Newfoundland and Labrador Hydro

(The rating is based on the Provincial guarantee. This report specifically analyzes Newfoundland and Labrador Hydro)

Current Report: October 2, 2001
Previous Report: September 20, 2000

RATING

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Rating	Trend	Rating Action	Debt Rated
R-2 (high)	Stable	Confirmed	Commercial Paper/Treasury bills

RATING HISTORY

	Current	2000	1999	1998	1997	1996	1995
Commercial Paper/Treasury bills	R-2 (high)	R-2 (high)	R-2 (high)	R-2 (high)	R-2 (middle)	R-2 (middle)	R-2 (middle)

UPDATE

Newfoundland and Labrador Hydro's ("the Utility") rating is a flow through of the rating of the Province of Newfoundland (see separate report dated July 24, 2001), which unconditionally guarantees the Utility's debt. The Utility's operating cash flows fell significantly in 2000 due to the revenue cap on export sales to Hydro-Québec under the three-year recall agreement, which ended in March 2001, and due to higher fuel costs. The reduced cash flows, combined with the sharply higher dividend requirement from the Province, resulted in a gross free cash flow deficit, which was financed with short-term debt. This resulted in a deterioration in the Utility's key ratios after five consecutive years of improvement. The favourable re-negotiation of the recall agreement with Hydro-Québec for another three years should result in a rebound in the Utility's operating cash flows in 2001 and a further increase in 2002. Approval of the Utility's first general rate application (includes important rate increases and a gradual move to higher approved ROEs) would also provide a significant boost to the Utility's short- and long-term earnings outlook and financial profile. Despite these positive considerations, the Utility's operating cash flows are not expected to be sufficient in 2001 and 2002 to cover the proposed dividend payments to the Province (currently projected at $53 million for 2001 and $105 million in 2002) and the current capital expenditure plan. Capital expenditures are projected to rise from $50.7 million in 2000 to about $87 million in 2001 and rise further in 2002 to about $115 million to finance (1) a 40-MW, $135 million new hydro generating facility (Granite Canal) to meet growing demand, and (2) the ongoing five-year (1997-2002) transmission and system reliability improvement program. As a result, term debt issuance is projected at $250 million in 2001 and $300 million in 2002. The term debt issuance will also be used to cover the Utility's maturities and sinking fund requirements over this period. The Utility's term debt maturity schedule is heavy in both 2001 and 2002, but drops off significantly until 2006.

CONSIDERATIONS

Strengths:

- Debt is unconditionally guaranteed by the Province
- New regulatory environment – rate of return basis
- Two-thirds interest in Churchill Falls
- Geographic isolation and unavailability of gas minimizes competitive pressures, impact of industry deregulation
- Rate Stabilization Plan contributes to long-term earnings stability

Challenges:

- Cash flows sensitive to water levels and oil prices
- High realized foreign exchange losses
- Large Labrador projects could pressure key debt ratios should construction commence
- Environmental issues related to sulphur content of Bunker C fuel

FINANCIAL INFORMATION

For the years ended December 31	2000	1999	1998	1997	1996	1995
EBIT interest coverage (times)	1.17	1.51	1.45	1.24	1.17	1.19
% net debt in capital structure (1)	66.4%	63.1%	65.2%	68.1%	69.4%	70.1%
Cash flow/total net debt (times) (1)	0.06	0.11	0.09	0.06	0.04	0.04
Cash flow/capital expenditures (times) (1)	1.33	1.97	3.11	2.30	1.61	1.34
Net income (bef. extras.) ($ millions)	35	68	70	43	29	33
Operating cash flow ($ millions)	62	111	86	58	39	41
Electricity sales (millions of kWhs)	8,206	7,988	7,598	6,781	6,589	6,506
Electricity revenues (cents per kWh sold)	3.68	3.96	3.98	4.30	4.35	4.38
Variable costs (cents per net gen kWh sold)	2.35	2.17	2.04	2.02	2.10	2.08
Fixed costs (cents per net gen kWh sold)	2.25	2.33	2.46	2.32	2.46	2.45
Avg. coupon on long-term debt	8.40%	8.38%	8.73%	9.51%	10.10%	10.10%

(1) Cash flows include dividends received, debt is net of sinking fund assets.

THE COMPANY

Newfoundland and Labrador Hydro, a Crown corporation of the Province of Newfoundland, generates and transmits electricity in Newfoundland and Labrador. The Utility sells about 65% of its output to a private sector electricity distributor, Newfoundland Power Inc., and distributes the remainder to rural customers and a small group of industrial companies.

ORDER-IN COUNCIL LIMIT

Cdn$300 million.

REGULATION

Newfoundland and Labrador Hydro is regulated by the Board of Commissioners of Public Utilities ("PUB"). In 1996, the Province enacted legislation that changes the way the Utility is to be regulated to a rate of return basis. In May 2001, the Utility filed its first general rate application since 1991 and its first full rate base application. The application includes: (1) the establishment of the rate base; (2) a rate increase of 6.7% for Newfoundland Power and a 10.4% rate increase in industrial rates effective January 1, 2002, based largely on (a) approval to re-base the price of Bunker C fuel to $20/barrel from $12.50/barrel, (the price of fuel has not been changed since 1991), and (b) an ROE of 3% (and a regulated debt/equity ratio of 85/15); (3) an increase in the Rate Stabilization Plan ("RSP") cap on Newfoundland Power to $100 million from $50 million; and (4) a variety of other matters, including the PUB's endorsement for moving to an ROE more comparable to industry norms (and a regulated debt/equity ratio of 60/40) in the longer term. In the past, regulatory approval was required only for changes in electricity rates beyond those resulting from the recovery of the RSP balance and for capital expenditure budgets.

CONSIDERATIONS

Strengths: (1) The Utility's debt is unconditionally guaranteed by the Province of Newfoundland. As a result, the rating of the Utility is a flow-through of the provincial government rating.
(2) The Utility recently filed its first full rate base application, which includes among other things, a request for a long-term approved ROE of 11% and the re-basing of the price of Bunker C fuel starting in 2002. Approval of the Utility's rate application would significantly improve the Utility's cash flow and borrowing outlook.
(3) The Utility has a two-thirds interest in Churchill Falls (Labrador) Corporation Limited, the lowest cost and possibly most efficient hydro-electric utility in North America. A long-term (until 2041) power contract with Hydro-Québec at rates well below market prices neutralizes much of the current cost advantage of this investment.
(4) The Utility's geographic isolation and unavailability of natural gas in much of the service region should minimize competitive pressures over the medium term from deregulation occurring throughout the North American industry. However, the Utility's geographic isolation also greatly limits its export potential.
(5) The Rate Stabilization Plan contributes to earnings stability over the longer term. The RSP provides for the deferral of cost variances resulting from changes in fuel prices, levels of precipitation and load. Customer rates are adjusted every 12 months to recover outstanding balances in the RSP over the following three years.

Challenges: (1) Annual cash flows are sensitive to water levels and oil prices given the Utility's generation base (about 56% hydro, 40% thermal). Although any cost variances from changes in fuel prices and water levels are deferred to the Rate Stabilization Plan and recovered over time and, therefore, do not impact earnings, they can cause significant changes in cash flows from one year to the next.
(2) The Utility has $96 million in realized foreign exchange losses. This amount will be recovered in future rates.
(3) Potential new Labrador capacity projects (which are on hold indefinitely) could be set up as independent operating companies, similar to Churchill Falls, with Newfoundland and Labrador Hydro holding an equity stake in the subsidiary. If the new entity or the projects are set up as part of Newfoundland and Labrador Hydro, the Utility's key debt ratios could be negatively impacted.
(4) A significant percentage of the Utility's electricity is thermal-based and is fuelled by Bunker C fuel, which has a high sulphur content. The Utility may have to deal with the environmental issues related to the sulphur content, which could result in increased costs.

EARNINGS

	For the years ended December 31					
($ millions)	2000	1999	1998	1997	1996	1995
Revenues	303.2	317.0	304.2	292.7	287.8	286.1
EBITDA	136.4	166.7	170.7	156.6	151.0	152.1
EBIT	100.9	130.6	138.6	126.7	122.4	124.7
Net interest expense	83.5	82.2	87.4	95.8	102.3	102.1
Net income before equity income & extraodinary items	17.4	48.4	51.2	30.9	20.1	22.6
Net income before extraordinary items	34.9	68.3	69.6	43.4	28.9	32.9
Net income	34.9	51.6	69.6	43.4	28.9	32.9

The revenue cap on export sales to Hydro-Québec was the primary reason for the sharp decline in the Utility's net income before equity earnings and extraordinary items to $17.4 million in 2000 from $48.4 million in 1999. Under the three-year recall power agreement with Hydro-Québec, which expired on March 8, 2001, any electricity sales beyond the specified revenue cap must be sold at cost. Some of the decline in export revenue was offset by higher retail sales to Newfoundland Power. Earnings were also adversely affected by higher operating and administration costs largely due to a change in accounting for employee future benefits and higher maintenance costs.

Outlook: The Utility's net income is expected to rebound in 2001 as a result of the re-negotiation of the three-year recall agreement with Hydro-Québec. The new recall agreement includes a higher revenue cap than under the previous agreement, which should result in increased net earnings from export sales over the 2001-03 period. Another factor, which will likely have a positive impact on the Utility's earnings starting in 2002 is the outcome of its first full rate base application (and first rate application since 1991-92). The Utility has applied for an increase in the cost of fuel (Bunker C fuel) included in rates from $12.50/barrel to $20/barrel, effective January 1, 2002 (the average price of Bunker C fuel is currently over $20/barrel). If approved, this would result in a 6.7% increase in rates to Newfoundland Power and a 10.4% increase in industrial rates in 2002. It should be noted that the re-basing of fuel costs does not have a long-term impact on the Utility's earnings as any differences between the cost of fuel included in rates and actual fuel costs are recovered over time through the Rate Stabilization Plan. The Utility has also applied for an ROE of 3%, and has requested the PUB's endorsement for moving to an ROE that is more comparable with industry norms in the longer term. For example, an ROE of 11% would result in an additional 6% increase in the rate charged to Newfoundland Power. This is the first time that the Utility has applied for rates based on a rate of return on rate base.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	For years ending Dec. 31				Stress testing		
Cash flow statement (non-consolidated)	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	136.4	166.7	170.7	156.6	109.1	109.1	109.1
Net income (before extras.)	34.9	68.3	69.6	43.4	(37.5)	(51.4)	(69.8)
Depreciation	35.5	36.1	32.1	29.9	35.3	36.7	38.9
Other non-cash adjustments	(8.1)	6.8	(16.2)	(14.9)	0.0	0.0	0.0
Operating cash flow	62.3	111.2	85.5	58.4	(2.2)	(14.7)	(30.9)
Plus: dividends received	5.2	8.4	12.6	10.5	5.2	5.2	5.2
Less: common dividends	69.9	17.0	16.8	20.9	(50.0)	(50.0)	(50.0)
capital expenditures (net of contrib.)	50.7	60.8	31.5	30.0	87.0	115.0	69.0
Gross free cash flow	(53.1)	41.8	49.8	18.0	(34.0)	(74.5)	(44.7)
Less: working capital changes	2.7	3.1	(0.2)	(2.5)	0.0	0.0	0.0
Free cash flow	(55.8)	38.7	50.0	20.5	(34.0)	(74.5)	(44.7)
Less: other investments	4.2	(95.2)	(89.6)	(116.9)	0.0	0.0	0.0
Plus: net financing	60.5	(140.2)	(135.1)	(137.3)	134.0	174.5	144.7
Net change in cash	0.5	(6.3)	4.5	0.1	100.0	100.0	100.0
Total net debt (1)	1,123	1,073	1,110	1,148	1,257.3	1,431.8	1,576.5
% net debt in capital structure (1)	66.4%	63.1%	65.2%	68.1%	66.9%	73.4%	79.8%
EBIT interest coverage (times)	1.17	1.51	1.45	1.24	0.80	0.71	0.60
Cash flow/ total debt (1)	0.06	0.11	0.09	0.06	(0.00)	(0.01)	(0.02)
Stress test assumptions							
EBITDA growth					-20%	0%	0%
Interest rate					9.3%	9.3%	9.3%

(1) Cash flows include dividends received, debt is net of sinking fund assets.

Financial profile: A significant decline in operating cash flows combined with a sharp increase in dividends paid to the provincial government in 2000 resulted in a gross free cash flow deficit, which the Utility financed with short-term debt (promissory notes increased to $121.2 million as at December 31, 2000, from $54.4 million the previous year). Operating cash flows fell significantly in 2000 to $62.3 million from $111.2 million the previous year, largely due to: (1) the cap on export sales revenue under the recall agreement with Hydro-Québec that expired in March 2001 (any export sales beyond the cap must be sold at cost); and (2) higher fuel costs.

As a result of the reduced net earnings and the debt financing requirements, the Utility's key ratios deteriorated in 2000 after five consecutive years of improvement. Despite the deterioration, the debt-to-capital ratio remains reasonable compared to other government-owned utilities, although EBIT interest coverage and cash flow/debt remain weaker.

Outlook: Capital expenditures are projected to rise from $50.7 million in 2000, to about $87 million in 2001, and rise further in 2002 to about $115 million to finance (1) a 40 MW $135 million new hydro generating facility (Granite Canal) to meet growing demand, and (2) the ongoing five-year (1997-2002) transmission and system reliability improvement program. Despite the re-negotiation of the three-year recall agreement with Hydro-Québec, which includes a higher revenue cap on export sales, the Utility is not expected to generate sufficient operating cash flows in 2001 nor in 2002 to cover its capital expenditures and dividend payments to the Province (dividend payments estimated at $53 million in 2001 and $105 million in 2002). The Utility is expecting to issue approximately $250 million in term debt in 2001, rising to $300 million in 2002. Key debt ratios will likely remain weak in the near term, although interest coverage should improve somewhat from the higher exports sales revenues. Over the longer term, key ratios should improve if the PUB approves all the requests included in the general rate application.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Utility, or DBRS expectations concerning the future performance of the Utility.

The following scenario has been analyzed: (1) EBITDA declines 20% in 2001, and remains constant during the following two years; (2) the Utility maintains its current capital plan; and (3) the Province requires the Utility to make annual dividend payments of $50 million (in line with the current dividend requirement for 2001). Under this scenario, operating cash flow would be negative and, therefore, would be insufficient to cover the current capital plan and dividend requirements. Financial ratios would deteriorate sharply and quickly. However, DBRS expects that the Utility would receive regulatory relief and that the Province would adjust its dividend policy to stabilize the Utility's financial situation.

OPERATING LINES OF CREDIT

The Utility has a Cdn$50 million operating line of credit, which currently remains unused. The Utility also has a Cdn$300 million commercial paper program. As at December 31, 2000, the Utility had Cdn$124.3 million of commercial paper outstanding. The amount of commercial paper outstanding has come down since the early part of 2001 and stood at $41.7 million at August 31, 2001.

DEBT MATURITY SCHEDULE

(Includes term debt maturities and sinking fund requirements for the Utility only.)

	2001	2002	2003	2004	2005
($ millions)	162.9	112.7	12.9	8.9	9.4

PROVINCE OF NEWFOUNDLAND

The Province of Newfoundland's (the "Province") long-term and short-term ratings were confirmed at BBB and R-2 (high), respectively, with Stable trends, in July 2001. The confirmation reflects: (1) continued improvements in the fundamentals of the Province's economy; (2) declining tax burdens; and (3) the growing importance of the energy sector, which will likely continue to fuel growth in the future.

The recent years of strong economic growth have allowed the Province to diversify its economic base, reduce unemployment and embark on a more sustainable growth path. In 2000-01, vigorous economic activity and stronger-than-expected revenue growth led to a DBRS-adjusted surplus of $1 million, significantly better than the $122 million deficit initially anticipated. Fiscal results are forecast to weaken in 2001-02, however. Higher expenditures combined with conservative revenue forecasts are projected to lead to a DBRS-adjusted deficit of $201 million on a modified cash basis.

As a result, achieving balanced budgets remains one of the Province's main challenges. Indebtedness is also high. In 2001-02, total debt is forecast to increase approximately $150 million, to $9.6 billion. This is expected to push the Province's debt-to-GDP ratio to an estimated 67.8% which, while lower than in the mid-1990s, remains the highest among all provinces. Given more moderate increases expected in income and sustained spending pressures, especially in health care and wages, improvements on the fiscal and debt fronts are likely to be slow in the years to come. Other challenges include the relatively high, though declining, provincial tax burden and the high dependence on federal transfers, which prevents the Province from fully benefiting from new sources of revenues, as any increase in the province's revenue is largely offset by a reduction in equalization.

Newfoundland & Labrador Hydro

(Non-Consolidated)

Balance Sheet

($ millions)	As at December 31				As at December 31		
Assets:	2000	1999	1998	Liabilities & Equity:	1998	1999	1998
Cash + equivalents	0.4	4.4	6.5	Accts pay + accr'ds	57.5	63.8	71.0
Receivables	41.3	45.5	57.2	Promissory notes	125.6	58.9	88.4
Rate stabilization acct	11.5	17.0	17.0	L.t.d. due in 1 year	162.9	12.1	87.1
Fuel, supplies + prepaids	45.0	44.9	32.7	Current liabilities	346.0	134.8	246.5
Current assets	98.2	111.8	113.4	Long-term debt	870.2	1,030.8	1,047.3
Fixed assets	1,256.8	1,243.2	1,237.1	Fx losses	9.0	8.0	7.0
Investments	293.2	290.0	285.8	Employee future benel	22.8	2.0	0.0
Rate stabilization acct	24.1	17.5	31.7	Shareholders' equity	568.6	626.2	591.6
Sinking funds	35.4	28.8	113.3				
Def'd charges + long-term receivables	108.9	110.5	111.1				
Total	1,816.6	1,801.8	1,892.4	Total	1,816.6	1,801.8	1,892.4

Ratio Analysis (1)	For years ended December 31							
Liquidity Ratios	2000	1999	1998	1997	1996	1995	1994	1993
Current ratio	0.28	0.83	0.46	0.24	0.31	0.20	0.39	0.44
Accumulated depreciation/gross fixed assets	23.2%	22.1%	21.1%	19.4%	17.9%	16.5%	15.1%	13.7%
Cash flow/total net debt (2)	0.06	0.11	0.09	0.06	0.04	0.04	0.05	0.05
Cash flow/capital expenditures	1.33	1.97	3.11	2.30	1.61	1.34	2.38	2.21
Cash flow-dividends/capital expenditures	(0.05)	1.69	2.58	1.60	1.15	0.81	2.38	2.21
% net debt in capital structure (2)	66.4%	63.1%	65.2%	68.1%	69.4%	70.1%	70.3%	69.6%
Average coupon on long-term debt	8.40%	8.38%	8.73%	9.51%	10.10%	10.10%	10.80%	10.60%
Common equity in capital structure	33.6%	36.9%	34.8%	31.9%	30.6%	29.9%	29.7%	30.4%
Common dividend payout (before extras.)	200.3%	24.9%	24.1%	48.2%	44.6%	59.3%	0.0%	0.0%
Coverage Ratios (3)								
EBIT interest coverage	1.17	1.51	1.45	1.24	1.17	1.19	1.11	1.14
EBITDA interest coverage	1.54	1.89	1.71	1.45	1.38	1.39	1.30	1.32
Fixed-charges coverage	1.17	1.51	1.45	1.24	1.17	1.19	1.11	1.14
Earnings Quality / Operating Efficiency								
Power purchases/revenues	6.7%	6.0%	4.4%	1.9%	1.8%	1.7%	1.9%	1.5%
Fuel costs/revenues	14.0%	11.1%	8.8%	15.0%	14.5%	14.1%	14.0%	14.9%
Operating margin	33.3%	41.2%	45.6%	43.3%	42.5%	43.6%	42.5%	43.6%
Net margin (before extras.)	11.5%	21.5%	22.9%	14.8%	10.0%	11.5%	7.6%	8.7%
Return on avg equity (before extras.)	5.8%	11.2%	12.3%	8.2%	5.7%	6.7%	4.5%	5.4%
Profit returned to government (bef extras.) (4)	176.8%	35.3%	34.8%	58.7%	59.7%	69.1%	33.3%	29.5%
GWh sold/employee	8.1	7.7	7.3	6.7	6.5	6.1	5.5	5.3
Self Generation - Cost Structure (5)	(cents per net generated kWh sold) (Tables may not add due to rounding)							
OM&A	1.62	1.54	1.54	1.28	1.37	1.37	1.44	1.38
Fuel	0.74	0.63	0.51	0.74	0.72	0.71	0.70	0.74
Variable costs	2.35	2.17	2.04	2.02	2.10	2.08	2.14	2.12
Gov't levies	0.19	0.20	0.21	0.19	0.19	0.18	0.19	0.18
Net interest expense	1.48	1.48	1.60	1.58	1.71	1.73	1.87	1.83
Total cash costs	4.01	3.85	3.86	3.79	4.00	3.99	4.20	4.13
Non-cash financial charges	(0.03)	0.01	0.04	0.05	0.07	0.06	0.05	0.10
Depreciation	0.62	0.65	0.60	0.51	0.50	0.48	0.47	0.42
Total costs	4.60	4.50	4.50	4.34	4.56	4.53	4.72	4.65
Purchased power (cents per gross kWh purchased)	0.80	0.74	0.57	0.61	0.60	0.60	0.62	0.59

(1) Debt related ratios not directly comparable to periods before 1996 due to a change in accounting policies.

(2) Cash flows include dividends received, debt is net of sinking fund assets.

(3) Before capitalized interest, AFUDC and debt amortizations.

(4) Includes all taxes, guarantee fees and dividends.

(5) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

Operating Statistics		For years ended December 31					
Electricity Sold - Breakdown		2000	1999	1998	1997	1996	1995
Utilities (mainly Nfld L+P)		4,263	4,084	4,157	4,306	4,187	4,214
Rural		842	830	811	815	765	751
Industrial		1,607	1,343	1,286	1,660	1,637	1,541
Exports		1,494	1,731	1,344	0	0	0
Total (GWh sold)		8,206	7,988	7,598	6,781	6,589	6,506
Energy sales growth		2.7%	5.1%	12.0%	2.9%	1.3%	2.2%
Generation							
Hydro	56%	899	899	899	899	899	899
Thermal	40%	645	645	645	645	645	645
Diesel	4%	58	58	58	58	58	57
Installed capacity (MW)		1,602	1,602	1,602	1,602	1,602	1,601
Energy Generated - hydro		5,016	4,801	4,260	4,628	4,574	4,393
- thermal		966	914	1,255	1,528	1,409	1,533
- diesel		43	41	41	41	64	74
Gross energy generated - GWh	69%	6,025	5,756	5,556	6,197	6,047	6,000
Plus: purchases	31%	2,545	2,538	2,382	932	878	838
Energy generated + purchased		8,570	8,294	7,938	7,129	6,925	6,838
Less: transmission losses + internal use		364	306	340	348	336	332
Total - GWh sold		8,206	7,988	7,598	6,781	6,589	6,506
Energy lost + used/energy gen + purch		4.2%	3.7%	4.3%	4.9%	4.9%	4.9%
Maximum primary peak demand		1,240	1,265	1,295	1,229	1,318	1,250
Peak demand/available capacity		77.4%	79.0%	80.8%	76.7%	82.3%	78.1%
Unit Revenues & Costs		(cents per kWh sold) (Tables may not add due to rounding)					
Revenues:							
Utilities		4.49	4.50	4.49	4.48	4.50	4.50
Rural		5.88	5.55	5.40	5.51	5.83	5.97
Industrial		2.96	3.56	3.27	3.23	3.27	3.27
Exports		0.89	2.22	2.22	-	-	-
Average electricity revenues		3.68	3.96	3.98	4.30	4.35	4.38
Ancillary revenues		0.02	0.01	0.02	0.02	0.02	0.02
Average revenues		3.69	3.97	4.00	4.32	4.37	4.40
Costs:							
Operating + administration		1.14	1.07	1.08	1.11	1.20	1.20
Power purchases		0.25	0.24	0.18	0.08	0.08	0.08
Fuel		0.52	0.44	0.35	0.65	0.63	0.62
Variable costs		1.90	1.74	1.61	1.84	1.91	1.90
Government levies		0.13	0.14	0.15	0.16	0.16	0.16
Net interest expense		1.04	1.03	1.12	1.37	1.49	1.52
Cash costs		3.07	2.91	2.88	3.38	3.57	3.58
Cash margin		0.63	1.06	1.13	0.94	0.80	0.82
Non-cash financial charges		(0.02)	0.00	0.03	0.04	0.06	0.05
Depreciation		0.43	0.45	0.42	0.44	0.43	0.42
Pre-tax margin		0.21	0.61	0.67	0.46	0.31	0.35
Variable costs		1.90	1.74	1.61	1.84	1.91	1.90
Fixed costs (deprec, int + levies)		1.58	1.62	1.72	2.02	2.15	2.15
Total costs		3.48	3.36	3.33	3.86	4.06	4.05