Appendix C – System Resources Details

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1.0 Resources Data Tables

Table C1.1 Ontario Power Generation Inc. Power Stations in Study

Name	Resource Type	Declared Net Capacity (MW)	Units
Bruce B	Nuclear	3,140	4
Darlington	Nuclear	3,524	4
Pickering A	Nuclear	2,060	4
Pickering B	Nuclear	2,064	4
Atikokan	Coal	215	1
Lakeview	Coal	1,140	4
Lambton	Coal	1,975	4
Lennox	Oil & Gas	2,140	4
Nanticoke	Coal	3,920	8
Thunder Bay	Coal	310	2
CTU's	Oil & Gas	22	5
Tacke Turbine	Wind	1	1
Abitibi Canyon	Hydro	314	5
Aguasabon	Hydro	46	2
Alexander	Hydro	67	5
Arnprior	Hydro	82	2
Aubrey Falls	Hydro	162	2
Barrett Chute	Hydro	176	4
Cameron Falls	Hydro	78	7
Caribou Falls	Hydro	87	3
Chats Falls(1)	Hydro	96	4
Chenaux	Hydro	139	8
Decew Falls 1	Hydro	23	4
Decew Falls 2	Hydro	144	2

Name	Resource Type	Declared Net Capacity (MW)	Units
Des Joachims	Hydro	429	8
Ear Falls	Hydro	17	4
G.W. Rayner	Hydro	46	2
Harmon	Hydro	141	2
Kakabeka Falls	Hydro	25	4
Kipling	Hydro	141	2
Little Long	Hydro	133	2
Lower Notch	Hydro	274	2
Manitou Falls	Hydro	66	5
Mountain Chute	Hydro	170	2
Otter Rapids	Hydro	182	4
Otto Holden	Hydro	243	8
Pine Portage	Hydro	131	4
R.H. Saunders	Hydro	1,005	16
Red Rock Falls	Hydro	41	2
Silver Falls	Hydro	48	1
Sir Adam Beck 1	Hydro	496	10
Sir Adam Beck 2	Hydro	1,360	16
Sir Adam Beck PGS	Hydro	174	6
Smoky Falls	Hydro	56	4
Stewartville	Hydro	182	5
Wells	Hydro	232	2
Whitedog Falls	Hydro	68	3
Other Hydro(2)	Hydro	206	86

(1) Capacity and units shown are for Ontario half of the station.

(2) They include plants with station capacity of less than 15 MW (156 MW) and 50 MW of hydro unit upgrades completed in year 2000.

Table C1.2 Ontario Power Generation Inc. Units Not In Study

Name	Capacity (MW)
Bruce A 1, 2, 3, 4 (Nuclear) (OS)	3,076
Lakeview Units 3, 4, 7, 8 (Coal) (RE)	1,138
Thunder Bay 1 (Coal) (RE)	94

Notes:
OS On long term scheduled maintenance or Forced Outage. Not available to operate (greater than 3 months)
RE Retired (no longer in service and not expected to be returned to service)

Table C1.3 Contract Generators Power Stations in Study

Resource Type	In-Service Capacity (MW)
Natural Gas	1,038
Natural Gas/ Black Liquor	103
Landfill Gas	57
Natural Gas/ Waste Heat	328
Hydro	75
Municipal Solid Waste	15
Steam	40
Subtotal (10 MW in size or greater shown above)	**1,656**
Subtotal (less than 10 MW in size) (See Table C1.4 for Details)	**110**
Total	**1,766**

Table C1.4 Contract Generators Small Power Stations in Study

Resource Type	In-Service Capacity (MW)
Natural Gas	10
Landfill Gas	5
Municipal Solid Waste	4
Wood Waste	17
Hydro	59
Waste/ Flare Gas	2
Subtotal (greater than or equal to 1 MW in size and less than 10 MW shown above)	97
Subtotal (less than 1 MW in size) – Mostly Hydro, with some Natural Gas	13
Total	**110 MW**

2.0 Generation Reserve Requirement

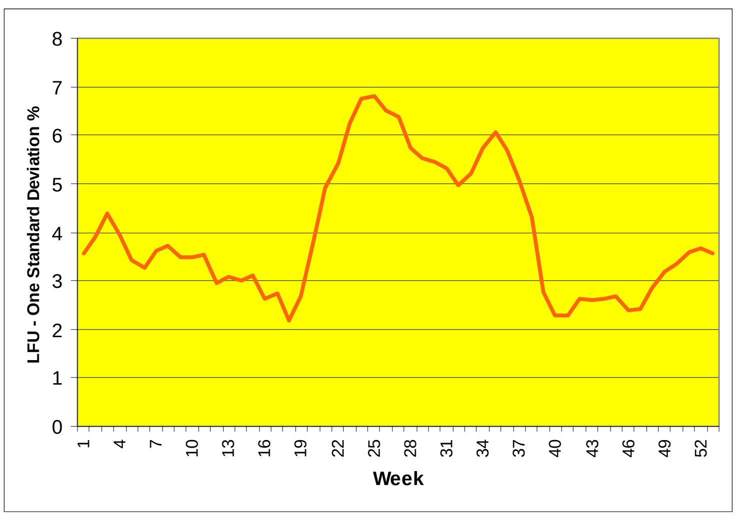
2.1 Method

The IMO uses a Load and Capacity (L&C) model to determine the Generation Reserve Requirements from week to week. The mix of generating plant, generating unit forced outage rates and the demand forecast and the associated uncertainties are inputs to the model. A Generation Adequacy Standard of 0.1 (day/year), is used to determine the Reserve Requirement for each week of the planning year. The adequacy of the available generation facilities to meet the demand over the 18-month study period can be assessed from the forecast weekly Margin, shown in Table C2.1.

2.2 Demand Forecast Uncertainty due to Weather

The total energy demand is split into weather and non-weather components. A normal distribution of weather swings, in any week, is provided by input of the associated standard deviation. This data is obtained from 30-year weather statistics and is updated annually. The standard deviation of weather-related demand (Load Forecast Uncertainty or LFU) varies between about 2% and 7 % through the year as shown in Figure C2.1. The peak demand probability distribution in any week is thus available to the L&C program.

Figure C2.1 Weekly Demand Forecast Uncertainty due to Weather



2.3 Resource Representation

Unit Ratings

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR). Hydroelectric system output is based on data provided by the Owners. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter values are included.

Forced Outage Rates of Generating Units

Derating-Adjusted Forced outage rates for each unit are used that reflect both forced outages and periods of derated output. Values are provided by Generation Plant Owners.

2.4 Representation of Interconnected Systems

There are effectively three systems that can provide assistance to Ontario, namely, USA, Quebec and Manitoba. For this study, interconnection assistance is not included, in the calculation of the Margin but is taken into account in the assessments, whenever a negative margin is indicated.

2.5 Transmission Systems

The Ontario IMO Controlled Grid consists of a robust southern grid and a sparse northern grid. The southern grid has few binding limits and these have been accounted for in this study. The northwestern part of the northern grid has limitations that potentially constrain generation capacity. Some 25-hz generation in the southern grid is bottled by frequency changer capability. Total generation limitations are modeled as a reduction in capability of up to 320 MW.

2.6 Study Procedures

For the 18-month assessment period, an LOLP value of 0.1 days per year was utilized to determine the Required Reserve in each week of the year. The uncertainty in the demand forecast varies from week to week, and the available generation mix may also vary, giving rise to a different Reserve Requirement for the Peak hour of each week. The risk is thus level throughout the year when calculating the Margin. Capacity available above the Reserve Requirement and Demand is considered to be surplus in any week and may be released for planned outages.

Table C2.1 Assessment of Gross Margin

Week Ending Day	Total Declared Net Capacity, MW	Primary Demand, MW	Generation Reserve Req. MW	Generation Reserve Req. %	Gross[1] Margin MW
08-Oct-00	30590	18980	2816	14.8	8794
15-Oct-00	30590	19037	2809	14.8	8744
22-Oct-00	30590	19434	2938	15.1	8218
29-Oct-00	30590	19605	2951	15.1	8034
05-Nov-00	30590	20297	3066	15.1	7227
12-Nov-00	30590	20901	3117	14.9	6572
19-Nov-00	30590	21237	3065	14.4	6288
26-Nov-00	30590	21427	3209	15.0	5954
03-Dec-00	30590	21736	3278	15.1	5576
10-Dec-00	30590	22069	3381	15.3	5140
17-Dec-00	30590	22327	3403	15.2	4860
24-Dec-00	30590	22556	3522	15.6	4512
31-Dec-00	30590	21790	3410	15.6	5390
07-Jan-01	29790	22235	3298	14.8	4257
14-Jan-01	29790	22596	3409	15.1	3785
21-Jan-01	29790	22632	3526	15.6	3632
28-Jan-01	29790	22367	3390	15.2	4033
04-Feb-01	29790	22333	3279	14.7	4178
11-Feb-01	29790	22227	3207	14.4	4356
18-Feb-01	29790	21979	3247	14.8	4564
25-Feb-01	29790	21618	3239	15.0	4933
04-Mar-01	29790	21415	3207	15.0	5168
11-Mar-01	29790	21100	3209	15.2	5481
18-Mar-01	29790	20818	3207	15.4	5765
25-Mar-01	29790	20545	3060	14.9	6185
01-Apr-01	29790	20183	2959	14.7	6648
08-Apr-01	29790	19884	2989	15.0	6917
15-Apr-01	29790	19584	2872	14.7	7334
22-Apr-01	29790	18985	2696	14.2	8109
29-Apr-01	29790	18936	2773	14.6	8081
06-May-01	29790	18798	2701	14.4	8291
13-May-01	29790	18659	2602	13.9	8529
20-May-01	29790	18711	2747	14.7	8332
27-May-01	29790	18669	3092	16.6	8029
03-Jun-01	29790	19042	3405	17.9	7343
10-Jun-01	29790	19735	3615	18.3	6440
17-Jun-01	29790	20319	3783	18.6	5688
24-Jun-01	29790	20576	3865	18.8	5349
01-Jul-01	29790	20675	3786	18.3	5329
08-Jul-01	29790	21174	3793	17.9	4823
15-Jul-01	29790	21756	3737	17.2	4297
22-Jul-01	29790	21760	3694	17.0	4336
29-Jul-01	29790	21548	3616	16.8	4626
05-Aug-01	29790	21211	3551	16.7	5028
12-Aug-01	29790	20877	3466	16.6	5447
19-Aug-01	29790	20870	3511	16.8	5409
26-Aug-01	29790	20696	3614	17.5	5480

Week Ending Day	Total Declared Net Capacity, MW	Primary Demand, MW	Generation Reserve Req. MW	Generation Reserve Req. %	Gross[1] Margin MW
02-Sep-01	29790	20588	3694	17.9	5508
09-Sep-01	29790	19682	3324	16.9	6784
16-Sep-01	29790	19462	3253	16.7	7075
23-Sep-01	29790	19088	3033	15.9	7669
30-Sep-01	29790	18904	2691	14.2	8195
07-Oct-01	29790	19095	2673	14.0	8022
14-Oct-01	29790	19273	2723	14.1	7794
21-Oct-01	29790	19541	2865	14.7	7384
28-Oct-01	29790	19744	2897	14.7	7149
04-Nov-01	29790	20193	2878	14.3	6719
11-Nov-01	29790	20946	3114	14.9	5730
18-Nov-01	29790	21308	3121	14.6	5361
25-Nov-01	29790	21527	3163	14.7	5100
02-Dec-01	29790	21791	3159	14.5	4840
09-Dec-01	29790	22173	3306	14.9	4311
16-Dec-01	29790	22475	3384	15.1	3931
23-Dec-01	29790	22715	3471	15.3	3604
30-Dec-01	29790	21788	3248	14.9	4754
06-Jan-02	29790	22555	3426	15.2	3809
13-Jan-02	29790	22778	3497	15.4	3515
20-Jan-02	29790	22840	3683	16.1	3267
27-Jan-02	29790	22611	3582	15.8	3597
03-Feb-02	29790	22555	3519	15.6	3716
10-Feb-02	29790	22354	3388	15.2	4048
17-Feb-02	29790	22189	3336	15.0	4265
24-Feb-02	29790	21801	3386	15.5	4603
03-Mar-02	29790	21634	3287	15.2	4869
10-Mar-02	29790	21302	3168	14.9	5320
17-Mar-02	29790	21048	3185	15.1	5557
24-Mar-02	29790	20713	3038	14.7	6039
31-Mar-02	29790	20365	3013	14.8	6412

[1] Gross Margin = Total Declared Net Capacity – Primary Demand – Generation Reserve Requirement. This quantity does not account for forced or planned outages for generation resources.