

## CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)

	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	2002	2001
		Restated (note 5)		Restated (note 5)
<b>Revenues</b>	<b>1,288</b>	1,507	<b>2,845</b>	3,046
Fuel (note 2)	<b>332</b>	338	<b>731</b>	706
Power purchased	<b>93</b>	173	<b>312</b>	275
<b>Gross Margin</b>	<b>863</b>	996	<b>1,802</b>	2,065
<b>Operating expenses</b>				
Operation, maintenance and administration	<b>620</b>	626	<b>1,212</b>	1,258
Depreciation and amortization	<b>193</b>	208	<b>378</b>	404
Property and capital taxes (note 2)	<b>28</b>	28	<b>59</b>	44
Restructuring costs (note 6)	-	-	<b>210</b>	-
Loss on transition rate option contracts (note 3)	-	-	<b>210</b>	-
Gain on sale of decontrol fixed assets (note 10)	<b>(99)</b>	-	<b>(99)</b>	-
	<b>742</b>	862	<b>1,970</b>	1,706
<b>Operating income (loss)</b>	<b>121</b>	134	<b>(168)</b>	359
Net interest expense	<b>39</b>	37	<b>78</b>	71
<b>Income (loss) before income taxes</b>	<b>82</b>	97	<b>(246)</b>	288
Income taxes (recoveries) (note 2)				
Current	<b>23</b>	238	<b>(45)</b>	272
Future	<b>(4)</b>	(158)	<b>(47)</b>	(103)
	<b>19</b>	80	<b>(92)</b>	169
<b>Net income (loss)</b>	<b>63</b>	17	<b>(154)</b>	119
<b>Basic and fully diluted earnings (loss) per common share (dollars)</b>	<b>0.25</b>	0.07	<b>(0.60)</b>	0.46
<b>Common shares outstanding (millions)</b>	<b>256.3</b>	256.3	<b>256.3</b>	256.3

## CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

(millions of dollars)

	Six Months Ended June 30	
	2002	2001
		Restated (note 5)
<b>Retained earnings, beginning of period as previously reported</b>	<b>344</b>	691
Adjustment (note 5)	-	(124)
<b>Retained earnings, beginning of period as restated</b>	<b>344</b>	567
Net income (loss)	<b>(154)</b>	119
Dividends	<b>(134)</b>	(100)
<b>Retained earnings, end of period</b>	<b>56</b>	586

See accompanying notes to the consolidated financial statements

## CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)

	Three Months Ended June 30		Six Months Ended June 30	
	2002	Restated (note 5) 2001	2002	Restated (note 5) 2001
<b>Operating activities</b>				
Net income (loss)	63	17	(154)	119
Adjust for non-cash items:				
Depreciation and amortization	193	208	378	404
Deferred pension asset	(18)	8	4	36
Other post employment benefits	36	23	52	57
Future income taxes	(4)	(158)	(47)	(103)
Provision for restructuring	-	-	210	-
Loss on transition rate option contracts	(18)	-	192	-
Gain on sale of investments	-	-	(7)	-
Gain on sale of decontrol fixed assets	(99)	-	(99)	-
Other	36	11	66	23
	<b>189</b>	<b>109</b>	<b>595</b>	<b>536</b>
Fixed asset removal and nuclear waste management fund	(109)	(95)	(160)	(217)
Expenditures on nuclear waste management	(21)	(13)	(52)	(23)
Expenditures on restructuring	(64)	-	(64)	-
Net changes to other long-term assets and liabilities	(75)	(3)	(67)	(40)
Deferred revenue	(8)	-	(14)	-
Non-cash working capital changes:				
Accounts receivable	570	13	588	132
Income tax recoverable	10	-	(77)	-
Fuel inventory	(64)	(39)	(48)	2
Materials and supplies	(16)	(56)	(19)	(59)
Accounts payable and accrued charges	(451)	202	(594)	(130)
<b>Cash flow provided by (used in) operating activities</b>	<b>(39)</b>	<b>118</b>	<b>88</b>	<b>201</b>
<b>Investing activities</b>				
Proceeds from Bruce decontrol (note 10)	-	370	-	370
Net proceeds from short-term investments	-	1	39	226
Proceeds on sale of decontrol fixed assets	342	-	342	10
Proceeds from sale of investments (note 11)	-	-	14	-
Expenditures for fixed assets	(210)	(154)	(366)	(269)
<b>Cash flow provided by investing activities</b>	<b>132</b>	<b>217</b>	<b>29</b>	<b>337</b>
<b>Financing activities</b>				
Repayment of long-term debt	-	-	-	(100)
Dividends paid	-	(14)	(134)	(100)
Short-term notes issued	-	-	200	-
Short-term notes repaid	(200)	-	(200)	(50)
<b>Cash flow (used in) financing activities</b>	<b>(200)</b>	<b>(14)</b>	<b>(134)</b>	<b>(250)</b>
<b>Net increase (decrease) in cash and cash equivalents</b>	<b>(107)</b>	<b>321</b>	<b>(17)</b>	<b>288</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>90</b>	<b>532</b>	<b>-</b>	<b>565</b>
<b>Cash and cash equivalents, end of period</b>	<b>(17)</b>	<b>853</b>	<b>(17)</b>	<b>853</b>

See accompanying notes to the consolidated financial statements

## CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)

	June 30 2002	December 31 2001
<b>Assets</b>		
<b>Current assets</b>		
Short-term investments	-	39
Accounts receivable	422	1,010
Income taxes recoverable	154	77
Fuel inventory	585	537
Materials and supplies	56	35
	<u>1,217</u>	<u>1,698</u>
<b>Fixed assets</b>		
Property, plant and equipment	14,519	14,460
Less: accumulated depreciation	1,743	1,479
	<u>12,776</u>	<u>12,981</u>
<b>Other assets</b>		
Deferred pension asset	302	330
Fixed asset removal and nuclear waste management fund (note 8)	1,368	1,208
Long-term note receivable (note 10)	225	225
Materials and supplies	189	179
Long-term accounts receivable and other assets	105	65
	<u>2,189</u>	<u>2,007</u>
	<u>16,182</u>	<u>16,686</u>
<b>Liabilities</b>		
<b>Current liabilities</b>		
Bank indebtedness	17	-
Accounts payable and accrued charges (note 3)	1,167	1,505
Deferred revenue due within one year	15	13
Long-term debt due within one year (note 7)	105	205
	<u>1,304</u>	<u>1,723</u>
<b>Long-term debt (note 7)</b>	<u>3,115</u>	<u>3,015</u>
<b>Other liabilities</b>		
Fixed asset removal and nuclear waste management (note 8)	4,817	4,724
Other post employment benefits	947	924
Long-term accounts payable and accrued charges (notes 3, 10)	384	336
Deferred revenue	201	215
Future income tax liabilities (note 2)	232	279
	<u>6,581</u>	<u>6,478</u>
<b>Shareholder's equity</b>		
Common shares	5,126	5,126
Retained earnings	56	344
	<u>5,182</u>	<u>5,470</u>
	<u>16,182</u>	<u>16,686</u>

See accompanying notes to the consolidated financial statements

## **NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2002 (UNAUDITED)**

### **1. Basis of Preparation**

These interim consolidated financial statements do not contain all disclosures required by Canadian generally accepted accounting principles for annual financial statements, and accordingly, the interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2001.

### **2. Taxes**

Under the *Electricity Act, 1998*, OPG is responsible for making payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by regulations made under the *Electricity Act, 1998*.

The Company is also required to pay property taxes. OPG makes payments in lieu of property tax on its nuclear and fossil generating assets to the OEFC, and also pays property taxes to municipalities.

OPG pays charges on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The Gross Revenue Charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial crown lands, in addition to graduated rate charges. GRC costs are included in fuel expense.

### **3. Transition Rate Options**

Under a regulation known as Transition – Generation Corporation Rate Options ("TRO"), OPG is required to provide transitional price relief upon market opening to certain large power customers based on the consumption and average price paid by each customer during a reference period from July 1, 1999 to June 30, 2000. The maximum anticipated volume subject to the transitional price relief is approximately 5.4 TWh in the first year after market opening, 3.6 TWh in the second year and 1.8 TWh in each of the third and fourth years. The maximum length of the program is four years, with the possibility that it will expire after only two years if certain decontrol targets are met.

A provision of \$210 million on the TRO contracts was recorded in the first quarter of 2002 related to the future loss on these contracts. The provision was determined using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on the contracts, interruptions of volume, and the recovery of market power mitigation rebates. These estimates are subject to measurement uncertainty. As a result, it is reasonably possible that actual results experienced may differ materially from the estimated amounts. The provision will be reduced over the term of the contracts based on volume.

During the second quarter of 2002, the provision was reduced by \$18 million and the amount was included in revenue. At June 30, 2002, the current portion of the provision for loss on these contracts was \$110 million and was included in Accounts Payable and Accrued Charges. The long-term portion of the provision, which was included in Long-Term Accounts Payable and Accrued Charges, was \$82 million.

### **4. Other Accounting Policies Related to Open Market**

#### *Market Power Mitigation Rebate*

OPG is required under its generating licence to comply with prescribed market power mitigation measures to address the potential for OPG to exercise market power in Ontario. The most significant market power mitigation measures are a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, for the first four years after market opening, a significant majority of OPG's expected energy sales in Ontario are subject to an average annual revenue cap of 3.8¢/kWh. OPG is required to pay a rebate to

the IMO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a twelve month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The first settlement period ends April 30, 2003. The quantities of energy subject to the rebate, as well as the hourly weights used to compute the average spot price for rebate purposes, have been fixed in advance but may be reduced for decontrol transactions. At each balance sheet date, OPG computes the average spot energy price that prevailed since the beginning of the current settlement period and recognizes a liability if the average price exceeds 3.8¢/kWh. No accrual was required at June 30, 2002 because the average price was less than 3.8¢/kWh.

#### *Energy Contracts for Open Market*

OPG is exposed to changes in electricity prices associated with an open spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the price of electricity, OPG has entered into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized over the term of the contract based on the timing of the underlying transactions and included in generation revenue. All contracts that are not designated as a hedge are valued at market value with changes in fair value recorded in energy marketing revenue as trading gains or losses.

#### *Emission Reduction Credits*

OPG utilizes emission reduction credits ("ERCs") to manage acid gas emissions (Nitrogen Oxide, Sulphur Dioxide and Carbon Dioxide) within the prescribed regulatory limits and voluntary limits. ERCs are purchased from trading partners in Canada and the United States. The cost of ERCs are held in inventory and charged to OPG's operations as part of fuel as required.

#### *Transmission Rights*

Transmission rights ("TRs") are option contracts issued by the IMO that provide protection for importers and exporters against differences between the Ontario market clearing price for energy and the intertie clearing price. Price differences can occur due to limits on transmission capacity between Ontario and the interconnected markets at a specific intertie. OPG purchases TRs in the Ontario market. TRs are accounted for as derivatives used for energy marketing purposes and valued at estimated market value. Changes in fair value are recorded as energy marketing gains or losses.

### **5. Restatement of 2001 Quarterly Results for Pension and Other Post Employment Benefits**

In 2001, OPG changed its policy of accounting for changes in the net actuarial gain or loss for pension and OPEB. This change in accounting policy results in the amortization of the net cumulative unamortized gain or loss in excess of 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets. Previously, the entire change in the net actuarial gain or loss was amortized over employee average remaining service life and plan assets were valued at market for purposes of determining actuarial gains and losses. The change in accounting policy for pensions and OPEB was applied retroactively to April 1, 1999. As a result of this change, the operating results for the six months ended June 30, 2001 have been restated to reflect an increase in employee benefit expenses of \$51 million and a decrease in net income of \$46 million.

Opening retained earnings at January 1, 2001 were reduced by \$124 million due to the change in accounting policy for pension and OPEB (\$104 million), as well as a revision to OPEB resulting from an assessment of OPG's claims history for 2000 (\$20 million).

## 6. Restructuring Costs

Restructuring charges are related to a reduction in the workforce of approximately 2,000 employees and include severance costs and related pension and OPEB expenses. During the first quarter of 2002, OPG approved voluntary severance packages for approximately 1,200 employees. Involuntary terminations will be required to meet the remaining workforce reductions over the next two to three years. The provision for restructuring costs recorded in the first quarter of 2002 was \$210 million. This amount is in addition to a restructuring charge of \$67 million recorded in the fourth quarter of 2001. During the second quarter of 2002, there were payments of \$64 million related to restructuring.

## 7. Long-term Debt

The Company reach an agreement with the OEFC to defer to December 2004, \$200 million principal amount of senior notes maturing in 2002. In connection with this deferral, the coupon rate on \$100 million principal amount of these notes was increased, based on commercial terms, by 0.50 per cent; the interest rate for the remaining \$100 million principal amount of these notes was unchanged.

## 8. Fixed Asset Removal and Nuclear Waste Management Liabilities

### *Nuclear Funds Agreement*

In March 2002, the Province of Ontario (the "Province") and OPG signed the Ontario Nuclear Funds Agreement (the "Agreement"). The Agreement establishes criteria for the management of segregated funds and limits OPG's financial exposure to the risk of cost increases for certain used fuel liabilities, subject to graduated liability thresholds. Under the terms of the Agreement, OPG will establish two custodial funds that will be held separate from OPG's operations. A Used Fuel Fund will be used to fund future costs of nuclear used fuel waste management. A Decommissioning Fund will be established to fund the future cost of nuclear fixed asset removal and low and intermediate level waste management. The Agreement will become effective when the two custodial funds are established, expected some time in the current year.

Since April 1, 1999, OPG has contributed \$1,368 million including interest earned of \$140 million to the nuclear fixed asset removal and nuclear waste management fund. The Decommissioning Fund will be funded through the receivable due from the Ontario Electricity Financial Corporation ("OEFC"), with the balance funded through OPG's existing segregated funds. The remaining segregated funds will be applied to the Used Fuel Fund. OPG will make annual contributions to the Used Fuel Fund of approximately \$450 million to 2008, and a reduced amount over the remaining life of the nuclear generating stations.

OPG will continue to be responsible for the risk of liability and cost increases with respect to fixed asset removal and low and intermediate level waste. OPG will also continue to be responsible for the risk of liability and cost increases for used fuel waste management, subject, however, to limits in OPG's financial exposure through the Agreement.

The Province will provide, under the Agreement, to the Canadian Nuclear Safety Commission ("CNSC"), as required by the *Nuclear Safety and Control Act* (Canada), a guarantee that there will be funds available to discharge the nuclear decommissioning and waste liabilities. This guarantee is expected to relate to the portion of the nuclear liabilities not funded by the Decommissioning and Used Fuel Fund, or by the OEFC receivable, and will be determined based on CNSC requirements. The terms and conditions of the guarantee are subject to the approval of the Minister of Finance.

In June 2002, the *Nuclear Fuel Waste Act* (Canada) received Royal Assent. Under the Act, owners of nuclear fuel waste are required to form a waste management organization to address and provide recommendations on long-term management of nuclear fuel waste. In addition, under the Act, OPG will be required to make an initial deposit of \$500 million into a trust fund within ten days of the Act coming into force and \$100 million for each of the three years thereafter. The Company will provide such funds by way of transfer from existing segregated funds accounts and from its annual contributions. The Act will come into effect when proclaimed into force which is expected in the fourth quarter of 2002.

## Cost Estimate Changes Made in 2002

OPG reviewed the significant assumptions that underlie the calculation of the accrued liabilities for fixed asset removal and nuclear waste management liabilities. As a result of this review, a number of assumptions were revised to reflect changes in the timing of certain programs and in the evolving technology used to handle the nuclear waste. These changes included a delay in the in-service date for used nuclear fuel disposal facilities from 2025 to 2035, the recognition of certain costs associated with dry storage of used nuclear fuel during station operating life, and recognition of additional costs related to nuclear waste management programs. In aggregate, these cost estimate changes would result in a net reduction to the nuclear waste management and decommissioning liability of \$215 million. In accordance with Canadian generally accepted accounting principles, the change in liability is being amortized over the average remaining service life of the nuclear generating stations. As a result, the accrued liabilities as at June 30, 2002 were reduced by \$8 million.

## 9. Derivative Financial Instruments

The tables below provide a summary of the fair value of OPG's derivative instruments. The first table relates to derivative instruments that are not treated as a hedge. These derivatives are carried on the balance sheet as assets or liabilities at fair value, with changes in fair value recognized in energy marketing revenue. The second table relates to derivative instruments designated as hedges. These derivatives are recognized in income over the term of the contract and are not recorded on the balance sheet. Fair values have been estimated by reference to quoted market prices for actual or similar instruments where available.

(millions of dollars)

	<u>June 30, 2002</u>	<u>December 31, 2001</u>
	Fair Value	Fair Value
<b>Carrying amount (fair value) of contracts not used for hedging purposes</b>		
Commodity derivative instruments	(7)	-

At June 30, 2002, the fair value of commodity derivative instruments not used for hedging purposes includes a \$9 million liability related to legacy contracts from the previous market structure, and transmission rights and other short-term contracts with a fair value of \$2 million.

	<u>June 30, 2002</u>			<u>December 31, 2001</u>		
	Notional quantity	Terms	Fair Value	Notional quantity	Terms	Fair Value
<b>Fair value of derivative contracts designated as hedges</b>						
Commodity derivative instruments						
Electricity	46 TWh	1-5 yrs	125	14	1-5 yrs	-
Gas	1,365,546 GJ	Aug/02	1	-	-	-
Foreign exchange derivative instruments	\$385 US	Apr/03	(19)	\$147 US	Mar/02	3

## 10. Decontrol Initiatives

### *Bruce Nuclear Generating Stations*

In May 2001, the Company completed the close of the operating lease agreement to lease its Bruce A and Bruce B nuclear generating stations to Bruce Power L.P. ("Bruce Power"). As part of the initial payment, OPG received \$370 million in cash proceeds and a \$225 million note receivable. The receivable of \$225 million is payable to OPG in two installments of \$112.5 million no later than four and six years from the date the transaction was completed. Interest is currently charged on the initial payment at a rate of 10.5 per cent, escalating over time to 18 percent annually. The interest is recorded as non-energy revenue.

Under the terms of the lease, OPG transferred certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. OPG will transfer pension assets and liabilities related to the approximately 3,000 employees who transferred from OPG to Bruce Power. Bruce Power has also assumed the liability for OPEB for these employees. OPG will pay Bruce Power in respect of OPEB benefits over a 72-month period. The impact to the deferred pension asset and the value of the OPEB obligation will be finalized through actuarial processes, which are expected to be completed in 2002.

As part of the lease agreement, OPG receives annual lease payments. The lease payments include monthly fixed payments and supplemental payments based on the number of operating units. The supplemental lease payment structure replaces a net revenue-sharing arrangement that was negotiated as part of the original lease agreement.

#### *Decontrol of Mississagi River Stations*

In March 2002, OPG announced the sale of four hydroelectric generating stations located on the Mississagi River, to Great Lakes Hydro Income Fund. The sale closed on May 17, 2002. OPG received cash proceeds of \$342 million from the sale and recorded a pretax gain of \$99 million.

#### *Other Decontrol Activities*

OPG continues to evaluate options associated with the fossil-fuelled stations that have been identified for decontrol, namely Thunder Bay, Atikokan, Lennox and Lakeview generating stations. The amounts that OPG will ultimately realize with respect to these potential transactions could differ materially from the amounts recorded in the financial statements.

## **11. Other Initiatives**

In February 2002, OPG sold its remaining ownership interest in Kinectrics Inc. to AEA Technology plc for approximately \$12 million in cash proceeds.

In March 2002, OPG divested its 49% joint venture interest in New Horizon System Solutions ("New Horizon") to Business Transformation Services Inc., a wholly owned subsidiary of Cap Gemini Ernst & Young. OPG entered into a nine-year information technology outsourcing agreement with New Horizon in order to continue to gain access to a broad spectrum of IT services in infrastructure and operations management.

## **12. Segment Disclosures**

### **Description of Reportable Segments**

With the opening of Ontario's electricity market to competition on May 1, 2002, OPG began operating a second reportable business segment referred to as the Energy Marketing segment. OPG now has two reportable segments: Generation and Energy Marketing. OPG also derives non-energy revenue under the terms of the lease arrangement with Bruce Power, including lease revenue, interest income and revenue from engineering analysis and design, technical and ancillary services. Non-energy revenue also includes isotope sales and gains and losses from decontrol activities.

#### **Generation**

OPG's principal business segment operates in Ontario generating and selling electricity. Commencing May 1, 2002, all of OPG's electricity generation is sold into the IMO-administered real-time energy spot market. As such, the majority of OPG's revenue is derived from spot market sales. In addition to revenue earned from spot market sales, revenue is also earned through offering available capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, black start capability and automatic generation control. Prior to market opening, OPG sold electricity directly to wholesale electricity customers in Ontario and to interconnected markets in Quebec, Manitoba and the U.S. northeast and midwest. Commencing May 1, 2002, physical sales to interconnected markets by OPG may be supplied using electricity purchased from

the IMO-administered physical market, other independent system operators or other generators and are therefore considered energy marketing activities.

## Energy Marketing

The Energy Marketing segment derives revenues from various financial and physical energy market transactions with large volume end-use customers and intermediaries such as utilities, brokers, aggregators, traders and other power marketers and retailers. Energy marketing in deregulated markets includes spot market sales and trading, the sale of bilateral risk management products and sales of energy-related products and services to meet customers' needs for energy solutions. The results of transactions in derivatives not designated as hedges of energy prices are included in the Energy Marketing segment. OPG also markets and sells electricity into the interconnected markets of other provinces and the U.S. northeast and midwest. Previously, OPG's energy marketing activity was not a reportable business segment. Accordingly, there are no comparative values for 2001.

### Reported Segment Income

(millions of dollars)

#### 3 months ended June 30, 2002

	Generation	Energy Marketing	Non-Energy & Other	Total
<b>Revenue</b>	1,186	19	83	1,288
Fuel	332	-	-	332
Power purchased	75	18	-	93
<b>Gross margin</b>	779	1	83	863
Operation, maintenance and administration	604	2	14	620
Depreciation and amortization	156	-	37	193
Property and capital taxes	14	-	14	28
Gain on sale of fixed assets	-	-	(99)	(99)
<b>Operating income (loss)</b>	5	(1)	117	121
Net interest expense			39	39
<b>Income before income taxes</b>				82

#### 3 months ended June 30, 2001

	Generation	Energy Marketing	Non-Energy & Other	Total
<b>Revenue</b>	1,458	-	49	1,507
Fuel	338	-	-	338
Power purchased	173	-	-	173
<b>Gross margin</b>	947	-	49	996
Operation, maintenance and administration	613	-	13	626
Depreciation and amortization	164	-	44	208
Property and capital taxes	12	-	16	28
<b>Operating income (loss)</b>	158	-	(24)	134
Net interest expense			37	37
<b>Income before income taxes</b>				97

6 months ended June 30, 2002	Generation	Energy Marketing	Non-Energy & Other	Total
<b>Revenue</b>	2,656	19	170	2,845
Fuel	731	-	-	731
Power purchased	294	18	-	312
<b>Gross margin</b>	1,631	1	170	1,802
Operation, maintenance and administration	1,178	2	32	1,212
Depreciation and amortization	306	-	72	378
Property and capital taxes	30	-	29	59
Restructuring costs	-	-	210	210
Loss on transition rate option contracts	-	-	210	210
Gain on sale of fixed assets	-	-	(99)	(99)
<b>Operating income (loss)</b>	117	(1)	(284)	(168)
Net interest expense			78	78
<b>Income (loss) before income taxes</b>				(246)

6 months ended June 30, 2001	Generation	Energy Marketing	Non-Energy & Other	Total
<b>Revenue</b>	2,968	-	78	3,046
Fuel	706	-	-	706
Power purchased	275	-	-	275
<b>Gross margin</b>	1,987	-	78	2,065
Operation, maintenance and administration	1,239	-	19	1,258
Depreciation and amortization	346	-	58	404
Property and capital taxes	25	-	19	44
<b>Operating income (loss)</b>	377	-	(18)	359
Net interest expense			71	71
<b>Income before income taxes</b>				288

#### Selected Balance Sheet Information

June 30, 2002				
Segment property, plant & equipment	13,866	-	653	14,519
December 31, 2001				
Segment property, plant & equipment	13,895	-	565	14,460

#### Selected Cash Flow Information

3 months ended June 30, 2002				
Capital expenditures	150	-	60	210
3 months ended June 30, 2001				
Capital expenditures	133	-	21	154
6 months ended June 30, 2002				
Capital expenditures	264	-	102	366
6 months ended June 30, 2001				
Capital expenditures	222	-	47	269

### **13. Seasonal Operations**

The Company's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, the Company's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter.

### **14. Comparative Figures**

Certain of the 2001 comparative figures have been reclassified and restated to conform to the 2002 financial statement presentation.

For further information, please contact:

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