BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

D. GRIBBLE

WORKPAPERS

IDACORP

Capital Structure

Projected December 31, 2003

	Recast 4		Orig Fcst	
IDACORP ($ in millions)				
STD				
LTD				
Total Debt				
Preferred Stock				
Equity				
Total Cap				

	Recast 4		Orig Fcst	
Idaho Power ($ in millions)				
STD	$38.7	2%	$43.6	2%
LTD	931.6	51%	874.0	49%
Total Debt	970.3	53%	917.5	51%
Preferred Stock	52.4	3%	103.5	6%
Equity	796.8	44%	764.9	43%
Total Cap	$1,819.5	100%	$1,785.9	100%

Ragen MacKenzie
A Division of Wells Fargo Investments, LLC
MEMBER NEW YORK STOCK EXCHANGE

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MAY 7, 2003
UTILITIES

IDACORP, INC.
(NYSE-IDA)
Weak First Quarter Due to Weather, Hydro, and Settlement Charges

Analyst Opinion: **HOLD**
Value Recommended List: **HOLD**

- *IDACORP reported 1Q03 earnings results of a loss of ($3.1) million or ($0.08) per share versus $0.66 per share last year.*
- *Idaho Power Company earned $0.36 versus $0.57 per share last year. Weather was significantly warmer than last year and resulted in reduced loads of about 6.5%.*
- *IDACORP Energy earnings were reduced $0.34 by a non-cash litigation settlement charge.*
- ***We have lowered our FY03 EPS estimate to $1.00, from $1.60, reflecting warm weather, poor hydro conditions, and the settlement charges. We are maintaining our FY04 estimate of $1.90 per share, which depends, among other things, on normal weather and normal hydro conditions.***

PRIMARY STOCK STATISTICS

FY End:	Dec
Price:	$23.72
52-Week Range:	$39-$21
Market Cap (million):	$906.2
Book Value:	$22.44
Dividend:	$1.86
Est. Sec. EPS Grth Rate:	6 %

EARNINGS ESTIMATES

	Prior	Current	P/E
Current Qtr:	-	$0.32	-
FY02A:	-	$1.62	14.6x
FY03E:	$1.60	$1.00	23.7x
FY04E:	$1.90	$1.90	12.5x
Price Target	$27		

SUMMARY AND STOCK OPINION

Consistent with its earnings pre-release, IDACORP reported weak first quarter results, with the utility's earnings negatively impacted by warm weather and poor hydro conditions and the energy trading unit's negatively impacted by a large litigation settlement with one of its customers. We estimate weather and hydro-related factors reduced earnings by about $0.25 per share and that the settlement resulted in a $0.34 per share reduction in earnings. As such, we are lowering our FY03 earnings estimate by $0.60 to $1.00 per share. We are maintaining our FY04 earnings estimate of $1.90 per share, which assumes normal weather and hydro conditions.

At this point, management seems to be committed to the current dividend payment, assuming good hydro conditions next year and that it receives rate relief from its general rate case, which has yet to be filed. However, we are now estimating earnings at the utility this year of $1.25 per share, which is significantly lower than the current annual dividend payment of $1.86 per share. We believe FY03 is likely to be the third consecutive year that the utility has under-earned its dividend, excluding tax-related benefits. We still believe the Company is likely to cut its dividend by about 30% within the next twelve months, and most likely, within the context of its general rate case, which will be filed this fall.

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2

VALUATION

Our $27 price target is based on a 13.5x multiple of our estimate of IDACORP's normalized earnings per share potential, which we estimate to be in the $1.90–$2.10 per share range. IDACORP's average price-to-earnings multiple over the last 10 years is about 14.4x. Our belief has been that the stock would return to favor as investors perceive ancillary business and financial risk to diminish and begin to more fully value IDACORP's primary business as a low-risk electric distribution company.

RISKS

We believe primary risks to IDACORP's ability to return to a more normal earnings range include continued slow economic activity, weather, including hydro conditions, and unfavorable regulatory action at the state or federal level.

FUNDAMENTALS

IDACORP reported a net loss for 1Q03 of ($3.1) million, or ($0.08) per share versus net income of $24.7 million, or $0.66 per share in 1Q02. About half of the earnings shortfall relates to litigation settlement charges that, when combined, amount to $10.9 million before tax ($0.34 per share after-tax). The majority of the remaining shortfall amount has been caused by warmer-than-normal weather, which reduced loads in 1Q03, and poor hydro conditions, which increase costs for the utility. Average temperatures during the quarter in Idaho Power's service territory were 19% warmer than in 1Q02.

Idaho Power

Idaho Power, the Company's regulated electric utility, contributed earnings per share of $0.36 versus $0.57 last year. Our estimate for the utility's earnings in 1Q03 was $0.40 per share. Warm weather during the quarter reduced the Company's load by approximately 11%, and is the major cause of this year's shortfall in earnings at the utility. General business revenues, which are comprised of revenues from Idaho Power's retail customer classes, decreased 6% to $175.1 million, down from $186.1 million in 1Q02. Total energy sold, on a megawatt-hour basis, declined 6.5% over the prior year. Residential customers' load was hit especially hard, declining 11.5% over the prior year. The load decline versus the prior year was partially offset by higher customer rates. Customer growth was solid in 1Q03, with Idaho Power adding approximately 10,715 new residential and commercial customers, reflecting growth rates of 2.8% and 2.7% for residential and commercial customers, respectively.

The Company's off-system sales volume declined by about 50% over the prior year, but the negative impact was significantly offset by an average sales price more than 80% higher than in 1Q02. For the quarter, off-system sales declined 7.7% to $18.6 million versus $20.2 million in 1Q02. Due to ongoing drought conditions in Idaho, off-system sales volumes are expected to be below normal.

Streamflow forecasts in Idaho Power's region are currently forecasted to be about 57% of normal, which compares to 56% below normal in 2002 and about 41% below normal in 2001. Management has indicated that it has secured resources to cover its native load in 2003. Normal precipitation and streamflow conditions in 2004 would likely not return Idaho Power's performance to normal due to low reservoir levels. Reservoir levels above Brownlee Reservoir, the Company's reservoir to its largest hydro facility, is about 86% of normal for this time of year.

Idaho Power will likely file a general rate case in FY03 due to growth in its service territory. Since IPC's last general rate case, which took place in 1994, its customer base has grown by more than 25%, or 80,000 customers. We expect the amount requested in the general rate case to amount to less than half of the amount requested under the deferral mechanism in prior years, or between $50 and $75 million.

IDACORP Energy

IDACORP Energy reported a net loss of ($10.8) million, or ($0.28) per share versus a net profit of $4.1 million, or $0.11 per share last year. We are currently estimating a net loss of about ($14.7) million, or ($0.38) per year for the full year. The majority of IDACORP Energy's contracts are expected to roll off by 2004, at which point the Company will have substantially exited the business. We are anticipating a net loss in FY03 and, to a lesser extent, in FY04 as IDACORP Energy continues to work through its exit and staffing levels continue to decline.

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BALANCE SHEET AND CASH FLOW

The Company ended 1Q03 with $41.5 million in cash and equivalents, reflecting, among other things, cash generated from operations of $95.5 million. IDACORP's long-term debt as a percentage of total capitalization at the end of the quarter was 55.1%, with preferred stock comprising 2.6% and equity 42.3% of total capitalization. At quarter-end IDACORP had about $1.0 billion in long-term debt (including current maturities), which is rated A- with a positive outlook by Standard & Poor's at the corporate level and Baa1 with a negative outlook by Moody's. IDACORP's book value at quarter-end was $22.44, with an estimated $20.00 book value at the utility. We are expecting the Company to generate positive free cash flow this year, which we define as cash from operation less capital expenditures and dividend payments. We expect cash flow to be bolstered by about $90 million due to rate-recovery of its excess power costs incurred in prior years.

IDACORP, Inc. is a holding company based in Boise, Idaho, that serves as the parent company to Idaho Power Company ~~and several unre~~gulated subsidiaries. Idaho Power Company is a regulated utility company providing electric services to people in southern Idaho, eastern Oregon and northern Nevada. IDACORP's other subsidiaries include: merchant generators, fuel cells, energy trading, telecommunications, and one financial subsidiary that invests in tax-advantaged real estate. Headquarters: Boise, ID.

S&P 500: 929.62

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Analyst Certification

By issuing this research report, each Ragen MacKenzie analyst whose name appears on the front page of this research report hereby certifies that: (i) the recommendations and opinions expressed in the research report accurately reflect the research analyst's personal views about any and all of the subject securities or issuers discussed herein and (ii) no part of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by the research analyst in the research report.

Rating System

BUY – Immediate purchase is recommended; the stock is expected to outperform the general market over the next 12-18 months.
HOLD – Holding the stock is recommended. The stock has moved out of our preferred buying range, but there is further upside to the share price; or stated objectives at the time of purchase have changed and share appreciation may take another 6-12 months.
SELL – The stock has reached the stated price objective and appreciation has been achieved; or certain company fundamentals have changed which warrant investors selling the stock to avoid price decline.

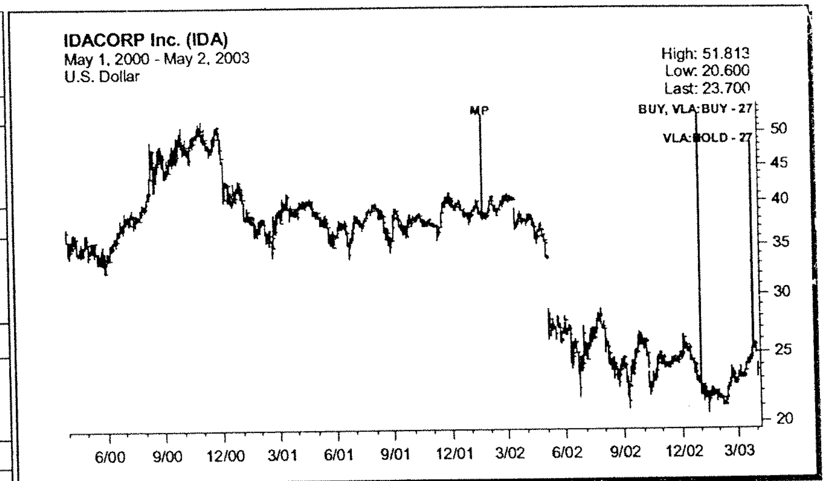
Notes

The price targets indicated in the chart below may be adjusted for stock splits. Where the price target was originally given as a range, the midpoint of the range has been used.
Until February 15, 2001, Ragen MacKenzie used the following system for analyst ratings: Buy, Accumulate (ACC), Market Perform (MP), Underperform, Sell.
From February 15, 2001–July 8, 2002, Ragen MacKenzie used the following system for analyst ratings: Strong Buy (SB), Buy, Market Perform (MP), Underperform, Sell.
The current rating system, explained above, has been in effect since July 9, 2002.

Ratings Allocations

Rating	% of covered companies with this rating	% for which IB Services have been provided
Analyst Coverage		
BUY	43%	7%
HOLD	55%	6%
SELL	2%	0%
Value Recommended List—Appreciation		
BUY	35%	0%
HOLD	65%	6%
SELL	0%	0%
Value Recommended List—Income		
BUY	20%	0%
HOLD	60%	33%
SELL	20%	0%
Growth Recommended List		
BUY	80%	25%
HOLD	20%	0%
SELL	0%	0%

Updated on 4/4/2003



Analyst Opinion
MARKET PERFORM

COMPANY REPORT
Allyson R. Rodgers, CFA
February 25, 2002

IDACORP, INC.

(NYSE-IDA)

		Fiscal Year: Dec	EPS		P/E
Price (2/25/02)	$38.17	2000A	$3.72	2000A	10.3x
52-Week Price Range	$41–$34	2001A	$3.35	2001A	11 4x
Annual Dividend Rate	$1.86	2002E	$3.12	2002E	12.2x
Indicated Yield	4.9%	T4Q	$3.35	T4Q	11.4x
Shares Outstanding	37.5 million	Est. Secular EPS Growth	8%	T4Q Relative P/E	.47x
Estimated Float	37.4 million	ROAE (4 Yr. Average)	13.1%	Market Cap/Sales	NM
Market Cap.	$1,431 million	Book Value Per Share	$23.09	(2002E P/E)/Growth	1.5x
Avg. Daily Volume	137,024 shares	LTD/Capitalization	46%	Price/Book Value	1.7x

SUMMARY AND STOCK OPINION

We recently visited IDACORP, Inc., in Boise, Idaho, and met with several key management personnel. We are impressed with Idaho Power's reliable and consistent earnings power, even as the Company takes on new growth initiatives. In our opinion, the management team operates within a favorable regulatory environment and the Company has been making reasonable business decisions that have added to IDACORP's bottom line for many years. We are re-initiating coverage of IDACORP with a MARKET PERFORM rating based on our opinion that IDACORP's stock is fairly valued given the current outlook for the utility and the energy trading and marketing business.

> **Company Overview**
>
> IDACORP, Inc. is an essential services company comprised of one regulated electric utility and five non-regulated subsidiaries, including energy trading and marketing, telecommunications and fuel cell businesses. Idaho Power Company, IDACORP's regulated subsidiary, supplies electricity to residential, commercial, industrial, and irrigation customers in southern Idaho and eastern Oregon. The Company's system is interconnected with power companies throughout the Northwest. Headquarters: Boise, ID.

The average forward P/E multiple for IDACORP's peer group is 12.3x forward earnings, while IDACORP trades in line with its peer group average at 12.2x our FY02 forward estimate. IDACORP pays a dividend of $1.86 that currently yields about 4.9%, which compares favorably with other western region utility yields. The average yield for a western region electric utility is 4.4%. Based on the Company's payout ratio of 60% (based on our FY02 earnings estimate), we consider the dividend secure. We believe the Company recognizes the importance of maintaining cash flow during these volatile times, and therefore do not expect the Company to raise its dividend over the course of the next couple of years.

IDACORP is comprised of a regulated electric utility (Idaho Power Company) and five non-regulated businesses, including IDACORP Energy, its energy trading and marketing subsidiary. Two of IDACORP's subsidiaries, IdaTech and IDACOMM, are early-stage businesses that have yet to reach profitability. We have used a sum-of-the-parts relative valuation methodology as a basis for our rating on the stock. We have assigned P/E multiples of 13.5x, 10.0x, and 10.0x to the utility's, energy and trading's, and other segments' earnings per share estimates for FY02, respectively. We believe our valuation of IDACORP's unregulated segments is conservative, given the early stages of the subsidiaries. However, we believe conservatism is appropriate given today's market environment. As IdaTech and IDACOMM progress, we expect to revisit our valuation.

Like other Northwest utilities, Idaho Power's electric and gas power costs spiked dramatically during the winter of 2000–2001. However, unlike its peers, Idaho Power put into place several years ago a purchase cost adjustment (PCA) mechanism that allows the Company to adjust the price of power embedded in its rate structure on an annual basis. The PCA (which is similar to the mechanism that gas distribution companies have in place) has served Idaho Power well as power prices escalated over the last year. Idaho Power is expected to recover up to 96% of its excess power costs through rate increases.

IDACORP, due to record earnings growth in its energy trading and marketing business, reported an outstanding FY00 and FY01 and, as such, has made for a difficult benchmark for FY02. Earnings in FY01 were negatively impacted by high power costs at the utility; however, offsetting this negative impact was a record year for the energy marketing and trading arm, which benefited from volatile prices. We expect the utility to return to a more normalized earnings level in 2002 as the Company benefits from lower power costs, and we expect a decline in earnings in the energy and trading business due to decreased volatility in power prices. For these reasons, our FY02 estimate is $3.12 per share, which is a 7% decline from FY01's earnings per share of $3.35. Our $3.12 earnings estimate also includes a $0.20 contribution from two of IDACORP's non-regulated subsidiaries, which is offset by our estimated ($0.45) loss from IDACORP's telecomm services and fuel cell businesses.

We believe IDACORP's non-regulated businesses, which include companies engaged in fuel cell development and telecom services, offer long-term growth potential. As with other Pacific Northwest utilities companies in our coverage universe, we believe we are being conservative in our estimates of these two businesses and have left room for upside potential. We have trimmed our expectations in these areas due to recent market volatility in the two respective sectors. We note, however, that IDACORP's telecom unit is self-funding and is expected to reach net income profitability within the next year or two.

Historical and Estimated Earnings by Segment

	1Q00A	2Q00A	3Q00A	4Q00A	FY00A	1Q01A	2Q01A	3Q01A	4Q01A	FY01A	FY02E
Idaho Power Company	$0.73	$0.40	$0.43	$0.42	$1.97	$0.37	$0.16	$0.00	$0.07	$0.60	$1.95
IDACORP Energy	0.15	0.46	0.69	0.28	1.58	0.62	0.83	0.93	0.49	2.87	1.42
IDACORP Financial	0.03	0.03	0.05	0.04	0.14	0.03	0.03	0.05	0.03	0.14	0.12
Ida-West Energy	0.25	0.03	0.02	0.02	0.32	0.01	0.04	0.02	0.07	0.13	0.08
Other Segments	(0.04)	(0.06)	(0.08)	(0.13)	(0.29)	(0.10)	(0.10)	(0.09)	(0.11)	(0.39)	(0.45)
IDACORP, Inc. EPS	$ 1.12	$ 0.86	$ 1.11	$ 0.63	$3.72	$ 0.93	$ 0.96	$ 0.91	$ 0.55	$ 3.35	$ 3.12

Source: Company reports and Ragen MacKenzie estimates

COMPANY OVERVIEW

IDACORP, Inc., based in Boise, Idaho, is a diversified energy services company comprised of one regulated electric utility and five non-regulated businesses, including energy trading and marketing. Idaho's service territory is mostly southern Idaho and includes parts of eastern Oregon. Idaho Power is unique in the Pacific Northwest in that it serves both winter-peaking loads as well as summer-peaking loads. This diversification allows Idaho Power Company to buy energy in the summer months when prices in the Pacific Northwest region are generally lower.

IDACORP recently changed its reporting for its IDACORP Energy subsidiary to reflect its transactions on a gross basis (versus net basis), which significantly changed the amount of total consolidated revenues attributable to IDACORP Energy. Prior to the restatement, IDACORP Energy revenues accounted for about 16% of total sales. The restated revenue attributable to IDACORP Energy is now 84% of consolidated revenues. While IDACORP Energy contributes the vast majority of revenue to the Company, we note that margins in the energy trading and marketing business, even in a good year, are extremely thin. Therefore, IDACORP Energy is a smaller proportion of total operating income than the regulated utility business in a normal utility year.

IDACORP's total operating revenues for 2001 were $5.648 billion, of which IDACORP Energy (IDACORP's energy and trading operations) contributed about $4.721 billion, or 84% of revenues, while about $914 million, or 16% of revenues, came from Idaho Power Company, IDACORP's utility. The remainder, $13 million, was generated by IDACORP's other non-regulated businesses such as Ida-West Energy, IDACOMM, IdaTech, and IDACORP Financial.

ECONOMIC OUTLOOK FOR IDAHO

The economic outlook for Idaho is expected to moderately outperform that of the United States. Idaho's economic growth over the last decade has been positively impacted by expansion in its non-agricultural employment. In fact, this growth has placed Idaho among the top ten fastest-growing states in the nation. Idaho has benefited over the last decade from a population growth rate higher than the national average. During this period, personal income growth doubled due to the expansion in services employment in areas such as call centers and back office operations.

Rates of growth in Idaho's non-agricultural employment and growth in real personal income are expected to decline in 2002 versus 2001. Growth in both of these areas came in below expectations for 2001. Hewlett-Packard and Micron Technology, whose recent decreases in capacity utilization have negatively impacted non-agricultural employment growth, heavily influence Idaho's economy. According to a January 2002 report published by Idaho's Department of Financial Management, non-agricultural employment is expected to grow 0.5% this year, which is significantly less than last year's pace of 1.8%. Idaho's personal income growth is estimated to be 2.2% versus last year's (2001's) growth rate of 2.7%. Although slower growth is expected for Idaho in 2002, both in employment as well as in real personal income, Idaho is expected to fare better than the national average, outpacing national growth in these key indicators through 2005.

BUSINESS SEGMENTS

IDAHO POWER COMPANY (IPC)

Idaho Power Company, which is IDACORP's regulated utility, currently serves more than 400,000 residential and commercial customers who reside mostly in Idaho. IPC's service territory encompasses approximately a 20,000 square mile area, with the majority located in southern Idaho and eastern Oregon serving a population base of more than 800,000 people. About 95% of IPC's general business revenues come from customers within the state of Idaho. Residential and commercial customers make up more than 60% of IPC's general business revenues.

IPC Revenue, Actual and Estimated

In 000's	FY98A	FY99A	FY00A	FY01A	FY02E
Electric Utility:					
General Business	$ 514,856	$ 516,148	$ 565,357	$ 650,608	$ 682,489
Off system sales	$ 214,418	$ 119,785	$ 229,986	$ 219,966	$ 98,543
Other revenues	$ 27,136	$ 22,403	$ 41,663	$ 43,626	$ 41,500
Total Electric Utility Revenues	756,410	658,336	837,006	914,201	822,532
Annual Growth Rate	**FY98**	**FY99**	**FY00**	**FY01**	**FY02E**
General Business	7.2%	0.3%	9.5%	15.1%	4.9%
Off system sales	113.2%	-44.1%	92.0%	-4.4%	-55.2%
Other revenues	12.3%	-17.4%	86.0%	4.7%	-4.9%
Total Electric Utility Revenues	25.0%	-13.0%	27.1%	9.2%	-10.0%

Source: Company reports and Ragen MacKenzie estimates

IPC owns and operates properties including 17 hydro facilities located on the Snake River and shares ownership in three coal-fired plants located throughout the region. Idaho Power Company also recently put into service a 90 MW combustion turbine to serve peaking loads. These resources combined supply about 89% (56% hydro and 33% thermal generation) of IPC's power needs under normal weather and hydro conditions. In most years, IPC's peaking load requires about 2,900 MW. Idaho Power typically relies on wholesale spot market purchases for serving a portion (about 11%) of its load. Idaho Power Company's energy portfolio is heavily dependent on hydro conditions in order to provide low-cost hydro generation. Idaho Power Company's earnings are sensitive to variations in the weather because 41% of general business revenues are dependent on residents, who use heating in the winter and air conditioning in the summer.

Deferred Charges and Recovery of Excess Power Costs. In 2001 Idaho Power faced drought, volatile wholesale prices, and heavier load requirements due to colder-than-normal weather. Fortunately, Idaho Power put into place a number of years ago a purchase cost adjustment (PCA) mechanism that allows the Company to adjust the price of power embedded in its rate structure on an annual basis. At the end of FY01, Idaho Power had incurred $227 million in excess power costs. Of this amount, IPC is allowed to recover $217 million, or 96%, of its excess power costs through rate increases to customers. Idaho Power Company does not have a PCA in place for Oregon, which represents about 5% of utility revenues. Idaho Power Company has not had a general rate case since 1995. Due to its growth in the customer base, we believe that the Company may file for a rate case within the next two years.

Improving Hydro Conditions Over Last Year. Early indications of reservoir inflows to Idaho Power's Brownlee Reservoir (IDACORP's main storage reservoir for its Hell's Canyon hydro complex) indicate that 2002 is likely to end at a lower-than-average level, yet significantly higher than last year's level. 2001 experienced one of the lowest reservoir levels on record, and early estimates of 2002 levels have been negatively impacted by 2001's drought.

Relicensing of Hell's Canyon. IPC plans to file its application for relicensing of the Hell's Canyon complex, IPC's largest hydro facility. Relicensing is a 30-year cycle process that is continuously ongoing at Idaho Power Company. The process of preparing and filing for federal relicenses, even in the smallest facilities, is an undertaking of a number of years. Hell's Canyon is a three-dam facility with a potential generating capacity of 1167 MW, which is greater than the rest of the hydro facilities combined.

IDACORP ENERGY

IDACORP Energy, which legally separated from the utility in June 2001, primarily focuses on natural gas and electricity wholesale trading. Also, IDACORP Energy owns strategic transmission rights and has the opportunity to trade its access rights to other utilities and marketers. Because power prices have begun to stabilize, IDACORP is focused on growing this business unit's earnings through deal origination. We believe IDACORP Energy intends to change the focus of its business over time to incorporate additional strategic assets. For example, IDACORP Energy does not own or manage any generation assets at this point in time, but we believe there may be some future opportunity in this area for the Company. IDACORP Energy employs approximately 120 people, of which about 15% are traders, with the core concentration located in Boise, Idaho.

Due to the market intelligence acquired through its trading and marketing activities, Idaho Power Company relies on the trading arm to transact its open market activities when it is in a net purchasing position. About 5% of IDACORP Energy's gross margin historically has been derived through power sales to Idaho Power Company. Likewise, when the utility is in a surplus position, it has the option to sell excess generation to IDACORP Energy. These transactions are conducted, as one would expect, at market prices through an arm's length transaction. As with other utilities, power sales made by the utility are then used to offset power costs.

IDA-WEST ENERGY

Ida-West owns and manages independent electric power projects. Ida-West is currently developing a 273 MW natural gas-fired turbine located in Middleton, Idaho, for Idaho Power Company. IPC selected IDA-West for developing the site through a proposal process. We believe there is a possibility that the timeline may be pushed back on this project due to the negative impact the slowing economy has had on load growth. This proposed Garnet facility has the potential to double its capacity over time.

Historically, Ida-West has been a stable contributor to IDACORP's earnings, adding about $0.08–$0.10 to earnings per share annually. Ida-West's $0.32 contribution to earnings per share in FY00 was positively impacted by a gain on the sale of its Hermiston project to an independent power producer, which resulted in a net-of-tax gain of about $8.3 million, or $0.22 per share. In FY01, Ida-West Energy contributed $0.13 to earnings. We are estimating a segment contribution of about $0.08 in FY02, which is more in line with its historical range.

IDACORP FINANCIAL SERVICES (IFS)

IDACORP Financial Services (IFS), since its inception in 1989, has been a stable contributor to earnings through its tax-advantaged investments. To date, IFS has more than $120 million invested in its properties, which are primarily affordable housing projects. More recently, IFS has expanded its investment scope to include historical rehabilitation projects such as the El Cortez hotel project in San Diego, California.

IDACORP Financial has over 300 properties in 42 states and one U.S. territory and invests about $30 million annually. This division's investment focus has historically been affordable housing projects, but it is planning to expand its tax-advantaged investments to include, among other things, energy credits. We believe this segment is a consistent bottom-line contributor in the $0.12–$0.14 range. We have estimated in the low end of this range for FY02 at $0.12.

IDACOMM

IDACOMM, IDACORP's traditional and high-speed Internet access provider, offers its service in areas located outside major metropolitan areas. Velocitus, IDACOMM's high-speed Internet service, currently operates in areas such as Boise and Pocatello, Idaho; Spokane, Washington; Portland, Oregon; Fresno, California; Reno and Las Vegas, Nevada; and most recently, Santa Fe, New Mexico. IDACOMM originally targeted the entire western region for expansion of its customer base, but due to challenging market conditions, has scaled back its more aggressive plans. While we believe IDACOMM may eventually return to a more aggressive expansion plan once a stronger cash flow position has been established, for now IDACOMM is targeting a slower rollout that includes expansion into eight cities with its fixed wireless service by year-end.

We believe it is important to differentiate between other telecom service providers and IDACOMM's *Velocitus* service. *Velocitus* is not a long-haul fiber company. Instead, the Company is focused on providing local fiber to organizations located outside major metropolitan areas. For example, it provides service to hospitals and schools in areas that may be overlooked by other service providers. We believe that the demand for this service is real and growing, and that IDACOMM's approach (build it *after* they come) to this business is reasonable. In light of IDACOMM's recent slower expansion plans, we expect IDACOMM to breakeven on a net income basis within the next 12–18 months.

IDATECH

IdaTech, IDACORP's non-regulated subsidiary located in Bend, Oregon, is focused on hydrogen-powered fuel cell development. The target market for IdaTech's fuel cell is for small-scale portable units to be used for distributed generation in residential and other markets. IdaTech has an agreement with Bonneville Power Administration (BPA) for alpha and beta testing of its fuel cells. IdaTech is also currently alpha testing a small number of fuel cells in Japan with Tokyo Boeki. IdaTech has announced its intention to launch a commercial product, most likely its fuel cell reformer, by year-end.

IdaTech, still currently in research and development stages, has yet to reach EBITDA profitability. IDACOMM and IdaTech combined have a dilutive effect on earnings of about ($0.40) per share annually. Due to the extended delays in production and adoption timelines inherent in these emerging industries, we believe we are being conservative in our projections for the financial performance of these two units. We believe that IDACORP's non-profitable subsidiaries offer long-term growth potential.

FULL-YEAR FINANCIAL RESULTS

IDACORP Energy was the major contributor to earnings in FY01 (85.7%) and contributed about 40% to earnings in FY00. Although IDACORP Energy reported a record year in FY01, its overall contribution to earnings was somewhat distorted by the below-normal performance of the utility. While the utility's profitability deteriorated in FY01 due to a regional drought and volatile power prices, IDACORP Energy's earnings per share grew 82% year-over-year, reflecting strong volume and transaction growth as well as a reduction in general overhead costs.

In FY01, IDACORP reported net income of $125 million, or $3.35 per share, versus $140 million, or $3.72 per share, in FY00. A decline in net income at the utility was offset by the 82% increase in earnings at IDACORP Energy. The regional drought experienced in FY01 increased Idaho Power's cost of providing power, while at the same time reducing its ability to use off-system sales to offset rising power costs.

10

Actual Quarterly EPS, by Segment

	1Q00A	2Q00A	3Q00A	4Q00A	FY00A
Idaho Power Company	$0.73	$0.40	$0.43	$0.42	$1.97
IDACORP Energy	0.15	0.46	0.69	0.28	1.58
IDACORP Financial	0.03	0.03	0.05	0.04	0.14
Ida-West Energy	0.25	0.03	0.02	0.02	0.32
Other Segments	(0.04)	(0.06)	(0.08)	(0.13)	(0.29)
IDACORP, Inc. EPS	**$ 1.12**	**$ 0.86**	**$ 1.11**	**$ 0.63**	**$ 3.72**

	1Q01A	2Q01A	3Q01A	4Q01A	FY01A
Idaho Power Company	$0.37	$0.16	$0.00	$0.07	$0.60
IDACORP Energy	0.62	0.83	0.93	0.49	2.87
IDACORP Financial	0.03	0.03	0.05	0.03	0.14
Ida-West Energy	0.01	0.04	0.02	0.07	0.13
Other Segments	(0.10)	(0.10)	(0.09)	(0.11)	(0.39)
IDACORP, Inc. EPS	**$ 0.93**	**$ 0.96**	**$ 0.91**	**$ 0.55**	**$ 3.35**

Source: Company reports

Operating income for the year was $243 million versus $248 million in the prior year, reflecting, among other things, higher purchased power costs at the utility. Operating income for the utility, IDACORP Energy, and Other segments in FY01 was $90 million, $177 million, and a loss of ($24) million, respectively, versus $169 million, $95 million, and a loss of ($16) million in FY00. Pretax income for the full year was $190 million versus $211 million, reflecting lower operating income, as well as higher interest expense due to IDACORP's increase in short-term financing to fund PCA costs.

IDACORP estimates that Idaho Power Company's earnings would have been $1.45 higher ($1.27 negative impact from excess power costs not included in the PCA adjustment and a write-off of $0.18 for excess power costs) without the negative impact of higher power costs. Idaho Power, on a normalized basis, should earn about $2.00 per share. We are expecting the utility to benefit from improving hydro conditions and lower power prices in FY02. For IDACORP Energy, we are expecting FY02 to establish a more normal base year for the subsidiary given the dramatic fall in power prices and volatility this year versus last. Thus, we are estimating a decline in earnings to $1.42 per share, which is also a decline from the segment's FY01 and FY00 earnings of $2.87 and $1.58, respectively. This business is extremely difficult to forecast given that it depends on the level of volatility of power prices and industry-wide diminishing credit quality. We have not anticipated an increase in the volatility in power prices in our estimates. We are anticipating segment contribution from IDACORP Financial and Ida-West Energy to be within the range of their historical contribution levels.

BALANCE SHEET

The Company ended 3Q01 with $62 million in cash and equivalents, which is below normal for the Company, due to the negative impact of excess power costs throughout the year. IDACORP's capital structure consists of 46% debt, 6% preferred securities, and 48% equity. For FY02, budgeted capital expenditure requirements for the utility for FY02 are $124 million. The Company has announced its intention to issue between $150 million and $250 million in debt and/or equity by the first half of 2002. Proceeds from the issuance are expected to add equity to the utility, provide liquidity to the energy trading and marketing business, and, to a lesser degree, be used to fund capital needs of other non-regulated businesses. IDACORP has about $900 million in long-term debt on its balance sheet, which is rated A+ with a negative watch by Standard & Poor's at the corporate level and Baa1 with a stable outlook by Moody's.

11

Book values of Idaho Power Company and IDACORP, Inc., as of September 30, 2001, were $20.83 and $23.09, respectively. Idaho Power Company has an authorized return on common equity of 11%. For the last three years, IDACORP has earned a return on equity significantly higher than its peer group over the same time period, due largely to the contribution to earnings from its non-regulated subsidiaries. In 2000, 1999, and 1998, IDACORP's return on average equity was 17.0%, 12.1%, and 12.2%, respectively. These returns compare to an industry average of 7.2%, 12.2%, and 10.9%, respectively.

RISKS

A significant portion of IDACORP's revenue and earnings is generated from its energy trading and marketing business. This business is difficult to forecast given that profitability in the sector is dependent on volatility in power prices. Accounting in the industry is mark-to-market, meaning that some of the profits booked in a given quarter are due to unrealized gains on changes in the fair market value of outstanding contracts and also a function of the amount of collateral posted by the Company. These gains are generally realized over a number of years. IDACORP Energy management has recently increased its disclosure in this area so that trendlines could be established. However, earnings in this segment of the business may be volatile.

IDACORP Energy is engaged in a lawsuit with Overton Power District for failure to meet payment obligations under a power contract where the Company believes Overton has breached its contract. Overton agreed to pay IDACORP Energy for power at prices significantly higher than today's market prices for a period beginning July 1, 2001 and continuing through June 30, 2011. Overton had agreed at the time to raise rates to customers in order to cover the power costs. The Company has a $73 million long-term asset on its balance sheet that has been discounted for uncertainties surrounding the situation. The Company believes the case with Overton is unique and does not believe it is indicative of the credit quality of its overall portfolio.

The Company, because of the drought conditions in the region, engaged in demand-side management programs in FY01. These programs were intended to reduce the load of some of its larger customers by paying the customers to reduce power consumption. One such arrangement with Astaris Corporation involved a 50 MW voluntary load reduction. The Company and Astaris also entered into a take-or-pay arrangement where Astaris agreed to pay a contracted price for power whether or not Astaris used the power. Subsequently, Astaris shut down operations and is disputing this take-or-pay arrangement. In November 2001, the Company filed with the Commission for resolution.

CONCLUSION

We believe IDACORP's management team has made reasonable business decisions that have consistently added to IDACORP's bottom line. Even though not all of the non-regulated businesses into which IDACORP has entered have met expectations, the Company has been able to identify those situations as such and redirect its focus. Of the five non-regulated businesses, two are not yet profitable; however, one of those is essentially self-funded and expected to reach net income breakeven within the next year or two, and the other should have its first commercial product launch later this year. The other non-regulated businesses have been solid contributors to earnings, with the energy trading and marketing business contributing the majority of net income in FY01. As for Idaho Power Company, we believe it operates in a favorable regulatory environment in Idaho and, due to the PCA mechanism put into place, has avoided some of the financial crises that have been a result of volatile power prices in the region. On a normalized basis, Idaho Power Company contributes about $2.00 per share. IDACORP pays a dividend of $1.86, a 4.9% yield, which compares favorably to other electric utilities. Due to the low payout ratio of 60% (based on our FY02 earnings estimate), we consider the dividend secure.

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Other public companies mentioned:
Hewlett-Packard Company (NYSE-HWP-$19.98, not rated)
Micron Technology, Inc. (NYSE-MU-$34.05, not rated)

S&P 500: 1109.43

IdaCorp, Inc.
(in thousands)

Income Statement	1Q00A	2Q00A	3Q00A	4Q00A	2000A	1Q01A	2Q01A	3Q01A	4Q01A	2001A	2002E
Electric Utility Revenues	166,480	213,555	231,935	225,035	837,006	200,452	228,214	286,807	198,728	914,201	822,532
Energy Marketing	180,702	332,665	799,490	822,868	2,135,725	929,563	1,347,286	1,825,249	619,267	4,721,365	2,315,000
Other	4,397	5,281	7,960	5,025	22,663	2,636	3,068	3,019	3,724	12,448	12,500
Operating Revenues	351,579	551,501	1,039,386	1,052,928	2,995,393	1,132,651	1,578,569	2,115,075	821,719	5,648,014	3,150,032
Utility Operating Expenses											
Purchased power	12,889	101,630	139,243	144,887	398,649	125,287	169,419	228,460	61,044	584,209	228,000
Fuel expense	24,659	20,056	23,811	25,689	94,215	25,247	22,350	25,947	24,775	98,318	97,500
Power cost adjustment	3,258	(21,943)	(45,612)	(56,391)	(120,688)	(58,246)	(68,086)	(57,770)	8,177	(175,925)	-
Other operations and maintenance	44,605	52,082	49,630	48,553	194,870	49,401	49,978	50,906	60,476	210,762	230,000
Depreciation	19,887	19,949	19,933	20,519	80,287	20,952	21,448	21,894	22,748	87,041	89,500
Taxes other than income taxes	5,427	5,463	5,024	4,252	20,166	5,235	5,409	4,947	4,102	19,693	20,000
Total utility operating expenses	110,726	177,236	192,028	187,509	667,498	167,876	200,518	274,384	181,322	824,099	665,000
Marketing CGS	169,449	300,759	741,903	778,324	1,990,434	857,588	1,286,727	1,755,807	578,483	4,478,605	2,164,525
Marketing SG&A	2,711	3,913	15,492	28,696	50,811	33,428	9,295	11,770	11,553	66,047	46,800
Other non-utility operating expenses	6,992	8,638	11,100	12,650	39,380	8,587	8,587	7,424	12,376	36,973	37,500
Total Operating Expenses	289,877	490,545	960,522	1,007,179	2,748,123	1,067,479	1,505,127	2,049,385	783,734	5,405,725	2,913,825
Income from operations	61,702	60,956	78,864	45,749	247,271	65,172	73,442	65,690	37,985	242,289	236,207
Other Income	20,674	3,978	1,043	4,853	30,549	4,993	3,598	4,385	10,317	23,294	30,000
Interest expense	(13,162)	(13,253)	(13,239)	(13,703)	(53,356)	(13,449)	(14,768)	(13,787)	(13,779)	(55,783)	(57,000)
Other interest	(2,211)	(1,463)	(1,758)	(2,401)	(7,833)	(3,203)	(3,041)	(3,925)	(4,371)	(14,540)	(10,000)
Preferred dividends of Idaho Power	(1,428)	(1,484)	(1,511)	(1,506)	(5,929)	(1,461)	(1,292)	(1,375)	(1,272)	(5,400)	(5,400)
Total other income (expenses) - net	3,874	(12,222)	(15,464)	(12,757)	(36,569)	(13,120)	(15,503)	(14,701)	(9,105)	(52,429)	(42,400)
Income before taxes	65,576	48,733	63,400	32,993	210,701	52,052	57,939	50,988	28,881	189,860	193,807
Income taxes	23,496	16,211	21,839	9,272	70,818	17,282	21,861	17,055	8,449	64,647	65,894
Net income	42,080	32,522	41,561	23,721	139,884	34,770	36,078	33,933	20,432	125,213	127,913
Average common shares o/s	37,612	37,612	37,524	37,517	37,566	37,415	37,414	37,410	37,480	37,430	41,000
EPS, Basic and Diluted	$ 1.12	$ 0.86	$ 1.11	$ 0.63	$ 3.72	$ 0.93	$ 0.96	$ 0.91	$ 0.55	$ 3.35	$ 3.12
Dividends paid	$ 0.47	$ 0.47	$ 0.47	$ 0.47	$ 1.86	$ 0.47	$ 0.47	$ 0.47	$ 0.47	$ 1.86	$ 1.86
Dividend payout ratio	41.6%	53.8%	42.0%	73.5%	50.0%	50.0%	48.2%	51.3%	85.3%	55.6%	59.6%
Percentage Analysis											
Purchased power	7.7%	47.6%	60.0%	64.4%	47.6%	62.5%	74.2%	79.7%	30.7%	63.9%	27.7%
Fuel expense	14.8%	9.4%	10.3%	11.4%	11.3%	12.6%	9.8%	9.0%	12.5%	10.8%	11.9%
Power cost adjustment	2.0%	-10.3%	-19.7%	-25.1%	-14.4%	-29.1%	-29.8%	-20.1%	4.1%	-19.2%	0.0%
Other operations and maintenance	26.8%	24.4%	21.4%	21.6%	23.3%	24.6%	21.9%	17.7%	30.4%	23.1%	28.0%
Depreciation	11.9%	9.3%	8.6%	9.1%	9.6%	10.5%	9.4%	7.6%	11.4%	9.5%	10.9%
Total Operating Expenses	82.5%	88.9%	92.4%	95.7%	91.7%	94.2%	95.3%	96.9%	95.4%	95.7%	92.5%
Margin Analysis											
Marketing CGS	93.8%	90.4%	92.8%	94.6%	93.2%	92.3%	95.5%	96.2%	93.4%	94.9%	**93.5%**
Operating margin	17.5%	11.1%	7.6%	4.3%	8.3%	5.8%	4.7%	3.1%	4.6%	4.3%	7.5%
Pre-tax margin	18.7%	8.8%	6.1%	3.1%	7.0%	4.6%	3.7%	2.4%	3.5%	3.4%	6.2%
Net margin	12.0%	5.9%	4.0%	2.3%	4.7%	3.1%	2.3%	1.6%	2.5%	2.2%	4.1%
Tax Rate	35.8%	33.3%	34.4%	28.1%	33.6%	33.2%	37.7%	33.4%	29.3%	34.0%	**34.0%**
Yr-Yr Change											
Electric Utility Revenues						20.4%	6.9%	23.7%	-11.7%	9.2%	-10.0%
Energy Marketing Revenues						414.4%	305.0%	128.3%	-24.7%	121.1%	-51.0%
Total Operating Revenue						222.2%	186.2%	103.5%	-22.0%	88.6%	-44.2%
Total utility operating expenses						51.6%	13.1%	42.9%	-3.3%	23.5%	-19.3%
Marketing CGS						406.1%	327.8%	136.7%	-25.7%	125.0%	-51.7%
Marketing S,G,&A						1133.2%	137.6%	-24.0%	-59.7%	30.0%	-29.1%
Operating Income						5.6%	20.5%	-16.7%	-17.0%	-2.0%	-2.5%
Pre-Tax Income						-20.6%	18.9%	-19.6%	-12.5%	-9.9%	2.1%
Net Income						-17.4%	10.9%	-18.4%	-13.9%	-10.5%	2.2%
EPS, Basic and Diluted						-16.9%	11.5%	-18.1%	-13.8%	-10.1%	-6.8%

Source: Company reports and Ragen MacKenzie estimates
Allyson R. Rodgers, CFA (206) 464-5951
02.25.2002

13

IDACORP, Inc. **Historical Balance Sheet (in 000's)**	**FY98A**	**FY99A**	**FY00A**	**3Q01A**
ASSETS				
Cash and Equivalents	$ 22,867	$ 111,338	$ 106,795	$ 62,415
Total Receivables	116,486	113,748	240,921	304,142
Energy Marketing Assets	-	37,398	1,060,128	294,825
Accrued Unbilled Revenues	34,610	31,994	44,825	32,427
Materials and Supplies	37,253	38,940	34,836	33,283
Regulatory Assets	2,965	893	8,672	68,190
Prepayments	16,042	16,097	24,575	26,845
Other	-	-	-	20,754
Current Assets	230,223	350,408	1,520,752	842,881
Investments and Other	124,021	139,091	157,068	187,750
Utility Plant, net	1,650,054	1,652,304	1,657,302	1,740,157
Construction Work in Progress	59,717	91,637	136,388	112,266
Other Property	7,154	8,670	11,346	21,125
Deferred Charges	385,650	398,261	556,850	1,045,022
TOTAL ASSETS	$ 2,456,819	$ 2,640,371	$ 4,039,706	$ 3,949,201
LIABILITIES AND CAPITALIZATION				
Notes Payable	38,524	19,757	120,600	325,500
Accounts Payable	101,975	145,737	272,376	353,466
Energy Marketing Liabilities	-	33,814	1,060,180	356,690
Derivative Liabilities	-	-	-	56,270
Interest Accrued	18,365	19,126	16,985	20,576
Other	40,025	38,902	52,407	61,831
Current Portion of Long-Term Debt	6,029	89,101	39,774	9,110
Current Liabilities	204,918	346,437	1,562,322	1,183,443
Regulatory Liabilities	106,831	107,991	110,901	110,013
Deferred Income Taxes	422,196	430,468	460,464	567,733
Energy Marketing	-	-	46,769	170,711
Derivative Liabilities	-	-	-	15,229
Other	70,572	75,136	69,259	62,395
Long-Term Debt	815,937	821,558	864,114	870,140
Preferred Stock	105,968	105,811	105,066	104,524
Common Stock	451,564	451,343	451,606	445,984
Retained Earnings	278,833	301,627	369,205	419,029
Common Shareholders' Equity	730,397	752,970	820,811	865,013
TOTAL LIABILITIES / CAPITALIZATION	$ 2,456,819	$ 2,640,371	$ 4,039,706	$ 3,949,201

Source: Company reports and Ragen MacKenzie estimates
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02.25.2002

14

IDACORP, Inc.
Historical Statement of Cash Flows (in 000's)

	1998	1999	2000	9-Mos
OPERATING ACTIVITIES:				
Net income	89,176	91,349	139,883	104,782
NON-CASH ITEMS INCLUDED IN NET INCOME:				
Allowance for uncollectible accounts	-	-	-	19,347
Depreciation and amortization	87,143	95,436	103,971	82,324
Provision for deferred income taxes	(10,182)	(1,820)	46,718	115,045
Power and natural gas cost deferrals and amortizations	21,658	(891)	(122,353)	(188,202)
Gain on sale of property and subsidiary investments-net	-	-	(14,000)	(1,605)
Energy commodity assets and liabilities	-	(3,584)	28,531	(116,299)
Other-net	-	-	-	2,314
Decrease (increase) in working capital components:				
Receivables and prepaid expense	4,883	2,683	(157,182)	(85,804)
Materials & supplies, fuel stock and natural gas stored	(925)	(1,687)	4,104	(510)
Payables and other accrued liabilities	(10,772)	42,906	107,191	41,715
Other	(11,094)	6,196	(3,228)	(2,230)
Monetization of Contract	-	-	-	-
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	**169,887**	**230,588**	**133,635**	**(29,123)**
INVESTING ACTIVITIES:				
Construction expenditures (excluding AFUDC-equity funds)	(89,184)	(110,974)	(140,302)	(138,260)
Other capital requirements	3,206	(5,060)	(642)	(3,266)
Proceeds from property sales and sale of subsidiary investments	-	-	17,500	11,126
Assets acquired and investments in subsidiaries	(19,139)	(25,416)	(29,166)	-
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	**(105,117)**	**(141,450)**	**(152,610)**	**(130,400)**
FINANCING ACTIVITIES:				
Increase (decrease) in short-term borrowings	(18,992)	(18,767)	100,843	204,900
Proceeds from issuance of long-term debt	80,556	98,730	94,381	120,000
Redemption and maturity of long-term debt	(39,154)	(9,815)	(102,427)	(144,390)
Sale (repurchase) of common stock	-	-	(8,014)	(7,969)
Cash dividends paid	(69,868)	(69,863)	(69,850)	(52,343)
Other-net	(1,350)	(952)	(501)	(5,055)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	**(48,808)**	**(667)**	**14,432**	**115,143**
NET INCREASE (DECREASE) IN CASH & CASH EQUIVALENTS	**15,962**	**88,471**	**(4,543)**	**(44,380)**
CASH & CASH EQUIVALENTS AT BEGINNING OF PERIOD	**6,905**	**22,867**	**111,338**	**106,795**
CASH & CASH EQUIVALENTS AT END OF PERIOD	**22,867**	**111,338**	**106,795**	**62,415**

Source: Company reports and Ragen MacKenzie estimates
Allyson R. Rodgers, CFA (206) 464-5951
02.25.2002

RELICENSING OF HYDROELECTRIC PROJECTS:

IPC, like other utilities that operate nonfederal hydroelectric projects, obtains licenses for its hydr projects from the FERC. These licenses generally last for 30 to 50 years depending on the size and com of the project. Currently, the licenses for five hydro projects have expired. These projects continue to operat under annual licenses until the FERC issues a new permanent license. Three more hydro project licenses will expire by 2010.

IPC is actively pursuing the relicensing of these projects, a process that may continue for the next ten to 15 years. IPC has filed applications seeking renewal of licenses for the Bliss, Upper Salmon Falls, Lower Salmon Falls, CJ Strike, Shoshone Falls and Upper and Lower Malad Hydroelectric projects. The licenses for the Hells Canyon Complex (Brownlee, Oxbow and Hells Canyon) and the Swan Falls project expire in 2005 and 2010, respectively. IPC is currently engaged in procedures necessary to file timely license applications for these projects. Although various federal and state requirements and issues must be resolved through the license renewal process, IPC anticipates that it will relicense each of the eight projects.

2002
10K

Final Environmental Impact Statements (EIS) have been issued for the Bliss, Upper Salmon Falls, Lower Salmon Falls and Shoshone Falls projects. New FERC licenses are anticipated in 2003. While the actual environmental costs of protection, mitigation and enhancement (PM&E) measures and other costs associated with the relicensing of the projects will not be known until the new licenses are issued by the FERC, costs associated with these licenses (assuming 30-year licenses) are expected to total approximately $8 million during the first five years of the licenses and $28 million over the following 25 years.

A final EIS has been issued in October 2002 for the CJ Strike project and a new FERC license is expected in 2003. While the actual costs of PM&E measures and other costs associated with the relicensing of the project will not be known until the new license is issued by the FERC, costs associated with the license (assuming a 30-year license) are expected to total approximately $9 million during the first five years of the license and $38 million over the following 25 years.

The four Mid-Snake River projects, Bliss, Upper Salmon Falls, Lower Salmon Falls and Shoshone Falls, and the CJ Strike projects, may affect five species of snails listed under the Endangered Species Act. See discussion in the Part II, Item 7 - "MD&A - LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Threatened and Endangered Snails."

The Upper and Lower Malad project license expires in July 2004 and the new license application was filed in July 2002. The application is proceeding through the normal FERC licensing process. The application includes proposed PM&E measures estimated to total (assuming a 30-year license) approximately $1 million during the first five years of the license and $3 million over the following 25 years. However, the actual costs of PM&E measures and other costs associated with the relicensing of the project will not be known until the new license is issued by the FERC.

The most significant relicensing effort is the Hells Canyon Complex, which provides 68 percent of IPC's hydro generation capacity and 40 percent of its total generating capacity. IPC developed its draft license application with the assistance of a collaborative team made up of individuals representing state and federal agencies, businesses, environmental, tribal, customer, local government and local landowner interests. The draft license application was issued in September 2002 and the final application will be filed in July 2003. The draft application includes proposed PM&E measures estimated to total approximately (assuming a 30-year license) $78 million during the first five years of the license and $100 million during the following 25 years. However, the actual costs of PM&E measures and other costs associated with the relicensing of the project will not be known until the new license is issued by the FERC.

At December 31, 2002, $50 million of pre-relicensing costs were included in Construction Work in Progress (CWIP) and $6 million of pre-relicensing costs were included in Electric Plant in Service. The pre-relicensing costs are recorded and held in CWIP until a new permanent license or annual license is issued by the FERC, at which time the charges are transferred to Electric Plant in Service. Pre-relicensing costs as well as costs

16

SUMMARY OF 2002 RESULTS AND 2003 OUTLOOK:

Overall Results

IDACORP's overall results show earnings per share (EPS) of $1.63, a decrease of $1.72 from 2001. IPC's EPS increased from $0.60 in 2001 to $2.24 in 2002 despite the operational impacts of continued below normal streamflow conditions on IPC's hydro system and reduced general business sales. At IE, EPS decreased significantly from $2.87 in 2001 to a current year loss of $0.39. IE's results have been significantly impacted by deteriorating credit, substantially reduced pricing spreads, and low volatility in the Western wholesale energy markets as well as the decision to wind down energy marketing operations. IDACORP's results also reflect an $8 million partial write-down of Ida-West's investment in equipment related to the proposed Garnet energy project.

Since the announcement to wind down its energy marketing operations, IE has recorded $9 million in severance expenses, non-cancelable lease liabilities and asset impairments, among other matters. IE has reduced its workforce from a peak last year of 125 to fewer than 60 employees as of December 31, 2002. Further reductions in the workforce to approximately 20 employees are expected by July 2003.

2002 10k

Utility operations benefited from a tax accounting method change that allowed IPC to record a $35 million tax benefit. $31 million of this benefit is attributable to 2001 and prior years.

This benefit was partially offset by expensing $12 million in lost irrigation revenues disallowed by the IPUC. IPC disagrees with the IPUC's decision to disallow recovery of the $12 million in lost irrigation revenues and has filed an appeal with the Idaho Supreme Court seeking to overturn the IPUC's decision. IPC filed its brief on January 31, 2003. It is anticipated that this case will not be decided by the Idaho Supreme Court until late 2003 or early 2004. If successful, IPC would record any amount recovered as revenue.

Hydroelectric Generation and Below Normal Water Conditions

The following table presents IPC's system generation for the last three years:

	MWh			Percent of total generation		
	2002	2001	2000	2002	2001	2000
Hydroelectric	6,069	5,638	8,500	45%	43%	52%
Thermal	7,286	7,622	7,701	55	57	48
Total system generation	13,355	13,260	16,201	100%	100%	100%

IPC relies on low-cost hydroelectric plants for a significant portion of its power supply. IPC's hydroelectric generation has decreased since 2000 as IPC has experienced three years of below normal water conditions. Under normal streamflow conditions, IPC's generation mix is 57 percent hydro and 43 percent thermal. The amount of electricity IPC is able to generate from its hydro plants depends primarily on the snowpack in the mountains above its hydro facilities, reservoir storage and streamflow conditions.

Current Snake River basin snowpack numbers suggest that streamflow conditions for 2003 will remain below normal. IPC's March 2003 accumulations were 78 percent of normal, compared to 85 percent at the same time a year earlier.

The U.S. Weather Service's River Forecast Center at this time is predicting April-through-July inflow into Brownlee Reservoir will be 3.7 million acre-feet (maf). The normal 30-year average for inflow during that time is 6.3 maf. Based on the above snowpack and forecasted inflows, IPC is expecting its fourth year of below normal water conditions. IPC currently plans to use wholesale purchases from the energy markets when necessary to meet its energy needs during 2003.

Moody's Investors Service

Global Credit Research
Opinion Update
20 JUN 2003

Opinion Update: Idaho Power Company

Idaho Power Company

Boise, Idaho, United States

Ratings

Category	**Moody's Rating**
Issuer Rating	A3
First Mortgage Bonds	A2
Senior Secured	A2
Senior Unsecured Shelf	(P)A3
Preferred Stock	Baa2
Commercial Paper	P-1
Parent: IDACORP, Inc.	
Issuer Rating	Baa1
Senior Unsecured MTN	Baa1
Commercial Paper	P-2

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Opinion

Credit Strengths

Credit Strengths for Idaho Power Company (IPC) are:

- Good regulatory relations and support provided by the power cost adjustment mechanism (PCA)

- Very low production costs under normal hydro conditions

- Continued growing economy and service territory

- Ongoing cost control efforts

- ~~Solid financial position~~, adequate liquidity and good banking relationships

Credit Challenges

Credit Challenges for IPC are:

- Effects of persisting drought and unfavorable weather

- General rate increase needed to recover costs of customer growth, additional capacity needs, and expansion of T&D system

18

- Costs and potential operational changes tied to hydroelectric plant relicensing process

- High dividend payout to IDACORP, the parent company

Rating Rationale

IPC's A2 senior secured rating reflects its solid financial position, low rates, and relatively low business risk profile, as well as its plans to control capital spending while striving to reduce other expenses. The A2 also reflects the generally supportive regulatory environment in Idaho. Yet the A2 rating also considers the risk that IPC might face less operating and financial flexibility as it seeks relicensing of hydroelectric plants and adds other supply resources by 2005 to meet expected demand growth.

We note that under normal hydro conditions IPC's production costs are among the lowest of any in the nation, reflecting its sizable hydroelectric capacity base and shared ownership of economic coal-fired plants. Also, evidence of generally supportive treatment from the Idaho Public Utilities Commission (IPUC) is apparent from benefits of a power cost adjustment (PCA) clause in Idaho. The PCA fosters more stable earnings and cash flow protection for investors.

Rating Outlook - Negative

Pg

IPC's rating outlook is negative as the utility continues to cope with difficult power supply markets in its region and prepares to seek a base rate increase to bolster utility returns and cash flow. We note that affiliate transaction issues with FERC and the IPUC have been largely resolved without undue cost, although certain internal compliance assessments still need to be completed.

What Could Change the Rating - UP

As reflected in the negative rating outlook, prospects for near-term improvement in the rating are limited. However, success in securing adequate general rate relief in combination with help from improving hydro conditions and other cash flow enhancing initiatives could help stabilize IPC's credit rating.

What Could Change the Rating - DOWN

Continued delay in return to more normal hydro and weather conditions in combination with unexpected harsh treatment from Idaho regulators in the upcoming general rate proceedings. Significant increases in relicensing costs and/or stringent operational constraints imposed as part of the license renewal process. Any unexpected return to significant, debt-financed investment in more risky nonutility investments by IDACORP that places additional demands on IPC cash flow.

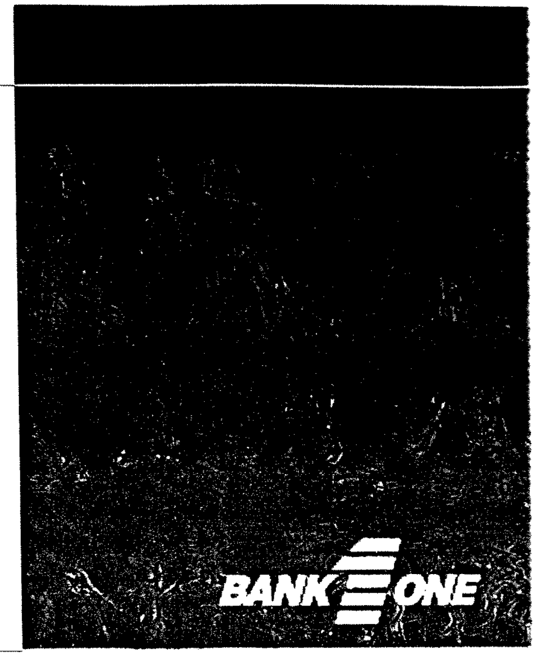
Recent Developments/Results

IPC largely resolved certain affiliate transaction issues with FERC and the IPUC in May without undue cost and is undergoing internal compliance assessments to assure compliance with due process in the future. Meanwhile, IPC's contribution to IDACORP's earnings to date in fiscal 2003 is being hampered by the effects of the lingering drought and unfavorable weather conditions. Importantly, cash flow still benefits from the PCA mechanism, which helps stabilize the earnings and cash flow effects of variability in hydro conditions and wholesale power prices. Also, IPC's recent long-term financing activity in a very favorable interest rate environment has considerably reduced its reliance on short-term debt, improved liquidity, and lowered its overall cost of capital. IPC's need to rely on short-term debt during the remainder of 2003 is expected to remain well below the unusually high levels experienced during 2001 when wholesale markets were extremely volatile. IPC's lower net supply costs contributed to significantly lower rates for customers, following the 5/16/03 PCA rate decision approving an average 18% rate reduction. The PCA rate cut could exceed anticipated general rate increases in 2004 to recover other costs of service not in current base rates. IPC is expected to file the general rate case this fall. Lastly, we note that IPC renewed its $200MM 364-day bank credit facility in March. The facility expires on 3/18/04.

19

20

BANC ONE CAPITAL MARKETS, INC.



INVESTMENT GRADE CORPORATES

Idaho Power Company, Inc. (IDA)

Update and New Issue Review

Philip C. Adams, CFA
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December 12, 2002

Coupon	Security	Maturity	Amount	Rating	Price	Yield	Spread
4.75%	FMB	11/15/12	$100 mil.	A2/A	99.13	4.86%	85 Bid
6.00%	FMB	11/15/32	$100 mil.	A2/A	99.68	6.02%	115 Bid

Recommendation: We think the new FMB issues by Idaho Power Company are currently fairly valued, and therefore rate them a HOLD. The issues came at T+105 and T+125 on November 12, and have tightened nicely since then. The current spreads are attractive for the ratings, but the small size of the issues and lack of frequency of the name in the market probably hamper liquidity. In addition, some intermediate-term strategic issues probably limit the near-term upside in the name.

Investment Summary

As a vertically integrated regulated utility subsidiary, IPC's single-A rated First Mortgage Bonds represent the most favored security class in the utility sector at present. The bonds were received well at issuance, and have tightened by 10 to 20 bp since. Moreover, IDACORP and Idaho Power look good to us in terms of: *a)* Demonstrating that Idaho's Power Cost Adjustment mechanism works reasonably well; *b)* Prudently exiting the gas and energy trading business, which was tying up capital without a decent risk-adjusted retun; and *c)* Prudently deciding *against* investing in natural gas midstream activities (which in our view would have done no better than trading). While we view the FMBs as a pretty good safe haven, their small size and the utilities' future capacity needs suggest that upside may be limited.

Business Overview

IPC is a wholly-owned subsidiary of IDACORP, Inc. based in Boise, Idaho (NYSE: IDA). IDA's market capitalization is about $913 million, down 41% YTD.

IPC is a regulated, integrated electric utility involved in the generation, purchase, transmission, distribution, and sale of electric energy. IPC also owns, through a subsidiary, an interest in Bridger Coal Company, which supplies coal to IPC's Bridger generating plant.

About 95% of IPC's revenues come from customers in the State of Idaho. IPC's territory covers 20,000 square miles in **southern and eastern Idaho** (72 cities) and **eastern Oregon** (10 cities), with an estimated population of 873,000.

21

from

As of 12/31/01, IPC had over 401,000 general business customers. Residential customers accounted for about 40% of total utility revenue in 2001, with commercial at 25%, industrial 24%, and irrigation customers at 11%.

IPC relies heavily on hydroelectric power. It owns and operates 17 hydroelectric power plants and one natural gas-fired power plant, and shares ownership in three coal-fired generating plants located in Wyoming, Oregon, and Nevada (fueled by low-sulfur coal form Utah and Wyoming). In a "normal" year, IPC's power sources would be 56% hydro, 33% thermal, and *11% purchased.*

IDACORP is exiting non-regulated marketing and trading. Because of the extraordinary, but temporary, success IDACORP had in trading, IPC accounted for only 16% of IDACORP's 2001 revenues and 37% of operating income. *By contrast, for the nine months ended September 30, 2002, utility operations accounted for 93% of consolidated revenue and 129% of consolidated operating income.*

IPC had 1,688 employees of IDACORP's 1,999 full-time total as of 12/31/01.

Investment Considerations

Strengths:

When water is plentiful, IPC has abundant, cheap power. IPC is one of the few investor-owned utilities with a predominantly (very low-cost) hydroelectric generating base, augmented by relatively low-cost coal-fired plants.

Access to purchased power. Through interconnections with the Bonneville Power Administration and other utilities, IPC has access to all the major electric systems in the West, facilitating the purchase of power when its own resources fall short.

The Idaho power cost adjustment (PCA) mechanism seems to work reasonably well. Administered by the Idaho Public Utilities Commission (IPUC), the PCA provides for an annual rate adjustment (effective annually on May 16) to recapture the previous year's actual increases in fuel and purchased power costs, as well as forecast costs for the coming year. The difference between the actual costs incurred and the forecast costs are deferred, with interest, and "trued-up" in the next annual rate adjustment. The relationship between IPC and IPUC has been generally supportive (although IPC doesn't get everything it asks for—see below.) Idaho has not passed legislation with respect to a formal restructuring of the electric industry, and IPC's Oregon service territory is exempt from that state's legislation.

Challenges:

IPC is on its third consecutive year of below-average water availability for hydroelectric power. Its reliance on purchased power remains higher than normal, forcing IPC to fund purchases in anticipation of rate relief. IPC relies heavily on hydroelectric power for its generating needs and can experience a negative impact from adverse weather, such as a low snow pack in the mountains above IPC reservoirs, or low precipitation levels. As demand outstrips hydroelectric capacity, more expensive coal and diesel facilities, along with purchased power, are needed to make up the difference.

IPUC doesn't always grant IPC everything it asks for. In the 2001 filing, IPC requested recovery of $227 million of power supply costs. In May, the IPUC authorized recovery of $168 million, but deferred recovery of $59 million pending further review. The approved amount resulted in an average rate increase of 31.6%. After hearings, the IPUC authorized recovery of $48 million, plus $1 million of accrued interest, beginning in October 2001. The remaining $11 million not recovered in rates from the PCA filing was written off in September 2001.

In the 2002 filing, IPC requested recovery of $255 million of excess power supply costs. IPUC granted recovery of about $256 million of power supply costs, mostly over a one-year period. *Approximately $12 million of lost revenues from an irrigation load reduction program were denied, as were $2 million of other costs. IPUC also denied a request to issue $172 million of Energy Cost Recovery Bonds (essentially an asset backed issue) that would have spread the recovery period across three years.* As a result of these actions by IPUC, IPC's total deferred power supply costs in Idaho declined from about $290 million at the end of 2001 to $218 million as of June 30. In Oregon, IPC had about $14.7 million of deferred costs, which it began collecting (in meaningful fashion) effective November 2001.

IPC has extensive capital expenditures planned for 2001 to 2005, aggregating $629 million. Over half of that is for transmission and distribution lines and substations. The company expects to be able to fund all but about $100 million of this five-year capital expenditure program from operating cash flow.

IPC is re-licensing ten of its 17 hydroelectric projects from FERC, a process that will take eight to 15 years. Re-licensing is not automatic. IPC must demonstrate (generally) that it is in the public interest for IPC to continue to hold the federal license.

There can be no assurance that weather patterns will revert to normal this winter or that sufficient

hydroelectric power will be available next year. Consequently, while IPC will have an opportunity to apply for rate relief again next spring, the outcome of future filings, and the excess fuel and power costs that the company may incur in 2002 and 2003, cannot be confidently estimated.

IPC is considering, but has not yet committed to, investing in additional fossil fuel plants to reduce its deficit in generating capacity. A 500MW plant might cost $400 to $500 million.

IDACORP disclosed on September 9, 2002 that several issues require resolution with FERC and IPUC surrounding the "winding down" of its power marketing operations. With respect to IPUC, the primary purpose of the proceeding is to determine the appropriate compensation IDACORP Energy should provide to IPC as a result of transactions between the affiliates since February 2001. Matters with the FERC include: *1)* Resolution of whether or not the trading operation properly paid the utility for use of its transmission assets; *2)* Certain transactions between IDACORP Energy and IPC (spinning reserves and load following services) were supposed to have prior FERC approval, but did not; and *3)* The assignment of Idaho Power's marketing contracts to IDACORP Energy in June 2001 was supposed to be approved in advance by FERC, but prior approval was not sought. **The remedies for these issues are not clear and will not likely be known for some time. We think the most likely outcome would be additional compensation for IPC—a good thing, though perhaps offset by a tougher stance at IPUC, which might seek to have these gains benefit IPC's customers in the form of lower rates in the future. There might also be fines involved, although we would expect them to be levied at the IDACORP level.**

Rating agencies' views differ. After downgrading IPC in March 2002, on June 27 S&P affirmed its ratings on IDACORP and Idaho Power (both have senior unsecured ratings of BBB+ and CP ratings of A-2 and revised the outlook to Positive from Negative. The action was the result of IDACORP's decision to wind down the power marketing business at its IDACORP Energy subsidiary, an activity that had substantially increased the consolidated entity's business risk and weakened its financial profile. While servicing existing commitments will take up to 24 months to wrap up, IDACORP will not pursue prospective customers, is reducing its trading staff, and is limiting its maximum value at risk limits to less than $3 million.

Moody's assigned a Negative outlook on the parent company IDACORP upon rating its $500 million debt shelf registration on March 8, 2002, but left their Idaho Power outlook Stable at that time. On September 10, 2002, however, Moody's changed its outlook on Idaho Power Company from Stable to Negative. Moody's outlook is based on "myriad factors" including the IPUC and FERC issues disclosed on September 9 (detailed above). Moody's now believes that the execution risks associated with the exit of the power marketing business now carry over to IPC, and is concerned that FERC or IPUC might take an extremely harsh stance.

Recent Results and Outlook

IDACORP recently announced that it would not pursue its previously announced strategy of investing in natural gas midstream processing. We view this as a positive development. The minimum purchase size would have been about $35 million, with "critical mass" requiring a total investment of $150 to $200 million. (The business is volatile, and the capital can better be deployed elsewhere, in my opinion.)

In 2001, IPC reported net income of $73 million, down 45% ($59 million) from the previous year. Operating income fell about $80 million to $90 million, despite PCA deferral accounting. Purchased power and fuel costs increased more rapidly than revenues and the PCA mechanism, and operating expenses increased modestly (including customer accounting system and uncollectible write-offs of $4 million; $5 million for leased diesel generators to ensure against shortages; a $7 million increase due to unscheduled outages at thermal plants; and $7 million higher depreciation). At year-end, IPC had total debt/capitalization of 56%, up about 5 points from year-end 2000. IPC's coverage ratio was 3.2x, down from 6.4x in 2000.

In the third quarter and nine months year-to-date, IPC has done much better than in 2001, and has emerged as the strength of IDACORP. Operating income for the third quarter was $22 million, up 69% from the year-earlier quarter, and 129% of the consolidated total. For the first nine months, IPC's operating income of $99 million is up 36%, and constitutes 138% of the consolidated total operating income of $72 million.

Recall that in the second quarter, IDACORP Energy, the marketing and trading subsidiary, reported a 32 cent per share *loss*. In the third quarter, IDACORP Energy contributed $0.02 per share, versus $0.92 in the third quarter of 2001. With the November 5, 2002 announcement that IDACORP Energy will exit the natural gas business, the company will record a restructuring charge in the fourth quarter of between $8 million and $13 million, or $0.13 and $0.20 per share, for severance benefits, non-cancelable lease liabilities, and asset impairment.

IPC's leverage as of September 30 was 52%, down 4 points from year-end. For the twelve months ended September 30, interest coverage was 3.3x, versus 3.2x for all of 2001.

23

Idaho Power Company

Moody's	S&P	
A2	A	First Mortgage Bonds
Negative	Positive	

$ millions, unless otherwise noted

Fiscal Year End: 12/31	LTM 09/30	2001	2000	1999
Balance sheet				
Cash & cash equivalents	15	43	83	95
Total assets	2,754	2,860	3,696	2,563
Total short-term debt	240	309	90	109
Total long-term debt	672	802	809	822
Preferred stock	54	104	105	106
Shareholders' equity	783	766	765	728
Total capitalization	1,750	1,981	1,769	1,764
Other debt-like instr (ODI)	0	0	0	0
Minority interests	0	0	0	0
Operating lease expense	0	0	0	0
Income statement				
Total revenue	859	912	836	658
EBITDA	203	210	371	299
EBIT	98	111	278	204
Gross interest expense	62	66	58	62
Pretax income	38	48	223	143
Earnings bef. non-recurring	57	28	137	97
Non-recurring items	23	50	0	0
Preferred Dividends	4	5	6	6
Net income	76	73	132	92
Cash flow statement				
Gross operating cash flow	258	16	175	187
Working capital changes	(23)	(65)	(6)	31
Net operating cash flow	233	(60)	161	214
Capital expenditures	45	(157)	(132)	(108)
Asset sales (acquisitions)	0	0	0	0
Dividends	(75)	(75)	(76)	(75)
Cash excess (shortfall)	203	(292)	(46)	30
Debt issuance (repayment)	(61)	212	40	74
Stock issuance (repurchases)	(50)	0	0	0
Other	(2)	(4)	(1)	(1)
Net cash increase (decrease)	122	(40)	(12)	75

	LTM 09/30	2001	2000	1999
Leverage				
Long-term debt/capital (%)	38.4	40.5	45.7	46.6
Total debt/capital (%)	52.2	56.1	50.8	52.7
Net debt/capital (%)	51.3	53.9	46.1	47.3
Debt/market cap (%)	nm	nm	nm	nm
FFO/debt (%)	28.3	1.5	19.4	20.0
Debt/EBITDA (x)	4.5	5.3	2.4	3.1
Debt/EBITDA-capex (x)	3.7	20.8	3.8	4.9
Coverage				
EBIT interest coverage (x)	1.6	1.7	4.8	3.3
EBITDA interest coverage (x)	3.3	3.2	6.4	4.8
FFO interest coverage (x)	4.2	0.2	3.0	3.0
EBITDA - capex/interest	4 0	0.8	4.1	3.1
Profitablity				
Gross Margin (%)	51.7	44.5	55.5	70.8
Operating Margin (%)	13.6	9.9	20.3	26.2
EBITDA/sales (%)	23.7	23.0	44.4	45.4
Return on capital (%)	5.7	5.9	15.8	11.9
Return on equity (%)	9.7	9.5	17.2	12.6
EBITDA/Total Capitalization	11.6	10.6	21.0	16.9
Consolidated Dividend Payout	92.0	95.8	53.1	76.1
Non-cash working capital/Revenue	-2.7	12.2	1.0	3.3

	2002	2003	2004	2005
Schedule of debt maturities	27	80	50	60

fiscal year end is December 31

*For rolling 12 month period

IDACORP

Investor Relations Release

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FOR IMMEDIATE RELEASE
September 18, 2003

IDACORP Reduces Dividend to Strengthen Balance Sheet

Annual Common Stock Dividend Set at $1.20 per Share

Action Driven by Growing Capital Requirements

Board Approves 160-MW Generating Project Proposal

BOISE – Taking a strategic step to strengthen IDACORP's financial position and its ability to fund Idaho Power's $675 million, three-year capital expenditure program, the company's board of directors today reduced the annual dividend paid on IDACORP (NYSE:IDA) common stock.

Today's action reduces the dividend from $1.86 to $1.20. The change will take effect with the dividend for the quarter ending October 31, which the board declared at $0.30 per share. The dividend will be paid December 1 to common shareholders of record on November 5.

"We understand the importance of the dividend to our shareowners, which made this a very difficult decision," said Chairman of the Board Jon H. Miller. "However, we also understand the need to invest significantly in our business over the next few years – primarily our utility operations at Idaho Power. Our approval today of a development contract for construction of a new power plant is a case in point."

"This strategic dividend action will improve cash flow, and help maintain a strong credit rating while balancing the level of borrowing necessary to meet these growing capital requirements," Miller added. "This decision also better aligns IDACORP's dividend policy and payout ratio with industry peers."

President and Chief Executive Officer Jan B. Packwood explained that with the closure of IDACORP's wholesale energy marketing business, the long-term sustainability of the dividend is dependent upon the earnings and operating cash flow generated by Idaho Power Company.

"As we stated in our second quarter earnings release," said Packwood, "Idaho Power's earnings and operating cash flow depend on many factors, but the most significant are weather and hydroelectric generating conditions, the ability to obtain rate relief to cover operating costs and capital spending requirements."

Based on last winter's snow pack and current and forecasted river flows, Idaho Power is experiencing its fourth consecutive year of below normal water conditions, which has negatively affected cash flows. "Although the board had hoped to defer making a decision on the dividend until 2004, the combination of lower-than-expected cash flow for 2003 and the decision to proceed with the Mountain Home project made it prudent for us to take this action now," Packwood said.

IDACORP

Investor Relations Release

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Packwood explained that Idaho Power will also increase its investment in its transmission and distribution infrastructure and its power plants – including the costs related to the relicensing of its hydroelectric facilities, the construction of new plants, and upgrade and replacement needs at its existing hydro and thermal power plants. He cited as an example of the growing capital requirements today's action by the board to approve the construction of a 160-megawatt generating plant near Mountain Home, Idaho, using simple-cycle combustion turbine technology. The project cost – including plant construction and associated transmission system upgrades – is $61 million. Idaho Power will take ownership of the plant once it's fully tested and operational.

"These requirements are the primary reason for growth in the company's capital budget from $427 million for the years 2001 through 2003 to an estimated $675 million over the next three years," he said. "Our coal-fired plants are approaching their fourth decade of service and we've had to rely on them to a much higher degree in recent years because of below-normal hydro conditions. The time has come to ensure we can make the improvements necessary to maintain reliable electrical service," Packwood said. "These investments also provide an opportunity to grow value for our shareowners by re-investing in the core business."

"Today's board action is a major step in strengthening our financial position and flexibility," he said. "An equally important factor will be our ability to recover past investments through fair and reasonable rates. We will be requesting authority to raise rates in Idaho later this year, to include a request for interim rate relief. Together these actions will ensure adequate, reliable and affordable electricity for our customers and a fair and competitive return for our investors."

Idaho Power Dividend Declarations:

- Directors declared a quarterly dividend on the four percent preferred stock of $1.00 per share, payable Feb. 2, 2004,to holders of record at the close of business on Jan. 15, 2004.
- Directors declared a quarterly dividend on the 7.68 percent serial preferred stock, $100 par value, of $1.92 per share, payable Feb. 17, 2004, to holders of record at the close of business on Jan. 26, 2004.
- Directors declared a quarterly dividend on the 7.07 percent serial preferred stock, without par value, of $1.76750 per share, payable Feb. 20, 2004, to holders of record at the close of business on Jan. 26, 2004.

Background Information

Boise, Idaho-based IDACORP, formed in 1998, is a holding company comprising Idaho Power, a regulated electric utility; Ida-West Energy, a manager and developer of independent power projects; IDACORP Financial, an investment vehicle that makes investments primarily in low-income housing projects; Ida-Tech, a developer of fully integrated fuel cell systems; IDACOMM, a telecommunications subsidiary providing high-speed access technologies; Velocitus, a commercial and residential Internet service provider; and IDACORP Energy, a marketer of energy and energy-related products and services that is winding down its operations.

Certain statements contained in this news release, including statements with respect to future earnings, ongoing operations, and financial conditions, are "forward-looking statements" within the meaning of federal securities laws. Although IDACORP and Idaho Power believe that the expectations and assumptions reflected in these forward-looking statements are reasonable, these statements involve a number of risks and uncertainties, and actual results may differ materially from the results discussed in the statements. Important factors that could cause actual results to differ materially from the forward-looking statements include: changes in governmental policies and regulatory actions, including those of the Federal Energy Regulatory Commission (FERC), the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utilities Commission (OPUC), with respect to allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power and other capital

Standard & Poor's is pleased to provide ongoing service to the investment community.

IDACORP and Unit Ratings Affirmed; Outlook Revised to Stable

Publication date:	03-Oct-2003
Analyst(s):	Swami Venkataraman, San Francisco (1) 415-371-5071

Credit Rating: A-/Stable/A-2

Rationale

On Oct. 3, 2003, Standard & Poor's Ratings Services affirmed its 'A-/A-2' corporate credit ratings on IDACORP Inc. and Idaho Power Co., and revised its outlook on the companies to stable from positive.

In June 2003, Standard & Poor's revised the outlook on the IDACORP and Idaho Power to positive from negative following the company's announcement that it would exit completely from the energy trading business. The resulting improved business profile raised expectations that the company would more readily achieve financial ratio levels commensurate with an 'A' rating over a two- to three-year period.

Standard & Poor's now expects that ratios will only meet expectations for the 'A-' rating and may even be slightly weaker in the interim, as Idaho Power continues to recover deferred power costs and face poor water conditions in the Snake River and lower than expected sales.

However, the exit from the energy trading business, the change from an average to a 70th percentile resource planning for load and water flows, and the 35% dividend reduction announced on Sept. 18, 2003 serve to strengthen IDACORP's credit profile. IDACORP's business profile has improved to a '4' from a '5' on a 10-point scale, where '1' is the least risky. Idaho Power's business profile is also a '4.'

The ratings on IDACORP and Idaho Power reflect the consistent, credit-friendly regulatory environment in Idaho and competitive rates and production costs. The annual power cost adjustment (PCA) mechanism, first

27

authorized by the Idaho Public Utilities Commission (IPUC) in 1993, allows annual rate adjustments based on the difference between actual and forecast power supply costs. During the year, 90% of the difference between actual and forecast costs of the Idaho jurisdiction is deferred with interest and recovered or refunded in the next 12-month period.

In May and October 2001 and May 2002, the IPUC raised overall rates by more than 43% via the PCA mechanism so as to allow Idaho Power to recover the majority of its deferred power costs incurred during the power crisis, a time period that was shorter than even the company's own request to issue securitization bonds that would be repaid through rates over three years. The IPUC also acknowledged Idaho Power's biannual Integrated Resource Plan (IRP) in 2002, using the 70th percentile water flows and load conditions for resource planning as opposed to the historical average level approach. This was an important positive change in the planning process and significantly reduced the chances of another significant accumulation of deferred power costs.

Idaho Power serves more than 400,000 customers in southern Idaho and eastern Oregon, which exhibit average economic characteristics overall. The service area, particularly around Boise, has exhibited strong population growth in the last decade of 10.1% compared with the national average of 3.8%. Growth in the customer base has accordingly been strong at over 2.5% annually. Given the regional importance of agriculture, income levels remain below the national average at about 88%, while rolling 12-month unemployment is 5.7% as of July 2003, the same as the national average. Food processing, lumber and mining account for about 40% of the state's employment and contribute to the economy's cyclicality, although the last decade has seen the growth of the technology industry in the Boise area.

Idaho Power has a favorable customer mix, with residential, commercial, irrigation, and industrial customers accounting for 34%, 27%, 14%, and 25%, respectively, of sales in 2002. There is no significant customer concentration, with the top customer accounting for 3.4% of revenues and the top 20 only 13.2%.

Idaho Power served a peak load of 2,963 MW in 2002 from 17 hydroelectric plants on the Snake River and its tributaries with a total nameplate capacity of 1,731 MW. The company also owns interests in three coal-generating plants, 707 MW in Wyoming, 55 MW in Oregon, and 261 MW in Nevada. Idaho Power also owns a 90 MW gas-fired peaking plant in Idaho. In an average year, hydroelectric sources provide about 57% of total generation needs, thus significantly exposing Idaho Power to waterflow variations. The 2002 IRP, which provides for planning based on 70th percentile load and water levels, rather than average conditions, and the PCA mechanism, are important risk mitigants for Idaho Power.

Idaho Power had among the lowest rates in the nation prior to the power crisis. Its residential and industrial rates today are above the state average largely due to the cumulative 46% PCA rate increase to recover deferred power costs. Rates will decrease as a matter of course. An 18% reduction was effected in May 2003 and another reduction is expected to occur in May 2004, although it is also expected that the decrease will be offset by a general rate case increase. Standard & Poor's does not consider competitiveness a major issue, given the lack of any impetus towards deregulation in Idaho. In Oregon, Idaho Power is exempt from any restructuring legislation.

IDACORP exited the energy marketing business following the sale of its business to Sempra Energy. Idaho Power now constitutes materially all of IDACORP's business and is the cornerstone of the company's credit quality.

Management policy is supportive of credit quality, as reflected by the decision to exit the energy trading business completely, aggressively settle legal disputes surrounding contracts signed during the power crisis, and decrease the dividend payout by 35% in view of the upcoming $675 million in capital expenditures over the next three years.

IDACORP's financial profile has rebounded since the power crisis, aided by the IPUC's decision to allow Idaho Power rapid recovery of all its deferred energy costs by 2003. The deferrals have yet to be completed owing to an unexpectedly warm winter in 2003 and continued poor water conditions in the Snake River. Over the next few years, Standard & Poor's expects that cash flow coverage of interest and debt will average about 4.0x and 20%, respectively, while total debt to total capitalization will be about 54%. IDACORP's exit from the trading business should save operating costs. Also, the upcoming general rate case for Idaho Power, the first in 10 years, should enable the company to improve its earnings and cash flows. Idaho Power is expected to request a 10% to 15% rate increase.

Currently, Standard & Poor's rates Idaho Power's first mortgage bonds a notch above the corporate credit rating reflecting overcollateralization of these bonds with utility property. In its analysis, Standard & Poor's considers the maximum amount of first mortgage bonds that could be outstanding under the terms of the indenture. In Idaho Power's case, this amount, currently $1.1 billion, is subject to change without bondholder approval and only requires a board resolution authorizing an increase. Should the same occur, and the increased maximum amount be no longer overcollateralized with utility property to a sufficient extent, the rating on the first mortgage bonds could be lowered to the level of the corporate credit rating.

Liquidity.

A $175 million one-year revolver (decreased from $350 million in March 2003, reflecting the exit from energy trading) and a $140 million three-year revolver at IDACORP supported $119 million in commercial paper as of June 30, 2003. Idaho Power has a separate $200 million one-year credit facility while cash on hand was about $20 million as on June 30, 2003.

IDACORP's liquidity position is comfortable. Debt maturities are few, at $90 million and $58 million in 2003 and 2004, respectively, and the $675 million capital expenditures over the next three years are expected to be funded almost entirely out of operating cash flows. The $175 million IDACORP line has a covenant that requires an EBITDA to interest ratio of 2.75x. The ratio, as defined by the bank line documents, stood at 2.94x for 2002. IDACORP has no material ratings-linked triggers.

Outlook

The stable outlook reflects the complete exit from energy trading and expectations for steady earnings and cash flows from Idaho Power over the next few years.

Ratings List

Rating

IDACORP Inc.

Corporate credit rating A-/Stable/A-2

Senior unsecured debt BBB+

Commercial paper A-2

Idaho Power Inc.

Corporate credit rating A-/Stable/A-2

Senior secured debt A

Senior unsecured debt BBB+

Preferred stock BBB

Commercial paper A-2

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Credit Ratings Actions.

For a complete list of ratings, please click the hyperlink provided here <http://www2.standardandpoors.com/NASApp/cs/ContentServer?pagename=sp/Page/FixedIncomeRatingActionsPg>

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Return to Regular Format

Research:

Summary: Idaho Power Co

Publication date: 08-Apr-2003
Credit Analyst: Swami Venkataraman, San Francisco (1) 415-371-5071

Credit Rating: A-/Positive/A-2

Rationale

The ratings on Idaho Power Co. (A-/Pos/A-2) derive from the consolidated credit quality of IDACORP (A-/Pos/A-2) and its subsidiaries and reflect the expected improvement in the financial profile at Idaho Power as the utility recovers deferred power costs from the western U.S. power crisis, a business profile that will benefit from the company's exit from all unregulated operations, the supportive regulatory environment in Idaho, and competitive rates and production costs. Future credit prospects are strengthened by IDACORP's decision to focus exclusively on its regulated utility operations. IDACORP has decided to exit power and gas trading at IDACORP Energy, cancelled the proposed 75% merchant, 250 MW Garnett power project, and decided not to pursue an entry into the mid-stream gas business.

Following the exit from power marketing, the regulated utility will once again constitute the bulk of IDACORP's business and be the cornerstone of the company's credit quality. The regulatory environment in Idaho is supportive, with a power cost adjustment (PCA) mechanism that allows IDACORP to share 90% of excess power costs with customers. Idaho Power expects to recover completely by June 2003, $256 million in deferred costs it incurred during the power crisis.

IDACORP's financial profile rebounded smartly in 2002, mainly on account of deferred cost recovery and ratios are now line with expectations for the rating. Funds from operations coverage of interest and debt to total capitalization stood at 5.5x and 52% respectively in 2002. Given that the large contribution to cash flows from PCA collections ($164 million in 2002) will be reduced in future years, cash flow interest coverage is expected to drop from the lofty levels of 2002, but will still remain in line with expectations for the rating.

Liquidity.

IDACORP's liquidity position is comfortable. A $175 million one-year revolver (decreased from $350 million in March 2003, reflecting the exit from energy trading) and a $140 million three-year revolver at IDACORP had $75 million and $140 million respectively available as of April 2003. Idaho Power has a separate $200 million one-year credit facility with $189.5 million available as of Dec. 31, 2002 while cash on hand was about $43 million as of Dec. 31, 2002. The $175 million IDACORP line has a covenant that requires an EBITDA to interest ratio of 2.75. The ratio stood at 2.94x as of Dec. 31, 2002.

Debt maturities are small, at $90 million and $58 million respectively, in 2003 and 2004. Idaho Power's recent $300 Million S-3 shelf filing would be utilized to refinance these bonds and to pay down others as dictated by market conditions. IDACORP has no material ratings linked triggers. Liquidity needs in the trading business are linked to credit ratings but are expected to wind down quickly over the next year.

Outlook

The positive outlook reflects the expected improvement in IDACORP's consolidated financial profile on account of the collection of deferred power costs as well as the expected decrease in business risk as the firm completes its exit from all unregulated operations.

31

Credit Ratings

	Standard & Poor's		Moody's		Fitch IBCA	
	IPCo	IDACORP	IPCo	IDACORP	IPCo	IDACORP
Corporate Credit Rating	A-	A-	A3	Baa 1	None	None
Senior Secured Debt	A	None	A2	None	A	None
Senior Unsecured Debt	BBB+	BBB+	A3	Baa 1	A-	BBB+
Preferred Stock	BBB	BBB-	Baa 2	Baa 3	BBB+	None
Trust Preferred Stock	None	BBB-	None	Baa 2	None	BBB
Commercial Paper	A-2	A-2	P-1	P-2	F-1	F-2
Rating Outlook	Positive	Positive	Negative	Negative	Stable	Stable
Business Profile	4	5	n/a	n/a	n/a	n/a
	June-02		*September-02*		*May-02*	

Questions - Contact Larry Spencer ex-2664.

32

IDACORP

FFO / Avg Total Debt

Operating Cash
Non Recourse LTD Int Exp (aft ta
Trust Preferred Div Exp (aft tax)
Adj Op Cash

Total Debt Prior Year (from Spillw
Adj Total Debt
Average Total Debt

FFO / Avg Total Debt

FFO Interest Coverage

Adj Op Cash
Adj Interest Expense
Op Cash Plus Interest Exp

Interest Expense (excl pref div)
Non Recourse LTD Int Exp
Trust Pref Int Exp Adj
Adj Interest Expense

FFO Interest Coverage

PreTax Interest Coverage

EBIT
AFDC - Equity
EBIT Less AFDC- Eq
Adj Interest Expense

PreTax Interest Coverage

Total Debt / Total Capital

LT Debt
Less IC Financial NRD
Adj LT Debt
Current Maturities
ST Debt
Adj Total Debt

Adj Total Debt
Common Equity
Preferred
Total Capital

Total Debt / Total Capital

S&P Ratios (Business Position 4):

FFO / Avg Total Debt	BBB	BBB	BBB
FFO Interest Coverage	A	>A	>A
PreTax Interest Coverage	BB	BBB	BBB
Total Debt / Total Capital	BBB	BBB	BBB
Weighted Average	**BBB**	**BBB**	**BBB**

33

FINANCIAL TARGETS

FFO / TOTAL DEBT

Business Position	AA		A		BBB		BB		B	
1	20.0	16.5	16.5	12.5	12.5	7.0	< 7.0		-	-
2	25.0	21.0	21.0	16.0	16.0	10.5	< 10.5		-	-
3	31.5	26.0	26.0	20.0	20.0	14.0	14.0	9.5	9.5	4.0
4	36.5	30.5	30.5	24.5	24.5	17.5	17.5	12.0	12.0	6.0
5	40.0	33.0	33.0	27.0	27.0	20.5	20.5	15.0	15.0	7.5
6	47.0	39.0	39.0	31.0	31.0	22.0	22.0	16.0	16.0	8.5
7	56.0	47.0	47.0	36.5	36.5	24.5	24.5	17.0	17.0	9.5
8	66.0	55.0	55.0	42.5	42.5	27.5	27.5	18.5	18.5	11.0
9	-	-	64.5	49.5	49.5	32.0	32.0	22.0	22.0	12.5
10	-	-	78.0	60.5	60.5	39.0	39.0	28.0	28.0	17.5

FFO INTEREST COVERAGE

Business Position	AA		A		BBB		BB		B	
1	3.1	2.6	2.6	1.9	1.9	0.9	< 0.9		-	-
2	3.9	3.3	3.3	2.5	2.5	1.5	< 1.5		-	-
3	4.5	3.9	3.9	3.1	3.1	2.1	2.1	1.3	1.3	0.5
4	5.1	4.5	4.5	3.8	3.8	2.7	2.7	1.8	1.8	0.9
5	5.4	4.8	4.8	4.0	4.0	3.0	3.0	2.1	2.1	1.1
6	6.6	5.7	5.7	4.5	4.5	3.1	3.1	2.2	2.2	1.2
7	8.4	7.0	7.0	5.1	5.1	3.3	3.3	2.3	2.3	1.3
8	10.2	8.3	8.3	5.9	5.9	3.5	3.5	2.4	2.4	1.5
9	-	-	9.5	7.1	7.1	4.3	4.3	2.9	2.9	1.8
10	-	-	11.3	8.6	8.6	5.3	5.3	3.6	3.6	2.3

PRETAX INTEREST COVERAGE

Business Position	AA		A		BBB		BB		B	
1	2.8	2.4	2.4	1.8	1.8	0.8	< 0.8		-	-
2	3.4	2.9	2.9	2.3	2.3	1.3	< 1.3		-	-
3	4.0	3.4	3.4	2.8	2.8	1.8	1.8	1.1	1.1	0.3
4	4.6	4.0	4.0	3.3	3.3	2.2	2.2	1.3	1.3	0.5
5	5.0	4.3	4.3	3.5	3.5	2.4	2.4	1.5	1.5	0.6
6	6.2	5.2	5.2	4.0	4.0	2.6	2.6	1.6	1.6	0.7
7	8.0	6.5	6.5	4.7	4.7	2.8	2.8	1.8	1.8	0.9
8	9.9	8.0	8.0	5.5	5.5	3.0	3.0	2.0	2.0	1.1
9	-	-	9.1	6.6	6.6	3.7	3.7	2.5	2.5	1.4
10	-	-	11.1	8.4	8.4	5.0	5.0	3.3	3.3	1.8

TOTAL DEBT / TOTAL CAPITAL

Business Position	AA		A		BBB		BB		B	
1	50.5	55.0	55.0	60.5	60.5	67.5	> 67.5		-	-
2	46.5	51.0	51.0	56.5	56.5	63.5	> 63.5		-	-
3	42.0	47.5	47.5	53.0	53.0	61.0	61.0	67.0	67.0	74.0
4	37.5	43.0	43.0	49.5	49.5	57.0	57.0	64.0	64.0	72.5
5	36.0	41.5	41.5	47.0	47.0	55.0	55.0	62.5	62.5	71.0
6	32.5	39.5	39.5	46.0	46.0	53.5	53.5	60.5	60.5	69.0
7	30.5	37.5	37.5	45.0	45.0	52.5	52.5	59.5	59.5	68.0
8	28.0	35.0	35.0	43.0	43.0	51.5	51.5	58.0	58.0	66.0
9	-	-	30.0	39.0	39.0	47.5	47.5	54.0	54.0	61.5
10	-	-	24.0	33.0	33.0	40.5	40.5	46.0	46.0	53.0

Standard and Poor's Corporate Credit Risk Analysis

Overall Rating Structure and Process

S&P Rates Issuer's overall credit worthiness and also specific debt instruments – over 30,000 current ratings.

- Corporate credit rating (CCR)
- Sovereign rating
- Specific Debt Instrument
    - Likelihood of default
    - Nature and provisions of obligation

Outlook is given for all long-term ratings to assess potential direction over 1 – 3 years

Credit Watch focuses on a possible short-term (90 days) change

Rating Scales

Investment Grade:	AAA	- 'Highest Rating'
	AA	
	A	- 'Capacity to meet financial obligation is strong'
	BBB	- 'Adequate protection'
Non-Investment Grade:	BB	- 'Faces uncertainties'
	B	- 'Likely to be impaired'
	CCC	- 'Vulnerable to non-payment'
	CC	
	C	
Debt in Selective Default:	SD/D	

Outlook:	Positive
	Negative
	Stable
	Developing
Credit Watch:	Positive
	Negative
	Developing (such as a merger)

Market Statistics

Global Corporate Rating:	64% Investment Grade
	36% Speculative Grade

Ratings Process

1. Ratings request and document preparation
2. S&P Analytical team prepares research and analysis
3. S&P Analytical team meets with management
4. S&P Committee decides and issues ratings (Committee is odd-numbered)
5. A possible appeal is submitted by the issuer
6. S&P continually watches issuer news

Ratings Methodology

Business and financial risk are both analyzed in an equally weighted, comparative process to determine a final rating. The business risk determines the appropriate level of financial risk as benchmarks vary greatly by industry.

Industry Characteristics
- Strength of prospects
- Industry structure

Competitive Position
- Basis of Competition
- Market Size and/or growth potential
- Market share and position

Management
- Track Record
- Business Strategy
- Controls/Information system

Financial Risk Analysis
- Five years of audited historical data along with 2 –3 year of forecast
- Ratios should reflect ongoing operational profitability
- Analytical focus on: policy, earnings protection measures, CF adequacy, flexibility, and capital structure
- CF is King!!!!!!!
- Key Ratios:
  - Total Debt/Capitalization
  - Funds from Operations (FFO)
  - EBITDA Interest Coverage
  - FFO/Total Debt
  - Free Operating Cash Flow/ Total Debt
  - Total Debt/EBITDA

CREDITWATCH

CreditWatch highlights the potential direction of a short- or long-term rating. It focuses on identifiable events and short-term trends that cause ratings to be placed under special surveillance by Standard & Poor's analytical staff. These may include mergers, recapitalizations, voter referendums, regulatory action, or anticipated operating developments. Ratings appear on CreditWatch when such an event or a deviation from an expected trend occurs and additional information is necessary to evaluate the current rating. A listing, however, does not mean a rating change is inevitable, and whenever possible, a range of alternative ratings will be shown. CreditWatch is not intended to include all ratings under review, and rating changes may occur without the ratings having first appeared on CreditWatch. The "positive" designation means that a rating may be raised; "negative" means a rating may be lowered; and "developing" means that a rating may be raised, lowered, or affirmed.

Back to Top

DUAL RATINGS DEFINITIONS

Standard & Poor's assigns "dual" ratings to all debt issues that have a put option or demand feature as part of their structure. The first rating addresses the likelihood of repayment of principal and interest as due, and the second rating addresses only the demand feature. The long-term debt rating symbols are used for bonds to denote the long-term maturity and the commercial paper rating symbols for the put option (for example, 'AAA/A-1+'). With short-term demand debt, Standard & Poor's note rating symbols are used with the commercial paper rating symbols (for example, 'SP-1+/A-1+').

Back to Top

INSURER FINANCIAL ENHANCEMENT RATING DEFINITIONS

A Standard & Poor's Insurer Financial Enhancement Rating is a current opinion of the creditworthiness of an insurer with respect to insurance policies or other financial obligations that are predominantly used as credit enhancement and/or financial guarantees. When assigning an Insurer Financial Enhancement Rating, Standard & Poor's analysis focuses on capital, liquidity, and company commitment necessary to support a credit enhancement or financial guaranty business. The Insurer Financial Enhancement Rating is not a recommendation to purchase, sell, or hold a financial obligation, in that it does not comment as to market price or suitability for a particular investor.

Insurer Financial Enhancement Ratings are based on information furnished by the insurers or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any credit rating and may, on occasion, rely on unaudited financial information. Insurer Financial Enhancement Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information or based on other circumstances. Insurer Financial Enhancement Ratings are based, in varying degrees, on all of the following considerations:

1. Likelihood of payment-capacity and willingness of the insurer to meet its financial commitment on an obligation in accordance with the terms of the obligation;
2. Nature of and provisions of the obligations; and
3. Protection afforded by, and relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws affecting creditors' rights.

Insurer Financial Enhancement Ratings

AAA
An insurer rated 'AAA' has EXTREMELY STRONG capacity to meet its financial

37

commitments. 'AAA' is the highest Insurer Financial Enhancement Rating assigned by Standard & Poor's.

AA
An insurer rated 'AA' has VERY STRONG capacity to meet its financial commitments. It differs from the highest-rated insurers only in small degree.

A
An insurer rated 'A' has STRONG capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher-rated insurers.

BBB
An insurer rated 'BBB' has ADEQUATE capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the insurer to meet its financial commitments.

Insurers rated 'BB', 'B', 'CCC', and 'CC' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'CC' the highest. While such insurers will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions.

BB
An insurer rated 'BB' is LESS VULNERABLE in the near term than other lower-rated insurers. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or economic conditions that could lead to the insurer's inadequate capacity to meet its financial commitments.

B
An insurer rated 'B' is MORE VULNERABLE than the insurers rated 'BB', but the insurer currently has the capacity to meet its financial commitments. Adverse business, financial, or economic conditions will likely impair the insurer's capacity or willingness to meet its financial commitments.

CCC
An insurer rated 'CCC' is CURRENTLY VULNERABLE, and is dependent upon favorable business, financial, and economic conditions to meet its financial commitments.

CC
An insurer rated 'CC' is CURRENTLY HIGHLY VULNERABLE.

Plus (+) or minus (-):
Ratings from 'AA' to 'CCC' may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories.

R
An insurer rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision the regulators may have the power to favor one class of obligations over others or pay some obligations and not others. Please see Standard & Poor's issue credit ratings for a more detailed description of the effects of regulatory supervision on specific issues or classes of obligations.

N.R.
An issuer designated N.R. is not rated.

Back to Top

38

Back to Top

RATING OUTLOOK DEFINITIONS

A Standard & Poor's Rating Outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term. In determining a Rating Outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An Outlook is not necessarily a precursor of a rating change or future CreditWatch action.

- Positive means that a rating may be raised.
- Negative means that a rating may be lowered.
- Stable means that a rating is not likely to change.
- Developing means a rating may be raised or lowered.
- N.M. means not meaningful.

	Business Profile	Actual	AA	A	BBB	BB	<BB	Actual	AA	A
		FFO % of Average Debt						FFO/Intere		
Q1 2002	4	12.2%	6.0%	6.0%	7.0%	5.5%	12.0%	2.9	0.6	0.7
Q2 2002	4	21.5%	6.0%	6.0%	7.0%	5.5%	12.0%	4.3	0.6	0.7
Q3 2002	4	37.1%	6.0%	6.0%	7.0%	5.5%	12.0%	6.9	0.6	0.7
Q4 2002	4	35.3%	6.0%	6.0%	7.0%	5.5%	12.0%	7.1	0.6	0.7
Q1 2003	4	29.7%	6.0%	6.0%	7.0%	5.5%	12.0%	7.4	0.6	0.7
Q2 2003	4	24.4%	6.0%	6.0%	7.0%	5.5%	12.0%	6.7	0.6	0.7
Est. 2003	3	16.8%	5.5%	6.0%	6.0%	4.5%	9.5%	3.9	0.6	0.8
Est. 2004	3	23.8%	5.5%	6.0%	6.0%	4.5%	9.5%	5.0	0.6	0.8
Est. 2005	3	23.7%	5.5%	6.0%	6.0%	4.5%	9.5%	4.8	0.6	0.8
Est. 2006	3	22.2%	5.5%	6.0%	6.0%	4.5%	9.5%	4.6	0.6	0.8

41D

	st Coverage				Pretax Interest Coverage					
	BBB	BB	<BB	Actual	AA	A	BBB	BB	<BB	Actual
Q1 2002	1.1	0.9	1.8	2.6	0.6	0.7	1.1	0.9	1.3	55.1%
Q2 2002	1.1	0.9	1.8	2.1	0.6	0.7	1.1	0.9	1.3	54.0%
Q3 2002	1.1	0.9	1.8	2.2	0.6	0.7	1.1	0.9	1.3	51.2%
Q4 2002	1.1	0.9	1.8	2.4	0.6	0.7	1.1	0.9	1.3	53.7%
Q1 2003	1.1	0.9	1.8	2.1	0.6	0.7	1.1	0.9	1.3	51.9%
Q2 2003	1.1	0.9	1.8	2	0.6	0.7	1.1	0.9	1.3	52.9%
Est. 2003	1	0.8	1.3	2.1	0.6	0.6	1	0.7	1.1	53.3%
Est. 2004	1	0.8	1.3	3.1	0.6	0.6	1	0.7	1.1	53.4%
Est. 2005	1	0.8	1.3	3.6	0.6	0.6	1	0.7	1.1	51.8%
Est. 2006	1	0.8	1.3	3.7	0.6	0.6	1	0.7	1.1	51.8%

17

Total Debt/Total Capital %

	AA	A	BBB	BB	<BB
Q1 2002	37.5%	5.5%	6.5%	7.5%	7.0%
Q2 2002	37.5%	5.5%	6.5%	7.5%	7.0%
Q3 2002	37.5%	5.5%	6.5%	7.5%	7.0%
Q4 2002	37.5%	5.5%	6.5%	7.5%	7.0%
Q1 2003	37.5%	5.5%	6.5%	7.5%	7.0%
Q2 2003	37.5%	5.5%	6.5%	7.5%	7.0%
Est. 2003	42.0%	5.5%	5.5%	8.0%	6.0%
Est. 2004	42.0%	5.5%	5.5%	8.0%	6.0%
Est. 2005	42.0%	5.5%	5.5%	8.0%	6.0%
Est. 2006	42.0%	5.5%	5.5%	8.0%	6.0%

Electric Utilities

Deutsche Bank

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August 29, 2003

Ratings Card

Issuer	Deutsche Bank Secured Rating	Deutsche Bank Unsecured Rating	Deutsche Bank Outlook	Moody's Senior Secured Rating	Moody's Unsecured Rating	Moody's Outlook	S&P Senior Secured Rating	S&P Corporate Credit Rating	S&P Unsecured Rating	S&P Outlook
AEP Texas Central Co	Upper BBB	Middle BBB	S	A3	Baa1	S	BBB	BBB	BBB	S
AEP Texas North Co.	Upper BBB	Middle BBB	S	A2	A3	S	BBB	BBB	BBB	S
Alabama Power	Upper A	Middle A	S	A1	A2	S	A	A	A	S
Alliant Energy Corp.	—	Lower BBB	S	—	—	—	—	BBB	—	N
Alliant Energy Resources	—	Middle BB	S	—	Baa3	S	—	BBB+	BBB	N
Ameren	—	Upper BBB	S	—	A3	S	—	A-	BBB+	S
Ameren Generating	—	Middle BBB	S	—	Baa2	S	—	A-	A-	S
AmerenCIPS	Middle A	Lower A	N	A1	A2	S	A-	A-	BBB+	S
AmerenUE	Middle A	Lower A	N	A1	A2	S	A-	A-	BBB+	S
American Electric Power	—	Lower BBB	S	—	Baa3	S	—	BBB	BBB	S
Appalachian Power	Upper BBB	Middle BBB	S	Baa1	Baa2	S	BBB	BBB	BBB	S
Arizona PS	Upper BBB	Middle BBB	S	A3	Baa1	S	A-	BBB	BBB	S
Atlantic City Electric	Lower A	Upper BBB	N	A2	A3	**WN**	BBB+	BBB+	BBB	**WN**
Avista	Middle BBB	Lower BBB	N	Baa3	Ba1	N	BBB-	BB+	BB+	S
Baltimore G&E	Middle A	Lower A	S	A1	A2	S	A	A-	BBB+	S
Boston Edison	—	Middle A	N	—	A1	S	—	A	A	S
Carolina P&L	Middle A	Lower A	S	A3	Baa1	S	BBB+	BBB+	BBB+	N
Central Maine Power	Middle A	Lower A	S	—	A3	S	—	BBB+	BBB+	N
Cincinnati G&E	Upper BBB	Middle BBB	S	A3	Baa1	S	A-	BBB+	BBB	S
Cinergy	—	Lower BBB	S	—	Baa2	S	—	BBB+	BBB	S
Cleveland Electric Illuminating	Upper BBB	Middle BBB	S	Baa2	Baa3	**WN**	BBB	BBB	—	**WN**
Columbia Energy	—	Middle BBB	S	—	Baa2	S	—	BBB	BBB	S
Columbus Southern Power	Upper BBB	Middle BBB	S	A3	A3	S	BBB	BBB	BBB	S
Commonwealth Edison	Middle A	Lower A	S	A3	Baa1	S	A-	A-	BBB+	S
Conectiv	—	Middle BBB	N	—	Baa1	**WN**	A-	BBB+	BBB	**WN**
Connecticut L&P	Lower A	Upper BBB	P	A2	A3	N	A-	BBB+	BBB	S
Consolidated Edison	—	Lower A	S	—	A2	N	—	A	A-	S
Consolidated Edison of NY	—	Middle A	S	—	A1	N	—	A	A	S
Consolidated Natural Gas	—	Lower A	S	—	A3	N	—	BBB+	BBB+	S
Constellation Energy Group	—	Upper BBB	S	—	Baa1	S	—	A-	BBB+	S
Delmarva P&L	Upper BBB	Middle BBB	N	A2	A3	WN	A	A-	BBB+	WN
Detroit Edison	Lower A	Upper BBB	S	A3	Baa1	S	A-	BBB+	BBB	S
Dominion Resources	—	Upper BBB	S	—	Baa1	N	—	BBB+	BBB+	S
DTE Energy	—	Middle BBB	S	—	Baa2	S	—	BBB+	BBB	S
Duke Capital	—	Lower BBB	N	—	Baa3	S	—	BBB+	BBB	N
Duke Energy	Lower A	Upper BBB	N	A3	Baa1	S	A-	BBB+	BBB+	N
Energy East	—	Upper BBB	S	—	Baa2	S	—	BBB+	BBB	N
Entergy Arkansas	Upper BBB	Middle BBB	S	Baa2	Baa3	S	BBB+	BBB	—	S
Entergy Corp.	—	Middle BBB	S	—	—	—	—	BBB		S
Entergy Gulf States	Upper BBB	Middle BBB	S	Baa3	Ba1	S	BBB-	BBB-	—	S
Entergy Louisiana	Upper BBB	Middle BBB	S	Baa2	Baa3	S	BBB+	BBB	BBB-	S
Entergy Mississippi	Upper BBB	Middle BBB	S	Baa2	Baa3	S	BBB+	BBB	BBB-	S
Entergy New Orleans	Upper BBB	Middle BBB	S	Baa2	Baa3	N	BBB	BBB	—	S
Exelon	—	Upper BBB	S	—	Baa2	S	—	A-	BBB+	S
Exelon Generation	—	Middle BBB	S	—	Baa1	S	—	A-	A-	S
FirstEnergy	—	Lower BBB	S	—	Baa2	**WN**	—	BBB	BBB-	**WN**
Florida P&L	Upper A	Middle A	S	Aa3	A1	S	A	A	—	N
Florida Power	Middle A	Lower A	S	A1	A2	N	BBB+	BBB+	BBB+	S
FPL Group Capital	—	Lower A	S	—	A2	N	A	A	A-	N
FPL Group, Inc.	—	Lower A	S	—	—	—	—	A-	—	N
Georgia Power	Upper A	Middle A	S	A1	A2	S	A	A	A	S
Gulf Power	Upper A	Middle A	S	A1	A2	S	A+	A	A	S
Indiana Gas	Upper A	Middle A	S	—	Baa1	S	—	A-	A-	N
Indiana Michigan Power	Upper BBB	Middle BBB	S	Baa1	Baa2	S	BBB	BBB	BBB	S
Interstate P&L	Upper BBB	Middle BBB	S	A3	Baa1	S	A	A-	BBB+	S
Jersey Central P&L	Upper BBB	Middle BBB	S	A2	A3	**WN**	BBB+	BBB	BBB	**WN**
Kentucky Power	Upper BBB	Middle BBB	S	Baa1	Baa2	S	BBB	BBB	BBB	S
KeySpan Energy	—	Upper BBB	S	—	A3	S	—	A	A	N
Metropolitan Edison	Upper BBB	Middle BBB	S	A2	A3	**WN**	BBB+	BBB	BBB	**WN**
Michigan Con Gas	Lower A	Upper BBB	S	A2	—	S	BBB+	BBB+	BBB	S
Mississippi Power	Upper A	Middle A	S	Aa3	A1	S	A+	A	A	S
National Fuel Gas	—	Upper BBB	S	—	A3	N	—	BBB+	BBB+	S

Symbols/Legend:

▲	DBSI upgrade	**S**	Stable Outlook	**DIs**	Distressed
▼	DBSI downgrade	**N**	Negative Outlook	**WP**	Watch Positive
P	Positive Outlook	**D**	Developing/Uncertain Outlook	**WN**	Watch Negative

Holding companies are highlighted

Bolded ratings/letters signify agency change from previous month.

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	Deutsche Bank			Moody's			S&P			
Issuer	Secured Rating	Unsecured Rating	Outlook	Senior Secured Rating	Unsecured Rating	Outlook	Senior Secured Rating	Corporate Credit Rating	Unsecured Rating	Outlook
NiSource Finance Corp.	—	Lower BBB	S	—	Baa3	**S**	—	BBB	BBB	S
NiSource Inc.	—	Lower BBB	S	—	—	—	—	BBB	—	S
Northeast Utilities	—	Middle BBB	P	—	Baa1	N	—	BBB+	BBB	S
Northern Indiana PS	Upper BBB	Middle BBB	S	Baa1	Baa2	**S**	BBB+	BBB	BBB	S
Northern States Power - MN	Middle BBB	Lower BBB	P	A3	Baa1	S	BBB+	BBB	BBB-	WP
Northern States Power - WI	Middle BBB	Lower BBB	P	A3	Baa1	S	BBB+	BBB+	BBB	WP
NSTAR	—	Lower A	N	—	A2	S	—	A	A-	S
NY State E&G	Middle A	Lower A	S	Baa1	Baa2	S	A-	BBB+	BBB	N
Ohio Edison	Upper BBB	Middle BBB	S	Baa1	Baa2	**WN**	—	BBB	—	**WN**
Ohio Power	Upper BBB	Middle BBB	S	A3	A3	S	BBB	BBB	BBB	S
Orange & Rockland	—	Middle A	S	—	A1	N		A	A	S
PECO Energy	Middle A	Lower A	S	A2	A3	S	A	A-	BBB+	S
Pennsylvania Electric	Upper BBB	Middle BBB	S	A2	A3	**WN**	BBB+	BBB	BBB	**WN**
PEPCO Holdings Inc.	—	Middle BBB	N	—	Baa1	**WN**	—	BBB+	BBB	**WN**
Pinnacle West Capital	—	Lower BBB	S	—	Baa2	S	—	BBB	BBB-	S
Potomac Electric Power	Upper BBB	Middle BBB	N	A1	A2	**WN**	A-	BBB+	BBB	**WN**
PPL Capital Funding	—	Lower BBB	S	—	Baa3	S	—	—	BBB-	N
PPL Corp.	—	Lower BBB	S	—	Ba1	S	—	BBB-	—	N
PPL Electric Utilities	Upper BBB	Middle BBB	S	Baa1	Baa2	S	A-	A-	—	N
PPL Energy Supply	—	Lower BBB	S	—	Baa2	S	—	BBB	BBB	N
Progress Energy	—	Middle BBB	S	—	Baa2	S	—	BBB+	BBB	N
PS E&G	Lower A	Upper BBB	S	A3	Baa1	S	A-	BBB	—	S
PS Enterprise Group	—	Middle BBB	S	—	Baa2	WN	—	BBB	BBB-	S
PS of Colorado	Middle BBB	Lower BBB	P	Baa1	Baa2	S	BBB+	BBB	BBB-	WP
PS of New Hampshire	Lower A	Upper BBB	P	A3	Baa1	S	BBB+	BBB+	—	S
PS of Oklahoma	Upper BBB	Middle BBB	S	A3	Baa1	S	BBB	BBB	BBB	S
PSEG Energy Holdings	—	Lower BBB	N	—	Baa3	WN		**BB-**	**BB-**	S
PSEG Power	—	Middle BBB	S	—	Baa1	WN	—	BBB	BBB	S
PSI Energy	Upper BBB	Middle BBB	S	A3	Baa1	S	A-	BBB+	BBB	S
Puget Sound Energy	Middle BBB	Lower BBB	S	Baa2	Baa3	N	BBB	BBB-	BBB-	S
Rochester G&E	Middle A	Lower A	S	Baa1	Baa2	S	BBB+	BBB+	—	N
San Diego G&E	Middle A	Lower A	N	A1	A2	S	A+	A+	—	S
SCANA	—	Upper BBB	S	—	A3	S	—	A-	BBB+	S
Sempra Energy	—	Upper BBB	N	—	Baa1	S	—	A-	A-	S
South Carolina E&G	Middle A	Lower A	S	A1	A2	S	A-	A-	BBB+	S
Southern California Gas	Middle A	Lower A	N	A1	A2	S	A+	A+	A	S
Southern Company	—	Lower A	S	—	A3	S	—	A	A-	S
Southern Indiana G&E	Upper A	Middle A	S	A3	Baa1	S	A-	A-	BBB+	N
Southern Power Company	—	Upper BBB	S	—	Baa1	S	—	BBB+	BBB+	S
Southwestern Electric Power	Upper BBB	Middle BBB	S	A3	Baa1	S	BBB	BBB	BBB	S
Southwestern PS	Middle BBB	Lower BBB	P	—	Baa1	S	—	BBB	BBB	WP
System Energy Resources	Upper BBB	Middle BBB	S	Baa3	Ba1	S	BBB-	BBB-	BBB-	S
Tampa Electric	Lower A	Upper BBB	S	A3	Baa1	S	BBB-	BBB-	BBB-	**WN**
Toledo Edison	Upper BBB	Middle BBB	S	Baa2	Baa3	**WN**	BBB	BBB	BBB-	**WN**
Vectren Corp.	—	Upper BBB	S	—	—	—	—	A-	—	N
Vectren Utility Holdings	—	Upper BBB	S	—	Baa1	S	—	A-	A-	N
Virginia Electric & Power	Middle A	Lower A	S	A2	A3	S	A-	A-	BBB+	S
Western Massachusetts Electric	Lower A	Upper BBB	P	—	A3	S	—	BBB+	BBB+	S
Wisconsin Electric Power	Lower AA	Upper A	N	Aa2	Aa3	WN	A-	A-	A-	S
Wisconsin Energy	—	Middle A	N	—	A2	WN	—	BBB+	BBB+	S
Wisconsin P&L	Lower A	Upper BBB	S	A1	A2	S	A+	A	A-	S
High Yield										
Allegheny Energy	—	Middle BB	N	—	**B2**	WN	—	B	CCC+	N
Allegheny Energy Supply	—	Lower BB	N	—	**B3**	WN	—	B	CCC+	N
Aquila	—	Lower BB	N	—	Caa1	N	B	B	B	N
CenterPoint Energy	—	Middle BB	N	—	Ba1	N	—	BBB	BBB-	S
CenterPoint Energy Houston	Lower BBB	Upper BB	S	Baa2	Baa3	S	BBB	BBB	—	S
CenterPoint Energy Resources	—	Lower BBB	S	—	Ba1	N	—	BBB	BBB	S
CMS Energy	—	Lower BB	N	B2	B3	S	—	BB	B+	N
Consumers Energy	Upper BBB	Middle BBB	S	Baa3	Ba1	S	BBB-	BB	B+	N
Edison International	—	Lower BB	P	—	B3	S	—	B-	B-	D
Monongahela Power	Middle BBB	Lower BBB	N	**Ba1**	**Ba2**	WN	BB-	B	B-	N
Nevada Power	Lower BB	Distressed	N	Ba2	B1	S	BB	B+	B-	N
Oncor Electric Delivery	Middle BBB	Lower BBB	N	Baa1	Baa2	S	BBB	BBB	BBB-	N
Potomac Edison	Middle BBB	Lower BBB	N	**Ba1**	**Ba2**	WN	BB-	B	B-	N
Sierra Pacific Power	Lower BB	Distressed	N	Ba2	Ba2	S	BB	B+	B-	N
Sierra Pacific Resources	—	Distressed	DIS	—	B2	S	—	B+	B-	N
Southern California Edison	Middle BB	Lower BB	D	Ba2	Ba3	**WP**	BB	BB	B+	D
TECO Energy	—	Middle BB	S	—	Ba1	S	—	BBB-	BB+	**WN**
TXU	—	Middle BB	S	—	Ba1	N	—	BBB	BBB-	N
West Penn Power	Middle BBB	Lower BBB	N	—	**Ba1**	WN	—	B	B	N
Xcel Energy	—	Middle BB	P	—	Baa3	S	—	BBB	BBB-	WP

Symbols/Legend:

▲ DBSI upgrade
▼ DBSI downgrade
P Positive Outlook
S Stable Outlook
N Negative Outlook
D Developing/Uncertain Outlook
Dis Distressed
WP Watch Positive
WN Watch Negative

Holding companies are highlighted

Bolded ratings/letters signify agency change from previous month.

44

Except for the ECONOMIC COMMENT, this material has been prepared by the Fixed Income Trading Desk and is not the product of the Fixed Income Research Department.

Goldman Sachs

Medium Term Note & Capital Markets Update

for the week ending Friday, September 12th, 2003

U.S. Treasury Market

	Last Fri.	Mon.	Tue.	Wed.	Thu.	Fri.	Wk. Chg.	Chg. 12/31/02
3M LIBOR	1.1422	1.14	1.14	1.14	1.14	1.14	-0.0022	-0.24
2yr	1.722	1.761	1.689	1.632	1.696	1.621	-0.101	0.019
3yr	2.272	2.344	2.244	2.161	2.244	2.139	-0.133	0.179
5yr	3.269	3.345	3.251	3.144	3.253	3.14	-0.129	0.404
10yr	4.349	4.428	4.357	4.273	4.316	4.254	-0.095	0.438
30yr (5.375% of 2/31)	5.189	5.264	5.227	5.154	5.205	5.16	-0.029	0.382
DJIA	9503.3	9586.3	9507.2	9420.5	9459.8	9471.6	-31.7	1130.0

Economic Commentary

Plenty of Demand, but Few Jobs

The economic news underscored the message of the prior week: The economy is growing fast, but not fast enough to generate employment gains. On the demand side, the situation is rosy. Although total retail sales rose much less than expected in August, the downside surprise was mostly in the nominal value of surging vehicle sales. Excluding vehicles, retail sal increased 0.7% in August atop an upward-revised 0.9% gain in July. Upward revisions to both June and July pushed the annualized third-quarter trend for the component used to estimate total personal consumption (which strips out building materials as well as vehicles) above 10%. Fiscal stimulus and rapid debt growth appear to be fueling the rise in sales—suggesting that further large gains in retail sales may prove to be more difficult. The Fed's flow of funds report showed that household debt climbed at a 10.9% year-over-year pace in the second quarter. Up to now, this debt growth has not driven up household debt service burdens because interest rates have been falling. With rates stabilizing, however, the current borrowing pace implies a rapid rise in household debt service burdens. Most likely, this will not occur because households will prudently slow the pace of their borrowing. The improvement in demand is also evident in the July trade report. Although the trade deficit widened slightly to $40.3 billion from $40.0 billion in June, the real trade balance was still narrower than the second quarter average, suggesting that trade could contribute positively to growth this quarter. Both imports and exports rose sharply. Exports have now risen rapidly for three months in a row—a sign that demand outside the US has also strengthened. On the labor side, the data continue to disappoint. Initial claims rose by 3,000 to 422,000 in the latest week, pulling the four-week moving average up to 407,250, more than 10,000 above the trough reached in mid-August. Continuing claims also drifted higher, but are still below the levels reached in May and June. These data suggest that it is too soon to anticipate meaningful improvement in the monthly payroll employment data. The producer price report for August was predictably boring, notwithstanding the recent sharp runup in commodity prices. At the finished goods level, increases in energy prices and, to a lesser extent food prices, accounted for virtually all of the 0.4% increase in August; the core index rose only 0.1%. Likewise, the core index of partly processed (intermediate) goods rose only 0.1%. Over the past six months, this index has changed relatively little.

The FOMC to Maintain the Status Quo

We expect little change at next week's FOMC meeting. Policy will remain locked on hold and the balance of the risks statement will remain asymmetric overall, with Fed officials worried about the risk that the disinflation process could persist. The statement is likely to be tweaked, but only modestly. Fed officials will likely acknowledge the strengthening of final demand. However, they also will point to the lack of improvement in the labor market as a justification for the asymmetric balance of the risks statement. The concluding line from the June statement is likely to be retained: *In these circumstances, the Committee believes that policy accommodation can be maintained for a considerable period.* In fact, Fed officials may wish to flesh this out with what they mean by the word "considerable" given the market's view that tightening is likely to commence by the second quarter of 2004. The recent comments of Fed officials such as Governor Bernanke suggest that the monetary authorities do not anticipate having to start the tightening cycle soon.

Another $87 Billion Here...

...And soon it will add up to real money, to paraphrase late Senator Everett Dirksen. The size of President Bush's request for an additional $87 billion of funds for Iraq, which includes the costs associated with keeping a large contingent of troops there and for rebuilding the Iraqi infrastructure, stunned many observers. Undoubtedly, the President will get the funds that he seeks. But the consequence will be an even bigger budget deficit. We have raised our fiscal 2004 deficit forecast to $525 billion from $475 billion earlier. We also now estimate that the likely ten-year cumulative deficit will be about $5.5 trillion, up from $4.5 trillion previously. The deficit issue is now on the radar screen of bond investors. They will be looking to see whether the policy of "guns and butter" will persist or whether the Bush administration is now prepared to make some tough choices in terms of taxes and other areas of discretionary spending. Significant upward pressure on bond yields, however, is unlikely soon. As long as the FOMC remains friendly, there should be sufficient liquidity available to accommodate both the public and private sectors.

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45

Bond Rally Sensible; Seeking Better Entry

Note: The following comments reflect trading views and may differ from our longer-term interest rate forecast.

In recent days, the US fixed income market has shed some of its fears of a runaway economy. Surprisingly weak labor market data for August were the catalyst for this shift in sentiment. The market's initial rally following the August retail sales report suggests that many participants still harbor fears of undue strength. Although we have not capitalized on this move in formal recommendations, it fits with our view that the current strength is unlikely to persist much beyond year-end. That said, we are disinclined to chase the market, especially given the potential for consumer price data to surprise on the upside. We will look for significant pullbacks to provide better entry points.

Economic Releases and Other Events:

Date	Time	Indicator	GS	Consensus	Last Report
Mon Sep 15	**8:30**	**Business Inventories (Jul)**	**-0.3%**	**-0.1%**	**+0.1%**
	8:30	**Current Account Balance (Q2)**	**-$143.0bn**	**-$138.0bn**	**-$136.1bn**
	9:15	**Industrial Production (Aug)**	**+0.5%**	**+0.2%**	**+0.5%**
	9:15	**Capacity Utilization (Aug)**	**74.8%**	**74.6%**	**74.5%**
Tue Sep 16	**8:30**	**Consumer Price Index (Aug)**	**+0.3%**	**+0.3%**	**+0.2%**
		Ex Food & Energy	**+0.2%**	**+0.2%**	**+0.2%**
Wed Sep 17	**8:30**	**Housing Starts (Aug)**	**+3.0%**	**-2.5%**	**+1.5%**
	14:00	**Federal Budget Balance (Aug)**	**-$85.0bn**	**-$78.0bn**	**-$54.7bn**
Thu Sep 18	**10:00**	**Leading Indicators (Aug)**	**+0.4%**	**+0.4%**	**+0.4%**
	12:00	**Philadelphia Fed Survey (Sep_**	**+20.0%**	**+18.5%**	**+22.1%**

- **Empire State Manufacturing Survey (Mon, Sep 15—8:30)**
- **Homebuilders' Survey (Tues, Sep 16—13:00)**
- **FOMC Meeting Results (Tue, Sep 16—14:15)**
- **Treasury 2-Year Note Announcement (Wed, Sep 17—11:00)**
- **August 12 FOMC Minutes (Thu, Sep 18—14:00)**

Fixed Rate Update

Over $5.3bn of new fixed-rate paper priced this week as new issue activity continues at a moderate pace thus far this month **(1) Coca-Cola HBC Finance B.V. (A3/A)** issued $500mm 10yr Senior Notes at +92bps (5.125% coupon) and $400mm 12yr Senior Notes at +120bps (5.50% coupon). **(2) GECC (Aaa/AAA)** priced $750mm 3yr Fixed-Rate Global Notes at +57bps (2.75% coupon). GECC also concurrently priced $1.75mm 3yr FRNs (see below for details). **(3) Carolina Power and Light (A3/BBB)** was in the market with a dual-tranche offerin consisting of $400mm 10yr First Mortgage Bonds, which came at +85bps (5.125% coupon) and $200mm 30yr First Mortgage Bonds, which priced at +102bps (6.125% coupon). **(4) HBOS Plc (Aa2/AA)** wrote $750mm of 5yr Senior Notes at +60. **(5) American General Finance (A1/A+)** issued $500mm 7yrs at +89 v.s. 08/10 UST. In emerging market space, **(6) Federative Republic of Brazil (B2/B+)** tapped the market to print a $750mm reopening of its 10% Global Bonds due 2011. The issue priced at a discount to yield 10.66%. Goldman Sachs served as a joint-bookrunner on the transaction. **(7) Ambev (Baa3/BBB-)** wrote $500mm of 10yr Senior Notes at 8.75%.

Swap Market Spreads (vs. 3 month LIBOR)

	2 year	3 year	5 year	10 year
Mid-Market Swap Spreads:	+29.50	+43.50	+40.50	+43.50
Last Week:	+31.50	+45.50	+45.50	+46.50

Indicative New Issue Fixed Rate Spreads

UST-Fri. close	2.14%	3.14%	3.70%	4.25%	5.16%
Industrial	**3 year**	**5 year**	**7 year**	**10 year**	**30 year**
AAA	30-35	45-50	55-60	65-70	90-95
AA	40-45	55-60	80-85	95-100	105-110
A	60-70	80-90	100-110	120-130	140-150
BBB	100-110	125-135	150-160	165-175	180-190
Utility	**3 year**	**5 year**	**7 year**	**10 year**	**30 year**
AAA	40-45	50-55	55-60	60-65	70-80
AA	60-65	65-70	75-80	100-105	110-120
A	75-85	85-95	95-105	110-120	120-130
BBB	110-120	130-140	145-155	160-170	175-185

IPCo CP Debt - Average Spread Over/(Under) LIBOR BBA US$ Fi›
01/01/2003 - 06/30/2003

(+) = higher than benchmark
(-) = lower than benchmark
- does not include bid-ask spread of trader

Data	Total
Average of Banc America Sec	0.04%
Average of Merrill Lynch	0.05%
Average of CS First Boston	0.05%
Average of Wells Fargo-Overnight	~~0.86%~~
Average of US Bank-Overnight	0.80%

Cost over LIBOR for CP

364-DAY

CREDIT AGREEMENT

DATED AS OF MARCH 19, 2003

AMONG

IDAHO POWER COMPANY,

THE LENDERS,

KEYBANK NATIONAL ASSOCIATION,
AS SYNDICATION AGENT,

WELLS FARGO BANK, N.A.,
U.S. BANK NATIONAL ASSOCIATION
AND
WACHOVIA BANK, NATIONAL ASSOCIATION,
AS CO-DOCUMENTATION AGENTS,

BANK OF AMERICA, N.A.,
AS SENIOR MANAGING AGENT,

AND

BANK ONE, NA
AS SWING LINE LENDER AND ADMINISTRATIVE AGENT

BANC ONE CAPITAL MARKETS, INC.
AND
KEYBANK NATIONAL ASSOCIATION
AS CO-LEAD ARRANGERS AND JOINT BOOK RUNNERS,

4944212 01702090

48

Cost over LIBOR through bankline of credit

PRICING SCHEDULE

	A/A2	A-/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	<BBB-/Baa3
APPLICABLE MARGIN	**LEVEL I STATUS**	**LEVEL II STATUS**	**LEVEL III STATUS**	**LEVEL IV STATUS**	**LEVEL V STATUS**	**LEVEL VI STATUS**
Eurodollar Rate	*0.540%*	*0.750%*	*0.850%*	*1.075%*	*1.30%*	*1.875%*
Floating Rate	*0%*	*0%*	*0%*	*0%*	*0%*	*0.500%*

APPLICABLE FEE RATE	**Level I Status**	**Level II Status**	**Level III Status**	**Level IV Status**	**Level V Status**	**Level IV Status**
Facility Fee	*0.110%*	*0.125%*	*0.150%*	*0.175%*	*0.200%*	*0.375%*

For the purposes of this Schedule, the following terms have the following meanings, subject to the final paragraph of this Schedule:

"Level I Status" exists at any date if, on such date, the Borrower's Moody's Rating is A2 or better *or* the Borrower's S&P Rating is A or better.

"Level II Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status and (ii) the Borrower's Moody's Rating is A3 or better *or* the Borrower's S&P Rating is A- or better.

"Level III Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status or Level II Status and (ii) the Borrower's Moody's Rating is Baa1 or better *or* the Borrower's S&P Rating is BBB+ or better.

"Level IV Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status, Level II Status or Level III Status and (ii) the Borrower's Moody's Rating is Baa2 or better *or* the Borrower's S&P Rating is BBB or better.

"Level V Status" exists at any date if, on such date, (ii) the Borrower has not qualified for Level I Status, Level II Status, Level III Status or Level IV Status and (ii) the Borrower's Moody's Rating is Baa3 or better *or* the Borrower's S&P Rating is BBB- or better.

"Level VI Status" exists at any date if, on such date, the Borrower has not qualified for Level I Status, Level II Status, Level III Status, Level IV Status or Level V Status.

"Moody's Rating" means, at any time, the rating issued by Moody's Investors Service, Inc. and then in effect with respect to the Borrower's senior unsecured long-term debt securities without third-party credit enhancement.

"S&P Rating" means, at any time, the rating issued by Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc., and then in effect with respect to the Borrower's senior unsecured long-term debt securities without third-party credit enhancement.

IDAHO POWER COMPANY
EFFECTIVE EMBEDDED COST OF
LONG-TERM DEBT
At December 31, 1993
($000's)

Line No	(1) Class and Series	(2) Date of Issue	(3) Principal Amount Issued	(4) Principal Amount Outstanding	(5) Premium	(6) Discount	(7) Underwriter Commission	(8) Expense of Issue		(9) Net Proceeds Received	(10) Annual Interest Requirements	(11) Effective Cost
	First Mortgage Bonds:											
1	5 1/4% Series, due 1996	4/1/66	$20,000	$20,000	-	-	$144.0	$62.3		$19,793.7	$1,050.0	5.305%
2	8.65 % Series, due 2000	1/1/90	80,000	80,000	-	100.0	520.0	4,056.8		75,323.2	6,920.0	9.187
3	9.50 % Series, due 2021	1/14/91	75,000	75,000	-	375.0	656.3	303.6		73,665.1	7,125.0	9.672
4	9.52 % Series, due 2031	8/19/91	25,000	25,000	-	-	112.5	45.8		24,841.7	2,380.0	9.581
5	8 % Series, due 2004	3/25/92	50,000	50,000	-	400.0	337.5	2,422.9		46,839.6	4,000.0	8.540
6	8 3/4% Series, due 2027	3/25/92	50,000	50,000	-	187.5	437.5	125.8		49,249.2	4,375.0	8.883
7	6.40 % Series, due 2003	4/28/93	80,000	80,000	-	-	500.0	3,692.3		75,807.7	5,120.0	6.754
8	7.50 % Series, due 2023	4/28/93	80,000	80,000	-	614.4	600.0	3,692.3		75,093.3	6,000.0	7.990
9	5.33 % Series, due 1998	9/1/93	30,000	30,000	-	-	150.0	182.1	(a)	29,667.9	1,599.0	5.390
10	Total First Mortgage Bonds		490,000	490,000		1,676.9	3,457.8	14,584.0		470,281.4	38,569.0	8.201
	Pollution Control Revenue Bonds:											
11	5.90% Series, due 2003	9-01-73	27,000	25,050	-	189.0	219.2	113.5		24,528.3	1,478.0	6.025
12	6.00% Series, due 2007	4-01-77	24,000	24,000	-	180.0	180.0	138.0		23,502.0	1,440.0	6.127
13	7.25% Series, due 2008	8-01-78	4,360	4,360	-	-	32.7	63.6		4,263.7	316.1	7.414
14	7 5/8% Series 1983, due 2013	12-15-83	60,500	60,500	-)-	-	681.0	1,277.6		66,141.4	5,192.6	7.851
15	7 5/8% Series 1984, due 2014	12-13-84	7,600	7,600	-)	-						
16	8.30% Series, due 2014	12-20-84	49,800	49,800	-	-	498.0	1,737.2		47,564.8	4,133.4	8.690
17	12.25% Series due 2011 - Redemption		-	-	-	-	-	227.7		(227.7)	-	-
18	Total Pollution Control Revenue Bonds		173,260	171,310	-	369.0	1,610.9	3,557.5		165,772.6	12,560.1	7.577
19	Praire Power REA Notes	(b)		1,833.6	-	-	-	-		1,833.6	52.4	2.857
20	TOTAL DEBT CAPITAL		$663,260	$663,143.6		$2,045.9	$5,068.6	$18,141.5		$637,887.6	$51,181.5	8.024%

(a) - Estimated
(b) - Includes various dates of issue and maturity - some at 2.0% that mature quarterly and some at 5.0% that mature monthly

EXHIBIT NO. 11
CASE NO. IPC-E-94-5
D. BOWERS, IPCO
PAGE 2 OF 4

IDAHO POWER COMPANY
EFFECTIVE EMBEDDED COST OF
PREFERRED STOCK
At December 31, 1993

($000's)

Line No	(1) Series	(2) Date of Issue	(3) Principal Amount Issued	(4) Principal Amount Outstanding	(5) Premium	(6) Expense of Issue	(7) Net Proceeds Received	(8) Annual Dividend Requirements	(9) Effective Cost
	Preferred Stocks:								
1	4 % Series ...	1944-56	$21,500	$17,750.6	$230.1	$416.1	$17,564.6	$710.0	4.042%
2	7.68% Series	9-27-72	15,000	15,000.0	17.5	33.9	14,983.6	1,152.0	7.688
3	8.375% Series	11-6-91	25,000	25,000.0	-	303.5	24,696.5	2,093.8	8.478
4	Flexible Auction Series (A)	11-6-91	50,000	50,000.0	-	1,052.1	48,947.9	2,000.0	4.086
5	7.07% Series	7-1-93	25,000	25,000.0		308.8 (B)	24,691.2	1,767.5	7.158
6	Serial Preferred Stock Redemption Costs					3,917.7	(3,917.7)		
7	TOTAL PREFERRED STOCK		$136,500	$132,750.6	$247.6	$6,032.1	$126,966.1	$7,723.3	6.083%

(A) Rate is reset on the basis of an Auction conducted each 49 days. The average effective rate over the last cycle for A rated utility companies was 4.0%.
(B) Estimated

5

EXHIBIT NO. 11
CASE NO. IPC-E-94-5
D. BOWERS, IPCO
PAGE 3 OF 4

In its June 1991 issue, Money Magazine listed Idaho Power Company as one of its 50 best "clean and green investments". In 1993 the U. S. Fish and Wildlife Service presented Idaho Power Company with the agency's "Director's Corporate Wildlife Stewardship Award". The award is the highest honor the agency can give a corporation.

Q. What is the status of Idaho Power Company's bond rating?

A. The following are the current First Mortgage Bond (FMB), Preferred Stock, and Pollution Control Revenue Bond (PCRB) ratings for Idaho Power Company:

	Moody's	Standard & Poors	Duff & Phelps	Fitch
FMB	A-2	A	A+	A+
Preferred	a3	A-	A	A
PCRB	a3	A-	-	-

Q. Have the Company's ratings been under pressure in recent years?

A. Yes. Idaho Power Company currently maintains a middle A rating on its First Mortgage Bonds, and a low A rating on its pollution control revenue bonds and preferred stock from both Moody's and Standard & Poor's. Standard & Poor's, as recently as October 1992, lowered the first mortgage bond, pollution control revenue bond, and preferred stock ratings of the Company.

Idaho Power
Indicative Rates as of August 7, 2003

Issuer	Maturity Date	Par Value (mil.)	AMT	Current Coupon
Humboldt Co-Nevada	12/1/2014	$49.8	Non-AMT	8.30%

Indicative Cash Market Fixed Rates as of August 7, 2003

Maturities	MMD[1]	Aaa/AAA Insured[2]	Spread to MMD	A2/A[2]	Spread to MMD
2014	4.09	4.50	0.41	5.00	0.91
2023	4.88	5.30	0.42	5.80	0.92
2033	5.02	5.40	0.38	5.90	0.88

[1] High Grade, general market names (non-AMT)

[2] 2023 and 2033 Maturities assume NC10.

Indicative Cash Market
Floating Rates as of August 7, 2003

Insured Auction Rate (Non-AMT)	
7-day	0.73 - 0.78
35-day	0.83 - 0.88

Note: BMA Reset on August 6 at 0.73%

Current Market Conditions - Thursday August 7, 2003

The tax-exempt yield curve remains steep on the short end and quite flat on the long end of the curve. As of 8/7/03 1-year MMD was 1.00% and 30-year MMD was at 5.02%, a spread of 402 bp. At 7/31/03 1-year MMD was .92% and 30-year MMD was at 4.95%, a spread of 403 bp. After a few weeks of significant volatility, the fixed income market has stabilized, although at higher yields. Moreover, the tax-exempt market has continued to perform well relative to its taxable counterpart.

BANK ONE

53

Idaho Power
Indicative Rates as of July 31, 2003

Issuer	Maturity Date	Par Value (mil.)	AMT	Current Coupon
Humboldt Co-Nevada	12/1/2014	$49.8	Non-AMT	8.30%

Indicative Cash Market Fixed Rates as of July 31, 2003

Maturities	MMD[1]	Aaa/AAA Insured[2]	Spread to MMD	A2/A[2]	Spread to MMD
2014	4.04	4.49	0.45	5.05	1.01
2023	4.81	5.25	0.44	5.80	0.99
2033	4.95	5.40	0.45	6.00	1.05

[1] High Grade, general market names (non-AMT)

[2] 2023 and 2033 Maturities assume NC10.

Indicative Cash Market
Floating Rates as of July 31, 2003

Insured Auction Rate (Non-AMT)	
7-day	0.75 - 0.80
35-day	0.85 - 0.95

Note: BMA Reset on July 30, 2003 at 0.85%

Current Market Conditions - Thursday July 31, 2003

The tax-exempt yield curve continues to be relatively steep on the short end and rather flat on the long end of the curve. As of 7/31/03 1-year MMD was .92% and 30-year MMD was at 4.95%, a spread of 403 bp. As of 7/24/03 1-year MMD was at .90% and 30-year MMD was at 4.74%, a spread of 384 bp. The tax-exempt market continues to be volatile and as a result of the weakening, credit spreads have widened. Although the fixed-income market has sold off within the last couple of days, the tax-exempt market has outperformed the taxable market. New issuance for the next 30 days in the tax-exempt market is expected to be moderate with about $ 8.6 billion coming to market (negotiated and competitive transactions), which is about the 30 and 60 day average.

Humboldt Bonds - Estimated Interest Rate

Principle	49,800,000.00	
Expense of Issue	2,389,181.50	From Below
Net Proceeds	47,410,818.50	

Average 10 Year BMA Interest Rate	3.04%
Plus: Average spread of Auction Rate over BMA Index	0.25%
Plus: Broker Dealer Fees	0.25%
Plus: Annual Insurance Premium	0.105%
Adjusted Interest Rate	3.65%
Effective Interest Rate (on Proceeds)	3.83%

$\left.\begin{matrix}0.25\% \\ 0.25\% \\ 0.105\%\end{matrix}\right\}$ .61

Expense of Issue:

Call Premium	1,494,000.00	
Insurance up-front premium	546,181.50	From Below
Underwriter's Fee	249,000.00	
Legal and Other Fees	100,000.00	
Total	2,389,181.50	

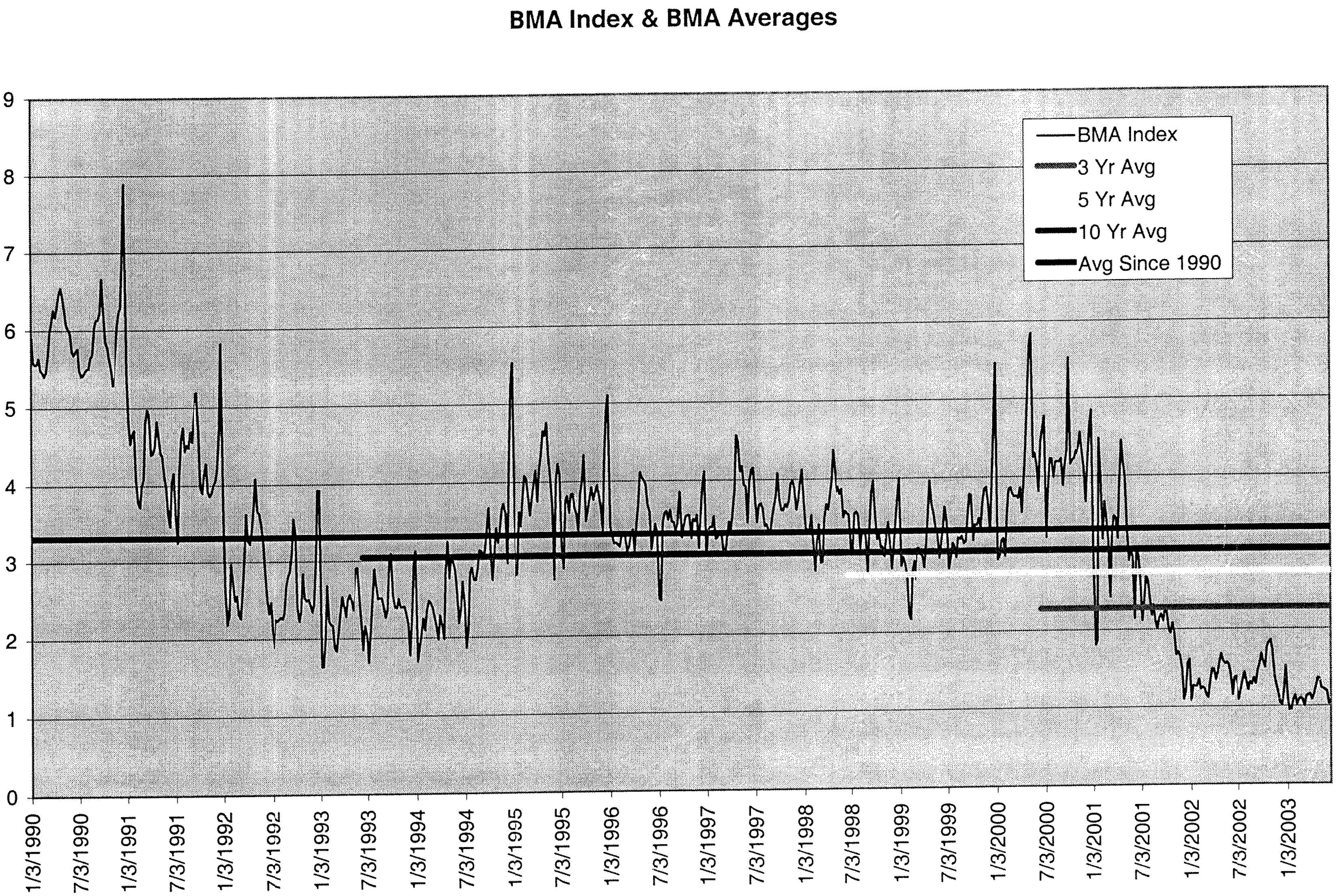
Assumed index rate for 2024 bonds	5.25%
Principle Repayment	49,800,000.00
Interest Repayments	52,290,000.00
Total Debt Service	102,090,000.00
Upfront Premium Rate	
Insurance up-front premium calculation	546,181.50

IDAHO POWER COMPANY
TAX-EXEMPT BONDS
RATE COMPARISON TO BMA INDEX

Date	BMA Index	AM Falls Rate	AM Falls Spread	Port of Morrow Rate	Port of Morrow Spread	Sweetwater-GS Rate	Sweetwater-GS Spread	Sweetwater-MS Rate	Sweetwater-MS Spread
Average Spread over BMA IPC Bond Lifes -			1.08		0.94		-0.07		-0.12
Average BMA = 3 years			2.28						
Average BMA = 5 years			2.75						
Average BMA = 10 years			3.04						
Average BMA = Life of Index (Since 1990)			3.31						

Falling Water due @ 5pm

	AM Falls Rate		Port of Morrow Rate		Sweetwater-GS Rate		Sweetwater-MS Rate	
Historical	Rate	Spread	Rate	Spread	Rate	Spread	Rate	Spread
2003	2.64	1.52	2.24	1.12	1.24	0.11	1.16	0.04
2002	2.77	1.40	2.50	1.12	1.61	0.24	1.56	0.18
2001	3.75	1.14	3.74	1.13	2.45	-0.16	2.45	-0.16
Since Issue (~~4/2000~~)	3.47	1.08	3.27	0.94	2.90	-0.07	2.86	-0.12
BMA Rate + Historical Spread								
Using 3 Year BMA	3.36	1.08	3.22	0.94	2.21	-0.07	2.17	-0.12
Using 5 Year BMA	3.83	1.08	3.69	0.94	2.67	-0.07	2.63	-0.12
Using 10 Year BMA	4.12	1.08	3.99	0.94	2.97	-0.07	2.93	-0.12
Using life of BMA - 1990	4.39	1.08	4.25	0.94	3.24	-0.07	3.20	-0.12


BMA Index & BMA Averages
BMA Index
3 Yr Avg
5 Yr Avg
10 Yr Avg
Avg Since 1990
9
8
7
6
5
4
3
2
1
0
1/3/1990
7/3/1990
1/3/1991
7/3/1991
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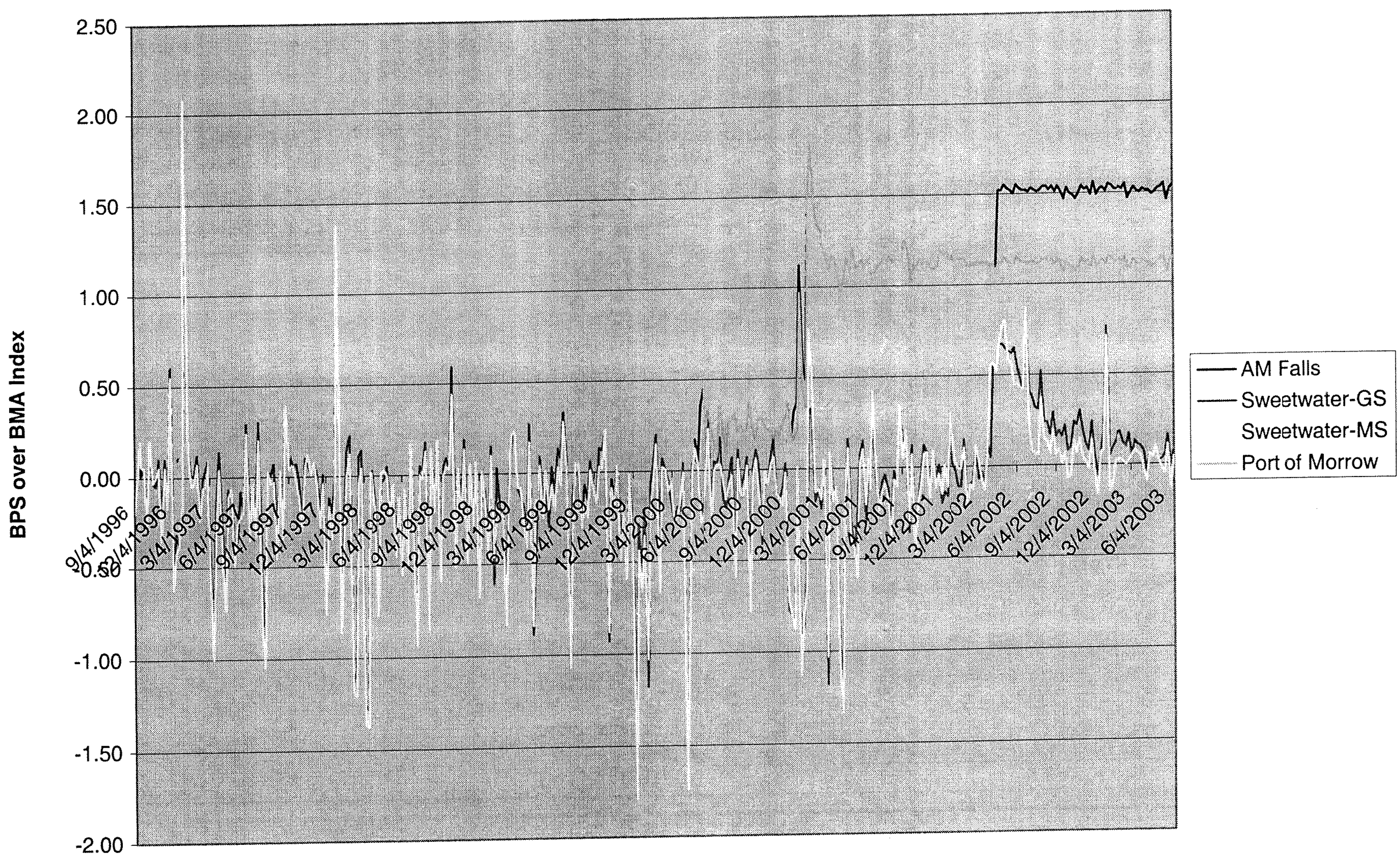
57

IPCo variable Rate Bonds vs BMA Index



59

NEW PRODUCT UPDATE

Moody's Announces Intent to Abolish Preferred Stock Rating Scale

November 28, 2000

SALOMON SMITH BARNEY
A member of citigroup

Moody's Announces Plan to Abolish Preferred Stock Rating Scale[1]

Yesterday, Moody's announced its intention to abolish its separate rating scale for preferred stock and to rate preferred stock and hybrid securities, including trust preferred securities such as Salomon Smith Barney's ("SSB's") TRUPS®, on a single consolidated debt rating scale. **Moody's proposed move to a single scale is not a credit event and does not reflect any change in Moody's view of the risk characteristics of preferred stock and other hybrid instruments, but is instead intended to increase the comparability of senior debt, subordinated debt, hybrid and preferred securities.**

Moody's Existing Preferred Stock and Debt Rating Scales

Unlike Moody's debt rating scale, which emphasizes investors' recovery rates in bankruptcy, Moody's existing preferred stock rating scale focuses on the likelihood that investors will receive timely payments of dividends and inherently anticipates a lower recovery rate in bankruptcy. However, as discussed in our *New Product Update* dated December 8, 1999, Moody's has become increasingly concerned that investors do not appreciate the primary difference between the agency's preferred stock rating scale and its debt rating scale. Therefore, while a security with a current preferred rating of "a1" anticipates greater losses in bankruptcy than a debt instrument rated "A1", Moody's fears that investors may use these ratings interchangeably.

Prospective Notching Practices for Issuers

To determine ratings for different classes of an issuer's liabilities, Moody's will first assign a primary rating to the issuer's most important class of liabilities, then rate other liabilities in relation to that rating.

For example, for investment-grade non-financial corporate issuers, Moody's will generally assign a senior unsecured debt rating, then rate other liabilities in relation to the senior unsecured rating:

Liability	Rating Relative to Senior Unsecured
▶ *Senior secured debt*	plus 1 notch
▶ *Senior unsecured debt*	0 notches
▶ *Subordinated debt, including junior subordinated debt*	minus 1 notch
▶ *Hybrid securities, including US-style TRUPS (cumulative, dated securities)*	minus 1 notch
▶ *Preferred stock/preference shares, including European- and Asian-style SPV preferred securities (non-cumulative, perpetual securities)*	minus 2 notches

The above notching guidelines should apply to all bond market sectors rated by Moody's, although the primary rating type will vary by industry sector.[2] For example, Moody's will generally first assign "deposit" ratings to banks and "insurance financial strength" ratings to insurance companies, and then determine ratings for subordinated debt, hybrid and preferred securities using the same notching differentials as above.

Moody's expects that hybrid securities, including US-style TRUPS, will likely be treated as subordinated debt in the event of the issuer's bankruptcy, and will therefore generally assign the same rating to hybrid securities as that assigned to subordinated debt. However, for issuers with significant amounts of senior debt, Moody's may rate hybrid securities two notches below senior debt.

Implication for Existing Issues

Moody's decision is not final, and the agency is currently soliciting feedback from the financial community on the impending change. However, in all likelihood, Moody's will formally abolish its preferred stock rating scale sometime in early 2001. At that time, the agency will announce adjustments to all outstanding ratings to reflect the debt rating scale in a single press release. Although the adjustments may ostensibly result in "downgrades" of two notches for certain issuers, they do not reflect any fundamental change in the creditworthiness of the issuers.

SSB will continue to monitor the latest rating agency developments regarding TRUPS and will keep issuers apprised of any developments.

Capital Markets	FI New Products Group – New York	FI New Products Group – London
Howard Hiller 212-723-6098	212-723-6029 John Dickey	44-207-986-8978
Yukari Saegusa 212-723-6101	Peter Jurdjevic Stanley Louie	Jennifer Piekut
C.J. Arrigo 212-723-6095	Adam Dohrenwend David Rosenwaks	James Revell

1 Similarly, in February of 1999, S&P introduced a single ratings scale for both preferred and debt instruments that replaced the previously separate preferred stock and debt ratings scales. See SSB's "*New Product Update: S&P Distributes Press Releases Relating to its Treatment of Preferred and Capital Securities*", dated February 17, 1999.

2 An exception to this general rule is the leveraged finance corporate issuer sector. Because issuers in this sector have complex and highly differentiated capital structures, Moody's believes that uniform notching guidelines could be misleading.

Moody's Investors Service
Global Credit Research

November 2000 **Rating Methodology**

Priority of Claim Standing Committee
Rating Symbols and Definitions Standing Committee

Contact	Phone
New York	
Richard Cantor	1.212.553.1653
Jerome Fons	
Brian Oak	
Patrick Finnegan	
Michael Rowan	
Michael Foley	
Chris Mahoney	
Ken Pinkes	
London	
Chester Murray	44.20.7772.5454
Michel Madelain	
Tokyo	
Tom Keller	81.3.3593.0922
Hong Kong	
Julia Turner	852.2916.1120

Notching for Differences in Priority of Claims and Integration of the Preferred Stock Rating Scale

Invitation to Comment

Contents

Summary

This *Rating Methodology* outlines ongoing refinements to Moody's notching practices for debt and preferred stock of a single business enterprise or issuer. We believe our analytical approach achieves comparability in the meaning of ratings across the widest possible range of corporate securities and also provides appropriate guidance for the Structured Finance and Public Finance markets. Our notching practices are intended to result in expected loss rates of similarly rated securities that are roughly the same, regardless of whether the bonds are secured, unsecured or subordinated claims on individual issuers. Moreover, to expand the range of comparability, we expect to rate preferred stock on an expected-loss basis as well, using our traditional debt rating symbols. We therefore plan to abolish the separate rating scale for preferred stock we have used in the past.

continued on page 3

A final determination on the issues outlined in this Rating Methodology will occur in early 2001. It is expected that rating adjustments for all outstanding preferred ratings will be made at that time and announced in a single press release. We expect that other changes to existing ratings will be issuer and issue specific, and will be addressed over the remainder of 2001 through ongoing credit monitoring. Moody's encourages interested parties to submit comments to the Priority of Claim Standing Committee to the attention of Patrick Finnegan, 99 Church Street, NY, NY, 10007, or at patrick.finnegan@moodys.com.

Since the various liabilities of a single corporate enterprise generally share the same (or nearly the same) probability of default, differences in their expected loss rates are determined by their relative priority of claim - and, hence, relative expected loss severities - in bankruptcy. Our notching practices translate these differences in expected losses to differences in ratings - in a manner that is consistent with the differences in historical loss rates associated with different rating categories. This general methodology is applied universally throughout the corporate sector, but practical aspects of its implementation differ between the investment-grade and leveraged-finance sectors.

For speculative-grade companies, where default is a clear and present danger, Moody's intensively analyzes each issuer's capital structure and bond covenants. Given the wide variability in capital structures that we see in the leveraged-finance sector, our expected-loss approach often leads to large differences in notching for relative seniority from one issuer to another.

In the investment grade sector, however, there is less of a basis for making such distinctions across issuers because one cannot reasonably predict an issuer's future capital structure - and hence the relative recovery prospects of its liabilities - at the time of default. Analysts of investment-grade issuers, therefore, generally rely on the average experience reflected in our defaulted bond recovery database to predict the relative recovery (and loss severity) of different classes of debt. As a result, notching practices in the investment-grade sector tend to be more uniform, based on average debt recovery statistics, without specific reference to individual issuers.

Typical Notching Practices for Investment-Grade Issuers

- If, as is generally the case, an investment-grade issuer's largest class of debt is unsecured, a Moody's rating committee first assigns a senior unsecured debt rating and then contemplates the ratings of its other liabilities in relation to the senior unsecured rating.
- Absent any issuer-, region- or industry-specific information that might alter the relative recovery assumptions, an investment-grade issuer's

  - Secured debts are generally rated one notch above its senior unsecured debt rating.

  - Subordinated debts (including junior and senior subordinated debts) are generally rated one notch below its senior unsecured debt rating.

  - Hybrid (debt/equity) security ratings are based upon the issue's expected seniority in bankruptcy, which is often the same as subordinated debt.

  - Preferred stock, which in the past has been rated on an entirely different scale, will soon be rated on the same debt rating scale. Cumulative preferred issues will generally be rated one notch below subordinated debt. Further, given the small differential in expected loss, Moody's will consider eliminating the existing notching differential between cumulative and noncumulative preferred.

  - Holding company debt is generally rated at or below the lowest rated debt security that would be assigned at the principal operating company.

Notching Practices for Leveraged-Finance Corporate Issuers[1]

- The largest class of rated liabilities for speculative-grade issuers may be either secured bank debt, secured bond debt, unsecured senior debt, subordinated debt, or preferred stock.
- A Moody's rating committee first assigns a "senior-implied" rating to a speculative grade issuer, which is the rating that would apply *if* the enterprise had a single class of liabilities and a consolidated legal entity structure. The enterprise's specific various liabilities are then rated above or below its senior implied rating based on their relative default probabilities and their relative expected loss severities in default.

[1] *See Moody's Special Comment, "Moody's Analytical Framework for Speculative Grade Ratings," May 1999.*

- Since these entities often have complex and highly differentiated capital structures, uniform notching guidelines could be misleading in this sector.
- The expected-loss methodology does, however, impose substantial discipline on notching across each company's liability structure.

  - The rating assigned to each of a company's liabilities is a function of the company's senior implied rating, the expected credit loss of that issue relative to the company's other liabilities, and the uncertainty introduced by the overall complexity of the capital structure. As a result, the par-weighted average of the ratings assigned to all of the company's liabilities will be equal to, or lower than, its implied senior rating.

  - Expected differences in loss severity generally give rise to wider notching differentials for companies with Ba3, single-B and Caa senior-implied ratings than for Ba1 or Ba2 issuers.[2] (Notching widens for companies rated Ba3 or below because the historical default rates in the B and Caa rating ranges vary less - on a percentage change basis - from one rating notch to another than they do in the Ba portion of the rating scale.)

What Is Notching?

Notching refers to the general practice of making rating distinctions among the different liabilities of a single entity or of closely related entities. When an entity has a number of different classes of debt outstanding, Moody's analysts generally employ a two-step rating process. First, they assign a rating to an issuer's most important class of liabilities or to a weighted average of its liabilities. Then, they decide how to rate the issuer's various debt instruments in relation to this initial rating. This two-step rating process helps ensure analytical consistency across an issuer's liability structure.

- In the investment-grade, nonfinancial corporate sector, analysts generally first assign a senior unsecured debt rating to an issuer, and then determine the company's senior secured debt, subordinated debt, and preferred stock ratings in relation to its unsecured debt rating. In the speculative-grade sector, the process is similar although the benchmark is the "senior-implied" rating, the rating that would be assigned if the company had a single class of debt and a consolidated legal entity structure.
- In the banking sector, analysts generally first assign a deposit rating (which itself may depend upon the sovereign's rating), and then assign ratings for debt and preferred securities issued at the level of the operating company or holding company. Since deposit obligations frequently benefit from third-party official support in times of stress, rating differentials for unsupported obligations can be significantly greater than the guidelines provided.
- In the insurance sector, analysts generally assign an insurance financial strength rating that speaks to the probability the insurer will fulfil its insurance policy obligations, and then ratings are assigned to the debt and preferred securities issued at the level of the operating company or holding company.
- In the structured finance sector, analysts generally first assign a rating to an entire securitization structure as if it were to be issued as a single-tranche security, and then decide how the ratings on individual tranches of the securitization should relate to the hypothetical single-tranche rating.
- In the public finance sector, analysts generally first assign a general obligation rating to a municipality, and then decide the ratings of its specific bond issues, which may carry less or more security than a general obligation pledge. Many sectors within Public Finance, although tax-exempt, resemble traditional corporate issuers and or structured transactions and therefore many of the same notching practices are employed. Examples of these are not-for-profit hospitals and universities as well as single family and multi-family tax-exempt housing transactions.

While this *Rating Methodology* focuses on the nonfinancial corporate sector, the general principles that are discussed here are relevant to virtually all bond market sectors rated by Moody's.

Moody's Historical Notching Practices for Corporate Securities

Moody's ratings have always placed considerable weight on relative priority of claim. Until relatively recently, however, notching practices were necessarily subjective, since there was no quantitative basis for deciding whether a particular difference in seniority was significant enough to merit a rating distinction, or whether it should give rise to a one-notch, or even a two-notch, rating distinction.

2 While this guideline is directly relevant for subordinated and preferred stock securities, notching for secured claims should generally widen later in the rating scale, when the issuer's rating moves from Ba3 to B1.

The notching practices developed during the early 1980s generally reflected a desire to recognize each subsequent layer of subordination with a correspondingly lower rating. For investment-grade companies, an issuer's senior unsecured debt was generally rated one notch lower than its secured debt, its subordinated debt was one notch below its senior debt, and its junior subordinated debt was one notch below its senior subordinated debt. However, for below-investment-grade issuers, notching for differences in priority of claim was often wider (by an extra rating notch) because we felt that as the likelihood of default increased, more emphasis should be place on priority of claim. At that time, we never considered the possibility that the changes in the width of the rating bands as one moves along the rating scale could influence the degree of notching.

Three key developments in the late 1980s subsequently led to changes in Moody's notching practices.

1. Moody's began compiling and analyzing its authoritative data set on corporate bond defaults and recoveries.
2. The meaning of Moody's corporate bond ratings steadily migrated away from a system that emphasized relative default rates, intrinsic financial strength, and the quality of the promise to one that emphasizes relative expected loss rates.
3. With the development of the junk bond market, most speculative-grade companies no longer had the simple balance sheets of fallen angels (with a preponderance of senior unsecured debt); rather, they employed highly complex and varied capital structures.

By the 1990s, historical data could be used to estimate the differences in expected-loss rates across instruments with different priorities of claim. Moreover, the significance of those differences in terms of expected loss could be compared to the differences in historical loss rates generally associated with different Moody's bond ratings. The pieces were now in place to develop simple notching guidelines that enhance consistency in the meaning of ratings across different classes of liabilities.

However, as the capital structures of speculative-grade companies became increasingly complex and varied, it became clear that investors in the leveraged finance market would be better served by an in-depth, expected-loss analysis of each component of a company's capital structure. Moody's Leveraged-Finance Group subsequently developed an analytical approach to notching that utilizes company-specific information, while achieving consistency in the meaning of ratings in terms of expected loss across companies.[3]

Historical Differences in Loss Severity by Class of Debt

Moody's June 1999 *Special Comment*, "Debt Recoveries for Corporate Bankruptcies," reports recovery rates on a wide variety of debt securities for 155 issuers with more than one class of debt outstanding at the time of default. This data can be used to calculate the average percentage difference in recovery rates between two classes of debt securities for individual issuers. In Figure 1, we apply these average percentage differences to the mean defaulted senior unsecured bond recovery price of 49 cents per face dollar, as reported in Moody's January 2000 *Special Comment*, "Historical Default Rates of Corporate Bond Issuers, 1920-1999."[4]

Table 1

Average Recovery and Loss Severity
(as a percent of par value)

	Recoveries	Loss Severities
Sr. Secured	64%	36%
Sr. Unsecured	49%	51%
Sr. Subordinated	28%	72%
Subordinated	22%	78%
Jr. Subordinated	17%	83%
Preferred Stock	5%	95%

[3] *See Moody's Special Comment, "Moody's Analytical Framework for Speculative-Grade Ratings," May 1999.*
[4] *We recognize that our data is heavily weighted toward the U.S. corporate experience. To the extent that the loss severity experience is different in other sectors or regions, the application of these notching principals will be adjusted where appropriate. This year, Moody's has published extensive country-specific studies - for the UK, Germany, and France - which analyze the relative standing of different claimants in corporate bankruptcy and the potential implications for differences in expected loss severity. See "Bankruptcy & Ratings: A Leveraged Finance Approach for Europe - UK versus France and Germany," Moodys Special Comment, March 2000.*

How do these averages compare to each other? Table 2 presents average loss severity recovery rates for different classes of debt *relative* to the average recovery rate on senior unsecured debt. For example, in default, senior secured debt loses 30% (which equals (51%-36%)/51%) less on average than senior unsecured debt; whereas, preferred stock loses 85% more on average than senior unsecured debt.

Table 2:
Relative Average Loss Severity
(relative to the average loss severity on senior unsecured debt)

Sr. Secured	-30%
Sr. Unsecured	0%
Sr. Subordinated	40%
Subordinated	52%
Jr. Subordinated	62%
Preferred Stock	85%

This relative loss severity data underpin the notching guidelines Moody's employs in the investment-grade corporate sector. For investment-grade credits, since the risk of default will likely remain low for many years into the future, it is very difficult to anticipate what a company's capital structure will look like when it eventually defaults. Therefore, despite the high variance in relative recovery rates that exists in the historical data, Moody's analysts generally rely heavily on historical average recovery rate data when notching the securities of investment-grade issuers for differences in priority of claim.

In contrast, for speculative-grade issuers, default is much more likely in the near future, capital structures and covenants tend to lock in a claimant's position, and analysts have a much better fix on the company's probable capital structure at the time of default. As a result, the average relative recovery statistics reported in Figure 1 are less relevant to notching practices in the speculative-grade sector. For these credits, Moody's analysts base their notching practices on company-specific analyses of relative loss severity.

Regardless of the source of data for the expected loss severity expectations, the following questions still need to be addressed:

- Are these differences in expected-loss severity large enough to warrant rating distinctions?
- If rating distinctions are appropriate, should secured and subordinated obligations carry ratings that differ from the issuer's unsecured rating by one or more rating notches?
- Should notching conventions be constant or should they vary with the issuers' placement on the rating scale?

An Expected-Loss Framework for Notching

Relative loss severity data is not enough, by itself, to determine the appropriate amount of notching. Within an expected-loss framework for the meaning of ratings, notching guidelines are a function of both expected loss severity and expected default probability. Table 3 outlines the mechanics of how - in three steps - the expected-loss framework can be used to derive notching guidelines.

Step 1. Identify the historical default rates of debt issuers with different senior unsecured debt ratings.

Step 2. Compare the expected loss rates of various debt instruments for issuers that carry these senior unsecured debt ratings.

Step 3. Assign the same rating to all securities that have similar expected loss rates.

Our estimates of expected default rates are derived from Moody's latest corporate bond default study, which reports the historical default frequencies associated with different senior unsecured ratings over a wide variety of investment horizons. Although all potential investment horizons are factored into the analysis, for simplicity, the analysis presented in this *Rating Methodology* is based exclusively on the ten-year cumulative default rate statistics.

For each initial senior unsecured narrow rating category (with the 1,2,3 rating modifiers), we estimate the expected cumulative default frequency by interpolating the historical default experience for the broad rating categories shown in column (a).[5] Expected-loss rates for an issuer's senior unsecured debt are then derived by multiplying the modified default rates by 51%, which is the average loss severity on defaulted senior unsecured bonds. Similarly, expected-loss rates for an issuer's senior secured debt and subordinat-

[5] *In 1982, Moody's introduced rating modifiers (i.e., Aa1, Aa2, etc.) and currently reports cumulative default statistics by modified rating category for horizons up to eight years. Statistically useful, cumulative default rates for these broad categories are thus not available for the ten-year horizon. Based on patterns observed in the cumulative default rates for shorter horizons, we interpolated the broad category default rates to derive ten-year default rates for modified ratings.*

ed debt are tabulated (according to an issuer's unsecured debt ratings) by multiplying the unsecured default rates by the average loss severity of 36% and 78% on secured and subordinated debt, respectively.

Regardless of an issuer's senior unsecured rating, the percentage difference in expected loss rates between secured and unsecured debt is 30%, which equals [(51%-36%)/51%]. Similarly, regardless of an issuer's senior unsecured rating, the percentage difference in expect loss rates between senior unsecured and senior subordinated debt is 40%, which equals [(71%-51%)/51%]. However, as shown in Table 3 and Charts 1 and 2, these percentage differences translate into absolute expected-loss-rate differences that vary from one rating category to another.

The expected-loss rates presented in Table 3 imply different notching criteria at different rating levels. For example, consider an issuer with a Baa2 senior unsecured debt rating. Ten-year expected-loss rates for its senior secured debt and subordinated debt are 1.52% and 3.28%, respectively. These loss rates are extremely close to the expected-loss rates for the senior unsecured obligations of issuers rated Baa1 (1.51%) and Baa3 (3.10%), respectively. This analysis for Baa2-rated issuers suggests that secured debt should be rated one notch above senior unsecured debt, and subordinated debt should be rated one notch below senior unsecured debt. The tight grouping of loss rates at the senior subordinated, subordinated and junior subordinated levels further suggests that no rating distinctions be made across obligations with these standings. Moreover, these results indicate that preferred stock should be rated one notch below an issuer's subordinated debt.[6]

Table 3

10-Year Average Cumulative Default Rates: 1970-1999		Smoothed 10-Year Cumulative Default Rates: 1970-1999		Expected-Loss on Sr. Secured Debt	Expected Loss on Sr. Unsec. Debt	Expected Loss on Sr. Sub. Debt	Expected-Loss on Sub. Debt	Expected-Loss on Jr. Sub. Debt	Expected-Loss on Preferred Stock
Sr. Unsec. Ratings	(a)	Sr. Unsec. Ratings	(b)	(c) = (b) x 36%	(d) = (b) x 51%	(e) = (b) x 72%	(f) = (b) x 78%	(g) = (b) x 83%	(h) = (b) x95%
Aaa	0.77%	Aaa	0.77%	0.28%	0.39%	0.55%	0.60%	0.64%	0.73%
Aa	0.98%	Aa1	0.89%	0.32%	0.45%	0.63%	0.69%	0.74%	0.84%
A	1.55%	Aa2	0.98%	0.35%	0.50%	0.70%	0.76%	0.81%	0.92%
Baa	4.41%	Aa3	1.08%	0.39%	0.55%	0.77%	0.83%	0.89%	1.02%
Ba	20.67%	A1	1.33%	0.48%	0.68%	0.95%	1.03%	1.10%	1.26%
B	43.43%	A2	1.54%	0.55%	0.79%	1.10%	1.19%	1.28%	1.46%
Caa	62.17%	A3	1.78%	0.64%	0.91%	1.27%	1.38%	1.48%	1.69%
		Baa1	2.94%	1.06%	1.51%	2.11%	2.28%	2.44%	2.79%
		Baa2	4.22%	1.52%	2.16%	3.02%	3.28%	3.51%	4.00%
		Baa3	6.06%	2.18%	3.10%	4.34%	4.70%	5.03%	5.74%
		Ba1	11.76%	4.23%	6.02%	8.42%	9.12%	9.77%	11.13%
		Ba2	19.13%	6.89%	9.79%	13.69%	14.84%	15.89%	18.11%
		Ba3	31.12%	11.20%	15.92%	22.27%	24.14%	25.84%	29.46%
		B1	37.78%	13.60%	19.33%	27.04%	29.31%	31.38%	35.77%
		B2	43.17%	15.54%	22.09%	30.90%	33.49%	35.86%	40.88%
		B3	49.34%	17.76%	25.24%	35.31%	38.27%	40.97%	46.71%
		Caa1	56.51%	20.34%	28.91%	40.45%	43.84%	46.93%	53.51%
		Caa2	61.99%	22.31%	31.72%	44.37%	48.09%	51.49%	58.69%
		Caa3	68.00%	24.48%	34.68%	48.96%	53.04%	56.44%	64.60%

[6] *In previous research, we have shown that, when applying an expected-loss perspective, there is generally little basis for making rating distinctions between cumulative and noncumulative preferred issuers. See "Preferred Stock Dividend and Credit Risk," Moody's Special Report, December 1994.*

Chart 1: 10-Year Expected Loss Rates - Investment Grade Issuers

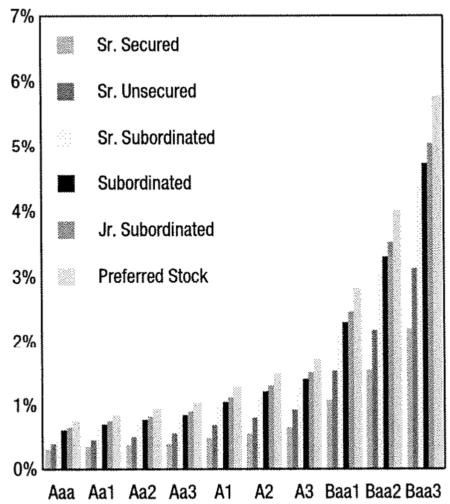
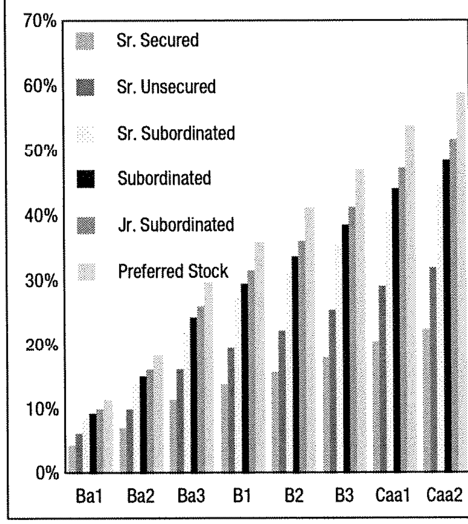


Chart 2: 10-Year Expected Loss Rates - Speculative Grade Issuers



While the general rules presented here - one notch up for secured and one notch down for subordinated - are generally consistent with the Table and the Charts, there are two notable exceptions.

First, in the highest (Aaa and Aa) rating categories, a pure expected-loss approach might imply a two- (or more) notch distinction, rather than the proposed one-notch rating differentials. However, as discussed in other reports, Moody's ratings are not based purely on expected-loss rates. In particular, Moody's assigns extra weight in the meaning of ratings to default risk (relative to severity of loss) for investment-grade credits, because the risk of default is very low.[7] Hence, at these high rating levels, ratings are adjusted upward or downward from senior unsecured levels by only one notch to reflect differences in priority of claim.[8]

Second, in the lower portion of the speculative range (issuers with senior unsecured debt rated Ba3 or lower), a pure expected-loss approach again suggests a two- (or more) notch differential is sometimes necessary to account for differences in priority of claim.[9] If ratings are intended to indicate relative expected-loss rates, then notching for subordination and preferred stock should generally be wider for issuers rated Ba3 or below, and notching for security should be wider for issuers rated B1 or below. Note that this recommendation is somewhat at variance with our historical practice, in which we generally widened notching differentials as soon as an issuer's rating fell below investment grade.

Notching for Hybrid Securities and Holding Company Debt

The general approach laid out in this Special Comment can also be applied to the ratings assigned to hybrid securities and holding company debt. In each case, the analyst estimates the expected loss severity of the instrument to be rated and compares that loss severity to a reference security that is rated - either the senior unsecured debt or senior implied rating of the principal operating company or business enterprise. Differences in expected loss severity are translated into rating notches by referencing an expected-loss matrix such as Table 3.

7 See "The Evolving Meaning of Moody's Bond, Ratings," Moody's Special Comment, August 1999.
8 Furthermore, the historical default rates for Aaa- and Aa-rated issuers are not very precisely estimated because so few have defaulted over a ten-year horizon. There is, therefore, less justification for a purely quantitative approach to relative ratings determination in this part of the rating scale.
9 For example, consider an issuer with senior unsecured debt rated B2. The expected losses on its secured and subordinated obligations are 15.54% and 33.49%, respectively. These values are very close to the losses one might expect to incur on the senior unsecured obligations of issuers rated Ba3 (15.92%) and Caa2 (31.72%), respectively at the senior unsecured level. The analysis suggests that the secured debt of an issuer rated B2 at the senior unsecured level should be rated two notches above its unsecured debt, and its subordinated debt should be rated three notches lower than its senior unsecured debt. In contrast to the one-notch adjustments recommended for most of the rating scale, two-notch adjustments will be more common for issuers holding senior unsecured debt rated B1 or lower.

66

Hybrid securities are structured securities that generally have both debt and equity characteristics from a balance sheet perspective. However, from an investor's perspective, a security's credit quality is determined by its default probability and its expected loss severity in default. Since the expected default frequency on most hybrid securities is the same as that of the issuing company's other debt securities, then hybrid's should be notched based on their expected priority in claim in bankruptcy. In most cases, we expect that hybrids will be treated like subordinated bonds in bankruptcy and so they will usually carry the same credit rating. However, some hybrid issuer's have a preponderance of more senior securities that could negatively affect the recovery of their hybrid securities in default. In such cases, the recovery of those securities is unlikely to differ meaningfully from the preferred stock of the same issuer; hence the rating could be the same as that of preferred stock.

Holding company debt is generally structurally subordinate to all debt and preferred stock of the principal operating company. Holding company debt will generally be rated at or below the lowest rated instrument of the principal operating company. The guiding principle is that the degree of subordination is determined by the extent to which structural elements distance an obligation from the entity's operating assets and economic value. An evaluation of an issuer's corporate structure, its other obligations, the obligations of its subsidiaries, the role of third party support available to subsidiary creditors (e.g. banks or operating utilities) and the covenant protections contained in the holding company obligations are all factored into the notching decision.

Notching Practices in the Leveraged Finance Sector

The notching guidelines discussed above are appropriate if one assumes that the expected-loss severity on a company's debt security equals the historical loss severity for that type of instrument. We generally make this assumption when analyzing investment-grade credits, because these companies are highly unlikely to default for many years, and it is generally very difficult to foresee their likely capital structure at the time of default.

In the leveraged-finance sector, however, analysts have a much better fix on a company's likely capital structure at the time of default. Moreover, capital structures in this sector are highly varied, so that loss severity on similar debt instruments are likely to vary significantly from one company to another. As a result, Moody's leveraged finance analysts undertake a detailed analyses of the capital structure of each speculative-grade company and the relative expected loss severity of each component of its liabilities.

The notching process for speculative-grade credits starts with the establishment of a senior-implied rating, which assumes that an enterprise's obligations are collapsed into a single generic class of senior debt.[10] As such, the senior-implied rating reflects the expected credit loss (i.e. default and loss severity) of that single class of debt. As stated earlier, Moody's generally expects that a company will default on all of its obligations at approximately the same time, so the key factor that distinguishes the rating of a company's "senior" and "junior" debt are differences in expected loss severity in the event of a default.[11] The notching process for speculative-grade credits distributes the expected loss severity that is incorporated in the senior implied rating across the enterprise's capital structure. In developing its opinion about this distribution, Moody's considers the relative size of the different classes of debt, the contractual terms of each specific instrument, and the company's likely capital structure and enterprise value in a distressed scenario, and the average historical recovery rates incorporated in this report.

Consider the following stylized example. Suppose a company has $500 million in total debt, comprised of $250 million in senior-secured bank loans and $250 million in subordinated bonds. The Moody's analyst estimate of the distressed value of the firm and or its assets in a default scenario is $250 million. The average loss severity on all the debt is therefore 50%. Suppose further than the expected loss severities on the bank debt and bonds are 25% and 75% respectively.[12]

[10] See Moody's Special Comment, "Moody's Analytical Framework for Speculative-Grade Ratings," May 1999.
[11] For enterprises with complex corporate structures, expected default rates may vary across debt instruments as well.
[12] On average, the price of secured bank debt trades at about 70% of par shortly after default, although the long-term recovery value may be closer to 90% or 95% of principal. In assigning ratings, Moody's analysts generally focus more on the long-term expected recoveries than post-default expected trading prices. For notching practices to be consistent, it is important that relative recovery rates for different instruments be estimated on a like basis, either long-term expected recoveries or post-default trading prices.

If this company had a 10-year cumulative default probability of 19%, its 10-year expected-loss rate would be 9.5% (=19%x50%), which would be consistent (from Table 3) with a Ba2 senior-implied rating. The expected-loss rate on its bank debt and bonds would be 4.8% and 14.3%, respectively, which (from Table 3) correspond to Ba1 and Ba3 ratings, respectively. In this case, the senior-secured bank debt would be rated one notch higher than the senior-implied rating, and the subordinated bonds are rated one notch lower than the senior implied rating.

On the other hand, if the company's default probability were 42%, its 10-year expected-loss rate would be 21% (=42%x50%), which would be consistent (from Table 3) with a B2 senior-implied rating. The expected-loss rate on its bank debt and bonds would be 10.5% and 31.5%, respectively, which (from Table 3) correspond to Ba2 and Caa2 ratings, respectively. In this case, a pure expected-loss analysis would suggest that the senior-secured bank debt should be rated three notches higher than the senior-implied rating, and the subordinated bonds should be rated three notches lower than the senior implied rating. However, because Moody's somewhat overweights default probability relative to loss severity in the meaning of its ratings, we would probably assign ratings to this issuer that would result in a four- or five-notch rating spread, rather than the six-notch spread that exists between Ba2 and Caa2.

These two examples highlight two key implications of the use of an expected loss approach to notching in the speculative-grade sector. One, the assignment of senior-implied ratings and the expected-loss analysis help achieve consistency in our notching practices. Since the expected-loss rate on a firm's total liabilities is the par-weighted average of the expected loss rates on each of its liabilities, the senior-implied rating is a weighted average of the ratings of its various debt instruments.[13] Two, wider notching is appropriate for companies with Ba3 or lower senior-implied ratings than for firms rated higher.[14] Given our historical practice of applying wider notching differentials to all below-investment-grade issuers, narrower notching differentials for Ba1 and Ba2 issuers are likely in the future for priority of claim purposes.

Making the Adjustment

In those cases where rating changes are called for, based on the guidelines presented here, Moody's will make those adjustments and their rationales transparent to the capital markets. Changes to our preferred stock ratings will be made on a single date and reported in a single press release. As the preferred stock is brought into the long-term debt rating system, downgrades of two notches may occur. These adjustments are not meant to reflect any fundamental change in the credit worthiness of these obligations. We expect that other changes to existing ratings will be issuer and issue specific, and will be addressed over the remainder of 2001 through ongoing credit monitoring.

[13] To the extent that the complexity of a company's capital structure increases uncertainty about the performance of its individual liabilities and reduces the company's financial flexibility, its senior implied rating may be in fact higher than the par-weighted average of the ratings on its individual liabilities.

[14] As indicated in Table 3, this rule of thumb can be applied directly when notching relative to an issuer's rating for its subordinated obligations. Notching for secured claims, however, should generally widen somewhat later in the rating scale, when the issuer's rating moves from Ba3 to B1.