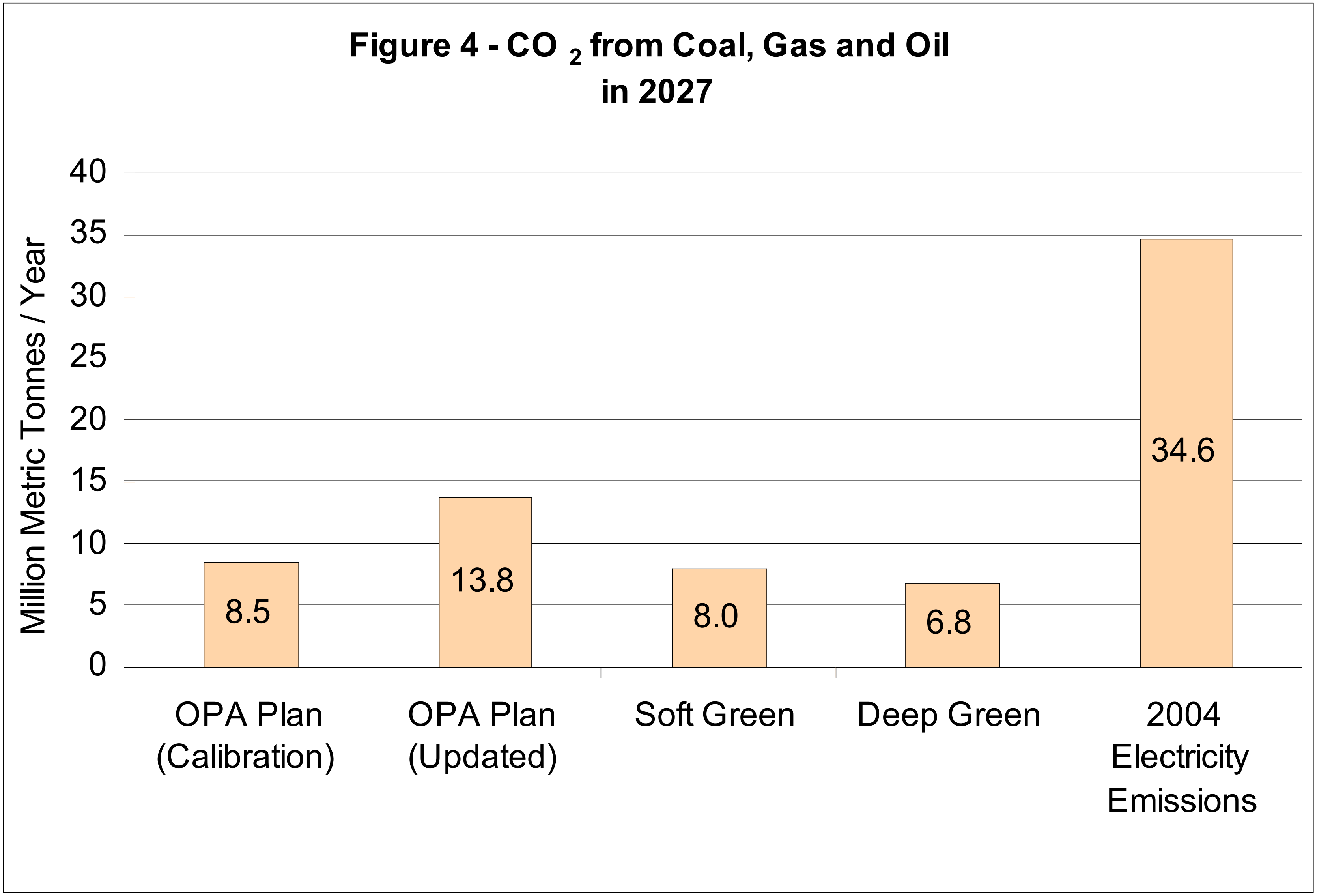
Figure 4 - CO_2 from Coal, Gas and Oil in 2027
Million Metric Tonnes / Year
40
35
30
25
20
15
10
5
0
8.5
13.8
8.0
6.8
34.6
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green
2004 Electricity Emissions

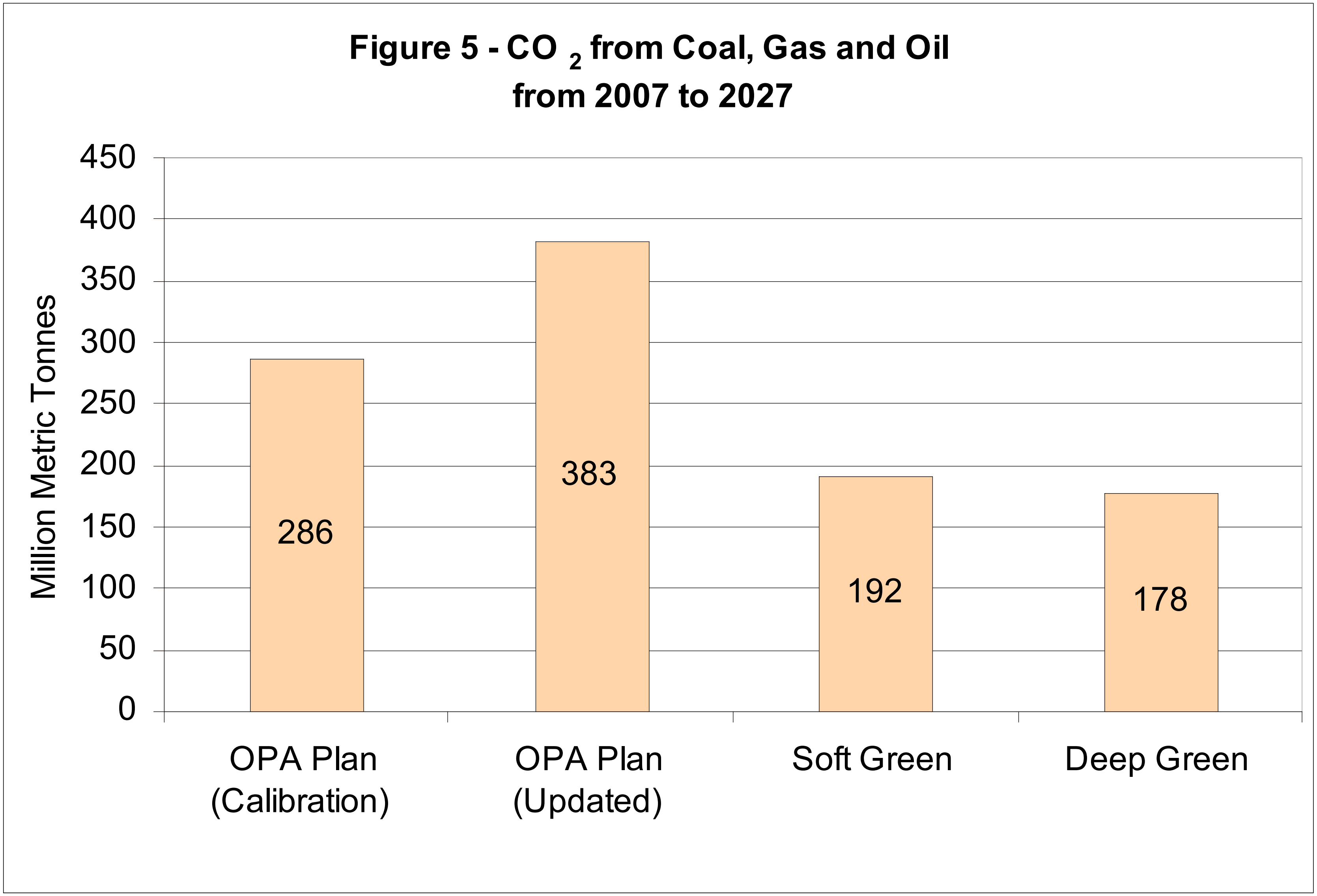
Figure 5 - CO_2 from Coal, Gas and Oil
from 2007 to 2027
Million Metric Tonnes
450
400
350
300
250
200
150
100
50
0
286
383
192
178
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green

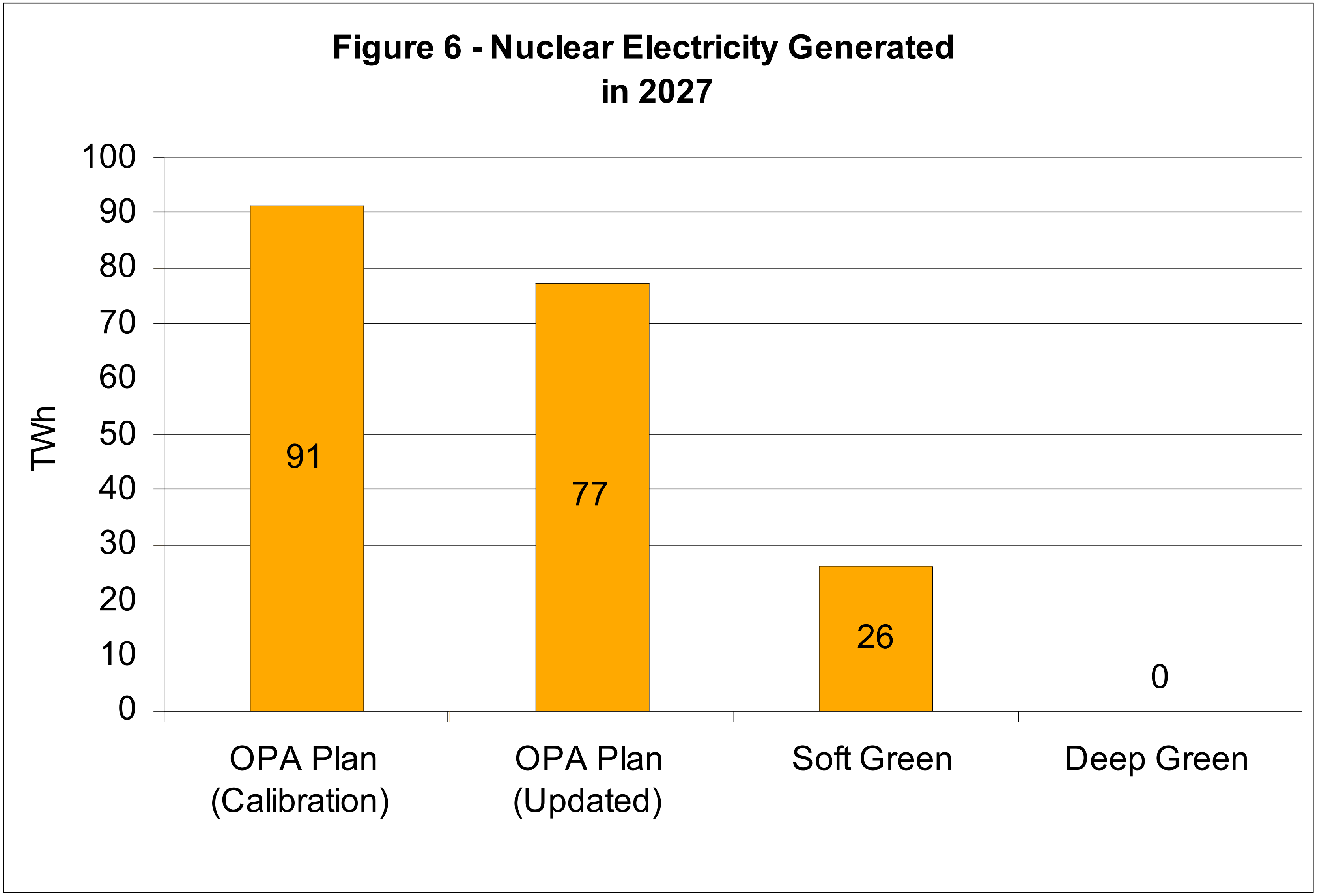
Figure 6 - Nuclear Electricity Generated
in 2027
TWh
100
90
80
70
60
50
40
30
20
10
0
91
77
26
0
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green

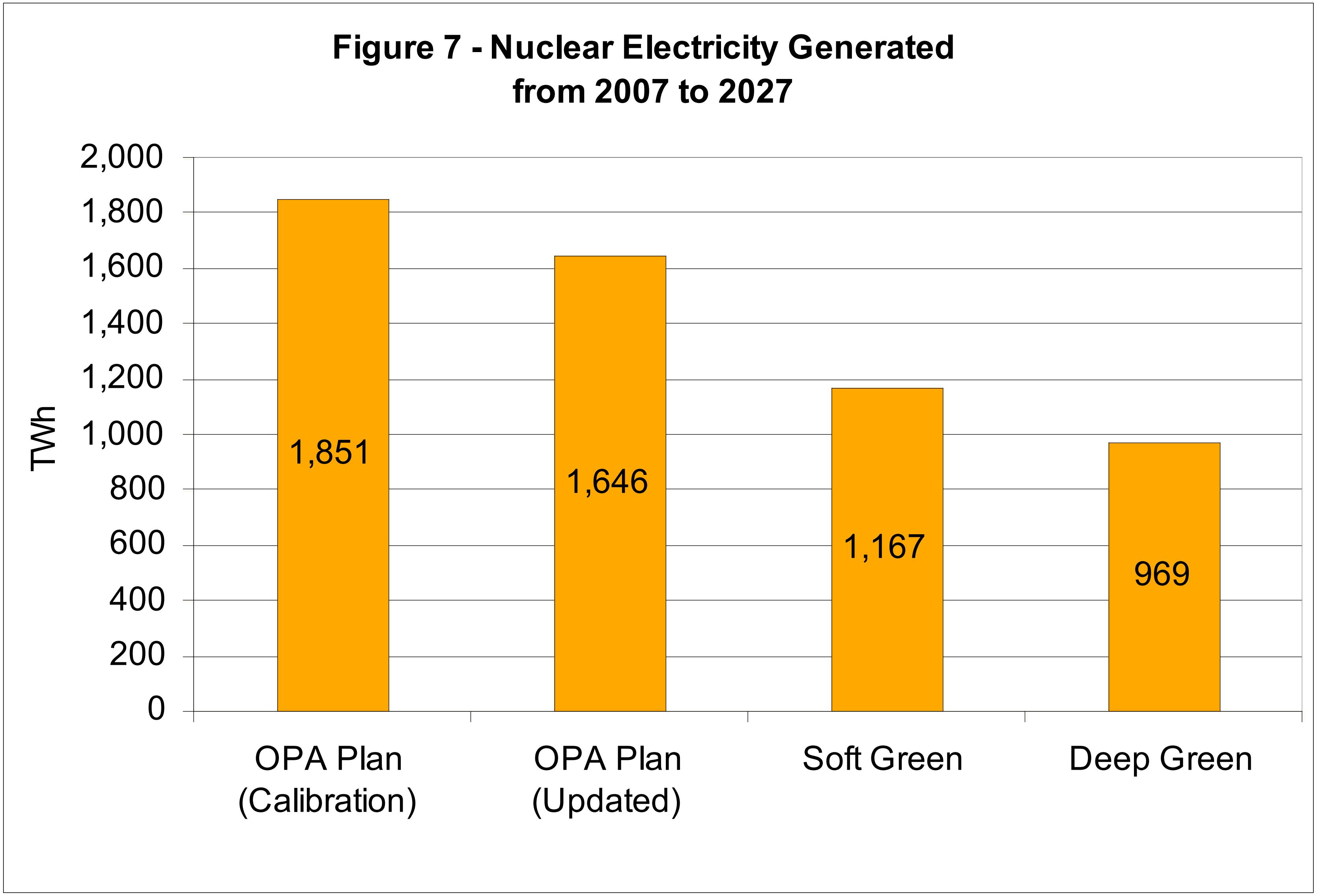
Figure 7 - Nuclear Electricity Generated
from 2007 to 2027
TWh
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1,851
1,646
1,167
969
OPA Plan (Calibration)
OPA Plan (Updated)
Soft Green
Deep Green

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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 had 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 consultation process was rolled out as a set of eight discussion papers covering all aspects required for planning the power system and culminating in a Preliminary Plan. Stakeholders such as WWF Canada were invited to comment and provide feedback.

This study analyzes the information provided by the OPA in order to develop a knowledge base and a numerical model of the Ontario power system. The purpose is to identify directions for reducing the environmental impact and the overall cost of electricity in Ontario, serving as a foundation for providing informed feedback during future consultation events and hearings.

Scope

Recent Work

In 2006, WADE Canada (formerly NewERA) analysed the Ontario power system using data published by the OPA in the Supply Mix Advice. The data was analysed with the WADE Economic Model, a computer model developed by the World Alliance for Decentralized Energy (WADE). This recent analysis provided insights into the economic and societal implications of various mixes of generation technologies, both centralized and decentralized, to meet demand growth and to offset power plant retirements in Ontario. Results of this study, funded in part by National Resources Canada and the OPA, were reported in detail and published (Godin and Tinkler 2006; NewERA 2006; Godin and Tinkler 2007).

The following results were reported:

- The WADE Model appears to calibrate well against the Central Generation (CG) analysis provided by the OPA's Supply Mix Advice Report;
- The Model can effectively be used to consider in greater detail the potential benefits of an energy supply scenario with significant amounts of Decentralized Energy (DE);
- First-run results confirm significant potential economic benefit with increasing DE, because of avoided transmission and distribution losses and associated investments;
- Because of the nature of Ontario's CG supply mix, there is a likelihood that increased DE may result in somewhat higher CO_2 emissions.

The WADE Economic Model

WADE has developed an economic model that compares the performance of DE and CG in meeting future electricity demand growth. The purpose of the Model is to calculate the economic and environmental impacts of supplying incremental electric load growth with varying mixes of DE and CG. It gives concrete numerical and graphical results for capital costs, retail costs, emissions and fuel use. The model allows complete flexibility in terms of evaluating options or scenarios for meeting future demand with different technologies and generation mixes. An emphasis on transmission and distribution network capital requirements (i.e. avoided network development costs) differentiates the model's approach from other energy economics analyses.

The WADE Economic Model has been used in a number of jurisdictions worldwide to evaluate the economic value of DE as a part of future energy supply mix. Studies have been done in the UK, Ireland, Scotland, Portugal, the European Union, China, Nigeria, Australia and the United States. Further information regarding the Model may be found in Appendix C of this report and at the URL:
http://www.localpower.org/resources/wademodel.htm

Present Study

The present study updates and recalibrates the model of the Ontario Power System constructed in 2006 with data recently published by the OPA as part of the IPSP consultation process. The first task of the present study is to calibrate the model using the OPA Preliminary Plan as presented.

With a calibrated model in hand, the second task is to update and analyse the Preliminary Plan and develop a critical assessment. In effect, this is a sensitivity analysis of the Preliminary Plan using realistic assumptions particularly with respect to the performance and cost of Ontario's current and proposed nuclear power plants.

The third task is to use the Updated model run to explore the impact, costs and environmental benefits of adopting strategies that would increase the penetration in Ontario of technologies with low environmental footprint, such as conservation and demand management (CDM), solar, wind, hydro, storage, cogeneration, and waste heat recycling with emphasis on distributed generation because of its potential for avoiding some of the transmission and distribution losses and associated investments. This resulted in two illustrative green scenarios: Soft Green and Deep Green.

The Soft Green scenario describes the impact of increased penetration of technologies such as wind, hydro, and CDM up to the higher levels envisioned as attainable by the OPA but not adopted in its Preliminary Plan. In addition there is greater penetration of solar, cogeneration and waste energy recycling. The outcome is that no new refurbishment of nuclear facilities is necessary beyond the amount already committed.

The Deep Green scenario illustrates a deeper penetration of green technologies to levels approaching what has been observed in selected jurisdictions world wide. It results in the avoidance of any refurbishment of nuclear plants (even though some refurbishments may have been committed) and the complete retirement of nuclear energy from Ontario by 2027. In addition, approximately half of the natural gas technologies, such as Combined Cycle and cogeneration, are required, as compared to the IPSP. The outcome is a further reduction in greenhouse gas emissions and a complete phase-out of nuclear power.

A detailed report prepared by WWF Canada and the Pembina Institute supporting information for the scenarios can be found in Appendix D.

Calibration with the OPA Preliminary Plan

The first task was to use the 2006 model run of the Ontario power system that was based on the Supply Mix Advice and re-calibrate it with data from the IPSP. Where new data was provided by the IPSP, this new data was given precedence. In addition, new CDM data was presented by the OPA to the Conservation Business Advisory Group in May 2007. This new data was given precedence over data in the Preliminary Plan. In other cases, data from the Supply Mix Advice was used.

The start year of the modelling work is 2007. The model then runs for the 20 years between 2008 and 2027.

Inputs

Electricity Demand

The Preliminary Plan prepared by the OPA was developed to supply growth over 20 years from in 2007 to 2027. However, some of the discussion papers provided data from 2005 to 2025. The modelling work described in this report covered the period from 2007 to 2027 and, where warranted, OPA data was adjusted accordingly.

Electricity generated by the power system was forecasted by the OPA to increase at an annual rate of 1.2% from 155 TWh in 2005 to 196 TWh in 2025. In this modelling work, the amount of electricity generated for the year 2007 starting point was determined by using data published by the Independent Electric System Operator (IESO) for 2006, as shown on Table 6. The 1.2 % growth rate was applied to the 2006 data to establish the expected 2007 amount of 157.9 TWh.

Peak demand was forecasted by the OPA to increase at an annual rate of 1.2% from 25,823 MW in 2005 to 32,531 MW in 2025. In the spreadsheet associated with the discussion papers, OPA indicated a peak of 26,399 MW in 2007 increasing to 34,899 in 2027. In this model run, the actual peak demand of 27,005 MW for 2006, as reported by IESO was increased by 1.2 % to provide the expected 2007 system peak of 27,337 MW. Accordingly, this study does not attempt to critique the OPA/IESO load forecast. It simply adjusts it to account for the higher 2006 actuals.

Annual growth rate numbers over the 20 year period used in this study were similar to those indicated by the OPA: 1.26% annual demand growth and 1.23% annual peak growth. These growth rates allow the model to match the OPA demand forecast for 2025 and 2027.

Table 6 – IESO Information

	IESO Monthly Generator Reports (April 2005 to March 2006)			IESO 2006 Press Release		IESO Reliability Report (March 2007)	
	Capacity (MW)	**Production (MWh)**	**Capacity Factor**	**Capacity (MW)**	**Production (MWh)**	**Capacity (MW)**	**Production (MWh)**
Central Generation							
Nuclear - Existing	11,045	80,597,364	83.3%		84,400,000	11,419	
Nuclear - Refurbished							
Nuclear - New							
Hydro	7,895	34,420,988	49.8%		34,800,000	7,788	
Interconnection							
Coal	6,358	28,664,347	51.5%		25,000,000	6,434	
Gas - Simple and Combined Cycle	2,736	10,038,989	41.9%		11,800,000	5,103	
Gas - Cogeneration (> 50MW)							
Gas/Oil	2,100	1,238,028	6.7%				
Biomass Cogeneration (> 50 MW)	151	298,989	22.7%				
Wind Farms	9	18,583	23.6%	300		395	
Total Central Generation	**30,294**	**155,277,288**	**58.5%**		**156,000,000**	**31,139**	
Decentralized Energy							
Conservation and Demand Management							
Demand Response							
Gas - Cogeneration (< 50 MW)							
Biomass - Cogeneration (< 50 MW)	74	223,573	34.5%			75	
Oil/Gas - Cogeneration (< 50 MW)							
Landfill and Biogas							

Solar							
Microturbines							
Substation Peakers							
Gas ICE (Backup)							
Total Decentralized Energy	**74**	**223,573**	**34.5%**	**0**	**0**	**75**	
Power System Total Supply	**30,368**	**155,500,861**	**58.5%**	**300**	**156,000,000**	**31,214**	
Ontario Internal Demand					151,000,000		152,300,000
Imports					6,200,000		
Exports					11,400,000		
Power System Total Demand					**156,200,000**		

Supply Resources

The supply mix in 2007 was arranged by the OPA according to a classification that mixed generating technologies and contractual supply arrangements. In order to use the data provided by the OPA in the WADE model, the supply mix had to be arranged into maximums of 15 central generation and 10 decentralized generation technologies. The model adds then attributes transmission and distribution losses to central generation technologies.

The 25 generation technologies modelled for the Ontario power system are discussed in the following sections along with comments as to how data provided by the OPA was adapted. Primary research was also conducted in order to validate the existing capacity in Ontario for various technologies. Appendix A., Tables A1 to A 9, provide the results of a survey of Ontario power generators.

In general, when data provided by the OPA was different than the data established by the survey, OPA data was used in the modelling work in order to maximize calibration with the IPSP. In other words, the numbers provided by the OPA for the total installed capacity of Ontario nuclear and coal power plants were used instead of the numbers published by Ontario Power Generation and Bruce Power.

However, the numbers provided by the OPA for natural gas generation were not immediately useable for the modelling work because the data was not segregated as to power only vs. cogeneration and as to large users (central generation) vs. onsite users (decentralized energy). Table 7 provided the reconciliation of OPA data with the numbers used as input for the modelling work. The capacities used as model input were based on the survey summarized in Appendix A. The total natural gas generation capacity used for model input is within 3% of the OPA total number. Accurate accounting of existing cogeneration capacity was necessary to allow recognition of its environmental benefits.

The survey also identified existing biomass and landfill gas capacities higher than the OPA numbers. The survey numbers were used to avoid ignoring existing plants. Table 7 also provides the reconciliation between the OPA numbers and the inputs into the model for biomass technologies. It is possible that some biomass plants also use natural gas and may be classified as such. The total of natural gas and biomass capacity used as model input is within 4% of OPA data.

The OPA does not provide a complete set of load factors applicable to each generation technology. In the modelling work, to maximize calibration with the OPA, load factors provided by the OPA were given precedence. However, it should be noted that load factors calculated from IESO 2005-06 monthly reports were used for the 2007 base year only. This resulted in electricity production amounts that matched information provided by IESO for 2006 and OPA for 2005. For the 20 year study period from 2008 to 2027, load factors provided in the OPA discussion papers were used.

In general, the load factors used by the OPA for future years were different than those calculated for 2006 using actual IESO data. The load factors for nuclear, cogeneration and biomass used by the OPA were significantly higher than values calculated from actual 2006 data. By contrast, load factors for coal and natural gas technologies were lower.

Table 7 – Reconciliation of OPA Natural Gas and Biomass Capacities with Model Data (MW)

	OPA Data		Calibration Run	
	2007	**2027**	**2007 Input**	**2027 Output**
Natural Gas				
Existing Gas	2,902	2,902		
Procurement Gas	485	3,265		
Other Generation Dev't. Gas	0	600		
Other Generation Dev't. Gas	0	414		
New Gas	0	1,486		
New Gas Peaking	0	750		726
Gas Combined Cycle (CCGT)			1,065	6,003
Industrial Gas Cogeneration (> 50 MW)			1,719	1,719
Industrial Gas/Oil Cogeneration (< 50 MW)			464	863
Oil/Gas	1,636	1,636	1.636	1,636
Total	**5,023**	**11,053**	**4,885**	**10,947**
Biomass				
Existing Biomass	68	68		
Procurement Biomass	5	5		
New Biomass	0	781		
Biomass & Landfill Gas (>50 MW)			150.6	372
Biomass & Landfill Gas (< 50 MW)			273.2	466
Total	**73**	**854**	**424**	**838**
Total (Natural Gas and Biomass)	**5,096**	**11,907**	**5,309**	**11,785**

Centralized Generation Technologies

- **Nuclear - Existing**: The capacities are those reported by the OPA (11,514 MW) as opposed to the numbers reported by OPG and Bruce Power (11,365 MW). The schedule for retirement is as per the OPA discussion paper.
- **Nuclear - Refurbished**: Includes procurement nuclear and refurbished nuclear. The schedule for refurbishment and target capacity in 2027 is as per the OPA discussion paper.
- **Nuclear - New**: Capacity is added as per the OPA.
- **Hydro**: Includes the OPA designations: Existing Hydro, Procurement Hydro, and New Hydro. The starting capacity is the installed capacity of 7,816 MW obtained by dividing the 5995 MW of effective capacity by the effective load factor of 76.7%. Installed capacity is added and reduced as per the OPA discussion paper. The effective load factor for new capacity is 71.1% as per the OPA.
- **Coal Steam Turbine**: The capacity is that reported by the OPA as opposed to the numbers reported by OPG. The schedule for retirement is as per the OPA, assuming that the "coal for insurance" will be needed because "coal for insurance" capacity in included in the total of required resources. The retirement schedule for the calibration run is as follows: 1,465 MW in 2011, 1,962 MW in 2012 and 2,987 MW in 2015[2].
- **Gas Combined Cycle (CCGT):** The 2007 capacity is that of the Brighton Beach and Goreway Phase 1 power plants, as per Appendix A. CCGT facilities with cogeneration capability are listed under Cogeneration to recognize their improved environmental performance. CCGT capacity is added to reach the OPA target in 2027.
- **Industrial Gas Cogeneration (> 50 MW):** 1,719 megawatts of cogeneration capacity was identified in Ontario as shown in Appendix A. No new capacity is added. The 414 MW of new cogeneration capacity identified by the OPA was added to the decentralized cogeneration technology.
- **Oil/Gas:** The starting capacity is that reported by the OPA which is assumed to be the Lennox power plant.
- **Wind Farms:** An installed capacity of 395 MW was determined by dividing the OPA effective capacity of 67 MW by the effective load factor of 17%. Capacity is added to match the OPA target for installed capacity.
- **Biomass Cogeneration (> 50 MW):** The starting capacity is the Kirkland Lake power plant. Capacity is added to match the OPA target in 2027 which is inferred to be the Atikokan and forestry segments.

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[2] The Ontario government recently announced that the program to phase-out coal power generation will be completed one year sooner than indicated in the IPSP. This recent change is not reflected in this modeling work in order to maximize calibration with the IPSP.

- **Interconnection:** In 2006, Ontario was a net exporter of electricity as reported by the IESO. In the Preliminary Plan, the OPA shows an effective interconnection capacity of 800 MW in 2007, presumably indicating that Ontario would be a net importer of electricity during peak time periods. In addition, the OPA plans “New Hydro Firm Purchases” of 1,500 MW during the 4 years from 2016 to 2019. Given that the OPA does not appear to assign GHG emissions to the interconnection generation, this capacity should be assumed to be hydroelectricity from Manitoba and Quebec using existing transmission and new facilities currently under construction.
  In this model run, interconnection capacity follows OPA assumptions, staring at 800 MW in 2007 and decreasing to 500 MW in 2027. The “New Hydro Firm Purchases” are treated as temporary increased amounts of interconnection. The load factor applied is reflective of a peak period use.
- **Storage:** Capacity is added as per the OPA. In principle, storage should have a load factor of zero or slightly less than zero because it does not represent a net addition to generation capacity and may in fact cause some net efficiency losses. However, the OPA methodology of assigning a 7% load factor to storage was followed.
- **Gas Simple Cycle (Peaking):** No capacity is shown for 2007. Capacity is added as per the OPA.
- **Coal Gasification:** No capacity is shown for 2007. Capacity is added as per the OPA. Full sequestration of CO_2 is assumed because the OPA does not assign any CO_2 emissions to coal gasification.
- **Solar (Greenfield):** This technology category applies to solar PV deployed in fields outside of urban areas, such as the recently approved Opti-Solar project. No capacity is shown for 2007. Capacity is added as per the OPA.

Decentralized Energy Technologies

As discussed above, the WADE model organizes power generation technologies according to the broad categories of central generation and decentralized energy. The model treats these categories differently in that transmission and distribution line losses are applied only to central generation. The cost for transmission and distribution can be independently adjusted for any central generation or decentralized energy technology.

The definition of decentralized energy is the subject of some debate and the purpose of this study is not to settle this matter. In this modeling work, generation technologies that would incur small or no line losses were classified as distributed energy. Generally, this means that all or some of the power is consumed on-site. However, existing cogeneration plants may be very large, over 500 megawatts. In this modeling work, large natural gas and biomass cogeneration facilities (> 50 MW) were treated as central generation while cogeneration plants less than 50 megawatts were classified as decentralized energy. Onsite renewable generation, self generation, substation peakers and waste energy recycling were also treated as decentralized energy. By contrast, wind farms, large hydro and greenfield solar installations were considered to be centralized generation.

The capacity numbers for CDM technologies are based on information communicated by the OPA to the Conservation Business Advisory Group in May 2007. In the Preliminary Plan, the total for CDM technologies was 6,135 MW and it was revised to 6,078 by the OPA in May 2007. However, a significant change from the Preliminary Plan was the removal of 500 MW of fuel cell capacity.

- **CDM (Efficiency):** The starting capacity is 199 MW as identified by the OPA for efficiency in the May 2007 update. Capacity is added as per the OPA.
- **CDM (Fuel Switching):** The starting capacity is 20 MW as identified by the OPA in May 2007. Capacity is added as per the OPA. No CO_2 emissions are associated with fuel switching because most analysts report that, when used in conjunction with demand side management, fuel switching results in no net GHG impact. The load factor is 310%% to reflect the fact that this technology has more impact on reducing electricity demand than reducing peak power requirements.
- **Demand Response, Time of Use Pricing & Conservation:** The starting capacity is the 81 MW identified by the OPA for demand response, conservation and time of use pricing. Capacity is added as per the OPA.
- **Industrial Gas Cogeneration (<50 MW):** The starting capacity is the 425 MW of small natural gas cogeneration capacity and the 39 MW identified for oil/gas, as listed in Appendix A. New capacity in the amount of 414 MW is added as per the OPA.
- **Biomass and Landfill Gas (< 50 MW):** The starting capacity is the 253 megawatts of small biomass cogeneration capacity identified in Appendix A and landfill gas (8.8 MW in 2006 plus 10.6 MW added in 2007). Capacity is added to meet the OPA target in 2027.
- **CDM Renewables (Onsite Wind & Hydro):** This category represents the OPA CDM Renewables category (onsite wind and hydro, except solar). Capacity is added to match the OPA target for CDM renewables.
- **Self Generation (CDM Cogen, Microturbines and Fuel Cells):** This category combines the OPA CDM Cogen with fuel cells, which were absent in the May revision. The Preliminary Plan presented in the discussion papers forecasted 500 MW of new fuel cell capacity by 2027. However, revised numbers provided to the CDM stakeholder advisory committee in May 2007 removed fuel cells as a specific category, presumably combining all self generation technologies together under the CDM umbrella.
  In the model run, this technology follows the OPA forecast, starting at 4 MW in 2007 and growing to 495 MW by 2027. The removal of the 500 MW of fuel cell capacity would result in 500 MW less of total installed capacity in 2027, as compared to the numbers shown in the Preliminary Plan. The power system's reserve margin would then become 17.3% in 2027, as opposed to 18.7% in the Preliminary Plan. However, the model was run to deliver a reserve margin of

18.7% in 2027, as per the original Preliminary Plan, thereby offsetting the loss of fuel cell capacity.

- **Solar (Rooftop):** There is no capacity in 2007. New capacity in the amount of 40 MW is added per the OPA.
- **Substation Peakers & CHeP**: There is no capacity in 2007 and none added.
- **Waste Heat Recycling:** There is no capacity in 2007 and none added.

Installed Capacity vs. Effective Capacity

The capacity numbers generally represented by the OPA are those for effective capacity during periods of peak demand as opposed to installed capacity. In effect, the OPA de-rated hydro installed capacity to 76.7% and wind to 17% to obtain their effective capacity during periods of peak demand.

The WADE model works from installed capacity. Therefore, OPA effective capacity numbers were converted back to installed capacity.

However, the WADE model applies two different load factors (capacity factors): one for determining electricity production and one for contribution to peak capacity. In keeping with OPA's methodology, hydro and wind load factors during peak demand were deemed to be 76.7% and 17% respectively. For all other technologies, the load factor during peak periods was set at 100% which is implied by OPA's approach.

The WADE model builds capacity to meet electricity demand. It also builds, when necessary, additional capacity to meet peak power demand. To do so, the model compares forecasted peak demand with the system's capacity during peak periods. The latter is calculated using installed capacities, the reserve margin, load factors during peak periods and transmission and distribution losses during peak periods.

The OPA Preliminary Plan and the green scenarios contemplate significant percentages of decentralized generation, from 15% to 30%. The calculation of effective capacity also needs to take into account the fact that, during peak periods, central generation is subject to high line losses, while decentralized energy is not. The model performs these calculations by applying peak line losses in the calculation of effective peak capacity.

CDM resources are energy saving resources that have a peak reduction impact. The OPA treats CDM as quasi supply resources that will assist the power system in meeting future demand and peak requirement. A similar approach was followed in this modelling work: CDM resources are entered as quasi supply resources with deemed installed capacities, effective capacities, load factors, and capital costs.

Line Losses

Line losses are a significant consideration. The International Energy Agency estimates that average transmission and distribution lines losses in OECD countries were 7% in 2003 (International Energy Agency 2005).

Generally, transmission and distribution losses increase with the square of the circuit loading i.e. doubling the current carried on a transmission or distribution circuit leads to quadrupling the energy losses. The result is that the rate of system energy loss rises steeply as the system becomes heavily loaded. Therefore line losses during peak periods are substantially higher than average line losses.

Transmission losses data used in this modelling work was provided in the OPA discussion papers, which were based on studies conducted by Navigant. Averaging the data found in the discussion papers resulted in estimates of 2.59% for average transmission losses and of 8.78% for peak transmission losses.

The OPA does not explicitly address the subject of distribution losses. Information provided in a recent Hydro One rate application estimates average distribution losses at 3.6% in urban areas and 7.3% in rural areas (Hydro One 2005). Estimating the electricity distribution infrastructure spilt in Ontario at 60% urban and 40% rural leads to an average for distribution losses across the system at 5.08%. This compares favourably with Hydro One's estimate for total distribution line losses of 5.05%. Distribution losses during peak periods are likely to be higher than average but relevant data was not found. As a conservative assumption, peak distribution losses were assumed to be identical to average distribution losses. However, future work to document peak distribution line losses is required.

In summary, central generation transmission and distribution losses used for this study were 7.67% on average and 13.86% during peak times. By contrast, decentralized generation was charged no losses on average and 3% losses during peak times, as per the default WADE Model setting.

Generation Costs

In the IPSP, the OPA does not provide information on total costs. Only a discussion of the costs/benefits of CDM and a summary of electricity cost to the consumer are provided. As explained in the following paragraphs, when available, cost information from the discussion papers was given precedence. Otherwise, information from the Supply Mix Advice and selected external references was used, as noted.

- **Capital Costs**: In this modelling work, capital costs and the operations and maintenance costs for generation technologies were generally those published by the OPA in the Supply Mix Advice. The capital costs of generation technologies used in this modelling work were as follows: $841/kW for CCGT and cogeneration (electrical side only), $1,959/kW for wind, $2,666/kW for hydro, $2,845/kW to $3,400/kW for nuclear and $5,613/kW (decreased over 20 years to $3,052/kW) for solar. A recent report by RBC Capital Markets forecasts that the total installed cost for PV solar will decline from approximately $7,370/kW in 2007 to $4,400/kW in 2011 reaching competitiveness to grid electricity without incentives in 2012-14 depending on the region (Bush and Riley 2007). Details of capital costs entered into the model are shown in Table B1 of Appendix B.
  The cost for new nuclear plants was set at $3,400 per kilowatt as per data reported by the OPA when estimating the value of CDM strategies.
  An amortization and cost of capital charge of 11% was used to match the OPA cost for generation. This allowed the costs of delivered electricity calculated by the model to match and calibrate with OPA's cost forecast.

- **CDM Costs**: The cost of CDM resources was based on the cost/benefit analysis in the context of a Total Resource Cost (TRC) test reported in the revised CDM discussion paper (p. 32 and p91 in Appendix B of the discussion paper). The costs for CDM include such items as incremental costs, administrative costs, fuel costs, etc. Total CDM costs are described as “Sums of delivery costs” and "Sums of societal costs".
  The present value of total CDM costs is $4.5 billion for delivering 5,400 MW of CDM, or $833 per kW of CDM. The CDM program avoids 5,900 MW of new generation, or $762 per kW of avoided generation. This estimate may be generally compared to capital costs for generation technologies. In this modelling work, $833/kW was assumed to be the total all inclusive cost for CDM on a present value basis. This cost was entered as a deemed capital cost for CDM as a quasi supply resource.
  The cost information reported by the OPA was in the context of a Total Resource Cost (TRC) analysis. It should be assumed that incentives are not included in the calculation of the $4.5 billion present value. Therefore, the CDM costs reported in this modelling work would not include amounts paid as incentives. However, OPA’s methodology would typically include incentive amounts in the calculation of the cost of delivered electricity to consumers. Clarification of the OPA’s treatment of CDM costs should be sought as part of the consultation process. Additional information about the nature of CDM costs (capital vs. operations and incentives) and costs differences between the major CDM technologies would also greatly enhance the accurate analysis and representation of CDM costs.
- **Operations and Maintenance Costs:** Operations and maintenance costs were generally the costs reported in the Supply Mix Advice. Fixed costs were spread over the annual amount of electricity produced calculated using the specified load factor. Details of operations and maintenance costs entered into the model are shown in Table B2 of Appendix B.
- **Fuel Costs:** The costs for coal and natural gas fuel were US$ 2.41/MMBTU and US$ 5.5/MMBTU respectively, based on the OPA discussion papers and the associated reports by Navigant. US dollars were converted to Canadian dollars at a rate of 0.90.
- **Interconnections:** Interconnections were assumed to use existing facilities. Therefore the use of interconnections would not result in new upfront or capital costs. To avoid inflating capital costs, interconnection technology was entered as having no capital cost but only fuel and operations costs. These costs were set to deliver the same delivered cost as hydro electricity.
- **Presentation of Cost Data:** Therefore, because of the treatment of CDM as a generation technology, the summary tables and charts in this report show capital costs that include capital costs for generation technologies but also all CDM costs, whether capital or operations. At a summary level, the cost results are accurate. However, the details of how costs are apportioned between capital and operations are less accurate because of the nature of the information provided by the OPA. There may be other ways to apportion the costs but they are unlikely to improve

accuracy at the detailed level. In order to improve accuracy at the detailed level, better information on costs is required, as well as treating CDM as a demand reduction resource, rather than a quasi supply resource. The recommendations associated with this report cover these aspects.

- **Levelized Unit Energy Costs:** The OPA summarizes all costs as Levelized Unit Energy Costs (LUEC). The Supply Mix Advice provided LUEC information for most generation technologies and the IPSP added some updated information. The WADE Model can be used to approximate LUEC as the cost of delivered electricity. Table B3 of Appendix B provides information about the cost of delivered electricity calculated by the model based on the parameters entered and compares them with OPA information where available. In general, costs calculated by the model fall within the ranges indicated by the OPA.

Transmission Costs

Transmission and distribution infrastructure costs are a significant part of the investments required to expand the power system. The International Energy Agency estimates that more than half of all future investments in the electricity industry will be for transmission and distribution infrastructure (International Energy Agency 2005).

The costs for transmission used for this modelling work were based on the OPA's Transmission discussion paper when relevant information was available. In the model, transmission costs are set by technology in $/kW. When generation capacity is added, an equivalent amount of transmission is added. Cost details are as follows:

- **Bruce to the GTA:** The cost for a new 500 kV transmission from Bruce to the GTA would be $600 million. The line would carry 1,500 MW, and the unit cost would be $400/MW. Furthermore, enabler investments of $100 million would be required ($66/kW). Total transmission investments between Bruce and the GTA are therefore $466/kW.
- **North Western Ontario to the GTA**: The elements are as follows:
    - Thunder Bay to Sudbury: one HVDC line carrying 1,500 to 2,000 MW and costing $1.6 to $2.0 billion ($1,028/kW);
    - Sudbury to Barrie: HVDC North-South tie carrying 1,000 to 1,500 MW for $800 million ($640/kW);
    - Barrie to GTA: investments of $200 million for carrying 1,500 MW ($133/k);
    - Total: $1,801/kW.
- **North Eastern Ontario to the GTA**: The elements are as follows:
    - Moose River to Sudbury: one 500 kV line carrying 1,500 MW and costing $800 million ($533/kW);
    - Sudbury to Barrie and Barrie to GTA are as above;
    - Total: $1,306/kW.

- **North American Average**: On the basis of costs published by the International Energy Agency, WADE estimated the average cost for building new transmission infrastructure in North America at US$ 317/kW, or CA$ 352/kW at a 0.90 exchange rate. The North American average was applied to new generation in southern Ontario.

The above transmission costs were applied as follows to the generation technologies:

- **Nuclear:** The transmission cost between Bruce and the GTA ($466/kW) was assigned.
- **Hydro**: Based on information found in discussion papers #4 (p 51) and #7 p. 51 to p. 62 the geographical distribution of new hydro resources was assumed as follows: 1,700 MW from north eastern Ontario and 150 MW from north western Ontario, for an average cost of $1,346/kW.
- **Wind Farms**: Based on the discussion papers referenced above, the mix of wind at the 6,000 MW level (reasonably close to 5,000 MW) is assumed as follows: 3,312 MW from southern Ontario, 2,124 MW from north eastern Ontario and 542 MW from north western Ontario. This results in an average cost of transmission of $822/kW. At the 10,000 MW level, the mix is as follows: 4,334 MW southern, 3,517 MW NE and 2,210 MW NW, for an average transmission cost of $1,003/kW.
- **The North American average** of $352/kW and was applied to CCGT, simple cycle gas, cogeneration, biomass, interconnection, coal gasification and solar greenfield; The transmission cost for interconnection was assumed to be at the North American average given that no large scale hydro imports from Manitoba appeared to be factored in the Preliminary Plan.

DE technologies were deemed to incur no transmission costs, except for DE cogeneration and biomass plants less than 50 MW which were assigned a transmission cost of $175 per kilowatt (approximately half of the North American average), in recognition of the fact that some of their power would be exported and carried by the grid.

The matter of sharing transmission corridors between generation technologies is not explicitly addressed. There will certainly be opportunities for transmission synergies that will be identified at a later stage when more detailed information becomes available.

Distribution Costs

The OPA did not explicitly address the issue of distribution costs except as a component of the cost of electricity delivered to consumers. In general, in this analysis, distribution costs are incurred by both CG and DE technologies. While DE technologies may or may not export electricity to grid, it is likely that the majority of users would require connection to grid, if only for backup purposes. Therefore, it is likely that users of DE technologies would require some levels of investment in distribution infrastructure. In this analysis, DE technologies are assumed to require, on average, half the infrastructure required for central generation technologies.

The capital cost for distribution infrastructure was set to $960 per kilowatt in order to yield a delivered cost distribution component of 2.1 cents per kilowatt hour similar to that calculated by the OPA

An exception was made for CDM efficiency, fuel switching, demand response, conservation and time of use pricing which obviously do not incur any distribution infrastructure costs.

As Spent Costs vs. Net Present Value Costs

The model in its present form only calculates total capital costs on an as spent basis, not on a Net Present Value (NPV) basis. It is important to mention that different methods of presenting costs may lead to different conclusions.

At the same level of as spent dollars, capital intensive technologies such as nuclear will result in a higher NPV cost than less capital intensive technologies such as natural gas turbines. Furthermore, large scale capital intensive technologies such as nuclear will also result in higher NPV costs than small scale capital intensive technologies such as solar because nuclear costs are incurred several years ahead of demand while solar is generally added year by year as needed.

Future work and the ability to perform NPV calculations is required to more accurately represent the actual cost of large scale capital intensive technologies when comparing them with small scale distributed generation.

Environmental

The greenhouse gas emissions reported by the model are not on a life cycle basis as are those used by the OPA. The model only calculates the CO_2 emissions associated with the combustion of coal, natural gas and oil. The model assigns no GHG emissions to nuclear, hydro, wind or solar technologies.

The air emissions of cogeneration technologies entered into the model are for the electrical side only. Air emissions are allocated between the electrical and thermal sides by assuming that cogeneration displaces a conventional 80% energy efficient boiler.

The NOx and SOx emissions factors for the various technologies were those provided in the Supply Mix Advice, except where new data was provided in the IPSP discussion papers. NOx and SOx emissions are charged to biomass technologies.

This analysis and modelling work is however limited in terms of assessment of environmental impacts. The model only estimates atmospheric impacts and other types of impacts, such as water pollution and waste generation are not fully accounted for.

Outputs

Table 8 summarizes the inputs and outputs of the model and compares them with relevant items of the OPA Preliminary Plan.

Table 8 - Calibration Run of the OPA Preliminary Plan as Presented vs. OPA and IESO Data

	2007				2027		
	IESO (2006)	OPA IPSP (Dec 2006)		Model Input (2007)	OPA IPSP (Dec 2006)		Model Output (2027)
		As Stated	Adjusted to Model Structure		As Stated	Adjusted to Model Structure	
Electricity Sales -TWh				146.1			187.8
Average Transmission and Distribution Losses (%)				7.67%			
Electricity Generated - TWh	156 (in 2006)	155 (in 2005)		157.92	196 (in 2025)		200.8
Electricity Demand Growth Rate - %		1.2%		1.26%			
Peak Demand - MW	27,005 (in 2006)	26,399		27,337	34,899	34,899	34,898
Peak Demand Growth Rate - %		1.2%		1.23%			
Peak Transmission and Distribution Losses (%)				13.86%			
Effective Capacity - MW		30,229		30,424	41,433		41,433
Reserve Margin (%)		14.5%		11.3%	18.7%		18.7%
Installed Capacity - MW	31,214 (March 2007)		32,382	32,573	47,856	47,569	46,799
Nuclear - Existing			11,514	11,514		750	750
Nuclear - Refurbished			0	0		10,484	10,213
Nuclear - New			0	0		1,400	1,400
Hydro			7,819	7,816		10,095	10,001
Coal ST			6,434	6,434		0	0

Gas Combined Cycle (CCGT)			1,204	1,065		6,109	6,003
Industrial Gas Cogeneration (> 50 MW)			1,719	1,719		1,719	1,719
Oil/Gas			1,636	1,636		1,636	1,636
Wind Farms			395	395		5,025	4,925
Biomass & Landfill Gas (> 50 MW)			0	151		379	372
Interconnection			800	800		500	490
Storage			0	0		1,000	985
Gas Simple Cycle (Peaking)			0	0		750	726
Coal Gasification			0	0		250	244
Solar (Greenfield)			0	0		40	40
Total Central Generation - MW			31,522	31,530		40,138	39,504
CDM (Efficiency and Solar DHW)			199	199		3,712	3,644
CDM (Fuel Switching)			20	20		203	200
Demand response, TOU Pricing & Conservation			81	81		1,458	1,431
Industrial Gas Cogeneration (<50 MW)			464	464		878	863
Biomass & Landfill Gas (< 50 MW)			73	273		475	466
CDM Renewables (Onsite Wind & Hydro)			19	2		170	167
Self Generation (CDM Cogen, Microturbines & Fuel Cells)			4	4		495	485
Solar (Rooftop)			0	0		40	40
Substation Peaker & CHeP			0	0		0	0
Waste Heat Recycling			0	0		0	0
Total Decentralized Energy - MW			860	1,044		7,431	7,295

Total CG and DE - MW			32,382	32,573		47,569	46,799
Costs							
Total Capital Costs over 20 Years - $ billion							$101.5
Generation							$64.6
Transmission							$10.7
Distribution							$26.3
Total Delivered Electricity Costs in 2027 - ¢/kWh						¢11.091	¢10.552
Generation Capital						¢7.544	¢5.488
Fuel							¢0.632
Operation & Maintenance							¢1.310
CO2							¢0.039
Conservation						¢0.472	
Transmission						¢0.974	¢0.978
Distribution						¢2.101	¢2.105
Environmental							
GHG (Total in 2027) - million tonnes					11.57		
GHG (Coal, Gas & Oil in 2027) - million tonnes/yr						8.13	8.49
GHG (Coal, Gas & Oil; 2007 to 2027) - million tonnes							286
GHG (Total in 2007) - kg/MWh					55		
GHG (Coal, Gas & Oil in 2027) - kg/MWh							42
NOx (Total in 2027) - tonnes/yr					36,110		
NOx (Coal, Gas, Oil & Biomass in 2027) - tonnes/yr						8,023	5,952
NOx (Total in 2027) - kg/MWh					0.171		
NOx (Coal, Gas, Oil & Biomass in 2027) - kg/MWh							0.030

	SOx (Total in 2027) - tonnes/yr					6,210		
	SOx (Coal, Gas & Oil in 2027) - tonnes/yr						1,347	1,383
	SOx (Total in 2027) - kg/MWh					0.029		
	SOx (Coal, Gas & Oil in 2027) - kg/MWh							0.0069
	Nuclear Electricity (in 2027) - TWh							91.4
	Nuclear Electricity (2007 to 2027) - TWh							1,851

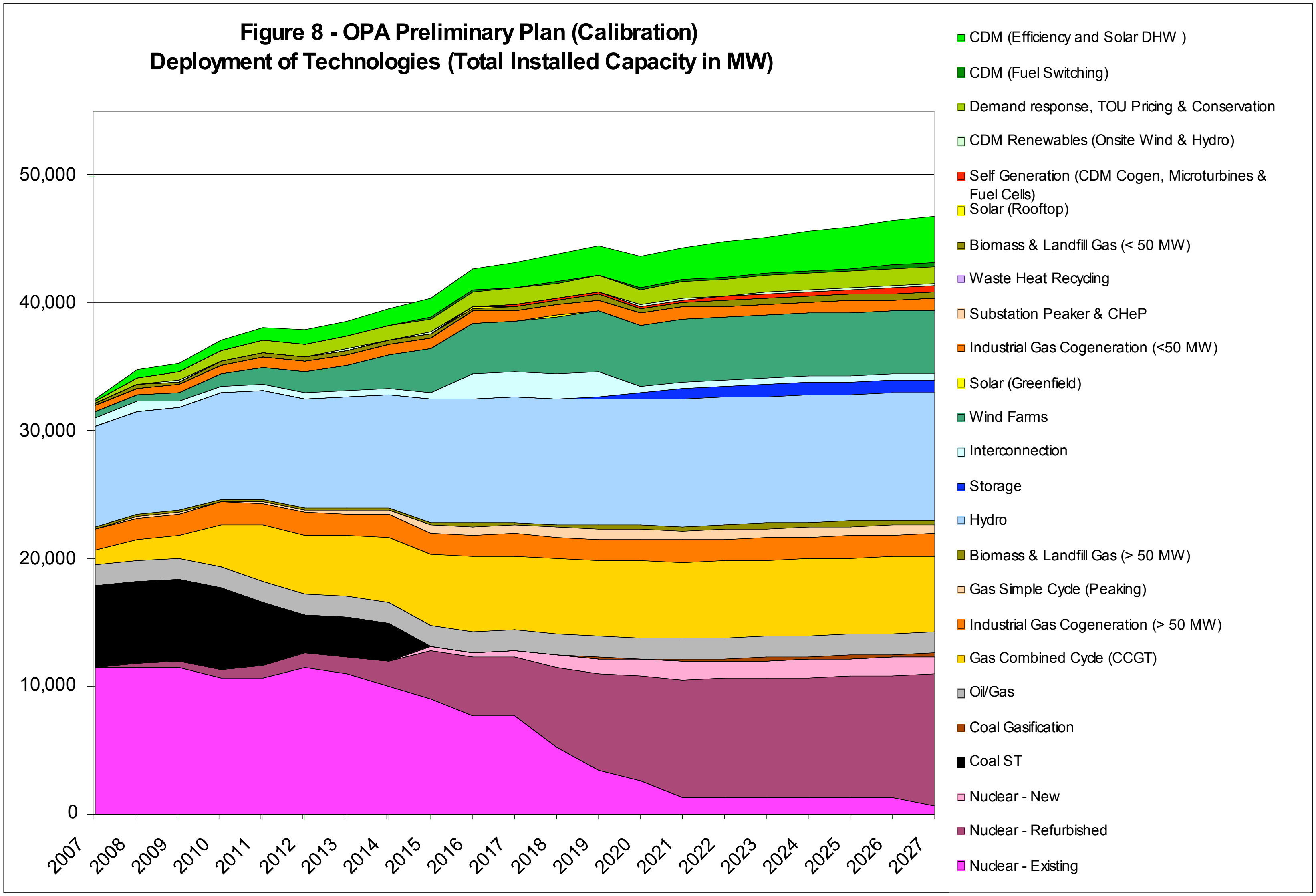
Figure 8 - OPA Preliminary Plan (Calibration)
Deployment of Technologies (Total Installed Capacity in MW)
50,000
40,000
30,000
20,000
10,000
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

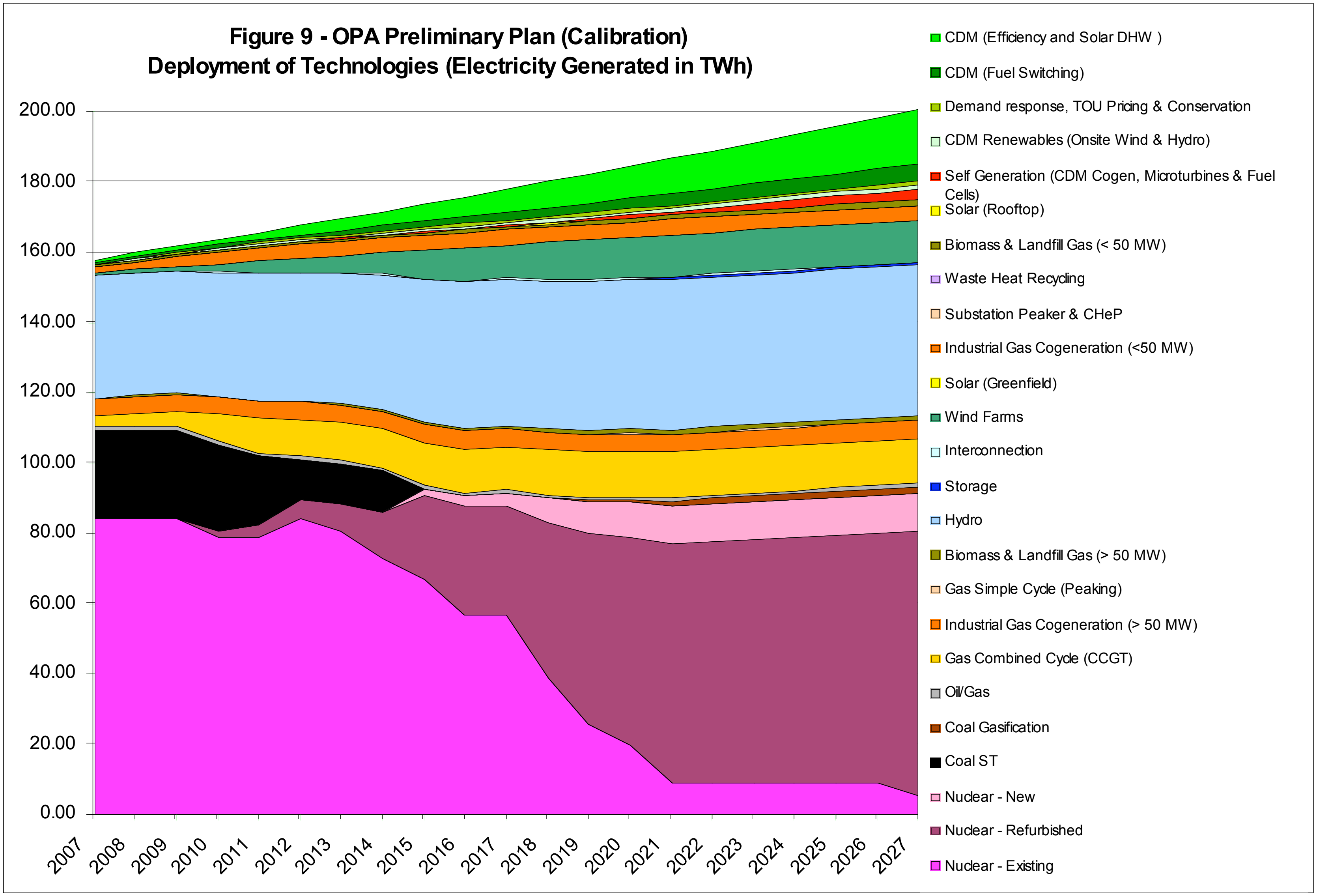
Figure 9 - OPA Preliminary Plan (Calibration)
Deployment of Technologies (Electricity Generated in TWh)
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

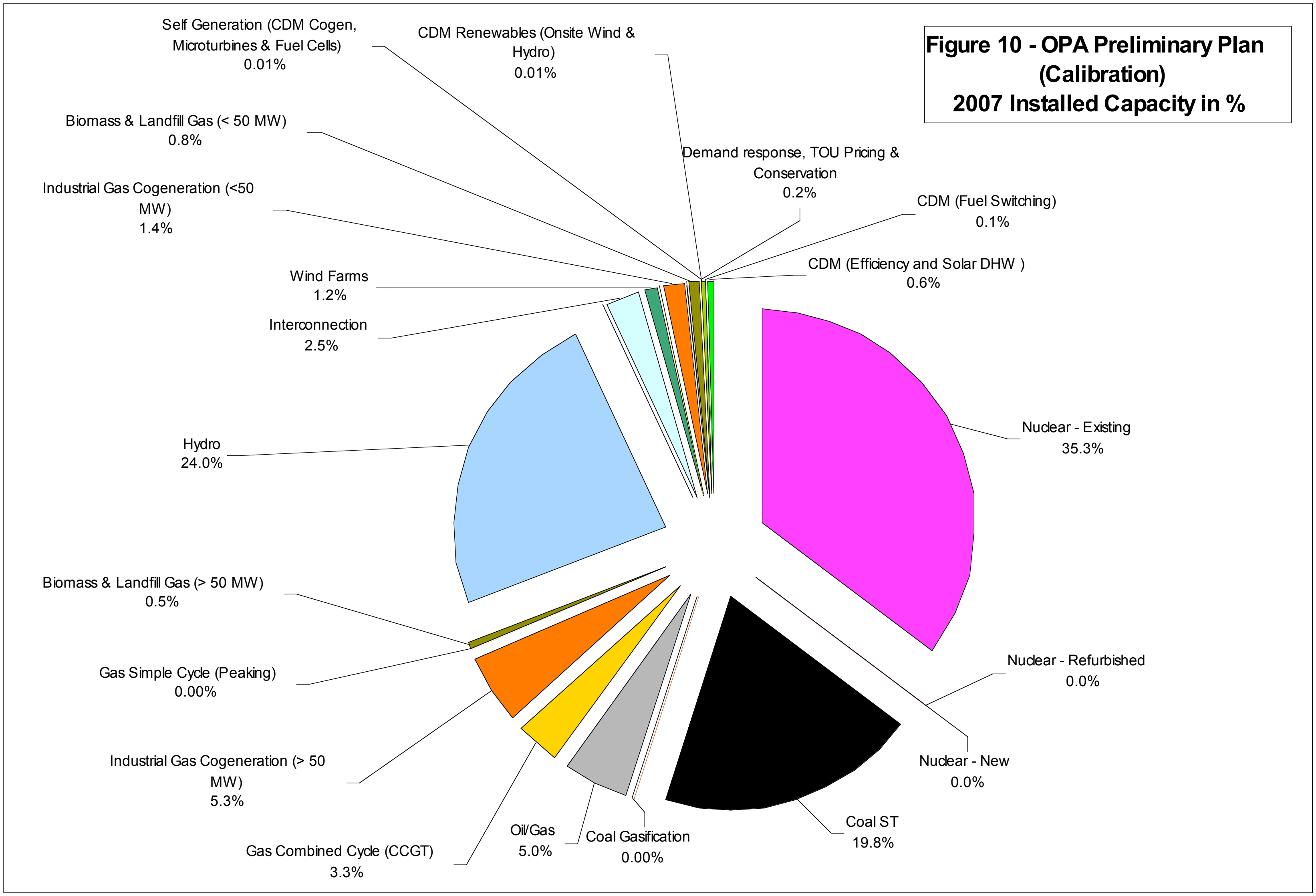
Figure 10 - OPA Preliminary Plan (Calibration)
2007 Installed Capacity in %
Self Generation (CDM Cogen, Microturbines & Fuel Cells) 0.01%
CDM Renewables (Onsite Wind & Hydro) 0.01%
Biomass & Landfill Gas (< 50 MW) 0.8%
Demand response, TOU Pricing & Conservation 0.2%
Industrial Gas Cogeneration (<50 MW) 1.4%
CDM (Fuel Switching) 0.1%
CDM (Efficiency and Solar DHW) 0.6%
Wind Farms 1.2%
Interconnection 2.5%
Hydro 24.0%
Nuclear - Existing 35.3%
Biomass & Landfill Gas (> 50 MW) 0.5%
Gas Simple Cycle (Peaking) 0.00%
Nuclear - Refurbished 0.0%
Industrial Gas Cogeneration (> 50 MW) 5.3%
Nuclear - New 0.0%
Coal ST 19.8%
Oil/Gas 5.0%
Coal Gasification 0.00%
Gas Combined Cycle (CCGT) 3.3%

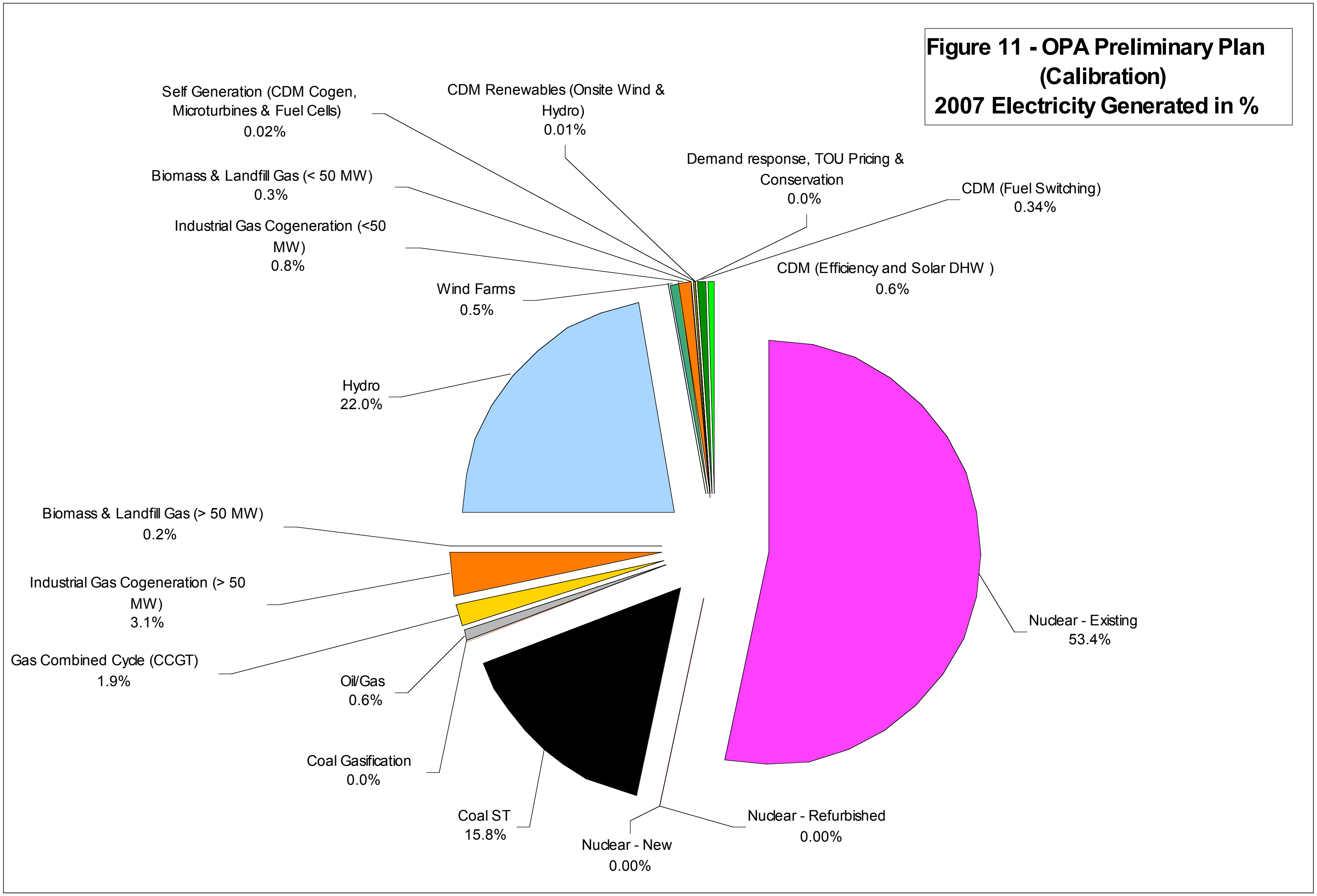
Figure 11 - OPA Preliminary Plan (Calibration)
2007 Electricity Generated in %
Self Generation (CDM Cogen, Microturbines & Fuel Cells) 0.02%
CDM Renewables (Onsite Wind & Hydro) 0.01%
Demand response, TOU Pricing & Conservation 0.0%
CDM (Fuel Switching) 0.34%
Biomass & Landfill Gas (< 50 MW) 0.3%
Industrial Gas Cogeneration (<50 MW) 0.8%
CDM (Efficiency and Solar DHW) 0.6%
Wind Farms 0.5%
Hydro 22.0%
Biomass & Landfill Gas (> 50 MW) 0.2%
Industrial Gas Cogeneration (> 50 MW) 3.1%
Gas Combined Cycle (CCGT) 1.9%
Oil/Gas 0.6%
Nuclear - Existing 53.4%
Coal Gasification 0.0%
Coal ST 15.8%
Nuclear - Refurbished 0.00%
Nuclear - New 0.00%

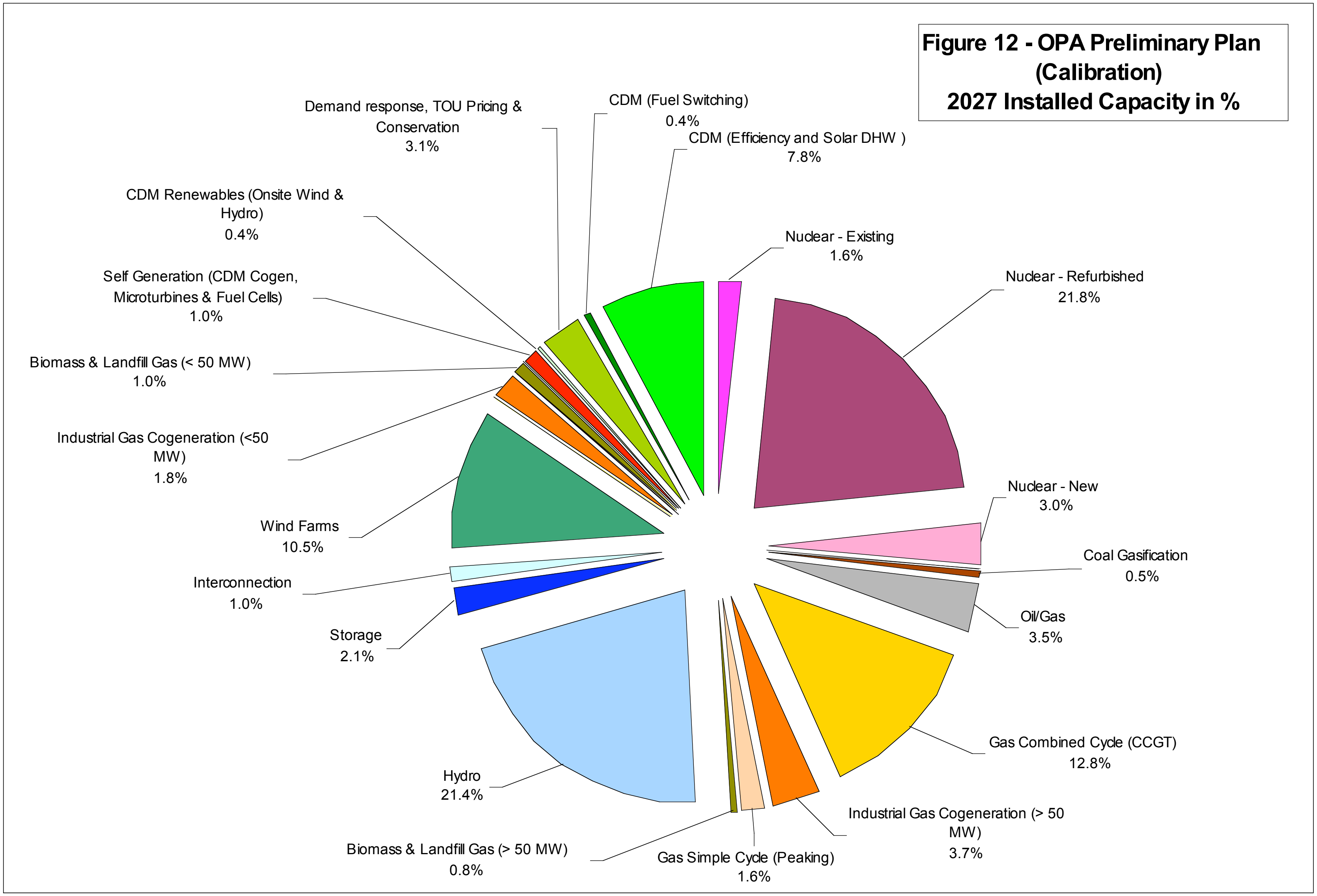
Figure 12 - OPA Preliminary Plan (Calibration) 2027 Installed Capacity in %
Demand response, TOU Pricing & Conservation 3.1%
CDM (Fuel Switching) 0.4%
CDM (Efficiency and Solar DHW) 7.8%
CDM Renewables (Onsite Wind & Hydro) 0.4%
Nuclear - Existing 1.6%
Nuclear - Refurbished 21.8%
Self Generation (CDM Cogen, Microturbines & Fuel Cells) 1.0%
Biomass & Landfill Gas (< 50 MW) 1.0%
Industrial Gas Cogeneration (<50 MW) 1.8%
Wind Farms 10.5%
Nuclear - New 3.0%
Coal Gasification 0.5%
Interconnection 1.0%
Storage 2.1%
Oil/Gas 3.5%
Gas Combined Cycle (CCGT) 12.8%
Hydro 21.4%
Industrial Gas Cogeneration (> 50 MW) 3.7%
Biomass & Landfill Gas (> 50 MW) 0.8%
Gas Simple Cycle (Peaking) 1.6%

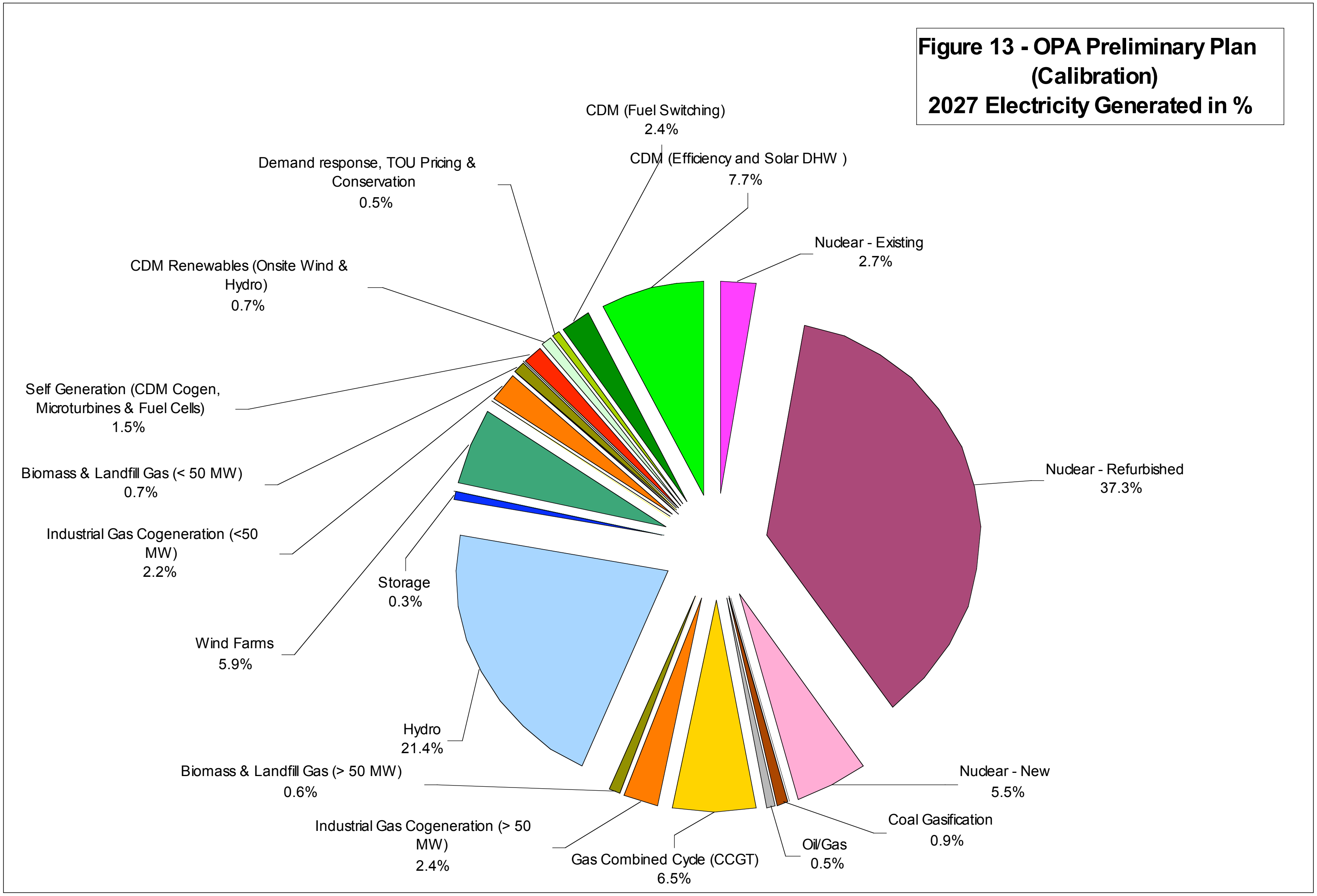
Figure 13 - OPA Preliminary Plan (Calibration)
2027 Electricity Generated in %
CDM (Fuel Switching) 2.4%
CDM (Efficiency and Solar DHW) 7.7%
Demand response, TOU Pricing & Conservation 0.5%
Nuclear - Existing 2.7%
CDM Renewables (Onsite Wind & Hydro) 0.7%
Self Generation (CDM Cogen, Microturbines & Fuel Cells) 1.5%
Nuclear - Refurbished 37.3%
Biomass & Landfill Gas (< 50 MW) 0.7%
Industrial Gas Cogeneration (<50 MW) 2.2%
Storage 0.3%
Wind Farms 5.9%
Hydro 21.4%
Biomass & Landfill Gas (> 50 MW) 0.6%
Nuclear - New 5.5%
Coal Gasification 0.9%
Industrial Gas Cogeneration (> 50 MW) 2.4%
Oil/Gas 0.5%
Gas Combined Cycle (CCGT) 6.5%

Electricity Demand

The amount of electricity generated in 2025, as predicted by the model, is 196.0 TWh and the same as forecasted by the OPA. In 2027, the model forecasts a system peak of 34,898 MW which matches the OPA's 34,899 MW.

Supply Resources

System capacity in 2027 and the individual generation technologies compare well with the Preliminary Plan and are within 3% of OPA values. Figures 8 and 9 present the deployment of the various technologies of the basis of installed generation capacity and electricity production respectively. As discussed above, installed capacities are different than the effective capacities used by the OPA. CDM technologies are treated as quasi supply resources and their "installed capacity" is numerically identical to their peak reduction capacity.

Figures 10 and 11 illustrate the mix of technologies in 2007, while Figures 12 and 13 do the same for 2027.

The share of decentralized energy under the OPA Preliminary Plan, including CDM, is 15.6% in 2027.

Costs

Capital costs for implementing the Preliminary Plan are $100.5 billion, as calculated by the model on an as spent basis in current dollars, as shown by Table 9.

Table 9 – Comparison of Model Cost Outputs with the Preliminary Plan

	OPA Preliminary Plan	Model Output
Total Capital Costs over 20 Years - $ billion		$101.5
Generation		$64.6
Transmission		$10.7
Distribution		$26.3
Total Delivered Electricity Costs in 2027 - ¢/kWh	¢11.091	¢10.552
Generation Capital	¢7.544	¢5.488
Fuel		¢0.632
Operation & Maintenance		¢1.310
CO_2		¢0.039
Conservation	¢0.472	
Transmission	¢0.974	¢0.978
Distribution	¢2.101	¢2.105

Cost components in terms of generation, transmission and distribution are also reported.

The cost for delivered electricity is slightly lower than OPA's estimate. However, this may be explained by the fact that, as discussed above, the model's cost estimate does not include incentive amounts while the OPA's estimate does. Given this difference, the model's cost estimate calibrates reasonably well the OPA's forecast of cost to customers.

Environmental

The model calculates greenhouse gas emissions from the heat rate, load factor, fuel use and fuel CO_2 factor used by each technology. The model does not calculate life cycle GHG emissions. CO_2 emissions predicted by the model are within 5% of emissions forecasted by the OPA for coal, natural gas and oil, as indicated in Table 10.

Emissions of NOx and SOx pollutants predicted by the model are also similar to OPA numbers.

Table 10 – Comparison of Model Environmental Outputs with the Preliminary Plan

	OPA Preliminary Plan	Model Output
GHG (Coal, Gas & Oil in 2027) - million tonnes/yr	8.13	8.49
GHG (Coal, Gas & Oil; 2007 to 2027) - million tonnes		286
GHG (Coal, Gas & Oil in 2027) - kg/MWh		42
NOx (Coal, Gas, Oil & Biomass in 2027) - tonnes/yr	8,023	5,952
NOx (Coal, Gas, Oil & Biomass in 2027) - kg/MWh		0.030
SOx (Coal, Gas & Oil in 2027) - tonnes/yr	1,347	1,383
SOx (Coal, Gas & Oil in 2027) - kg/MWh		0.0069
Nuclear Electricity (in 2027) - TWh		91.4
Nuclear Electricity (2007 to 2027) - TWh		1,851

Coal for Insurance

As mentioned earlier in this report, the calibration model run was done with the assumption that the capacity amounts labelled "Coal for Insurance" by the OPA would be needed and operating to produced electricity. Information in the discussion papers does not allow a clear determination of how the OPA treated Coal for Insurance in the load calculations of the Preliminary Plan. For this calibration model run, the Coal for Insurance capacity was deemed to be operating because this capacity is included in the tables and totals of the discussion papers and the associated spreadsheets.

However, for completeness, the model was also run under the assumption that the Coal for Insurance would not run but simply stand idle. The results from this run are reproduced in Appendix B, Table B6. The results show that the operation of the Coal for Insurance results in higher total air emissions over the 20 year study period: 286 million tonnes of CO_2 are emitted when the Coal for Insurance capacity is fully utilized and opposed to 224 million tonnes when the same capacity stands idle. Other outcomes such as costs and amounts of installed capacities in 2027 are virtually unchanged.

Update of the OPA Preliminary Plan

The second task of the study was to critically analyse the assumptions made by the OPA and, as required, input into the model modified, realistic assumptions. In particular, OPA assumptions concerning the performance and cost of Ontario's existing and proposed nuclear facilities were reviewed.

Inputs

Most inputs into this model run are the same as for the calibration model run where all OPA information was input as stated except for the necessary adjustments to account for differences in methodology. However, in this second model run, changes were made to OPA assumptions concerning the performance and cost of current and proposed nuclear facilities, as follows:

- The load factor for nuclear technologies was reduced from the 87.8% and 90% optimistically forecasted by the OPA to the historical average of 72% as calculated from data provided by the OPA's discussion paper concerning supply resources.
- The costs of nuclear technologies were increased to match the cost reported by the Ontario Auditor General (OAG) report on Bruce Power. In this report, the OAG estimated the cost of refurbished nuclear power at $71.33 per megawatt hour plus $12.56 per megawatt hour as the value of inflation protection provided by the contract, for a total of $83.89/MWh. The expected lifetime of nuclear plants was also shortened from 30 years to 25 years in the OAG report.
  In addition, the Pembina Institute has calculated that the value of the absorption of the debt retirement charge amounts to $10.50 per megawatt hour. Therefore, the real cost of nuclear electricity may be as high as $94.39 per megawatt hour. Other observers, such as Energy Probe, have also reported on the probability of the repeat of cost overruns which have historically plagued the nuclear industry.
  In this Updated model run, the cost of nuclear electricity was increased to match the estimate reported by the OAG. The information compiled by the Pembina Institute and others is mentioned simply to indicate that nuclear costs have a probability to be higher. In order to match the cost reported by the OAG in this model run, the amortization and cost of capital charge for nuclear technologies was increased from 11% to 12.92% while capital costs remained the same as in the Supply Mix Advice. This change increased the cost of power for refurbished facilities to the amount reported by the OAG, or $83.89 per MWh. The same cost parameters were applied

to the cost of new nuclear facilities, except that the installed cost was set at $3,400 per kW as indicated earlier, resulting in a unit cost of $96.69 per MWh for new nuclear plants.

Despite the lower load factor for nuclear plants, the total capacity of nuclear capacity built over 20 years was kept the same as in the Preliminary Plan. This resulted in less electricity produced by nuclear facilities. Retirement of the coal plants was delayed by two years in order to allow load balancing during the transition period. The retirement schedule was updated as follows: 1,465 MW in 2013, 1,982 MW in 2014 and 2,987 MW in 2017. A summary of coal-fired capacity for all model runs is shown in Table B4 of Appendix B. The assumption of a 2 year delay in the retirement of coal plants, while it resulted in slightly lower costs and 2027 emissions, is only indicative. Additional information and further study may indicate that a different delay period would be preferable.

To compensate for the electricity not produced by nuclear facilities, natural gas combined cycle capacity was increased by 75% while all other technologies were kept at the same levels as in the Preliminary Plan.

In the Preliminary Plan, it appeared that the OPA assumed full sequestration of CO_2 for the 250 MW coal gasification facility. However, the geology and geography of Ontario would make CO_2 sequestration difficult. For this critical assessment of the Preliminary Plan, the sequestration feature was removed from the gasification facility. As a result, CO_2 emissions are increased but capital and operating costs are reduced.

Outputs

Table 11 presents a comparison of all model runs inputs and outputs. Figures 14 and 15 graphically represent the deployment of technologies for the Updated model run of the OPA Preliminary Plan, and Figures 16 and 17 describe the mix of technologies in 2027. The mix of technologies in 2007 is unchanged from the calibration run.

The following outcomes are worth noting:

- The installed capacity for the total power system increases by approximately 12%, as compared to the calibration run, to account for the lower amounts of electricity produced by nuclear facilities. Installed capacities are similar for all technologies, except for CCGT which is increased by approximately 75%.
- The retirement of coal facilities is delayed by 2 years and more electricity is produced by coal fired facilities during the 20 year period.
- Capital costs are approximately 12% higher while delivered costs are 17% higher. Capital costs are higher due to the higher cost of the nuclear generation component and due to the higher amount of total capacity required.
- Greenhouse gas emissions are higher than for the calibration run because in 2027, more electricity is produced by natural gas facilities, at the expense of nuclear facilities.
- Total greenhouse gas emissions over the 20 year period are higher mostly because the coal facilities are kept in operation for a longer period of time.

Table 11 - Ontario Power System - Model Run Comparison

	Inputs (2007)			Outputs (2027)					
	OPA IPSP (Dec 2006)		Model Input	OPA IPSP (Dec 2006)		Model Runs			
	As Stated	Adjusted to Model Structure		As Stated	Adjusted to Model Structure	OPA Plan (Calibration)	OPA Plan (Updated)	Soft Green	Deep Green
System Statistics									
Electricity Sales -TWh			146.1			187.8	187.8	187.8	187.8
Average Transmission and Distribution Losses (%)			7.67%						
Electricity Generated - TWh	155 (in 2005)		157.9	196 (in 2025)		200.8	200.7	199.0	197.7
Electricity Demand Growth Rate - %	1.2%		1.26%						
Peak Demand - MW	26,399		27,337	34,899	34,899	34,898	34,898	34,898	34,898
Peak Demand Growth Rate - %	1.2%		1.23%						
Peak Transmission and Distribution Losses (%)			13.86%						
Effective Capacity - MW	30,229		30,424	41,433		41,433	41,433	41,433	41,433
Reserve Margin	14.5%		11.3%	18.7%		18.7%	18.7%	18.7%	18.7%
Installed Capacity - MW		32,382	32,573	47,856	47,569	46,799	52,471	52,967	55,271
Nuclear - Existing		11,514	11,514		750	750	750	750	0
Nuclear - Refurbished		0	0		10,484	10,213	10,493	3,428	0
Nuclear - New		0	0		1,400	1,400	1,400	0	0
Hydro		7,819	7,816		10,095	10,001	10,102	10,904	10,937

	Coal ST		6,434	6,434		0	0	0	0	0
	Gas Combined Cycle (CCGT)		1,204	1,065		6,109	6,003	10,967	3,457	2,236
	Industrial Gas Cogeneration (> 50 MW)		1,719	1,719		1,719	1,719	1,719	2,719	2,723
	Oil/Gas		1,636	1,636		1,636	1,636	1,636	1,636	0
	Wind Farms		395	395		5,025	4,925	5,039	10,137	15,256
	Biomass & Landfill Gas (> 50 MW)		0	151		379	372	379	594	578
	Interconnection		800	800		500	490	502	3,543	3,549
	Storage		0	0		1,000	985	1,010	1,021	1,106
	Gas Simple Cycle (Peaking)		0	0		750	726	753	400	400
	Coal Gasification		0	0		250	244	251	0	0
	Solar (Greenfield)		0	0		40	40	40	806	1,006
Total Central Generation - MW			31,522	31,530		40,138	39,504	45,040	39,395	37,793
	CDM (Efficiency and Solar DHW)		199	199		3,712	3,644	3,713	5,673	7,538
	CDM (Fuel Switching)		20	20		203	200	203	308	501
	Demand response, TOU Pricing & Conservation		81	81		1,458	1,431	1,457	2,147	2,503
	Industrial Gas Cogeneration (<50 MW)		464	464		878	863	878	878	878
	Biomass & Landfill Gas (< 50 MW)		73	273		475	466	475	698	694
	CDM Renewables (Onsite Wind & Hydro)		19	2		170	167	170	170	170
	Self Generation (CDM Cogen, Microturbines & Fuel Cells)		4	4		495	485	495	837	834
	Solar (Rooftop)		0	0		40	40	40	1,504	3,005
	Substation Peaker & CHeP		0	0		0	0	0	100	100
	Waste Heat Recycling		0	0		0	0	0	1,257	1,253

Total Decentralized Energy - MW		860	1,044		7,431	7,295	7,431	13,572	17,479
Total CG and DE - MW		32,382	32,573		47,569	46,799	52,471	52,967	55,271
Costs									
Total Capital Expenditures from 2007 to 2027 - $ billion						$101.5	$113.3	$109.1	$128.4
Generation						$64.6	$70.2	$69.3	$84.5
Transmission						$10.7	$12.5	$11.7	$12.9
Distribution						$26.3	$30.7	$28.2	$31.1
Total Delivered Electricity Costs in 2027 - ¢/kWh					¢11.091	¢10.552	¢12.372	¢10.993	¢11.879
Generation Capital					¢7.544	¢5.488	¢6.507	¢6.165	¢7.059
Fuel						¢0.632	¢0.932	¢0.471	¢0.366
Operation & Maintenance						¢1.310	¢1.238	¢1.001	¢0.917
CO2						¢0.039	¢0.096	¢0.027	¢0.019
Conservation					¢0.472	¢0.000	¢0.000	¢0.000	¢0.000
Transmission					¢0.974	¢0.978	¢1.141	¢0.927	¢0.979
Distribution					¢2.101	¢2.105	¢2.457	¢2.403	¢2.538
Environmental									
GHG (Life Cycle Total in 2027) - million tonnes				11.57					
GHG (Coal, Gas & Oil in 2027) - million tonnes/yr					8.13	8.49	13.80	8.02	6.82
GHG (Coal, Gas & Oil; 2007 to 2027) - million tonnes						286	383	192	178
GHG (Life Cycle Total in 2007) - kg/MWh				55					
GHG (Coal, Gas & Oil in 2027) - kg/MWh						42	69	40	35
NOx (Life Cycle Total in 2027) - tonnes/yr				36,110					

	NOx (Coal, Gas & Oil in 2027) - tonnes/yr					8,023	5,952	8,723	4,215	3,518
	NOx (Life Cycle Total in 2027) - kg/MWh				0.171					
	NOx (Coal, Gas & Oil in 2027) - kg/MWh						0.030	0.043	0.021	0.018
	SOx (Life Cycle Total in 2027) - tonnes/yr				6,210					
	SOx (Coal, Gas & Oil in 2027) - tonnes/yr					1,347	1,383	1,509	335	308
	SOx (Life Cycle Total in 2027) - kg/MWh				0.029					
	SOx (Coal, Gas & Oil in 2027) - kg/MWh						0.0069	0.0075	0.0017	0.0016
	Nuclear Electricity (in 2027) - TWh						91.4	77.3	26.2	0.0
	Nuclear Electricity (2007 to 2027) - TWh						1,851	1,646	1,167	969

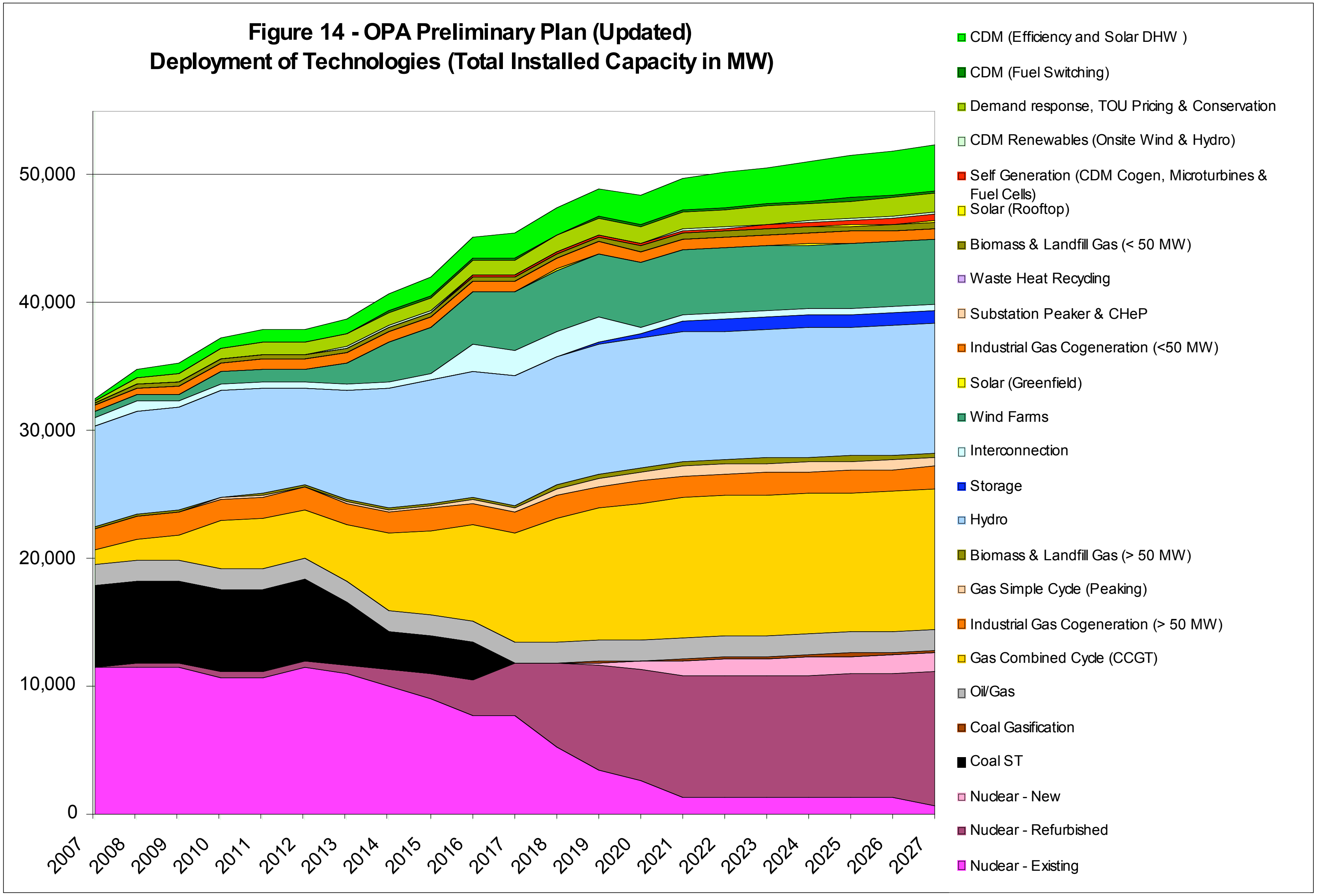
Figure 14 - OPA Preliminary Plan (Updated)
Deployment of Technologies (Total Installed Capacity in MW)
50,000
40,000
30,000
20,000
10,000
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

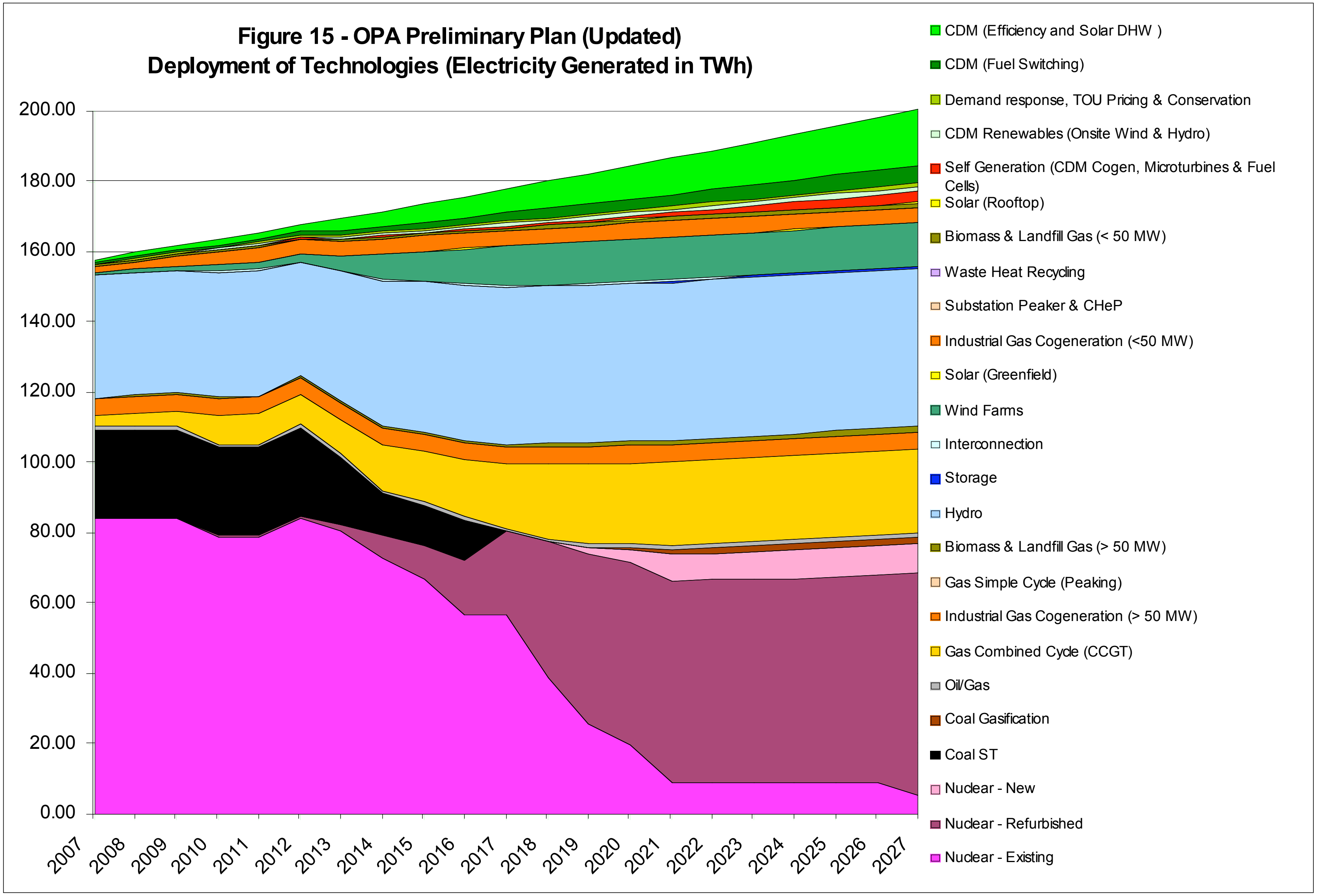
Figure 15 - OPA Preliminary Plan (Updated)
Deployment of Technologies (Electricity Generated in TWh)
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

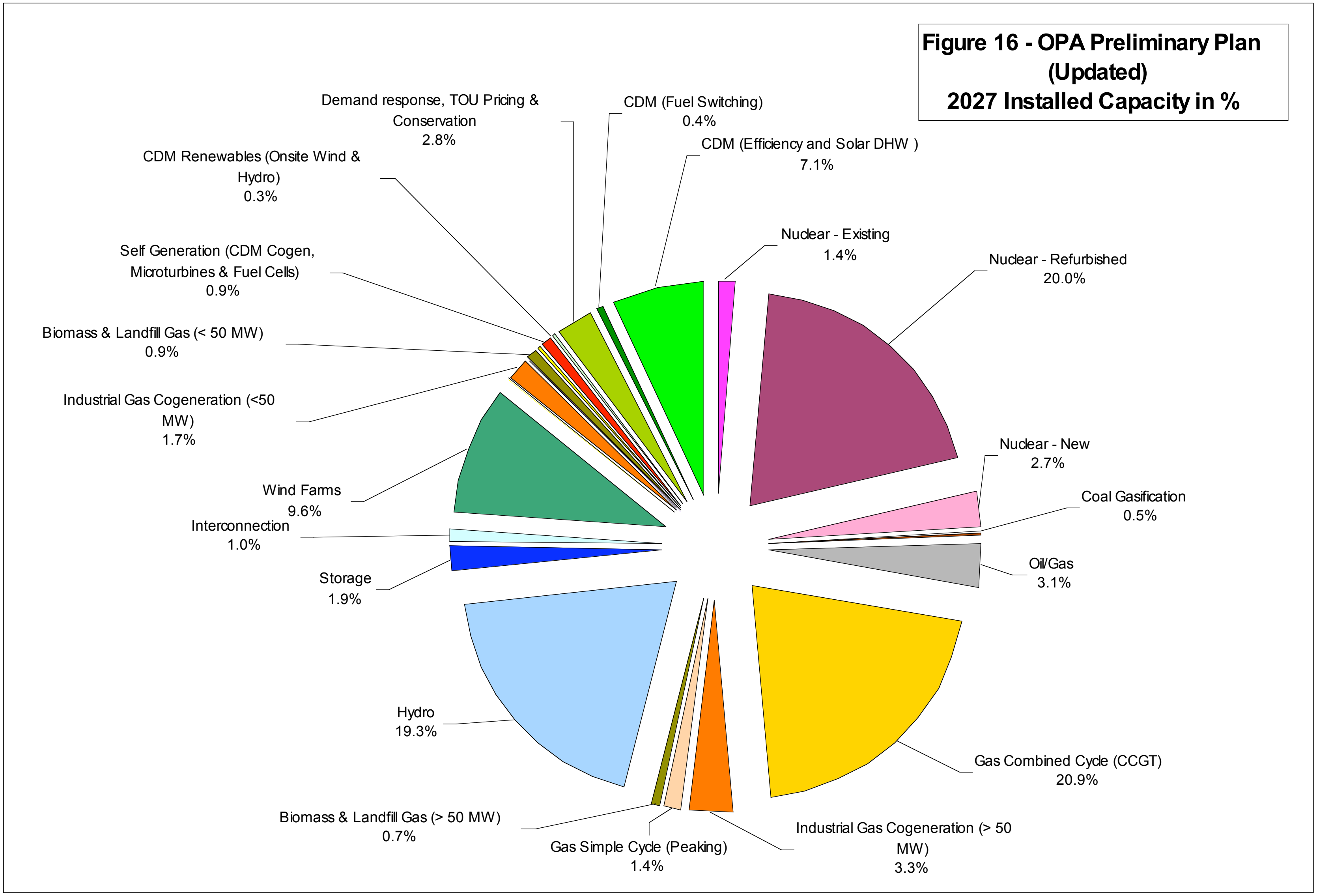
Figure 16 - OPA Preliminary Plan (Updated)
2027 Installed Capacity in %
Demand response, TOU Pricing & Conservation 2.8%
CDM (Fuel Switching) 0.4%
CDM (Efficiency and Solar DHW) 7.1%
CDM Renewables (Onsite Wind & Hydro) 0.3%
Self Generation (CDM Cogen, Microturbines & Fuel Cells) 0.9%
Biomass & Landfill Gas (< 50 MW) 0.9%
Industrial Gas Cogeneration (<50 MW) 1.7%
Wind Farms 9.6%
Interconnection 1.0%
Storage 1.9%
Hydro 19.3%
Biomass & Landfill Gas (> 50 MW) 0.7%
Gas Simple Cycle (Peaking) 1.4%
Industrial Gas Cogeneration (> 50 MW) 3.3%
Gas Combined Cycle (CCGT) 20.9%
Oil/Gas 3.1%
Coal Gasification 0.5%
Nuclear - New 2.7%
Nuclear - Refurbished 20.0%
Nuclear - Existing 1.4%

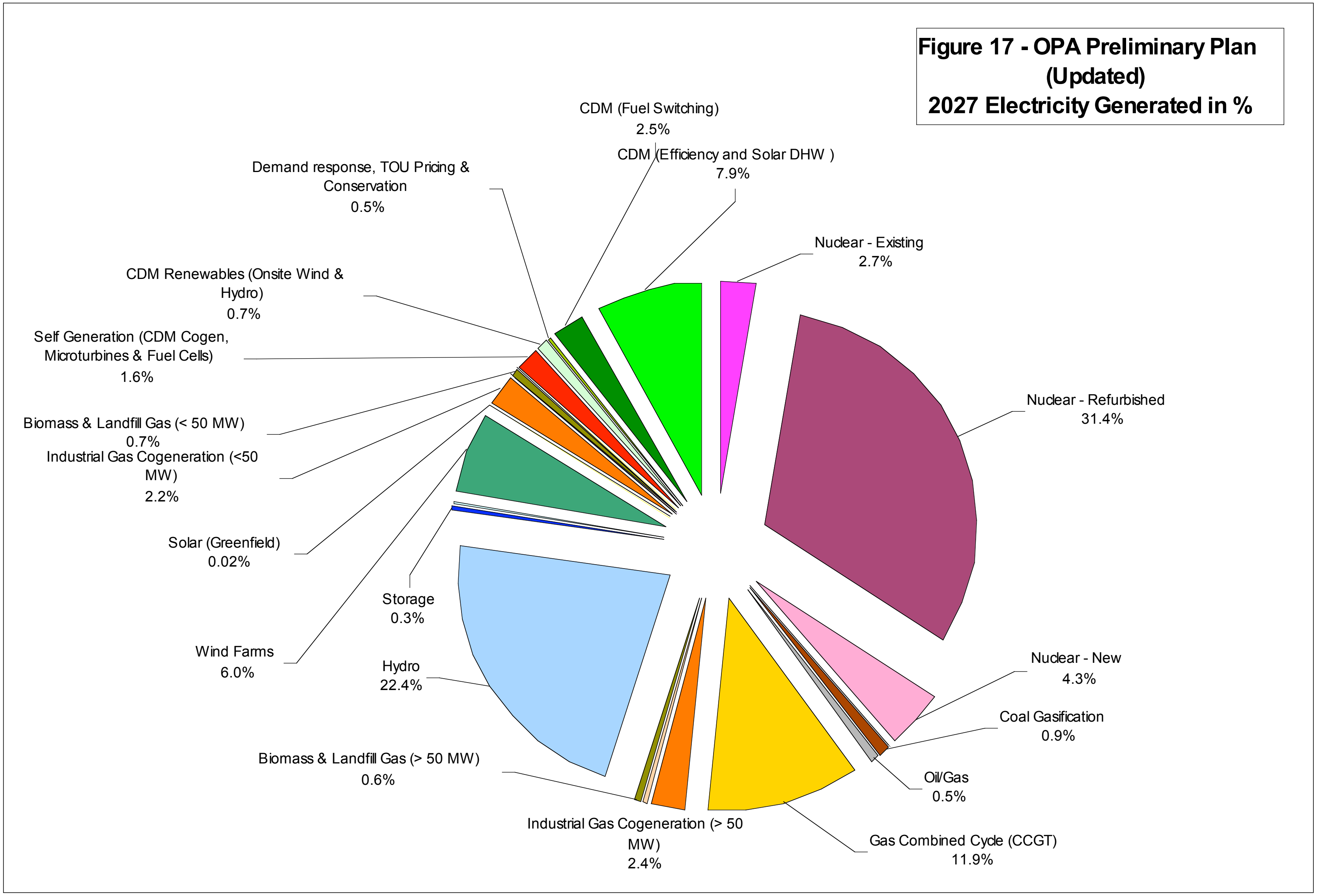
Figure 17 - OPA Preliminary Plan
(Updated)
2027 Electricity Generated in %
CDM (Fuel Switching)
2.5%
CDM (Efficiency and Solar DHW)
7.9%
Demand response, TOU Pricing &
Conservation
0.5%
Nuclear - Existing
2.7%
CDM Renewables (Onsite Wind &
Hydro)
0.7%
Self Generation (CDM Cogen,
Microturbines & Fuel Cells)
1.6%
Nuclear - Refurbished
31.4%
Biomass & Landfill Gas (< 50 MW)
0.7%
Industrial Gas Cogeneration (<50
MW)
2.2%
Solar (Greenfield)
0.02%
Storage
0.3%
Wind Farms
6.0%
Hydro
22.4%
Nuclear - New
4.3%
Coal Gasification
0.9%
Biomass & Landfill Gas (> 50 MW)
0.6%
Oil/Gas
0.5%
Industrial Gas Cogeneration (> 50
MW)
2.4%
Gas Combined Cycle (CCGT)
11.9%

Soft Green

The third task was to use the Updated scenario to model and explore various opportunities to reduce the environmental impact of electricity production. This effort led to the development of the model run titled “Soft Green”.

The purpose of this scenario is to show that future power needs in Ontario can be met without any investment in new or refurbished nuclear capacity beyond what has been already committed. Instead of focusing on nuclear power, green resources already identified by the OPA, such as CDM, renewable energy, cogeneration, solar and hydro energy purchased from adjacent provinces are deployed up to the higher levels reported by the OPA. This scenario results in lower CO_2 emissions than the OPA Preliminary Plan, and a coal phase-out in 2011, or one year sooner than indicated in the Preliminary Plan. A detailed description of the green scenarios, including supporting information is presented in Appendix D.

The specific features of this scenario are as follows:

- No nuclear refurbishments are made beyond those already committed (~3,000 MW), and no new nuclear facilities are built.
- Existing interconnections with Manitoba and Quebec and new interconnection capacity under construction with these provinces are used up to their maximum capacity to import hydropower resources.
- CDM resources are acquired in amounts up to the higher levels 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 directive.
- Wind power resources are acquired up the maximum that can be integrated into the grid without significant changes to grid operation or regulation, as identified by OPA.
- With respect to hydro resources, the OPA Preliminary Plan and the calibration run include all of the near term and future (not constrained) 2300 MW of hydro potential as outlined in Discussion Paper #4, with the exception of the Albany River (860 MW). The Albany River is covered by Northern Rivers Commitment and this potential large development (and others) would be subject to agreement with First Nations affected. The Soft Green scenario adds approximately 700 MW of hydro resources to the amount in the calibration and Updated runs. This capacity would likely the development of the Albany River. However, should arrangements not be possible for this development, the 700 MW of hydro power could be redeployed as an equivalent amount of new biomass generation.
- Cogeneration and waste heat power facilities are increased to reflect industrial potential - displacing some future combined cycle gas power generation.
- Solar power resources are increased to levels similar to “solar roofs” programs deployed by other jurisdictions.

- Bio-energy resources are increased to maximum levels identified by OPA.
- On-site Combined Heat and Power (CHP) through micro-turbines in commercial and institutional facilities are increased through modest specifically targeted programs.
- Coal gasification with or without carbon capture and storage is eliminated from the plan.

Inputs

All inputs into the model are the same as for the Updated model run, except for the following:

Centralized Generation Technologies

- **Nuclear - Refurbished**: The amount of refurbished nuclear capacity is limited to approximately 3,000 MW by 2027.
- **Nuclear - New**: No capacity is added and not nuclear plant is built. Ontario nuclear capacity is therefore significantly reduced.
- **Hydro**: Installed capacity is added to reach approximately 10,793 MW in 2027 (vs. 10,095 MW in the Updated run).
- **Coal Steam Turbine**: The schedule for retirement is not delayed but completed one year sooner than indicated in the Preliminary Plan with the "Coal for Insurance" not needed. The retirement schedule is as follows: 1,972 MW in 2009, 1,960 MW in 2010, and 2,502 MW in 2011.
- **Gas Combined Cycle (CCGT):** Capacity is added up to 3,400 MW in 2027, which approximately corresponds to the capacity in the planning or construction stages as per Appendix A.
- **Industrial Gas Cogeneration (>50 MW):** 1,000 MW of capacity is added through the 20 year period to reach up to a capacity of 2,719 MW in 2027.
- **Wind Farms:** Capacity is added to reach the OPA upper limit of 10,000 MW for installed capacity in 2027.
- **Interconnection:** Interconnection fully utilizes the existing 3,550 MW of import capacity for hydro electricity from Manitoba and Québec: 330 MW existing and 400 MW under construction from Manitoba, and 1,550 MW existing and 1,250 MW under construction from Quebec.
  In the Soft Green model run, interconnection capacity in the model increases from 800 MW in 2007 to 3,530 MW by 2011, all of it being hydro electricity. The costs for transmission are at the North American average, unchanged from the two previous model runs. In effect, Ontario becomes a net importer of electricity over the 20 year period, importing hydro electricity from Manitoba and Quebec using existing infrastructure, particularly during peak times. The capacity factor was increased to 100% to reflect the fact that, for imports, the limitation is not the

hydro generation facility but the transmission lines and the contractual arrangements.

- **Gas Simple Cycle (Peaking):** Capacity is added up to 400 MW. In addition to the 3,400 of CCGT, this corresponds with the approximately 3,800 MW of such capacity existing and planned.
- **Coal Gasification:** No capacity is added.
- **Solar (Greenfield):** Up to 800 MW of greenfield solar capacity is added by 2027.

Decentralized Energy Technologies

- **CDM (Efficiency):** Capacity is added to reach a target of 5,638 MW in 2027.
- **CDM (Fuel Switching):** Capacity is added to reach a target of 307 MW in 2027.
- **DR, Time of Use Pricing and Conservation:** Capacity is added to reach a target of 2,129 MW by 2027.
- **Biomass and Landfill Gas (< 50 MW):** Capacity is added to reach a target of 870 MW of landfill and agricultural biomass by 2027.
- **Solar (Rooftop):** This technology describes the opportunity to use rooftops of commercial and industrial buildings to produce renewable electricity in an urban setting without land disturbance. Capacity is added to reach 1,500 MW by 2027.
- **Substation Peakers & CHeP**: This technology represent the use of gas fired internal combustion engines and turbines at strategic locations during periods of peak demand. These generators can be located at substations in order to provide relief during period of high congestion. In addition, institutional facilities have such generators already installed for back-up power purposes. Existing back up generators represent a low cost option for proving peak power. Up to 100 MW of this technology is added by 2027.
- **Waste Heat Recycling**: This technology produces power from industrial waste heat sources. Industrial energy recycling 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 United States 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 US, 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. In this model run, up to 1,250 MW of waste energy recycling was built by 2027.

A summary of the target 2027 capacities for all technologies and model runs is provided in Table B5 of Appendix B.

Outputs

Table 11 also provides detailed results for the Soft Green model run. Figures 18 and 19 describe the deployment of technologies, and Figures 20 and 21 show the mix of technologies in 2027.

Notable outcomes are as follows:

- The share of decentralized energy increases to 26% in 2027. The avoidance of line losses associated with DE means that required electricity production decreases slightly from 200.7 TWh to 198.9 TWh in 2027.
- Total installed capacity is similar to the Updated model run.
- Capital costs are reduced by approximately 6% as compared to the Updated model run. While the deployment of solar assets increases capital costs, less refurbishment of nuclear facilities, no new nuclear plant, and a greater penetration of CDM technologies contribute to reducing costs.
- Delivered electricity costs are reduced by approximately 13%, primarily due to lower fuel costs.
- Greenhouse gas emissions in 2027 are reduced by 43% as compared to the Updated model run and are also lower than the calibration run. In effect, CDM, wind and solar displace nuclear energy, coal and some natural gas generation.
- Over the course of the 20 year study period, total CO_2 emissions are reduced substantially because the retirement of the coal plants is not delayed but advanced by one year.
- The amount of nuclear electricity generated in 2027 drops significantly, by 66% compared to the Updated model run and by 71% vs. the calibration run.

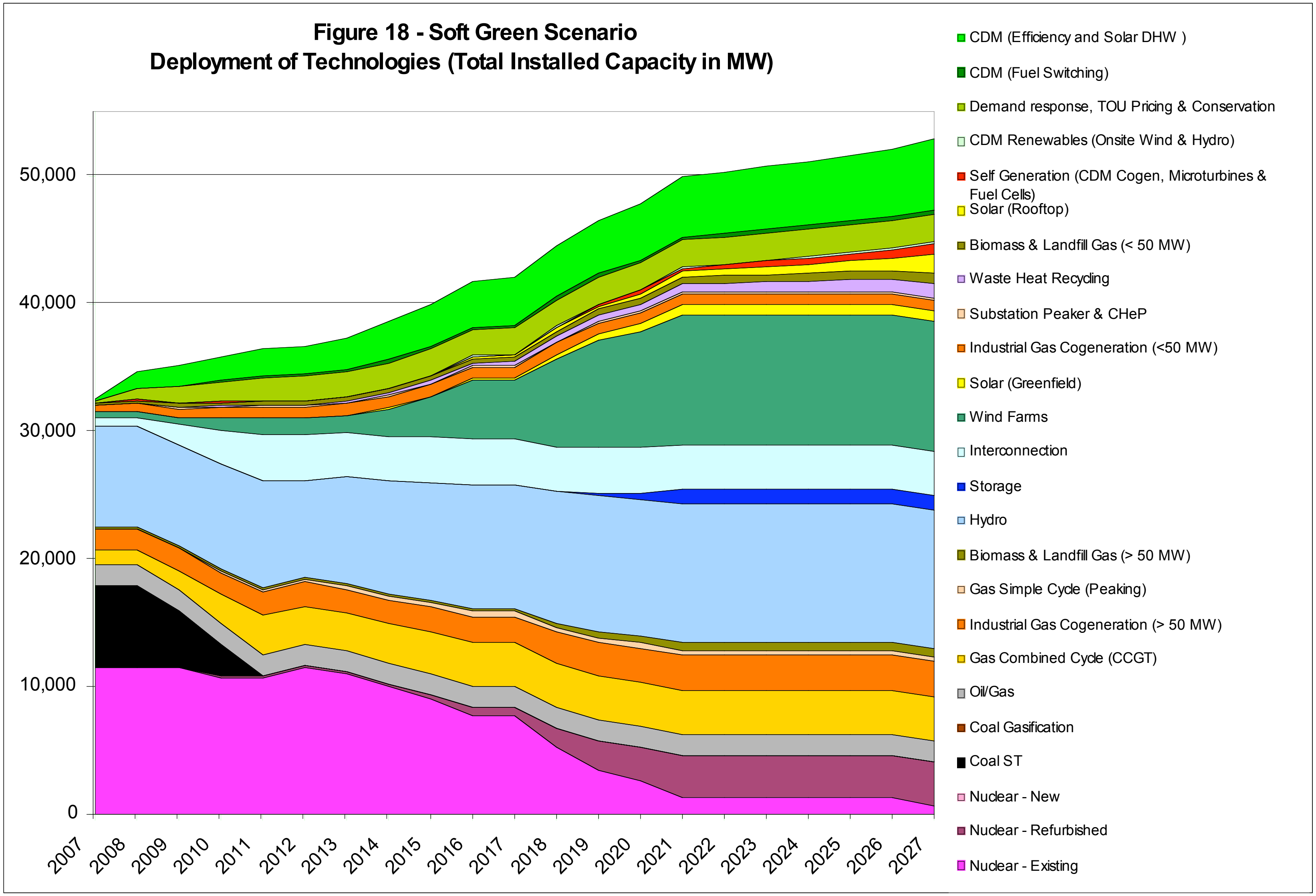
Figure 18 - Soft Green Scenario
Deployment of Technologies (Total Installed Capacity in MW)
50,000
40,000
30,000
20,000
10,000
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

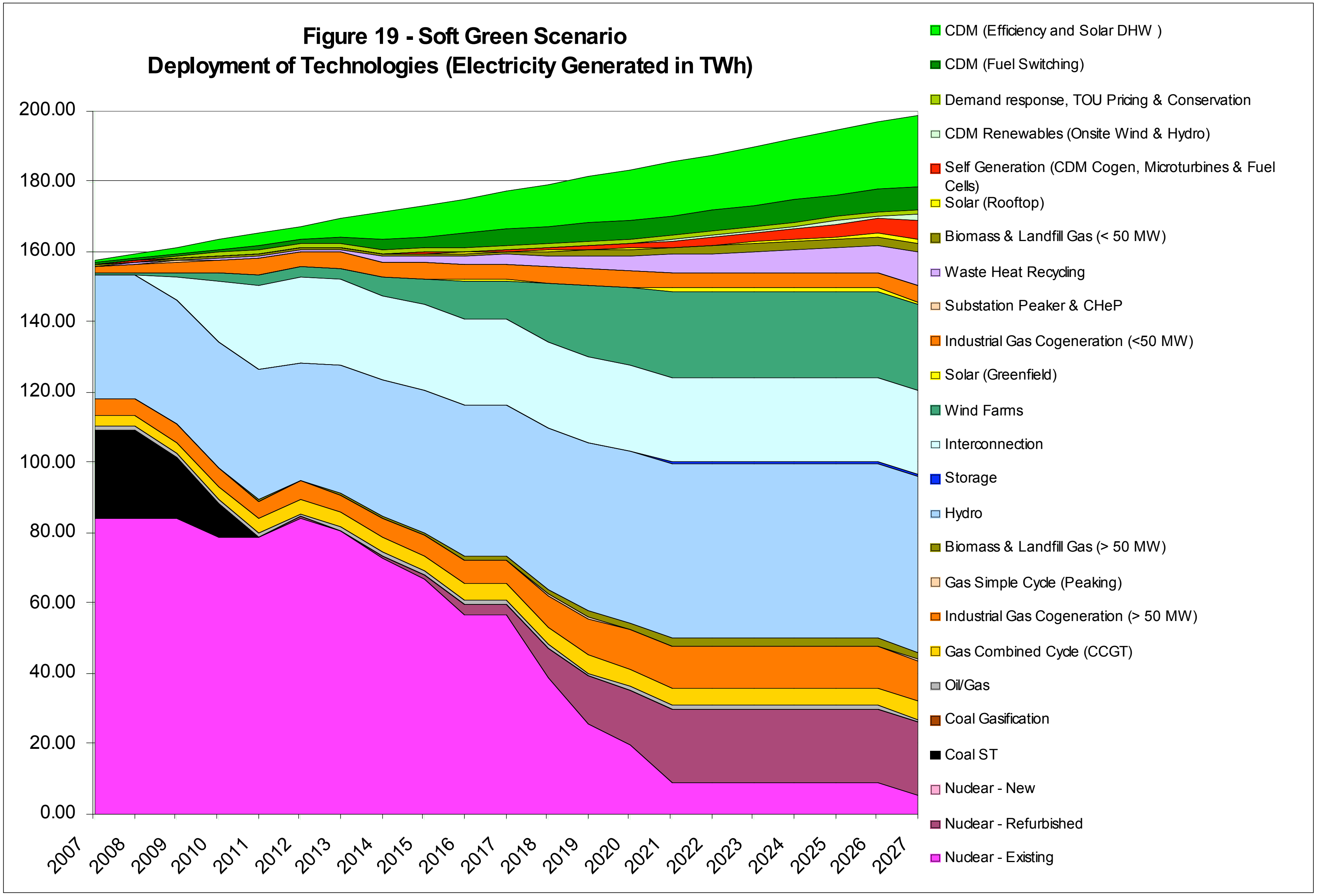
Figure 19 - Soft Green Scenario
Deployment of Technologies (Electricity Generated in TWh)
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

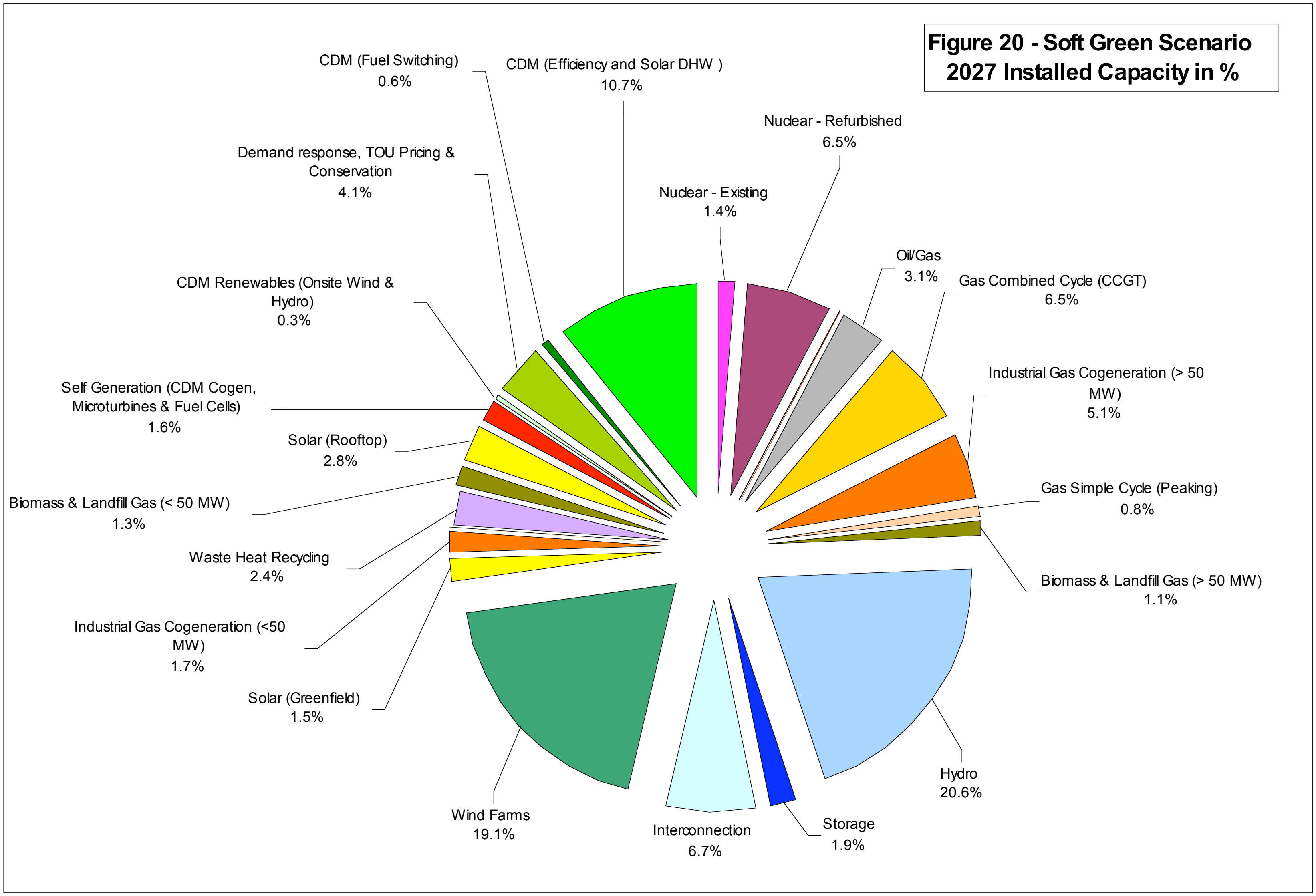
Figure 20 - Soft Green Scenario
2027 Installed Capacity in %
CDM (Fuel Switching)
0.6%
CDM (Efficiency and Solar DHW)
10.7%
Nuclear - Refurbished
6.5%
Demand response, TOU Pricing & Conservation
4.1%
Nuclear - Existing
1.4%
Oil/Gas
3.1%
Gas Combined Cycle (CCGT)
6.5%
CDM Renewables (Onsite Wind & Hydro)
0.3%
Industrial Gas Cogeneration (> 50 MW)
5.1%
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
1.6%
Solar (Rooftop)
2.8%
Gas Simple Cycle (Peaking)
0.8%
Biomass & Landfill Gas (< 50 MW)
1.3%
Waste Heat Recycling
2.4%
Biomass & Landfill Gas (> 50 MW)
1.1%
Industrial Gas Cogeneration (<50 MW)
1.7%
Solar (Greenfield)
1.5%
Hydro
20.6%
Wind Farms
19.1%
Interconnection
6.7%
Storage
1.9%

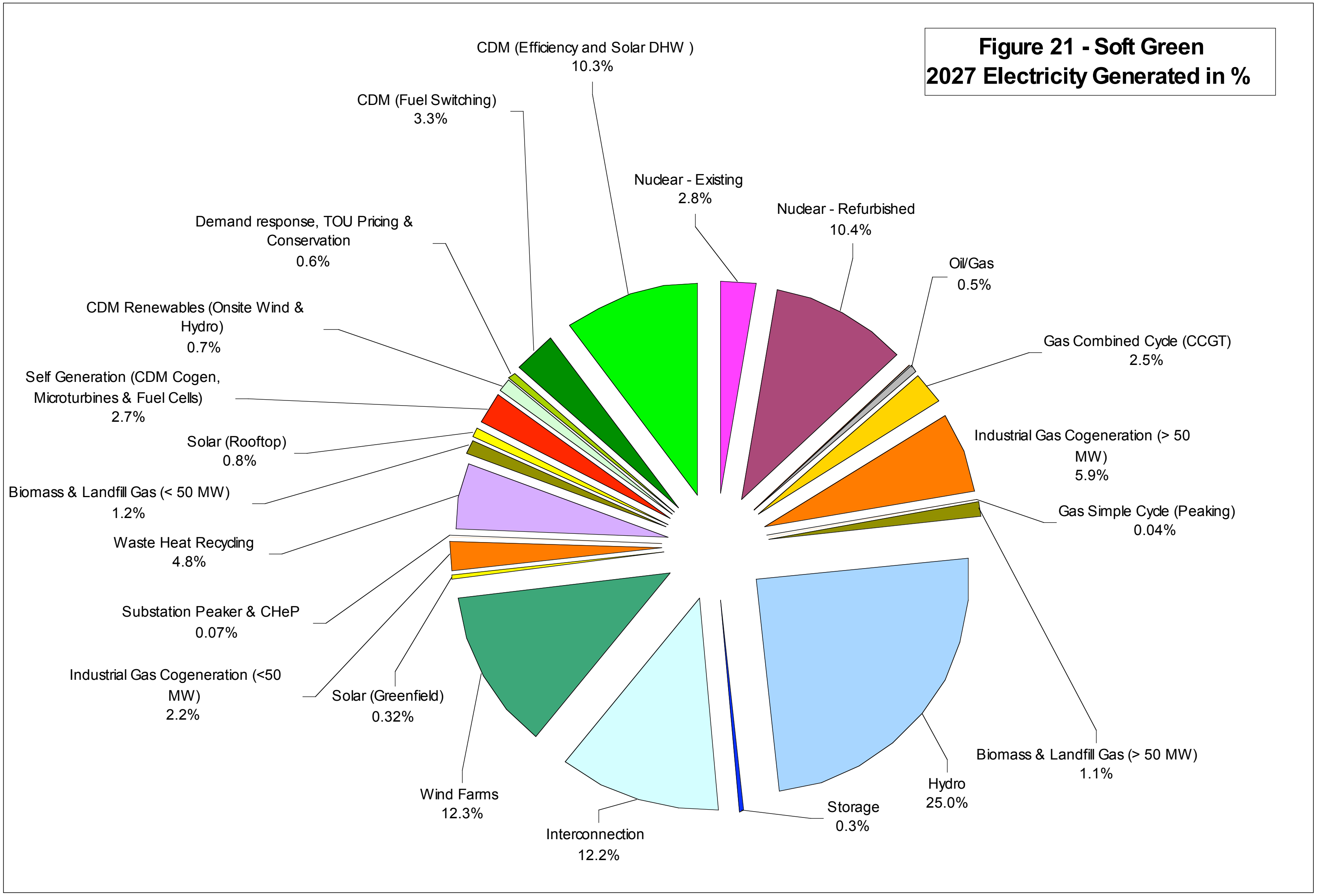
Figure 21 - Soft Green
2027 Electricity Generated in %
CDM (Efficiency and Solar DHW)
10.3%
CDM (Fuel Switching)
3.3%
Nuclear - Existing
2.8%
Nuclear - Refurbished
10.4%
Demand response, TOU Pricing & Conservation
0.6%
Oil/Gas
0.5%
CDM Renewables (Onsite Wind & Hydro)
0.7%
Gas Combined Cycle (CCGT)
2.5%
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
2.7%
Industrial Gas Cogeneration (> 50 MW)
5.9%
Solar (Rooftop)
0.8%
Biomass & Landfill Gas (< 50 MW)
1.2%
Gas Simple Cycle (Peaking)
0.04%
Waste Heat Recycling
4.8%
Substation Peaker & CHeP
0.07%
Industrial Gas Cogeneration (<50 MW)
2.2%
Solar (Greenfield)
0.32%
Biomass & Landfill Gas (> 50 MW)
1.1%
Hydro
25.0%
Wind Farms
12.3%
Storage
0.3%
Interconnection
12.2%

Deep Green

The Deep Green scenario goes further than the Soft Green option in order to demonstrate the potential of green power technologies for Ontario. Its purpose is to illustrate 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 power plants can be phased out completely, and the cost to Ontarians will not be significant. In some cases, the Deep Green scenario implies that some existing contracts for the refurbishment of nuclear plants or for the purchase of natural gas fired electricity would need to be cancelled or amended and penalties may need to be incurred. However, the purpose of the scenario is to illustrate that CDM and renewable technologies are indeed capable of displacing nuclear and natural gas from Ontario's energy future.

The features of this scenario, as compared to Soft Green, are as follows:

- CDM resources including fuel switching are acquired up to those levels identified by many studies (e.g.: (IFC Consulting 2005) as being cost effective and in line with achievements in other jurisdictions.
- Existing grid transmission, regulation, and control systems are currently optimized around central power generation resources. This limits the amount of wind power that can be technically integrated into the grid. However, it would be possible to double wind power beyond Soft Green with the implementation of power storage. Storage technologies such as Vanadium Redox Batteries (VRB) are being demonstrated for wind farms in the United States, Ireland and other jurisdictions in order to improve the ability to dispatch power. Information from the an Irish feasibility study and from a VRB manufacturer indicate that, with this technology, a wind farm's ability to meet peak demand increases from 50% to 75% with a 70% round trip efficiency. Experience at the San Gergonio wind farm indicate that total electricity production increases by 16% and on-peak availability is improved by 78%. Capital costs increase by 46%, from $1959/kW for a conventional wind farm to $2,868/kW for a wind farm equipped with VRB technology (Kuntz 2005; Tapbury Management Limited 2005).
- After 2015, solar photovoltaic systems are expected to become cost competitive with grid electricity(Bush and Riley 2007). Therefore, solar power resources are increased to deployment levels achieved in other jurisdictions that use aggressive policies.
- No refurbishment of nuclear faculties is contemplated, even the amounts already contracted. It is recognized that penalties may need to be paid to cancel existing contracts but detailed information was not available to value this impact. In addition, the remaining existing nuclear capacity is retired at the end of the study period, resulting in no production of nuclear electricity in Ontario in 2027.
- The increased levels of CDM, wind and solar capacity allow a curtailment of natural gas generation. Therefore, the Lennox facility is retired and new CCGT

plants are limited to approximately half of the levels in the Preliminary Plan, even though construction of some of these plants may have already been committed.

Inputs

All inputs into the model are the same as for Soft Green, except for the following:

Centralized Generation Technologies

- **Nuclear - Refurbished**: No refurbished nuclear capacity is added. In addition, the remaining 750 MW of existing nuclear capacity is retired in the last year of the study period. The net result is that there is no production of nuclear electricity in Ontario in 2027.
- **Gas Combined Cycle (CCGT):** Capacity is added up to 2,200 MW in 2027.
- **Oil/Gas:** The Lennox power plant is retired starting in 2019.
- **Wind Farms:** In the Deep Green scenario, wind power capacity in Ontario is increased up to 15,000 MW. 10,000 MW are conventional wind farms, as specified in the Soft Green scenario. In addition, 5,000 MW are wind farms equipped with VRB technology, at the cost indicated above and an average load factor of 32.2% and a peak load factor of 30.6%.
- **Solar (Greenfield):** Up to 1,000 MW of greenfield solar capacity is added by 2027.

Decentralized Energy Technologies

- **CDM (Efficiency):** Capacity is added to reach a target of 7,500 MW in 2027.
- **CDM (Fuel Switching):** Capacity is added to reach a target of 500 MW in 2027.
- **DR, Time of Use Pricing and Conservation:** Capacity is added to reach a target of 2,500 MW by 2027.
- **Solar (Rooftop):** Capacity is added to reach 3,000 MW by 2027.

Outputs

Table 11 also provides detailed results for the Deep Green scenario. Figures 22 and 23 illustrate the deployment of technologies, and Figures 24 and 25 describe the mix of technologies in 2027.

The major results are as follows:

- The share of decentralized energy increases to 31.6% in 2027. The avoidance of line losses associated with DE means that required electricity production decreases slightly from 200.8 TWh to 197.7 TWh in 2027.
- Total installed capacity increases by approximately 4% as compared to the Soft Green scenario due to the lower load factors of the added solar and wind technologies.

- Capital costs are higher by 18% as compared to the Soft Green option. The addition of lower cost CDM and the avoidance of high cost nuclear act to lower costs. However, this effect is overtaken by the addition of relatively high cost solar and wind technologies and a smaller amount of low cost natural gas capacity.
- Delivered electricity cost increases by 8% as compared to Soft Green. The impact of higher capital costs is somewhat offset by lower fuel costs. Deep Green delivered electricity costs are nevertheless lower than the Updated model run.
- The Deep Green model run results in the lowest GHG emission and air pollution levels of all model runs. CO_2 emissions are reduced by 15% vs. Soft Green and by 51% as compared the Updated run. The additional green resources are sufficient to reduce the amount of natural gas capacity required.

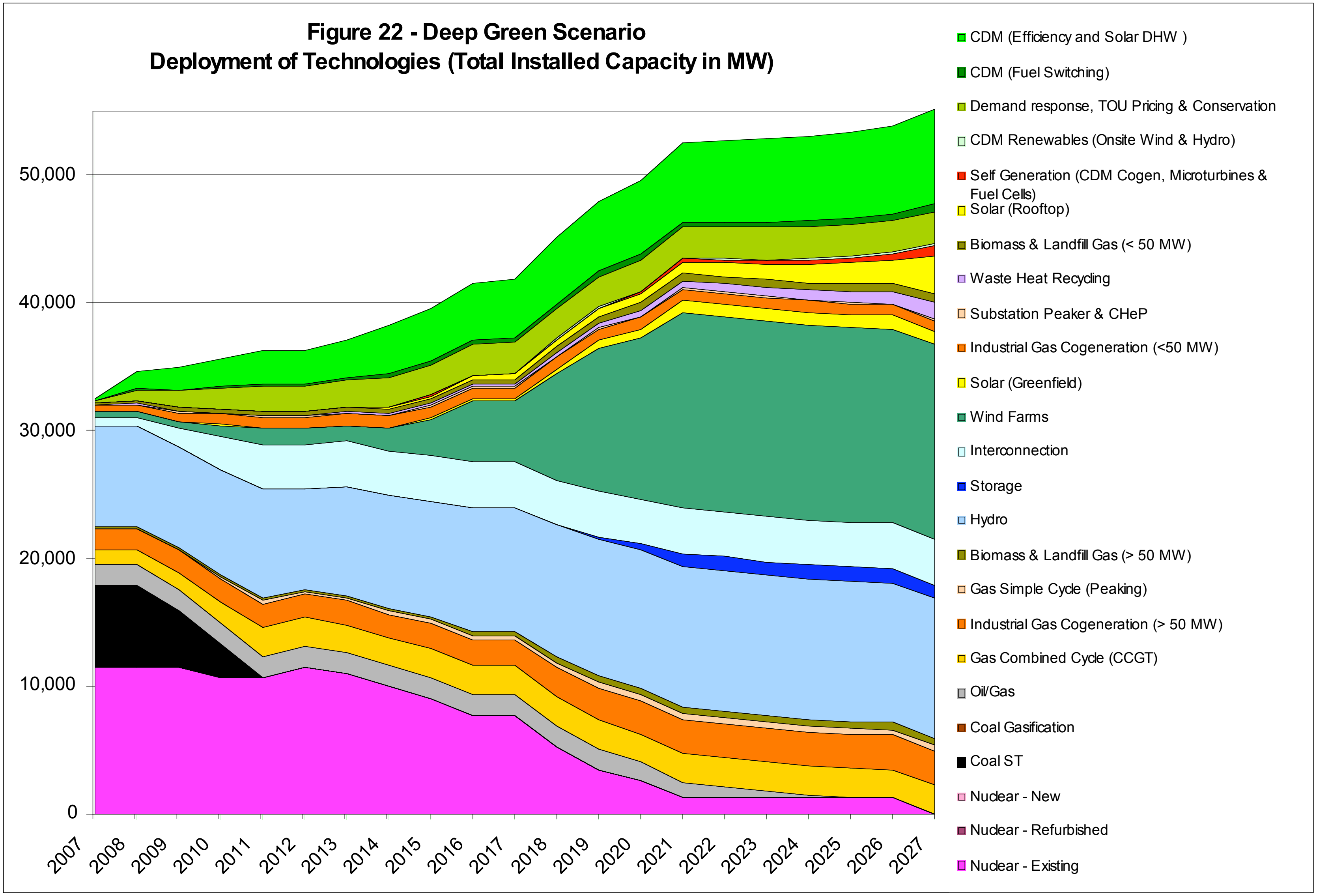
Figure 22 - Deep Green Scenario
Deployment of Technologies (Total Installed Capacity in MW)
50,000
40,000
30,000
20,000
10,000
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

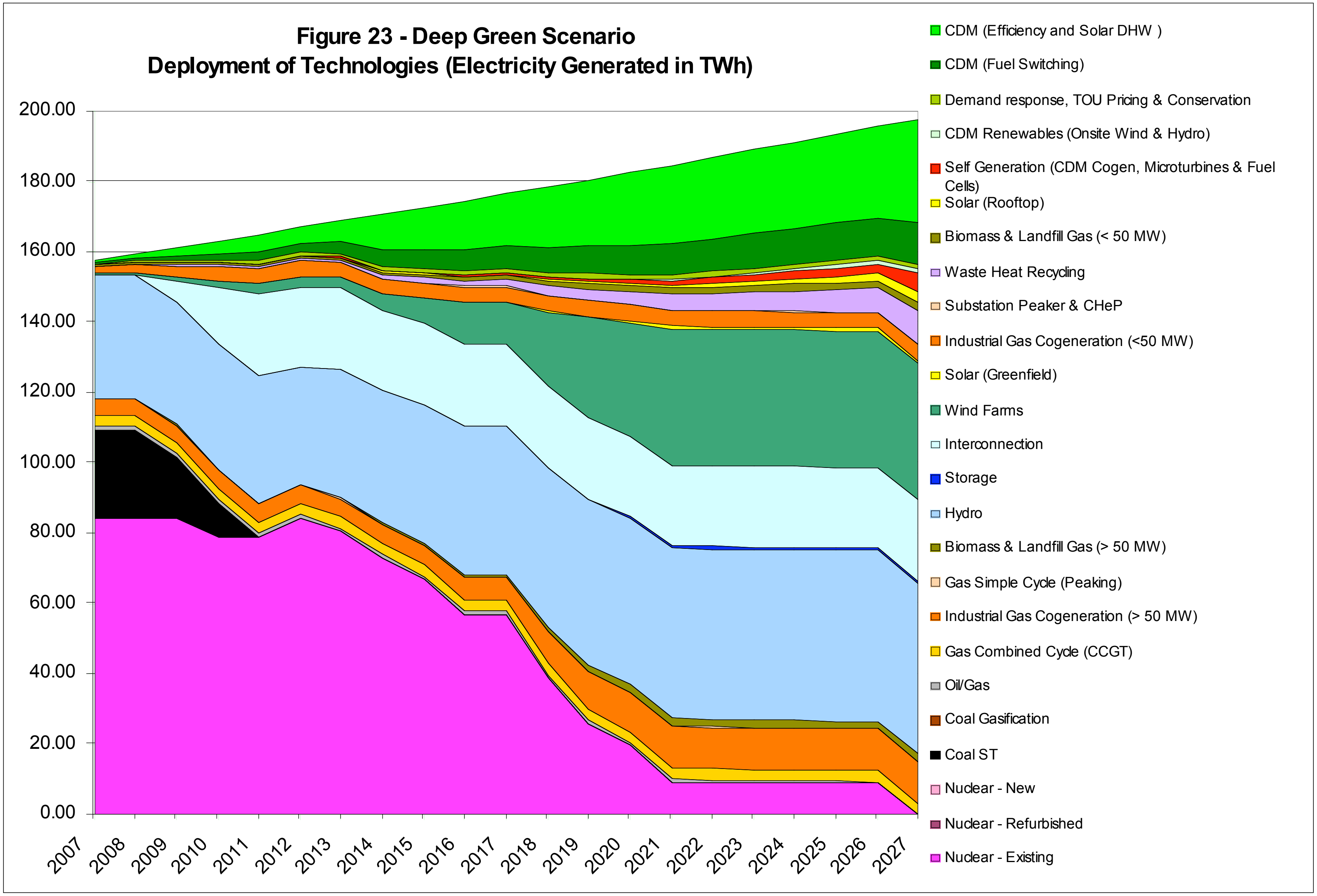
Figure 23 - Deep Green Scenario
Deployment of Technologies (Electricity Generated in TWh)
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CDM (Efficiency and Solar DHW)
CDM (Fuel Switching)
Demand response, TOU Pricing & Conservation
CDM Renewables (Onsite Wind & Hydro)
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
Solar (Rooftop)
Biomass & Landfill Gas (< 50 MW)
Waste Heat Recycling
Substation Peaker & CHeP
Industrial Gas Cogeneration (<50 MW)
Solar (Greenfield)
Wind Farms
Interconnection
Storage
Hydro
Biomass & Landfill Gas (> 50 MW)
Gas Simple Cycle (Peaking)
Industrial Gas Cogeneration (> 50 MW)
Gas Combined Cycle (CCGT)
Oil/Gas
Coal Gasification
Coal ST
Nuclear - New
Nuclear - Refurbished
Nuclear - Existing

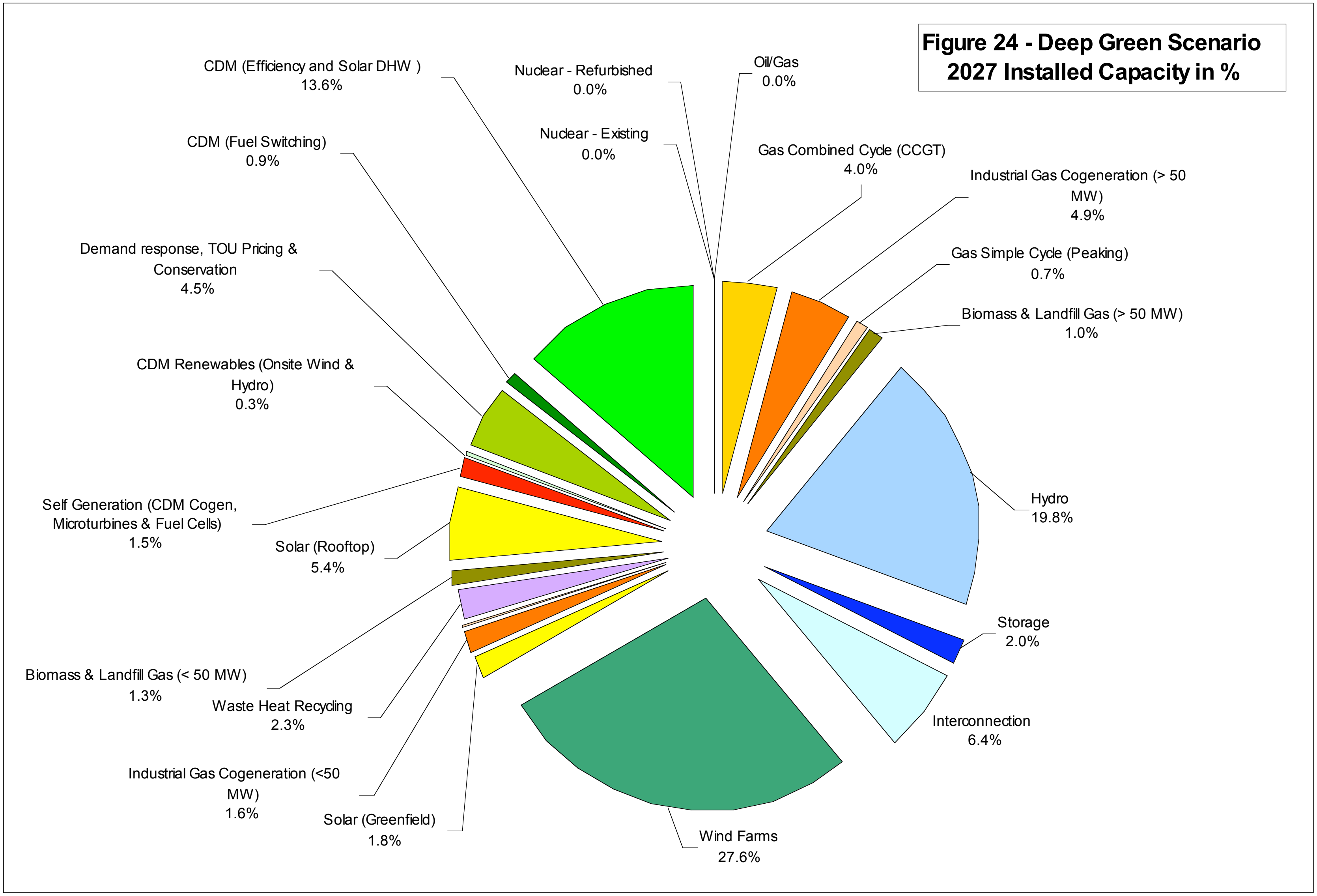

Figure 24 - Deep Green Scenario
2027 Installed Capacity in %
CDM (Efficiency and Solar DHW)
13.6%
Nuclear - Refurbished
0.0%
Oil/Gas
0.0%
Nuclear - Existing
0.0%
CDM (Fuel Switching)
0.9%
Gas Combined Cycle (CCGT)
4.0%
Industrial Gas Cogeneration (> 50 MW)
4.9%
Demand response, TOU Pricing & Conservation
4.5%
Gas Simple Cycle (Peaking)
0.7%
Biomass & Landfill Gas (> 50 MW)
1.0%
CDM Renewables (Onsite Wind & Hydro)
0.3%
Hydro
19.8%
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
1.5%
Solar (Rooftop)
5.4%
Storage
2.0%
Biomass & Landfill Gas (< 50 MW)
1.3%
Waste Heat Recycling
2.3%
Interconnection
6.4%
Industrial Gas Cogeneration (<50 MW)
1.6%
Solar (Greenfield)
1.8%
Wind Farms
27.6%

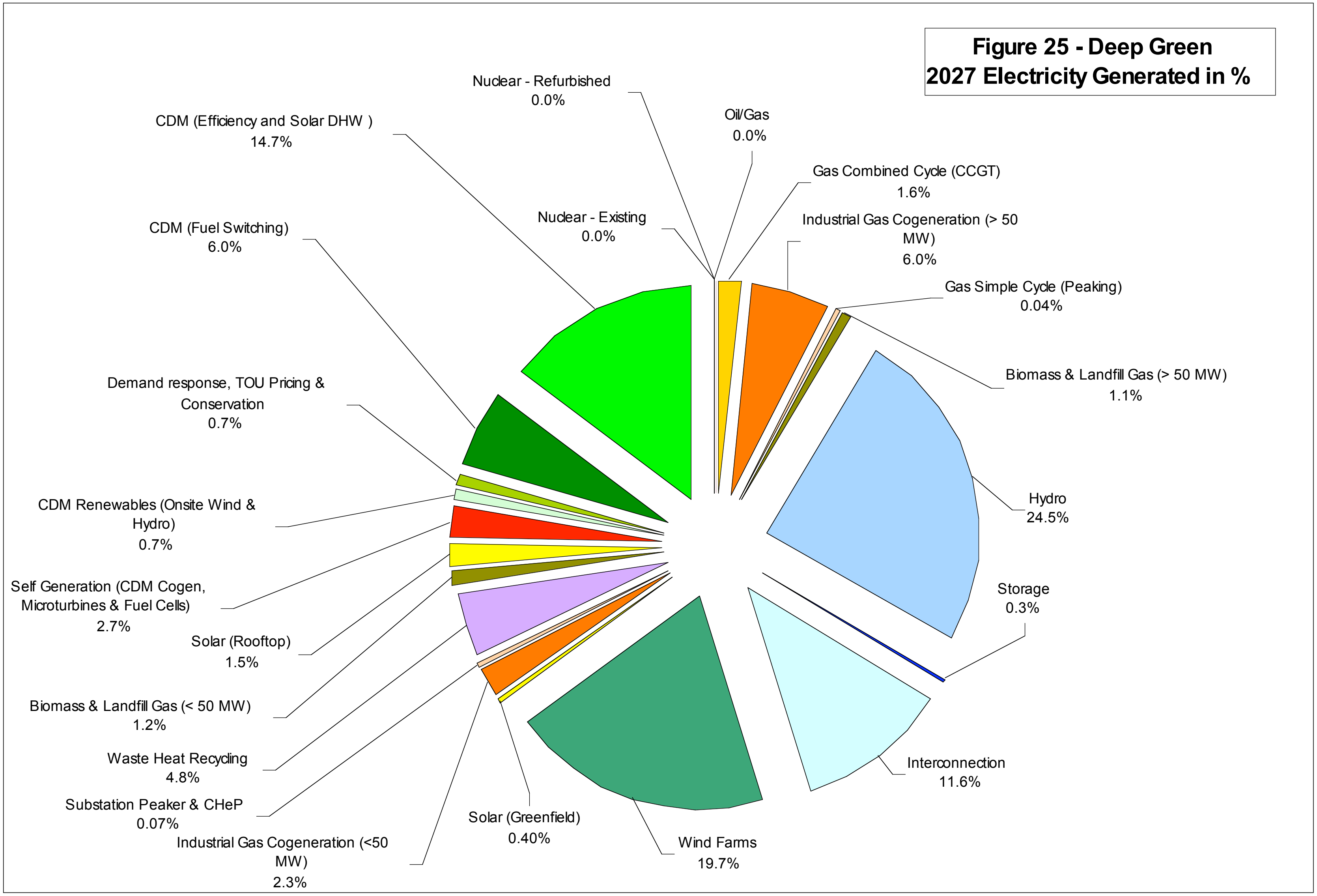
Figure 25 - Deep Green
2027 Electricity Generated in %
Nuclear - Refurbished
0.0%
CDM (Efficiency and Solar DHW)
14.7%
Oil/Gas
0.0%
Gas Combined Cycle (CCGT)
1.6%
Nuclear - Existing
0.0%
CDM (Fuel Switching)
6.0%
Industrial Gas Cogeneration (> 50 MW)
6.0%
Gas Simple Cycle (Peaking)
0.04%
Biomass & Landfill Gas (> 50 MW)
1.1%
Demand response, TOU Pricing & Conservation
0.7%
Hydro
24.5%
CDM Renewables (Onsite Wind & Hydro)
0.7%
Storage
0.3%
Self Generation (CDM Cogen, Microturbines & Fuel Cells)
2.7%
Solar (Rooftop)
1.5%
Biomass & Landfill Gas (< 50 MW)
1.2%
Interconnection
11.6%
Waste Heat Recycling
4.8%
Substation Peaker & CHeP
0.07%
Solar (Greenfield)
0.40%
Wind Farms
19.7%
Industrial Gas Cogeneration (<50 MW)
2.3%

Recommendations

This study demonstrated that the Ontario power system may be independently simulated using computer modelling tools and data provided by the OPA and other public sources. The development of this capability allowed for a critical review of the current OPA IPSP and the identification of strategies that would reduce the environmental impact of power production from the combined consideration of GHG emission and nuclear liability.

Recommendations for future work include the following:

Improvements and Sensitivity Analysis

- Additional research and analysis is required to fully account for the economic and environmental benefits of green resources and decentralized energy. In particular, the following four points need to be researched and analyzed:
    - Improved Modeling of Conservation and Demand Management: CDM is a not a component of the existing computer model. OPA treats CDM as a quasi generation source, which is counter-intuitive. Correct modeling of CDM would involve estimating costs and penetration by CDM technology over time in order to reduce both peak and total demand. In addition, a better understanding and quantification of various CDM technologies should be developed based on early field experience in Ontario and other jurisdictions, including accurate accounting of capital costs, operational costs and incentives. This approach would allow scenario modeling of various mixes of CDM technologies in order to better identify costs and demand impact.
    - Costs and Performance of Transmission and Distribution: In a world dominated by centralized generation, the need to transmit and distribute power is taken as a given and generally treated as a single average number. However, the reality is far more complex and there is a range of different costs. An improved understanding of costs and performance drivers will lead to the identification of situations where local power generation outperforms transmission and distribution assets. In other words, there is a need to understand where the "low hanging fruits" are. In particular, there is a need to better quantify peak losses of distribution systems and the peak and average losses associated with distributed generation.
    - Full Accounting of the Benefits of Thermal Energy Cogeneration: In the modeling work done to date by the OPA and when using the WADE model, the focus is strictly on electricity. In cogeneration situations, costs and benefits should be allocated to the electrical and thermal components. The benefit of cogeneration is modeled from the displacement of other power generation technologies. However, this approach, while fair, understates the benefit of cogeneration because, in some situations, cogeneration also displaces inefficient boilers. In order to account for the latter, data on the existing boiler fleet needs to be established. From this data, the benefit of cogeneration in improving the performance of the thermal fleet can be calculated and used to justify policies

supporting cogeneration. The scope of work required is to numerically characterize the existing fleet of thermal energy generators, particularly the segments most likely to be replaced by cogeneration equipment.

- Estimating GHG Benefits of Avoided Fugitive Methane Emissions from Landfills: Methane is a powerful GHG gas and it is produced as a result of the biological processes that occur in landfills over time. While landfills are capped, some amounts of methane gas escape into the atmosphere. When a DE project is implemented at a landfill site, the methane is captured and burned to produce electricity. Landfill gas DE projects avoid methane emissions but the amount of these avoided emissions is not accurately known. Further investigation into this area would allow a better quantification of the environmental benefit.
- As Spent Costs vs. Net Present Value Costs: The model in its present form only calculates total capital costs on an as spent basis, not on a Net Present Value (NPV) basis. As noted in the report, different methods of presenting costs may lead to different conclusions. Adding to the model the capability to perform NPV calculations would be invaluable. The following adjustments are suggested:
    - NPV vs. as spent dollars to properly account for differences in capital intensity;
    - A time shift forward is required for large scale projects such as nuclear investments. As an example, to meet 2015 demand, the nuclear option requires that the vast majority of costs to be incurred between 2010 and 2015; by contrast, with solar, costs are essentially incurred in the same year as demand.
    - Mega projects such as nuclear are built in large increments. This means that supply is added ahead of demand. A 1,400 MW nuclear facility is not likely to operate at full rate (or would cause other facilities to not operate at full rate) until 2-3 years after start-up. By contrast, solar is added as needed in increments that match demand year by year.
    - Mega projects also result in costs in addition to direct capital costs, such as owners' costs, working capital and provision for contingencies. For technologies purchased in small increments, these costs are borne by the manufacturer and included in the cost of the equipment.
- Broader inclusion and/or costing of externalities should be considered including monetizable factors such as nuclear risk.
- The assumptions and outcomes for the work should be validated through consultation with stakeholders in Ontario (e.g. OPA, Hydro One, Toronto Hydro and other LDCs). The consultation process could be interviews, meetings or a small conference. This may lead to sensitivity analysis using the computer model to test various assumptions proposed by stakeholders.

Assessment of Green Energy Supply Scenarios for Toronto/GTA

A study similar to the present one should be conducted for the Greater Toronto Area because of its importance to Ontario demand. Specific elements include the following:

- Obtain licensing rights to apply the WADE Model to Toronto/GTA;
- Working closely with stakeholders (e.g. Toronto Hydro, City of Toronto, other LDCs) develop appropriate input parameters for modeling energy supply options for Toronto/GTA;
- In collaboration with WWF Canada, identify alternative energy futures for urban environments such as Toronto/GTA for detailed assessment using the model;
- Undertake model runs, analyze and report on results.

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Appendix A – Ontario Power System Installed Capacity by Technology

Table A1 - Ontario Nuclear Power Capacity - 2006

Generating Station Name	Total Station MCR (MW)	Zone	Fuel Type	Source/Ownership
Darlington	3,524.0	Toronto	Nuclear	Ontario Power Generation Inc.
Bruce B	3,180.0	Bruce	Nuclear	Bruce Power Inc.
Pickering B	2,064.0	Toronto	Nuclear	Ontario Power Generation Inc.
Pickering A	1,057.0	Toronto	Nuclear	Ontario Power Generation Inc.
Bruce A	1,540.0	Bruce	Nuclear	Bruce Power Inc.
TOTAL	**11,365.0**			

Future Developments

Station Name	MW	Date	Source/Notes
Nuclear Upgrade	27	2007 Q3	IESO
Nuclear Upgrade	27	2008 Q3	IESO
Bruce A Unit 1 & 2 re-start	1500	Through 2036	OPA
New Darlington	TBD	TBD	OPG, OPG submitted an application for a Site Preparation License to the Canadian Nuclear Safety Commission (CNSC) for a new nuclear power plant at the Darlington nuclear generating station site.
Pickering B Refurbishing	TBD	TBD	OPG, The Pickering B nuclear generating station has four CANDU reactors which have been producing electricity for more than 20 years, and are expected to operate safely for a decade or so. The units could be shut down at the end of their predicted service lives, or could be refurbished and continue to produce electricity for Ontario until 2050-2060. Refurbishing Pickering B would extend its service life by replacing major components such as feeder tubes, fuel channels and/or steam generators, among other things.

Table A2 – Ontario Hydro Power Capacity - 2006

Generating Station Name	Total Station MCR (MW)	Zone	Fuel Type	Source/Ownership
BECK2 - OPG Niagara	1,451.0	Niagara	Hydro	Ontario Power Generation Inc.
SAUNDERS - OPG Ottawa	1,045.0	East	Hydro	Ontario Power Generation Inc.
BECK1 - OPG Niagara	498.0	Niagara	Hydro	Ontario Power Generation Inc.
DESJOACHIMS - OPG Ottawa	429.0	Essa	Hydro	Ontario Power Generation Inc.
CANYON (Abitibi Canyon) OPG NE	319.0	Northeast	Hydro	Ontario Power Generation Inc.
LOWERNOTCH - OPG NE	274.0	Northeast	Hydro	Ontario Power Generation Inc.
WELLS	250.0	Northeast	Hydro	Mississagi Power Trust
HOLDEN (Otto Holden) OPG Ottawa	243.0	Northeast	Hydro	Ontario Power Generation Inc.
CHATSFALLS - OPG Ottawa	192.0	East	Hydro	Ontario Power Generation Inc.
OTTERRAPIDS - OPG NE	182.0	Northeast	Hydro	Ontario Power Generation Inc.
STEWARTVLE - OPG Ottawa	182.0	East	Hydro	Ontario Power Generation Inc.
BARRETT - OPG Ottawa	176.0	East	Hydro	Ontario Power Generation Inc.
BECK2PGS - OPG Niarara	174.0	Niagara	Hydro	Ontario Power Generation Inc.
MTNCHUTE - OPG Ottawa	170.0	East	Hydro	Ontario Power Generation Inc.
AUBREYFALLS	164.0	Northeast	Hydro	Mississagi Power Trust
KIPLING - OPG NE	149.0	Northeast	Hydro	Ontario Power Generation Inc.
CHENAUX - OPG Ottawa	144.0	East	Hydro	Ontario Power Generation Inc.
DECEWFALLS - OPG Niagara	144.0	Niagara	Hydro	Ontario Power Generation Inc.
PINEPORTAGE - OPG NW	142.0	Northwest	Hydro	Ontario Power Generation Inc.

HARMON - OPG NE	141.0	Northeast	Hydro	Ontario Power Generation Inc.
LITTLELONG - OPG NE	133.0	Northeast	Hydro	Ontario Power Generation Inc.
Evergreen Energy (OPG)	126.0			Ontario Power Generation Inc.
CARIBOUFALLS - OPG NW	87.0	Northwest	Hydro	Ontario Power Generation Inc.
ARNPRIOR - OPG Ottawa	82.0	East	Hydro	Ontario Power Generation Inc.
CAMERONFALLS - OPG NW	81.0	Northwest	Hydro	Ontario Power Generation Inc.
MANITOUFALLS - OPG NW	73.0	Northwest	Hydro	Ontario Power Generation Inc.
Abitibi Iroquois Falls	70.0	Northeast	Hydro	Abitibi-Consolidated Company of Canada
ALEXANDER - OPG NW	68.0	Northwest	Hydro	Ontario Power Generation Inc.
WHITEDOG - OPG NW	67.8	Northwest	Hydro	Ontario Power Generation Inc.
MACKAYGS	62.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
SMOKY - OPG NE	52.0	Northeast	Hydro	Ontario Power Generation Inc.
AGUASABON - OPG NW	51.0	Northwest	Hydro	Ontario Power Generation Inc.
CLERGUE	51.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
RAYNER	48.4	Northeast	Hydro	Mississagi Power Trust
SILVERFALLS - OPG NW	48.0	Northwest	Hydro	Ontario Power Generation Inc.
ANDREWS	46.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
REDROCK	43.6	Northeast	Hydro	Mississagi Power Trust
HIGHFALLS	27.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
KAKABEKA - OPG NW	25.0	Northwest	Hydro	Ontario Power Generation Inc.
HOLINGSWTH	23.2	Northeast	Hydro	Great Lakes Power Limited – Generation Division
DECEWND1 - OPG Niagara	23.0	Niagara	Hydro	Ontario Power Generation Inc.
GARTSHORE	23.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
SCOTTGLP	22.4	Northeast	Hydro	Great Lakes Power Limited – Generation Division
LONGSAULTE	20.0	Northeast	Hydro	Long Sault Joint Venture
CARMICHAEL	20.0	Northeast	Hydro	Beaver Power Corporation
MARTINDALE	19.0	Northeast	Hydro	Ontario Power Generation Inc.
EARFALLS - OPG NW	18.0	Northwest	Hydro	Ontario Power Generation Inc.
STEEPHILLF	16.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
HOGG	15.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
MISSIONFLS	15.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division

NAGAGAMI	15.0	Northeast	Hydro	Beaver Power Corporation
WAWATAY	14.4	Northwest	Hydro	Clean Power Operating Trust
HARRIS	13.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
CALMLAKE	11.0	Northwest	Hydro	Abitibi-Consolidated Company of Canada
VALRIEFALLS	10.4	Northwest	Hydro	Valerie Falls Limited Partnership
MCPHAIL	10.0	Northeast	Hydro	Great Lakes Power Limited – Generation Division
STURGEONFALL	9.0	Northwest	Hydro	Abitibi-Consolidated Company of Canada
SERPENT	8.0	Northeast	Hydro	Beaver Power Corporation
AUXSAUBLE	4.7	Northeast	Hydro	Beaver Power Corporation
Glen Miller	8.0			2005 Q4 per OPA
TOTAL	**8,028.9**			

Future Developments

Station Name	MW	Date	Source/Notes
Modifications to Sandy Falls	-3	2007 Q3	IESO
Lac Seul	13	2007 Q4	IESO
Abitibi Canyon Upgrade	10	2008 Q1	IESO
Modifications to Lower Sturgeon	-5	2008 Q1	IESO
Umbata	23	2008 Q2	IESO/OPA
Modifications to Wawatin	-11	2008 Q2	IESO
Island Falls	20	2009 Q4	OPA
Other new projects (4)	21	TBD	OPA
Niagara Tunnel (Beck)	~300	2009	OPG, likely to be higher operating rate for Beck 1

Table A3 – Ontario Coal Power Capacity - 2006

Generating Station Name	Total Station MCR (MW)	Zone	Fuel Type	Source/Ownership
Nanticoke	3,920.0	Southwest	Coal	Ontario Power Generation Inc.
Lambton	1,972.0	West	Coal	Ontario Power Generation Inc.
Atokokan	230.0	Northwest	Coal	Ontario Power Generation Inc.
Thunder Bay	326.0	Northwest	Coal	Ontario Power Generation Inc.
TOTAL	**6,448.0**			
Future Developments				
Station Name	**MW**	**Date**	**Source/Notes**	

Table A4 – Ontario Natural Gas Power Capacity - 2006				
Generating Station Name	**Total Station MCR (MW)**	**Zone**	**Fuel Type**	**Source/Ownership**
Centralized Generation				
Power Only				
Brighton Beach (Windsor)	580.0	West	Gas - Combined Cycle	Brighton Beach Power L.P.
Total	**580.0**			
Cogeneration (> 50 MW)				
TransAlta Sarnia	575.0	West	Gas Cogeneration	TransAlta (steam and 291 MW used onsite by Bayer, NOVA, Dow and Suncor; includes the previously listed Dow Chemical cogeneration plant)
Cardinal Power	156.0	East	Gas Cogeneration	Cardinal Power of Canada (CCGT with steam sold to Canada Starch)
Iroquois Falls	120.0	Northeast	Gas Cogeneration	Iroquois Falls Power Corporation (Owned by Northland Power; gas turbine with HRSG; steam sold to Abitibi-Consolidated)
GTAA Cogeneration Plant	117.0	Toronto	Gas Cogeneration	GTAA (90 MW sold to OPA; 2 gas turbines, 2 HRSG and 1 steam turbine; steam used by Pearson Airport)
Kingston Cogen	115.0	East	Gas Cogeneration	Kingston Cogen Limited Partnership (Gas turbine with HRSG; steam sold to Invista)
Abitibi Consolidated Fort Frances	112.0	Northwest	Gas Cogeneration	Abitibi-Consolidated (Gas turbine with steam used by the pulp mill; possibly being replaced by

				a new biomass fueled facility)
West Windsor Power	112.0	West	Gas Cogeneration	Tractebel Canada Inc.(Gas turbine with power turbine; steam sold to ADM and Canadian Salt)
Lake Superior Power (Sault Ste Marie)	110.0	Northeast	Gas Cogeneration	Lake Superior Power (owned by Brookfield Power; 2 gas turbines and 1 steam turbine; steam sold to industrial customers)
TransAlta Mississauga/Douglas	108.0	Toronto	Gas Cogeneration	TransAlta
TransAlta Windsor-Essex	68.0	West	Gas Cogeneration	TransAlta
TransAlta Ottawa	68.0	Ottawa	Gas Cogeneration	TransAlta
Whitby Cogeneration	58.0	Toronto	Gas Cogeneration	Whitby Cogeneration LP (natural gas turbine with HRSG)
Total	**1,719.0**			
Decentralized Energy				
Cogeneration (< 50 MW)				
Tunis (Iroquois Falls)	48.0		Gas and Waste Heat Recovery	Epcor Power LP
Facilities less than 5 MW (31 facilities	46.2		Gas Cogeneration	CIEEDAC 2007
Nipigon	40.0	Northwest	Gas and Waste Heat Recovery	Epcor Power LP
North Bay	40.0		Gas and Waste Heat Recovery	Epcor Power LP
Kapuskasing	40.0		Gas and Waste Heat Recovery	Epcor Power LP
Invista - Maitland	38.3	East	Gas Cogeneration	Invista (formerly Dupont Canada)
Ford - Windsor	28.0		Gas Cogeneration	Ford Motor (Steam extraction turbine - CIEEDAC 2007)
Imperial Oil Nanticoke Refinery	20.0		Gas Cogeneration	Imperial Oil (Steam turbine; CIEEDAC 2007)
Terra - Courtright/Bickford	15.5		Gas Cogeneration	Terra International (Gas turbine CIEEDAC 2007)

Casco - London	15.0		Gas Cogeneration	Casco (Three gas turbines; power and steam used internally; CIEEDAC 2007)
London Health Sciences Centre	11.0		Gas Cogeneration	London Health (Two steam turbines; CIEEDAC 2007)
Casco - Port Colborne	10.0		Gas Cogeneration	Casco (Two gas turbines; power and steam used internally; CIEEDAC 2007)
Jungbunzlauer - Port Colborne	10.0		Gas Cogeneration	Jungbunzlauer (Two gas turbines; CIEEDAC 2007)
Stelco - Hamilton	10.0		Gas Cogeneration	Stelco (Two steam turbines; CIEEDAC 2007)
Heinz - Leamington	8.6		Gas Cogeneration	H. J. Heinz (Two gas turbines; CIEEDAC 2007)
Trent Valley Cogeneration - Trenton	7.2		Gas Cogeneration	Toromont Energy (One gas turbine, one HRSG and one ICE; OPA and CIEEDAC 2007)
Sudbury District Energy Hospital	6.8		Gas Cogeneration	Toromont Energy (Two ICE; OPA and CIEEDAC 2007)
University of Toronto	6.0		Gas Cogeneration	University of Toronto (One gas turbine; CIEEDAC 2007)
Sudbury District Energy Plant	5.0		Gas Cogeneration	Toromont Energy (Two ICE; OPA and CIEEDAC 2007)
Cornwall District Heating	5.0		Gas Cogeneration	CDH District Heating (ICE - CIEEDAC 2007)
Labatt	5.0		Gas Cogeneration	Labatt Breweries Ontario (One gas turbine; CIEEDAC 2007)
Commercial Alcohols - Chatham	5.0		Gas Cogeneration	Commercial Alcohols (One gas turbine; CIEEDAC 2007)
Maple Lodge Farms - Brampton	4.8		Gas Cogeneration	Maple Lodge Farms (One gas turbine; CIEEDAC 2007)
TOTAL	**425.4**			
Future Developments				
Station Name	**MW**	**Date**	**Source/Notes**	
Greenfiled Energy Centre	1005	2008 Q4	OPA; combined cycle	

Goreway Phase 1	485	2007 Q2	IESO/OPA; simple cycle
Great Northern Tri-Gen	12	2008 Q1	IESO/OPA; cogeneration
Portlands Energy Centre I	250	2008 Q2	IESO/OPA; Simple Cycle
Countryside London Cogen	12	2008 Q2	IESO/OPA; cogeneration
Warden Energy Centre	5	2008 Q2	IESO/OPA; cogeneration
Durham College District Energy	2	2008 Q2	IESO/OPA; cogeneration
Goreway Phase 2	375	2008 Q3	IESO/OPA; combined cycle addition
Greenfield South Power Plant	280	2008 Q4	OPA; combined cycle
St Clair Energy Centre	570	2009 Q1	OPA; combined cycle
Portlands Energy Centre II	288	2009 Q2	OPA; combined cycle addition
East Windsor Cogeneration	84	2009 Q2	OPA; cogeneration
Algoma Energy Cogeneration	63	2009 Q2	OPA; cogeneration
Halton Hills	683	2010 Q2	OPA combined cycle
Thorold Cogeneration	236	2010 Q4	OPA cogeneration

Table A5 – Ontario Oil/Gas Power Capacity - 2006				
Generating Station Name	**Total Station MCR (MW)**	**Zone**	**Fuel Type**	**Source/Ownership**
Centralized Generation				
Lennox	2,140.0	East	Oil/Gas	Ontario Power Generation Inc.
Total	**2,140.0**			
Decentralized Energy				
Cogeneration (< 50 MW)				
Marathon Pulp	14.0		Heavy Oil	Tembec (Two extraction turbines; CIEEDAC 2007)
Hiram Walker	7.9		Heavy oil and natural gas	Hiram Walker & Sons (Two steam turbine and one diesel engine; CIEEDAC 2007)
Brock University - Thorold	6.6		Diesel	Brock University (8 diesel engines; CIEEDAC 2007)
Redpath Sugar - Toronto	5.6		Light fuel oil and natural gas	Tate & Lyle North America (One steam turbine; CIEEDAC 2007)
York University	5.0		Light fuel oil and natural gas	York University (One gas turbine; CIEEDAC 2007)
Total	**39.0**			
Future Developments				
Station Name	**MW**	**Date**	**Source/Notes**	

Table A6 – Ontario Wind Power Capacity - 2006

Generating Station Name	Total Station MCR (MW)	Zone	Fuel Type	Source/Ownership
Erie Shore Wind Farm	99.0		Wind	
Prince I	99.0		Wind	Brookfield Power
Prince II	90.0		Wind	Brookfield Power
Amaranth/Melancthon I	68.0	Southwest	Wind	Canadian Hydro Developers, Inc.
Kingsbridge I	40.0	Southwest	Wind	EPCOR Power Development Corporation
Huron Wind	9.0		Wind	Ontario Power Generation Inc.
Pickering Wind Turbine	1.8		Wind	Ontario Power Generation Inc.
Total	**406.8**			
Future Developments				
Station Name	**MW**	**Date**	**Source/Notes**	
Ripley	76.0	2007 Q4	IESO/OPA	
Melancthon II	132.0	2008 Q2	IESO/OPA	
Kruger Energy Port Alma	101.0	2008 Q4	OPA	
Leader A & B	200.0	2008 Q4	OPA	
Wolfe Island	198.0	2008 Q4	OPA	
Kingsbridge II	160.0	TBD	OPA	
Other new projects (20)	167.6	TBD	OPA	

Table A7 – Ontario Biomass Power Capacity - 2006				
Generating Station Name	**Total Station MCR (MW)**	**Zone**	**Fuel Type**	**Source/Ownership**
Centralized Generation				
Kirkland	150.6	Northeast	Wood waste	Kirkland Lake Power Corporation
Total	**150.6**			
Decentralized Energy				
Cogeneration (< 50 MW)				
Bowater - Thunder Bay	67.0		Wood waste	Bowater (Wood waste power boiler with steam turbine; power and steam appear to be used onsite; CIEEDAC 2007)
NPCOCHRANE	46.5	Northeast	Wood waste	Cochrane Power Corporation
Calstock	35.0	Northeast	Wood waste and waste heat recovery	Epcor Power LP
Tembec - Smooth Rock	27.0	Northeast	Wood waste	Tembec Pulp Group - Kraft Pulp Division- Smooth Rock Falls (Steam turbine; CIEEDAC 2007)
Domtar - Espanola	22.0		Wood waste and natural gas	Domtar (One steam turbine; CIEEDAC 2007)
Tembec - Kapuskasing	21.6		Wood waste	Tembec (Two steam turbine; CIEEDAC 2007)
Kimberley Clark - Terrace Bay	20.0		Wood waste	Kimberley-Clark (Steam turbine; CIEEDAC 2007)
Domtar - White River	7.5		Wood waste	Drayton Valley Power (Steam used onsite)
Domtar - Chapleau	7.2		Wood waste	Domtar (Condensing extraction turbine)
Total	**253.8**			

Landfill and Biogas				
Humber Treatment Plant - Toronto	4.7		Digester gas	City of Toronto (Two ICE; CIEEDAC 2007)
Eastview Landfill	2.5		Digester gas	2005 Q3 per OPA
Hamilton Digester Plant	1.6		Digester gas	2006 Q3 per OPA
Total	**8.8**			
TOTAL	**262.6**			

Future Developments

Station Name	**MW**	**Date**	**Notes**
Trail Road Landfill	5.0	2007 Q1	OPA
Britannia Landfill Gas Utilization	5.6	2007 Q1	OPA
Halton Landfill Biogas	2.1	TBD	OPA
West Lorne BioOil Cogeneration	2.5	TBD	OPA
Abitibi-Consolidated	45.5	2008	Abitibi-Consolidated announced in March 2007 a new biomass energy generator to be located at its Fort Frances pulp and paper mill. Construction is scheduled to begin in the summer of 2007, and the generator is anticipated to be in operation during the fall of 2008. The equipment will use wood waste to generate steam and 45.5 MW of electricity for the mill. The new biomass boiler will burn mill-generated wood waste and primary sludge, as well as harvest slash from woodlands operations and wood waste from area sawmills.
Algonquin Power Energy from Waste (Brampton)	15	In operation	Algonquin Power; from MSW

Table A8 – Ontario Solar Power Capacity - 2006				
Generating Station Name	**Total Station MCR (MW)**	**Zone**	**Fuel Type**	**Source/Ownership**
Total	**0**			
Future Developments				
Station Name	**MW**	**Date**	**Source/Notes**	
OptiSolar Farms (Sarnia Solar 1 to 4)	40.0	2010	CBC News (2007). Ontario approves massive solar farm. OptiSolar will be paid 42 cents a kilowatt-hour for the solar power generated, a much higher premium than the 11 cents a kilowatt-hour paid for wind power,	
Other small solar projects	0.03	TBD	Ontario Power Authority (2007). Renewable Energy Standard Offer Program Quarterly Report Q1 2007 January – March. Toronto, Ontario, Canada.	

Table A9 – Conservation and Demand Management Capacity - 2006

Generating Station Name	Total Station MCR (MW)	Zone	Fuel Type	Source/Ownership
Loblaw Demand Response	10.0			OPA; 2006 Q2
York Region Demand Response	3.0			OPA; 2006 Q3
Total	**13.0**			
Future Developments				
Station Name	**MW**	**Date**	**Source/Notes**	

Appendix B – Model Details

Table B1 - Capital Costs for Generation Capacity ($/kW)				
	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 ST	$1,840	$1,840	$1,840	$1,840
Gas Combined Cycle (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.				

Table B2 - Operations and Maintenance Costs for Generation Capacity ($/MWh)

	OPA Plan (Calibration)	OPA Plan (Updated)	Soft Green	Deep Green
Nuclear - Existing	¢14.8	¢14.8	¢14.8	¢14.8
Nuclear - Refurbished	¢14.8	¢14.8	¢14.8	¢14.8
Nuclear - New	¢14.8	¢14.8	¢14.8	¢14.8
Hydro	¢7.8	¢7.8	¢7.8	¢7.8
Coal ST	¢11.4	¢11.4	¢11.4	¢11.4
Gas Combined Cycle (CCGT)	¢8.7	¢8.7	¢8.7	¢8.7
Industrial Gas Cogeneration (> 50 MW)	¢4.7	¢4.7	¢4.7	¢4.7
Oil/Gas	¢9.5	¢9.5	¢9.5	¢9.5
Wind Farms	¢17.8	¢17.8	¢17.8	¢17.8
Biomass & Landfill Gas (> 50 MW)	¢17.3	¢17.3	¢17.3	¢17.3
Interconnection	¢8.1	¢8.1	¢8.1	¢8.1
Storage	¢66.6	¢66.6	¢66.6	¢66.6
Gas Simple Cycle (Peaking)	¢15.5	¢15.5	¢15.5	¢15.5
Coal Gasification	¢15.1	¢9.7	¢9.7	¢9.7
Solar (Greenfield)	¢14.8	¢14.8	¢14.8	¢14.8
CDM (Efficiency and Solar DHW)	¢0.0	¢0.0	¢0.0	¢0.0
CDM (Fuel Switching)	¢0.0	¢0.0	¢0.0	¢0.0
Demand response, TOU Pricing & Conservation	¢0.0	¢0.0	¢0.0	¢0.0
Industrial Gas Cogeneration (<50 MW)	¢4.7	¢4.7	¢4.7	¢4.7
Biomass & Landfill Gas (< 50 MW)	¢25.0	¢25.0	¢25.0	¢25.0
CDM Renewables (Onsite Wind & Hydro)	¢12.8	¢12.8	¢12.8	¢12.8
Self Generation (CDM Cogen, Microturbines & Fuel Cells)	¢13.9	¢13.9	¢13.9	¢13.9
Solar (Rooftop)	¢14.8	¢14.8	¢14.8	¢14.8
Substation Peaker & CHeP	¢7.5	¢7.5	¢7.5	¢7.5
Waste Heat Recycling	¢3.0	¢3.0	¢3.0	¢3.0

Table B3 - Detailed Cost Information

Technology	Model Run	OPA Information			Model Information						
		Supply Mix Advice		Preliminary Plan	Input Parameters						Output
		LUEC - 11% WACC (¢/kWh)	Capital Cost ($/kW)	LUEC (¢/kWh)	Installed Costs ($/kW)	Load Factor (%)	Return on Capital (%)	Financing Term (Years)	O&M Costs (¢/kWh)	Fuel Cost ($/GJ)	Delivered Cost (¢/kWh)
Nuclear - Existing	All	¢7.93	$2,845	¢4.95	$2,845	87.8%	11.00%	30	¢14.8	$0.22	¢6.35
Nuclear - Refurbished	Calibration			¢6.3 to ¢8.0	$2,845	90.0%	11.00%	30	¢14.8	$0.22	¢6.24
Nuclear - Refurbished	Updated, Soft and Deep Green				$2,845	72.0%	12.92%	25	¢14.8	$0.22	¢8.39
Nuclear - New	Calibration			¢6.5 to ¢8.0 ($3,400/kW)	$3,400	90.0%	11.00%	30	¢14.8	$0.22	¢7.10
Nuclear - New	Updated, Soft and Deep Green				$3,400	72.0%	12.92%	25	¢14.8	$0.22	¢9.67
Hydro	All	¢9.99	$2,666	¢8 to ¢10	$2,666	59.3%	11.00%	30	¢7.8	$0.00	¢7.22
Coal ST	All		$1,840		$1,840	27.0%	11.00%	30	¢11.4	$2.54	¢13.34
Gas Combined Cycle (CCGT)	All	¢7.03	$841	¢9 to ¢12	$841	24.8%	11.00%	20	¢8.7	$5.79	¢10.37
Industrial Gas Cogeneration (> 50 MW)	All	¢7.94	$1,294		$841	87.0%	11.00%	20	¢4.7	$5.79	¢5.03
Oil/Gas	All		$651		$635	6.7%	11.00%	30	¢9.5	$5.79	¢19.74

Wind Farms	All	¢10.29	$1,913	¢8.89 to ¢11.72 ($1,959/kW for 200 MW wind farm)	$1,959	27.8%	11.00%	30	¢17.8	$0.00	¢11.69
Biomass & Landfill Gas (> 50 MW)	All	¢6.17	$2,208	¢8.9 to ¢11.5	$2,208	51.8%	11.00%	20	¢17.3	$0.95	¢9.40
Interconnection	Calibration and Updated				$1	2.7%	11.00%	30	¢8.1	$5.97	¢7.22
Interconnection	Soft and Deep Green				$1	100.0%	11.00%	30	¢8.1	$6.02	¢7.22
Storage	All				$2,666	7.0%	11.00%	30	¢66.6	$0.00	¢59.99
Gas Simple Cycle (Peaking)	All	¢13.13	$635	¢9 to ¢12	$635	2.7%	11.00%	20	¢15.5	$5.79	¢43.87
Coal Gasification with Sequestration	Calibration	¢9.09	$2,499		$2,499	84.5%	11.00%	30	¢15.1	$2.54	¢8.02
Coal Gasification without Sequestration	Updated, Soft and Deep Green	¢6.83	$1,923		$1,923	84.5%	11.00%	30	¢9.7	$2.54	¢6.49
Solar (Greenfield)	All (in 2007)	¢29.94	$5,613	¢25 to ¢30	$5,613	9.0%	11.00%	20	¢14.8	$0.00	¢96.21
Solar (Greenfield)	All (in 2027)				$3,052	9.0%	11.00%	20	¢14.8	$0.00	¢53.03
CDM (Efficiency and Solar DHW)	All	¢5.7 (average of all CDM)		$833/kW (average PV of all CDM)	$833	58.5%	11.00%	20	¢0.0	$0.00	¢2.09

CDM (Fuel Switching)	All	¢5.7 (average of all CDM)		$833/kW (average PV of all CDM)	$833	310.4%	11.00%	20	¢0.0	$0.00	¢0.38
Demand response, TOU Pricing & Conservation	All	¢5.7 (average of all CDM)		$833/kW (average PV of all CDM)	$833	9.2%	11.00%	20	¢0.0	$0.00	¢12.98
Industrial Gas Cogeneration (<50 MW)	All	¢7.94	$1,294		$841	87.0%	11.00%	20	¢4.7	$5.79	¢4.76
Biomass & Landfill Gas (< 50 MW)	All	¢6.17	$2,208	¢12.4 to ¢19.0	$3,200	51.8%	11.00%	20	¢25.0	$1.50	¢12.38
CDM Renewables (Onsite Wind & Hydro)	All	¢5.7 (average of all CDM)		$833/kW (average PV of all CDM)	$2,545	94.9%	11.00%	20	¢12.8	$0.00	¢5.13
Self Generation (CDM Cogen, Microturbines & Fuel Cells)	All	¢5.7 (average of all CDM)		~¢5 to ¢17	$3,741	73.9%	11.00%	20	¢13.9	$6.95	¢12.20
Solar (Rooftop)	All (in 2007)	¢29.94	$5,613	¢25 to ¢30	$5,613	11.4%	11.00%	20	¢14.8	$0.00	¢72.06
Solar (Rooftop)	All (in 2027)				$3,052	11.4%	11.00%	20	¢14.8	$0.00	¢39.86
Substation Peaker & CHeP	All				$1,000	15.0%	11.00%	20	¢7.5	$5.79	¢16.10
Waste Heat Recycling	All				$1,500	87.0%	11.00%	20	¢3.0	$0.00	¢2.78
Notes:											
1 - The capital costs for cogeneration are entered in the model as the cost for the electrical side only, which are taken as the cost of the equivalent electrical technology.											

2 - The capital costs entered in the model for CDM Renewables are a 50%/50% average of the costs for small wind and hydro. The load factor is from the OPA.
3 - The capital costs entered in the model for Self Generation and Substation Peakers were taken for the 2006 NewERA study.
4 - The capital costs entered in the model for Waste Heat Recycling were provided by Recycled Energy Development LLC
5 - The costs for DE Biomass were escalated by approximately 30% vs. CG biomass.
6 - The Operations & Maintenance costs include variable and fixed costs. Information was taken from the Supply Mix Advice. Fixed costs were spread to the annual amount of electricity produced which was determined using the specified load factor.
7 – The effective peak load factors for hydro are 76.7% for existing capacity and 71.1% for new capacity. The effective peak load factor for conventional wind is 17% and 30.6% for wind farms equipped with VRB storage technology. The effective peak load factor for all other technologies is 100%.

Table B4 - Total Coal Steam Turbine Installed Capacity (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Calibration	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	0	0	0	0
Updated	6,434	6,434	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	0	0
Soft Green	6,434	6,434	4,462	2,502	0	0	0	0	0	0	0	0
Deep Green	6,434	6,434	4,462	2,502	0	0	0	0	0	0	0	0

Table B5 - Summary of Scenarios 2027 Target Capacities					
		OPA Plan (Calibration)	OPA Plan (Updated)	Soft Green	Deep Green
	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 B6 - Calibration Run of the OPA Preliminary Plan without Coal for Insurance vs. OPA and IESO Data

	2007				2027		
	IESO (2006)	OPA IPSP (Dec 2006)		Model Input (2007)	OPA IPSP (Dec 2006)		Model Output (2027)
		As Stated	Adjusted to Model Structure		As Stated	Adjusted to Model Structure	
Electricity Sales -TWh				146.1			187.8
Average Transmission and Distribution Losses (%)				7.67%			
Electricity Generated - TWh	156 (in 2006)	155 (in 2005)		157.92	196 (in 2025)		200.9
Electricity Demand Growth Rate - %		1.2%		1.26%			
Peak Demand - MW	27,005 (in 2006)	26,399		27,337	34,899	34,899	34,898
Peak Demand Growth Rate - %		1.2%		1.23%			
Peak Transmission and Distribution Losses (%)				13.86%			
Effective Capacity - MW		30,229		30,424	41,433		41,433
Reserve Margin		14.5%		11.3%	18.7%		18.7%
Installed Capacity - MW	31,214 (March 2007)		32,382	32,573	47,856	47,569	46,796
Nuclear - Existing			11,514	11,514		750	750
Nuclear - Refurbished			0	0		10,484	10,113
Nuclear - New			0	0		1,400	1,400

	Hydro			7,819	7,816		10,095	10,003
	Coal ST			6,434	6,434		0	0
	Gas Combined Cycle (CCGT)			1,204	1,065		6,109	5,992
	Industrial Gas Cogeneration (> 50 MW)			1,719	1,719		1,719	1,719
	Oil/Gas			1,636	1,636		1,636	1,636
	Wind Farms			395	395		5,025	4,992
	Biomass & Landfill Gas (> 50 MW)			0	151		379	375
	Interconnection			800	800		500	495
	Storage			0	0		1,000	991
	Gas Simple Cycle (Peaking)			0	0		750	741
	Coal Gasification			0	0		250	247
	Solar (Greenfield)			0	0		40	40
Total Central Generation - MW				31,522	31,530		40,138	39,493
	CDM (Efficiency and Solar DHW)			199	199		3,712	3,639
	CDM (Fuel Switching)			20	20		203	199
	Demand response, TOU Pricing & Conservation			81	81		1,458	1,432
	Industrial Gas Cogeneration (<50 MW)			464	464		878	870
	Biomass & Landfill Gas (< 50 MW)			73	273		475	472
	CDM Renewables (Onsite Wind & Hydro)			19	2		170	167
	Self Generation (CDM Cogen, Microturbines & Fuel Cells)			4	4		495	485
	Solar (Rooftop)			0	0		40	40
	Substation Peaker & CHeP			0	0		0	0
	Waste Heat Recycling			0	0		0	0
Total Decentralized Energy - MW				860	1,044		7,431	7,303

Total CG and DE - MW			32,382	32,573		47,569	46,796
Costs							
Total Capital Costs over 20 Years - $ billion							$101.3
Generation							$64.5
Transmission							$10.6
Distribution							$26.2
Total Delivered Electricity Costs in 2027 - ¢/kWh						¢11.091	¢10.560
Generation Capital						¢7.544	¢5.481
Fuel							¢0.639
Operation & Maintenance							¢1.324
CO2							¢0.040
Conservation						¢0.472	
Transmission						¢0.974	¢0.975
Distribution						¢2.101	¢2.100
Environmental							
GHG (Life Cycle Total in 2027) - million tonnes					11.57		
GHG (Coal, Gas & Oil in 2027) - million tonnes/yr						8.13	8.56
GHG (Coal, Gas & Oil; 2007 to 2027) - million tonnes							224
GHG (Life Cycle Total in 2007) - kg/MWh					55		
GHG (Coal, Gas & Oil in 2027) - kg/MWh							43
NOx (Life Cycle Total in 2027) - tonnes/yr					36,110		
NOx (Coal, Gas & Oil in 2027) - tonnes/yr						8,023	6,016

	NOx (Life Cycle Total in 2027) - kg/MWh					0.171		
	NOx (Coal, Gas & Oil in 2027) - kg/MWh							0.030
	SOx (Life Cycle Total in 2027) - tonnes/yr					6,210		
	SOx (Coal, Gas & Oil in 2027) - tonnes/yr						1,347	1,399
	SOx (Life Cycle Total in 2027) - kg/MWh					0.029		
	SOx (Coal, Gas & Oil in 2027) - kg/MWh							0.0070
	Nuclear Electricity (in 2027) - TWh							91.9
	Nuclear Electricity (2007 to 2027) - TWh							1,884

Appendix C – Description of the WADE Model

The World Alliance for Decentralized Energy (WADE) has developed an Economic Model that compares the performance of DE and CG in meeting future electricity demand growth. The purpose of the Model is to calculate the economic and environmental impact of supplying incremental electric load growth with varying mixes of DE and CG. It gives concrete numerical and graphical results for capital costs, retail costs, emissions and fuel use. The model allows complete flexibility in terms of evaluating options or scenarios for meeting future demand with different technologies and generation mixes. An emphasis on transmission and distribution network capital requirements (i.e. avoided network development costs) differentiates the model's approach from other energy economics analyses(Casten and Collins 2005).

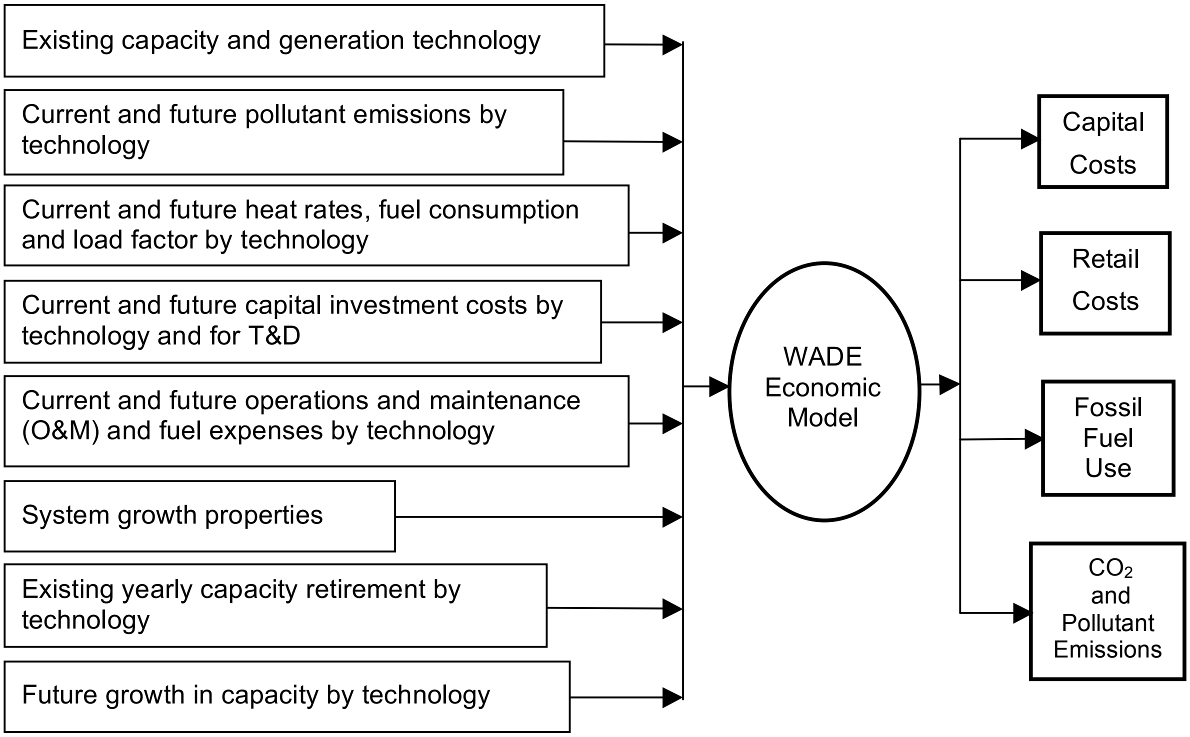
The Model summarizes the overall results for each particular set of inputs in a table. It quantifies the emissions and potential costs impact of decentralized energy, both in absolute and relative terms, enabling easy comparison between CG and DE, and various combinations thereof. In essence, the WADE Model was designed to answer the question: "What is the optimal mix of power generation to meet projected electric load growth?"

The WADE Economic Model has been used in a number of jurisdictions worldwide to evaluate the economic value of DE as a part of future energy supply mix. Studies have been done in the UK, Ireland, Portugal, the European Union, China, Nigeria, Australia and the United States (Casten and Collins 2005). Further information regarding the Model may be found at the web address: http://www.localpower.org/resources/wademodel.htm

The purpose of the WADE Economic Model is to calculate the economic and environmental impact of supplying electric load growth with varying mixes of decentralized (DE) and central generation (CG). By tailoring input assumptions, based on an understanding of specific regional conditions, the model can be adapted to any country, region or city in the world.

Starting with generation capacity for year 0 and estimates of retirement and load growth, the model builds user-specified capacity to meet future growth and retirement over a 20-year period. Details of the Model's inputs and outputs are summarized below:

The WADE Economic Model: Inputs and Outputs



The Model's data input requirements are detailed and extensive, requiring comprehensive information on a range of factors including:

- Existing capacity and generation by technology type
- Current and future pollutant emissions by technology type
- Future and current heat rates and fuel consumption by technology type
- Future and current capital and investment costs by technology type and for transmission and distribution (T&D)
- Future and current average operation and maintenance (O&M) costs and fuel expenses by technology type
- System growth properties for the chosen system
- Estimates of existing yearly capacity retirement by technology type, to be entered in 5-year blocks.
- Estimates of future growth in capacity by technology type, to be entered in 5-year blocks.

The Model outputs are:

- Total capital costs for investment (generation capacity and T&D) over 20 years

- Retail (delivered electricity) costs in year 20 (T&D amortization + generation plant amortization + O&M + fuel costs) for new generation capacity
- Fossil fuel use by the new capacity in year 20, both in total and by type
- CO_2 and other pollutant (SO_x, NO_x, PM_{10}) emissions from new generation capacity in year 20
- Generation by source in year 20

The WADE Economic Model builds cases for new capacity to meet incremental demand over 20 years, ranging from scenarios with 0% DE / 100% CG to 100% DE / 0% CG. The Model also builds cases between these extremes. In addition, the Model enables users to run any number of scenarios that, for example, favour certain technologies, change fuel prices or meet specific environmental goals.

The Model takes into account many real but little-understood features of electricity system operation – such as the significant impact of peak-time network losses on the amount of generation required to meet new demand.

Where the WADE Model has been applied in other jurisdictions, users have commented on the importance of quality information being fed into the model. Therefore, a considerable amount of work regarding data gathering and data validation was done.

Assumptions Incorporated into the WADE Model and Study

The WADE economic model takes a macro-economic view of the power generation and delivery options and mixes of CG and DE to find the optimum economic balance. Other studies have previously been done where the economics of individual generators or groups of generators were examined, and some of these options have rightly been shown to have marginal economics, or even negative economics.

These marginal economic results are in some cases a symptom, or extension of historic policies, regulations and practices which have discouraged the development DE. NewERA has done much work in the area of identifying what policy changes are needed. However, this is not the subject of this report. It is a subject that could be addressed in subsequent reports or studies. The WADE economic model makes no assumptions about what policies are needed to disseminate the benefits of DE to various stakeholders. The model does, however, identify the size of the societal benefit, or prize, of having the optimal mix of DE and CE.

As an illustrative example, when diesel engines first supplanted steam engines on the North American railroad system, on a unit cost basis they were considerably more costly than steam locomotives. Therefore, in a unit cost comparison they could, at first sight, appear more costly and less economic. However, when the overall system benefits (and environmental benefits) were considered, and the avoided system costs recognized, diesel locomotives made economic sense (Hollinshead 2003). The WADE model allows us to do such an overall system review to find the optimum balance between CG and CE.

One of the key questions to be addressed in such a study is how to handle joint costs between different products. For example, a residential solar installation that doubles as roofing material can off-set or reduce the price of a roof. So should the cost of the solar installation be reduced by the savings in roofing material?

In evaluating the economics of a cogeneration opportunity, it is necessary to examine the co-generator economics in the context of some of the host facility's parameters. Important questions are: Which costs are relevant to the co-generator decision economics, and which costs are irrelevant? How are joint costs to be treated and how are separable costs to be treated?

An important concept from the field of management accounting is that the only costs that are relevant to a particular product and decisions regarding that product are the costs that occur beyond the "split-off point" of that product. The decision to incur added costs beyond the split-off point is a matter of comparing the revenue available (if any) at the split-off point with the differential income attainable beyond the split-off point (Horngren).

The allocation of joint costs to different products before the split-off point is essentially arbitrary and can be problematic, as it can be done in a number of ways and can lead to misleading results, and incorrect decisions. For example, in the residential solar example, if it duals as roofing material, allocating the entire cost of the solar system to power generation could result in a misleading result. In a CHP system, allocating all the heat recovery costs to power generation could also result in a misleading result. The WADE model does not attempt to allocate these benefits, but merely identifies total net emissions reduction, and potential electric system avoided costs and economic benefits to society.

Appendix D - WWF/Pembina - Green Electricity Scenarios for Ontario