SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): June 17, 2004

The Williams Companies, Inc.

(Exact name of registrant as specified in its charter)

Delaware	1-4174	73-0569878
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

One Williams Center, Tulsa, Oklahoma	74172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 918/573-2000

Not Applicable

(Former name or former address, if changed since last report)

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Item 7. Financial Statements and Exhibits.

Williams files the following exhibit as part of this report:

Exhibit 99.1 Copy of Williams' slide presentation dated June 17, 2004.

Item 9. Regulation FD Disclosure.

The Williams Companies, Inc. wishes to disclose for Regulation FD purposes its slide presentation, filed herewith as Exhibit 99.1, utilized during a public conference call and webcast held the morning of June 17, 2004.

Pursuant to the requirements of the Securities Exchange Act of 1934, Williams has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE WILLIAMS COMPANIES, INC.

Date: June 17, 2004

/s/ Brian K. Shore

Name: Brian K. Shore
Title: Secretary

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INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
99.1	Copy of Williams’ slide presentation utilized during the June 17, 2004, public conference call and webcast.

Exhibit 99.1

Williams

Williams Power Tutorial

June 17, 2004

Forward Looking Statements

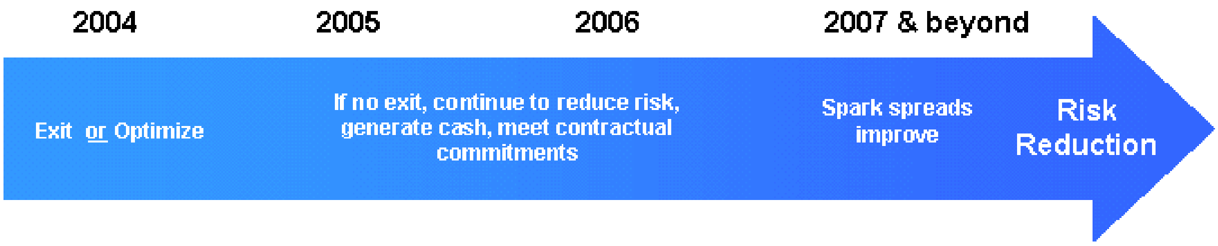
Williams' reports, filings, and other public announcements might contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" with in the meaning of Private Securities Litigation Reform Act of 1995. You typically can identify forward-looking statements by the use of forward-looking words, such as "anticipate," "believe," "could," "continue," "estimate," "expect," "forecast," "may," "plan," "potential," "project," "schedule," "will," and other similar words. These statements are based on our intentions, beliefs, and assumptions about future events and are subject to risks, uncertainties, and other factors. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, other factors could cause our actual results to differ materially from the results expressed or implied in any forward-looking statements. Those factors include, among others:

- changes in general economic conditions and changes in the industries in which Williams conducts business;
- changes in federal or state laws and regulations to which Williams is subject, including tax, environmental and employment laws and regulations;
- the cost and outcomes of legal and administrative claims proceedings, investigations, or inquiries;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including our credit ratings and general economic conditions;
- the level of creditworthiness of counterparties to our transactions;
- the amount of collateral required to be posted from time to time in our transactions;
- the effect of changes in accounting policies;
- the ability to control costs;
- the ability of each business unit to successfully implement key systems, such as order entry systems and service delivery systems;
- the impact of future federal and state regulations of business activities, including allowed rates of return, the pace of deregulation in retail natural gas and electricity markets, and the resolution of other regulatory matters;
- changes in environmental and other laws and regulations to which Williams and its subsidiaries are subject or other external factors over which we have no control;
- changes in foreign economies, currencies, laws and regulations, and political climates, especially in Canada, Argentina, Brazil, and Venezuela, where Williams has direct investments;
- the timing and extent of changes in commodity prices, interest rates, and foreign currency exchange rates;
- the weather and other natural phenomena;
- the ability of Williams to develop or access expanded markets and product offerings as well as their ability to maintain existing markets;
- the ability of Williams and its subsidiaries to obtain governmental and regulatory approval of various expansion projects;
- future utilization of pipeline capacity, which can depend on energy prices, competition from other pipelines and alternative fuels, the general level of natural gas and petroleum product demand, decisions by customers not to renew expiring natural gas transportation contracts;
- the accuracy of estimated hydrocarbon reserves and seismic data; and
- global and domestic economic repercussions from terrorist activities and the government's response to such terrorist activities.

In light of these risks, uncertainties, and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time that we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

The Road Ahead

1Q '04 Earnings Call



Key Points

1Q '04 Earnings Call

- Expected to generate positive cash flow from operations
  - Significantly hedged cash flow through 2010
- Significant natural gas business
- Merchant upside in West and Northeast
- Working to reduce risk through forward power sales
- Operational and environmental obligations contracted to third parties
- Resolving legacy issues
- Strong commercial and financial capabilities
- Continued efforts to increase transparency

Today's Discussion

- **Overview of natural gas operations**
- **Updated regional power information**
  - Positions
  - Fuel management
  - Short- and long-term fundamentals
  - Opportunities
- **Updated financials**
- **Q&A**

Key Takeaways

- Daily / hourly power plant optimization creates significant value above the forward curve
- Sustained $5-$10 spark spreads are not realistic
- Long-term fundamentals favor tail risk
- Steam plants in California economically and operationally viable
- Confident in cash flow guidance

Natural Gas

Physical Natural Gas

- **Average annual requirements**
  - 2.8 Bcf/d with peak of 3.5 Bcf/d
    - 40% for Power
      - 20% power-plant supply
      - 20% third-party transactions
    - 60% for Williams' core businesses
- **Transportation**
  - 2.5 Bcf/d
    - 30% for gas marketing (including power-generation fuel)
    - 70% for Williams' core businesses
- **Storage**
  - 17 Bcf
    - 67% for gas marketing (including power-generation fuel)
    - 33% for Williams' core businesses
- **Improving market liquidity and credit**

E&P Gas Marketing

- **Total volumes marketed**

	MMBtu/d
Piceance Basin	255,000
San Juan Basin	150,000
Powder River	140,000
Arkoma	15,000
Green River	7,000
Total	**567,000**

- **Transportation**

	MMBtu/d
Colorado Intrastate Gas Co.	309,000
Wyoming Interstate Pipeline	287,000
Trailblazer Pipeline	202,000
Transcolorado Gas Transmission	100,000
Northwest Pipeline	50,000
Questar Pipeline	30,000
Transwestern Pipeline	25,000
Total	**1,003,000**

- **Storage - 5 Bcf at Clay Basin**

Midstream Fuel Management

- **Supply fuel and shrink**

	MMBtu/d
San Juan (includes X-haul)	270,000
Rockies	160,000
Gulf Coast	140,000
Canada	200,000
Total	**770,000**

- **Transportation**

	MMBtu/d
Mobile Bay	362,250

Transco Agency Service (FS Business)

- 190,000 MMBtu/d no-notice obligation
- 8 customers (Mid-Atlantic and Northeast)
- Notification has been given to terminate
- April 1, 2005 contracts terminate
- FERC settlement implications
- 1.3 Bcf of Eminence storage

Third-Party Marketing

- **Transportation**

	MMBtu/d
Colorado Interstate	34,500
Questar	30,000
Southern Star Central	29,500
Columbia	15,000
Transco SW VA	15,000
Alliance Pipeline	10,000
Total	**134,000**

- **Storage**

	Bcf
Union Gas Dawn	2.0
NGPL Gulf Coast	1.6
NGPL Mid Continent	0.8
Total	**4.4**

- **Third-party sale obligations - 65,000 MMBtu/d**

Power

Characteristics

- **Asset-based power business with long-term contractual commitments**
  - 6 tolling contracts
    - Approximately 7,700 megawatts
    - Approximately $400 million in annual demand charges
  - 8 key offsetting contracts
  - Over-the-counter (OTC) hedges

Estimated coverage of demand payment = 101% cumulative through 2010*

* As of 3/31/04. See slide 88 for more detailed information.

Types of Hedging Transactions

- **Resale of tolling rights**
- **Full requirements**
- **Forward power sales**
- **Mid-market structured sales**

Note: Appropriate quantity of gas purchased (if needed) at time of power hedge

Types of Hedging Transactions
Resale of Tolling Rights

- **Resale of all or part of rights under tolling arrangements**
- **Example**
  - California Department of Water Resources (CDWR) Product D
    - Essentially mirrors underlying tolling contract

Types of Hedging Transactions
Full Requirements

Williams

- **Counterparty-tailored arrangement where Williams …**
  - Serves counterparty's power demand requirements
  - Dispatches counterparty's power plants / resources
  - Markets excess energy produced by these resources and covers short positions
- **Examples**
  - Georgia Electric Membership Corporations
    - Four individual contracts
  - Allegheny Electric Cooperative

Types of Hedging Transactions
Forward Power Sales

- **Physical or financial sale of a defined quantity of power over a set period of time**
- **Examples**
  - CDWR Products A, B and C
  - Cleco Utility Group
  - Standard OTC transactions
- **Typical counterparties**
  - Power marketers
  - Financial institutions
  - Utilities
- **Time horizon for hedging with forward contracts has lengthened as credit and liquidity have improved**

Types of Hedging Transactions
Mid-Market Structured Sales

- **Non-standardized, near-term transactions**
  - Customized to meet customer/counterparty needs
  - Term less than 3 years
- **Examples**
  - Resale of tolling, full requirements, load serving, capacity
- **Typical counterparties**
  - Utilities, municipalities and cooperatives
  - Power marketers and retail aggregators
  - Financial institutions
- **Opportunity to hedge near-term volumes over next 2 to 3 years**

Generation Optimization
Considerations

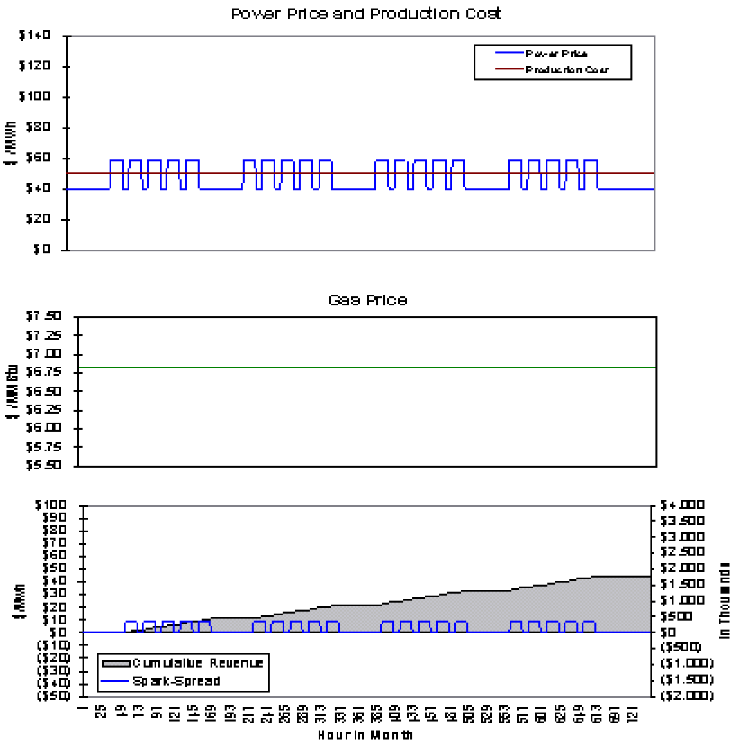
- **Hourly prices provide additional value beyond forward prices**
- **Thus, cannot determine full value based solely on forward prices**
- **Each unit has unique operational characteristics**
  - Peaker vs. intermediate vs. base-load
  - Start-up costs, start time, minimum run time, ramp-down capability, etc.

Generation Optimization
Example Assumptions

- **Examples illustrate value of daily/hourly markets**
  - Example 1: Monthly optimization
  - Example 2: Daily/hourly optimization
- **Forward prices assumptions***
  - On-peak: $58.62 / MWh
  - Off-peak: $40.21 / MWh
  - Gas: $6.83 / MMBtu
- **Simplified unit operational characteristics applied to both examples**
  - 650 MW capacity; 7,000 heat rate; $2.25 variable O&M and 8-hour minimum run time

* Average of actual May 2004 historical hourly prices for PJM's Ironwood real-time LMP (locational marginal price) and Tetco M-3 gas

Generation Optimization
Example 1: Monthly Dispatch



Spark-Spread Revenue*

On-Peak:	$1.8 million
Off-Peak:	$0.0 million
Total:	**$1.8 million**

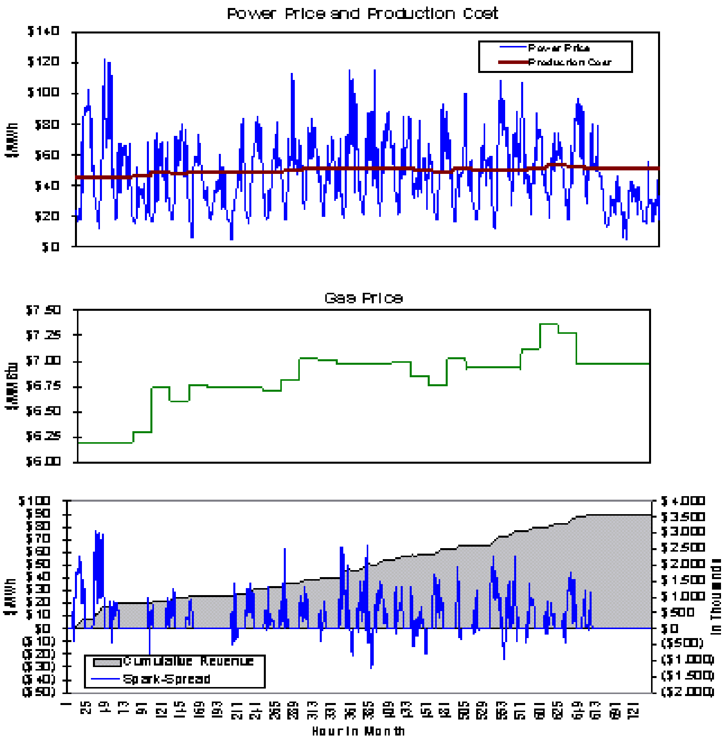
Spark-Spread Margin*

On-Peak:	$8.55 / MWh
Off-Peak:	$0.00 / MWh

- **Never dispatch out-of-money**
- **No dispatch off-peak since:** Production Cost > Off-Peak average price

* Net of variable O&M. Intended to be illustrative example and does not include all specific operational costs & parameters

Generation Optimization
Example 2: Daily/Hourly Dispatch



Spark-Spread Revenue*

On-Peak:	$2.1 million
Off-Peak:	$1.5 million
Total:	**$3.6 million**

Spark-Spread Margin*

On-Peak:	$(28)-62/ MWh
Off-Peak:	$(45)-77/ MWh

- **Occasional dispatch out-of-money to maximize total spark-spread revenues (subject to 8-hour minimum run time)**

* Net of variable O&M. Intended to be illustrative example and does not include all specific operational costs & parameters

$5-$10 Spark Spreads Not Realistic

- Additional capacity and infrastructure enhancements needed to support growth
- New construction not viable at $5-$10/MWh spark spreads
  - For all but most efficient plants, revenues would be less than construction / interconnection costs
- Difficult for majority of power plants to recoup production costs at $5-$10/MWh spark spreads
- Market forces will align spark spreads with growth requirements, resulting in supply-demand balance
  - Timing of return to balance uncertain, different by region

$5-$10 Spark Spreads Not Realistic

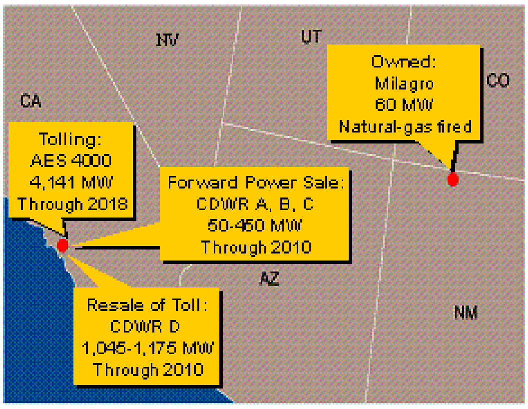
Utilization Factor:	45%	
Spark-Spread:	$5.00/MWh	
Spark-Spread Revenue:	$19.71/kW-yr	(.45 * 8760 * $5.00) /1,000
Construction	$615/kW **	
Interconnection	$229/kW **	
Total	$844/kW	
Total	$74.97 /kW-yr *	
plus Fixed 0&M	$10.34 /kW-yr **	
Total Annual	$85.31 /kW-yr	

* 8.0% cost of capital, 30 years
** Assumption for Adv. Gas/Oil Comb Cycle from EIA Annual Energy Outlook 2004

West

AES 4000 Tolling Arrangement

- **Capacity: 4,141 MW***
- **Base term: June 2013**
  - 5-year option for either party to extend to 2018
- **Annual demand payment:**
  - $153 million in 2004-05
  - Escalates 1.0% annually until 2013; flat after 2013
- **Variable O&M payment $2.28/MWh in 2004**
  - Annual escalator is lesser of 2.5% or CPI



* Receiving non-availability payments for 266 MWs that have been retired

AES 4000 Capacities and Heat Rates

	Capacity (MW)	Heat Rate (MMBtu/MWh)
Alamitos		
– Unit 1	184	10.7
– Unit 2	184	10.6
– Unit 3	336	9.5
– Unit 4	336	9.7
– Unit 5 *	504	9.4
– Unit 6 *	504	9.5
– Unit 7 **	133	16.5
Huntington Beach		
– Unit 1 *	226	9.8
– Unit 2	226	9.8
– Unit 5 **	133	16.5
Redondo Beach		
– Unit 5	184	11.8
– Unit 6	184	11.8
– Unit 7	504	9.4
– Unit 8	504	9.4
AES 4000 Total	**4,141**	**9.84*****

* CDWR Product D; ** Unavailable due to environmental limitations; *** Excludes unavailable units
Note: Based on AES 4000 tolling agreement.

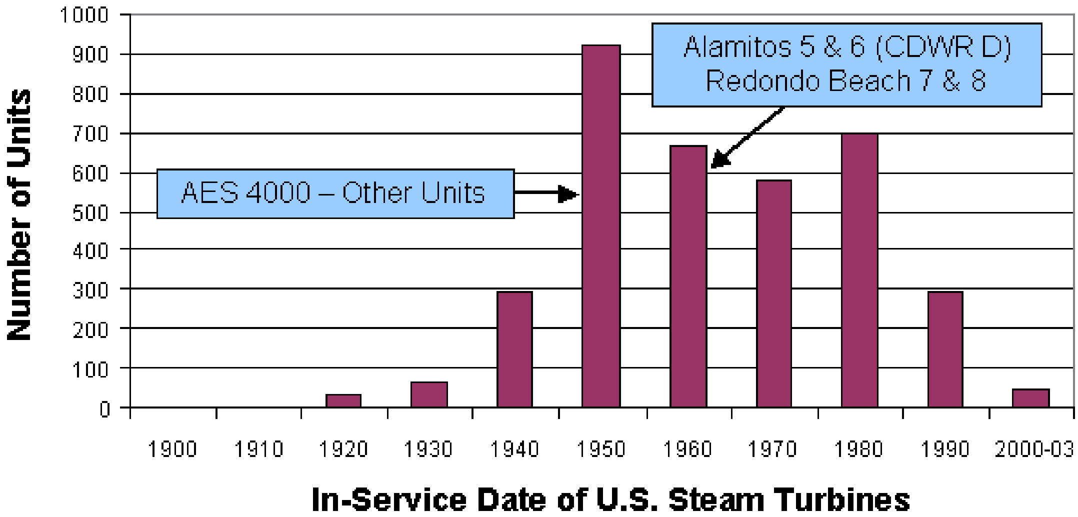
Repowering Considerations

AES 4000

- **Younger plants are more efficient, have higher capacities, dispatched more frequently**
- **Favorable economics to repower older units**
  - Convert 184MW steam units into 450-525 MW combined cycle
  - Estimate cost to be 75-80% of comparable new capacity
  - Goal to exit has precluded additional capital expense
  - No intention to repower at this time

Repowering Considerations
AES 4000

- Third-party engineering study found average U.S. plant life across all fuels is 70.1 years
- Excluding unavailable units, average AES 4000 age is 43 years



AES 4000 Offsetting Contracts

- **CDWR Products A, B, C**
  - Forward power sale
  - Product A
    - July 1, 2003 to Dec 31, 2007
    - 200 MW 7x24 @ $62.50/MWh
  - Product B
    - July 1, 2003 to Dec 31, 2010
    - 450 MW 6x16 @ $87.00 to $74.07/MWh
  - Product C
    - July 1, 2008 to Dec 31, 2010
    - 50 MW 6x16 @ $70.00/MWh

Contract terms: http://www.cers.water.ca.gov/power_contracts.cfm

AES 4000 Offsetting Contracts

- **CDWR Product D**
  - Resale of tolling rights
    - Essentially, a mirror-image toll
  - Term
    - Jan. 2003 to Dec. 31, 2010
  - Quantity
    - 1,175 MW through Dec. 31, 2007
    - 1,045 MW through Dec. 31, 2010
  - Price
    - $140/kW-year (to Dec. 31, 2007) to $117/kW-year (Jan. 1, 2008, to Dec. 31, 2010)
  - Includes availability guarantees and potential penalties

Contract terms: http://www.cers.water.ca.gov/power_contracts.cfm

Fuel Management
West

- **AES 4000**
  - Transportation agreements cover 95% of 650,000 MMBtu/d peak need
    - Kern: 107,625 MMBtu/d
    - El Paso: 5,484 MMBtu/d
    - SoCal: 506,794 MMBtu/d
  - Storage
    - 4 Bcf SoCal Intrastate
    - 1 Bcf Clay Basin storage
- **CDWR contract**
  - CDWR Product D contract gas management / supply

AES 4000 Locational Advantages

- **AES 4000 generation "in-city" with premium Los Angeles locations**
- **Serves constrained load pocket**
- **Williams sells critical ancillary services to California ISO**
- **AES 4000-generated energy could benefit from accelerated schedule to enhance reserve margins and/or locational marginal pricing (LMP)**
  - No premium associated with LMP included in projections
- **Development of capacity market**

WECC reserve margins not reflective of unique Southern California fundamentals

Short-Term Fundamentals
West

- **Hydroelectric capability ~80% of 30-year average** (National Oceanic and Atomospheric Administration)
- **Major SP-15 transmission line capacity lowered by one-third for summer 2004**
- **Triple-digit temperatures in May resulted in SP-15 hourly peak prices in excess of $180/MWh**
- **California ISO predicts peak demand growth of 3.56% (approx. 1,500 MW) in 2004, with no growth in net resource capacity**
- **31% year-on-year peak demand increase in April; 7% year-on-year average energy use increase in April** (California ISO)

Long-Term Fundamentals
West

- No merchant generation investment until functioning market proven
- Long-term power purchase agreements likely necessary to secure financing for new power plants
- Infrastructure enhancements causing high interconnection costs for new generation
- CA Public Utility Commission easing restrictions which previously prevented long-term hedging by utilities
- Potential LMP implementation should result in premium energy prices for "in-city" generation
- Unfavorable political climate for utilities to add generation to rate base

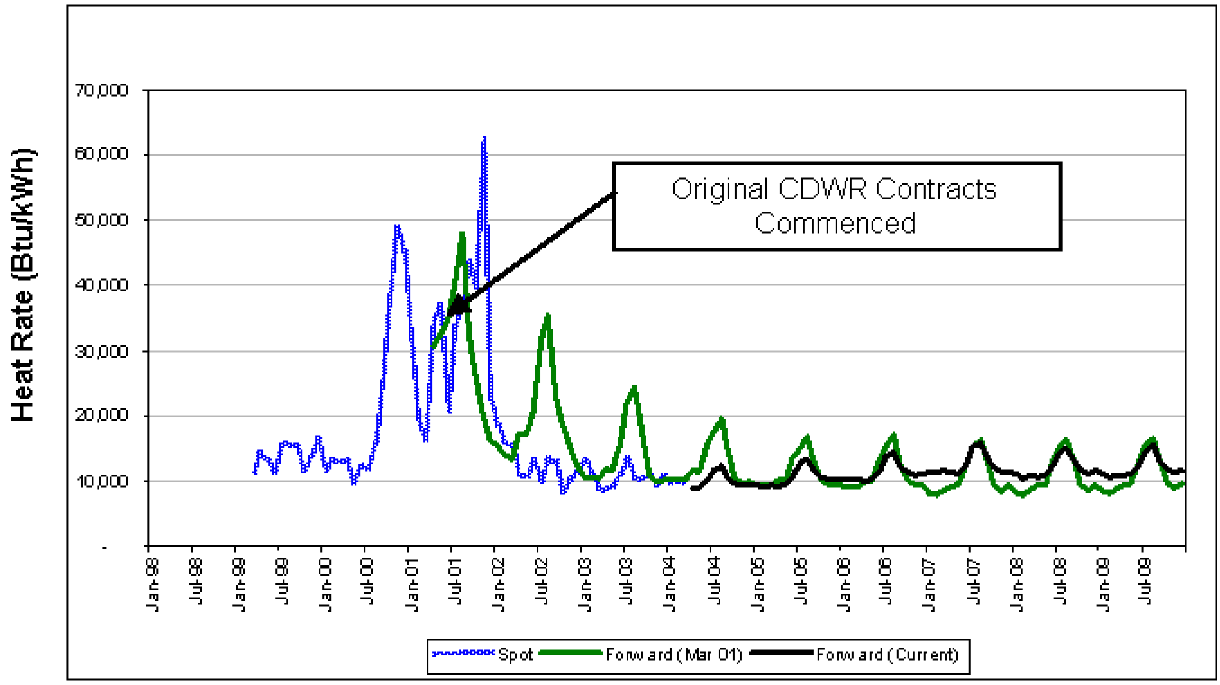
Opportunities
West

- **Short-term**
  - 1- to 3-year RFPs issued by utilities
  - Resource adequacy rules currently being developed in CA
  - Ability to sell physical capacity (viewed by utilities as superior to financial products offered by non-physical marketers)
- **Long-term**
  - Hedging opportunities expected to emerge as 18,000 MW of contracts* in CA expire
- **AES 4000 contract includes option to re-power units**
- **LNG re-gasification projects would likely reduce regional fuel prices**

* Including QF (qualifying facilities), utility and CDWR between 2004-2013. See Slide 79 in Appendix.

AES 4000 Hedging vs. Market

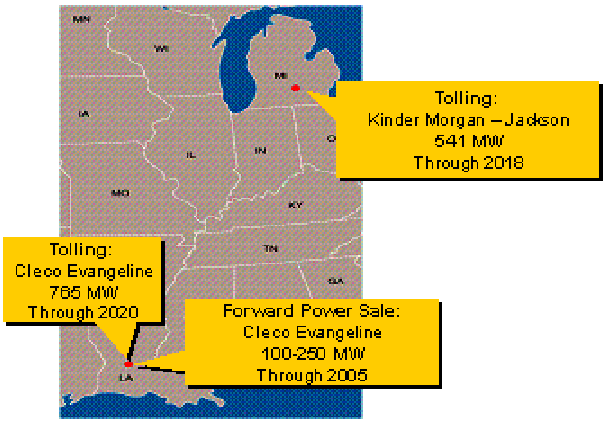
West



Mid-Continent

Portfolio Characteristics
Mid-Continent

- **Tolling agreements**
  - 1,306 MW
  - 7,700 average heat rate
  - Accounts for approximately 22% of approximately $400 million annual demand charges



Offsetting Contracts
Mid-Continent

- **Forward power sales**
  - Capacity sold from Cleco Evangeline
    - 250 MW through 2004
  - Call option from Cleco Evangeline
    - 200 MW through 2004
    - 100 MW through 2005

Fuel Management
Mid-Continent

- **Cleco Evangeline (Entergy)**
  - 145,000 MMBtu/d Columbia Gulf firm transportation capacity
  - Peak day needs of 110,000 MMBtu/d
  - 1 Bcf Egan (storage)
- **KM Jackson (ECAR)**
  - 75,000 MMBtu/d full-requirements supply agreement
  - Balancing account provided
  - Gas Daily index price

Short-Term Fundamentals
Mid-Continent

- **Cleco Evangeline (Entergy)**
  - Markets depressed in short-term
  - Possibility for some upside to spark spreads to relieve temporary system constraints
- **KM Jackson (ECAR)**
  - Markets depressed in short-term

Long-Term Fundamentals
Cleco Evangeline (Entergy)

- **Broader market significantly oversupplied**
- **Reserve margins will remain high for considerable length of time**
- **Plant located in relatively constrained portion of electric power grid**

SPP reserve margins not reflective
of unique Central Louisiana fundamentals

Long-Term Fundamentals
KM Jackson (ECAR)

- **AEP's expected integration into PJM market (~Oct 2004) increases transmission efficiency**
- **MISO's implementation of a wholesale energy market targeted for March 2005**
  - KM Jackson facility located in MISO footprint, providing future opportunities for energy and capacity sales into an organized market

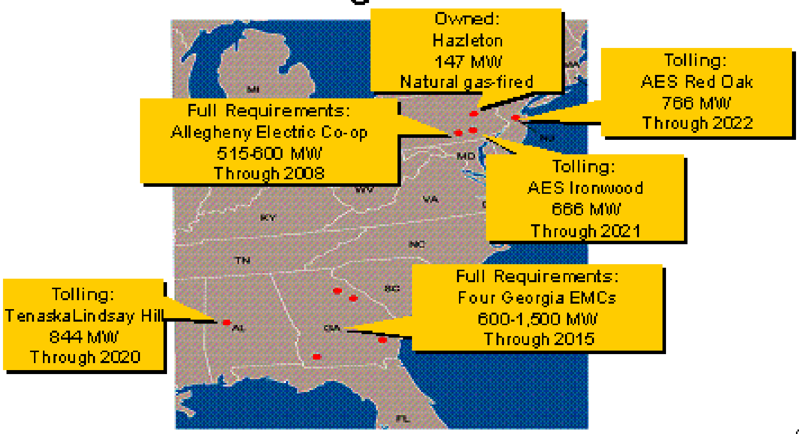
Opportunities
Cleco Evangeline and KM Jackson

- **Short-term**
  - RFPs issued by host utilities for capacity and energy
  - Resale of tolling to retail aggregators and market participants
- **Long-term**
  - RFPs issued by host utilities for capacity and energy
  - Cooperative and municipal load-serve transactions

East

Portfolio Characteristics
East

- **Tolling agreements**
  - 2,276 MW
  - 7,000 average heat rate
  - Accounts for approximately 40% of approximately $400 million annual demand charges



Offsetting Contract
East - PJM

- **Full requirements**
  - Agreement with Allegheny Electric Cooperative
    - Not affiliated with Allegheny Energy Supply (AYE)
  - Term
    - December 2008
  - Capacity sold
    - Approximately 600 MW peak demand

Offsetting Contracts
East – SERC

- **Full requirements**
  - 4 agreements with Walton, Colquitt, Satilla and Rayle EMCs
  - Term
    - December 2015
  - Capacity sold
    - 600 MW in 2005, growing to 1,500 MW in 2015

Fuel Management
East

- **AES Ironwood (PJM)**
  - Peak daily requirement - 130,000 MMBtu/d
  - 80,000 MMBtu/d no-notice supply agreement
- **AES Red Oak (PJM)**
  - Peak daily requirement - 130,000 MMBtu/d
  - 50,000 MMBtu baseload supply agreement
  - Supplemental supply agreement
- **Tenaska Lindsay Hill (SERC)**
  - Peak daily requirement - 110,000 MMBtu/d
  - 65,000 MMBtu/d seasonal transportation agreement
  - Hedging of heating oil fuel requirements

Short-Term Fundamentals
Ironwood/Red Oak (PJM)

- **PJM forecasts 2.1% increase in 2004 peak demand**
  - Significantly higher than 0.4% realized in 2003
- **2004 year-to-date actual PJM Eastern spark spreads* $5.82/MWh higher than 2003 comparables due to high coal prices and corresponding off-peak energy prices**
- **ComEd integrated into PJM market on May 1, 2004**
- **Potential to efficiently serve larger market with Virginia integration into PJM**

*Assumes around-the-clock avg. real-time prices for PJM's JCPL Zone and Transco Z-6 with 7,000 heat rate

Long-Term Fundamentals
Ironwood/Red Oak (PJM)

- **Three RTOs (PJM, ISO-NE and NYISO) reevaluating design of capacity markets**
  - Proposed redesign intended to provide clearer price signals on value of capacity
  - Revision to price mitigation for reliability units would more fairly compensate existing units
  - Likely structure will include demand curve component
  - Proposed redesign would likely increase capacity value
- **Announced retirements in PJM are currently approximately 1,300 MW of ~70,000 MW demand**
  - Another 3,500+ MW likely to be retired within five years

Short- and Long-Term Fundamentals
Tenaska Lindsay Hill (SERC)

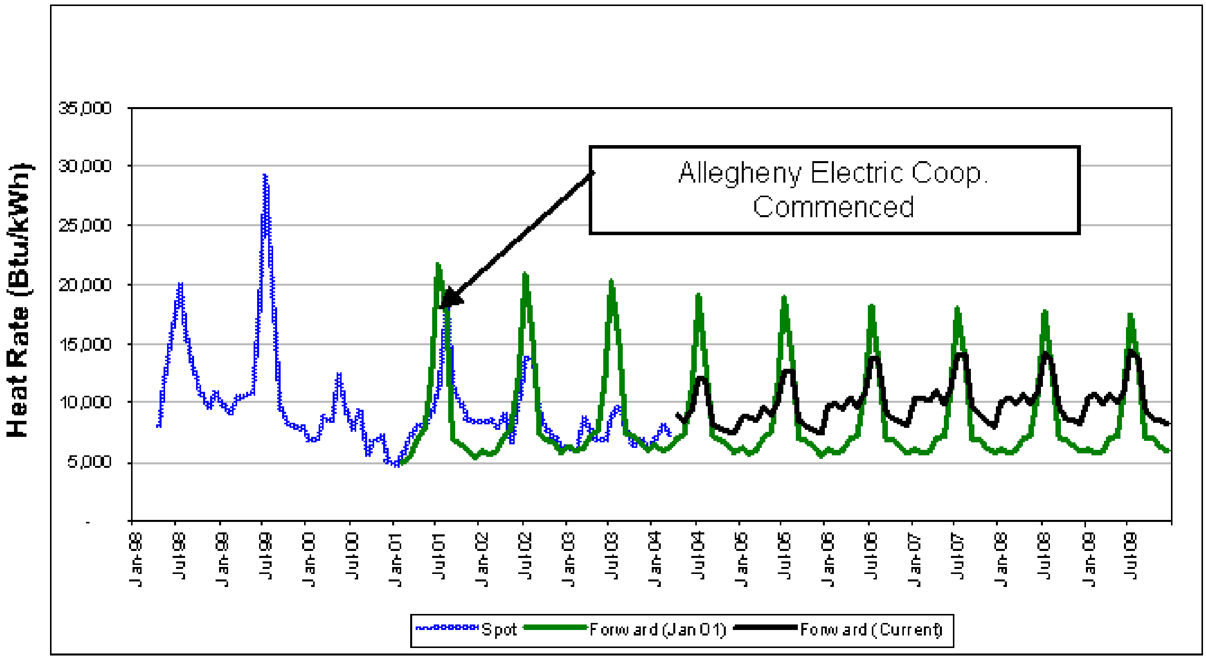
- **Committed to Georgia EMCs through 2015**

Opportunities
East

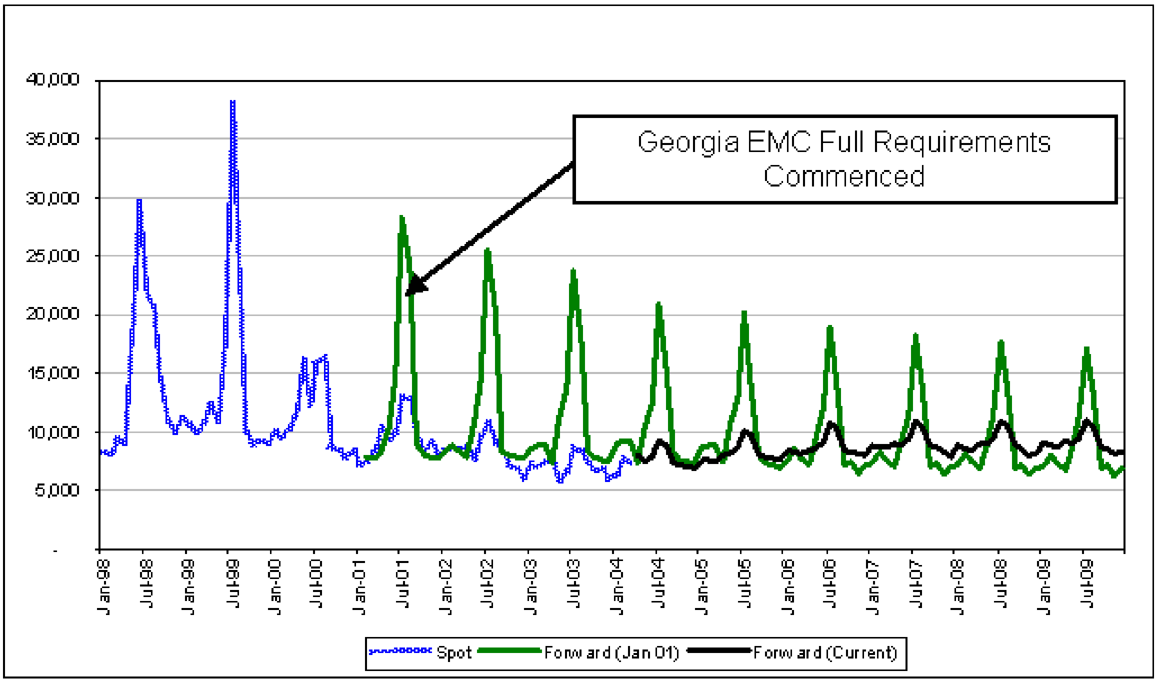
- **Ironwood/Red Oak (PJM)**
  - Increasing longer-term market liquidity
  - Utilities, municipalities and cooperatives are re-entering the market for structured deals
  - Continued grid inefficiencies should benefit Red Oak
  - Forward sales to bidders of future retail load auctions (BGS and Maryland); total value of 2004 BGS auction was $5.1 billion
- **Tenaska Lindsay Hill (SERC)**
  - Committed to Georgia EMCs through 2015

Ironwood/Red Oak Hedging vs. Market

East - PJM



Tenaska Hedging vs. Market
East - SERC



Consolidated Financials

Undiscounted Cash Flows
Combined Segment Portfolio

Dollars in millions

Combined Segment Portfolio *Estimated as of 3/31/04*	3 Mo. A	2004 A+F	2005 F	2006 F	2007-2010 F	2011-2022 F
Tolling Demand Payment Obligations	($88)	($395)	($397)	($401)	($1,637)	($3,861)
Resale of Tolling	$41	$128	$97	$81	$190	$0
Full Requirements	($1)	$15	$25	$22	$71	$147
Long-term Physical Forward Power Sales	$27	$92	$90	$68	$137	$0
OTC Hedges	$36	$156	$56	$89	($35)	($33)
Tolling Cash Flows Associated With Hedges	$7	$179	$278	$299	$835	$367
Subtotal	$22	$175	$149	$158	($439)	($3,380)
Merchant Cash Flows	$0	$11	$58	$130	$1,323	$5,567
Est. Combined Power Portfolio Cash Flows	$22	$186	$207	$288	$884	$2,187
Forecasted Direct SG&A	($8)	($50)	($50)	($50)	($200)	($500)
Forecasted Indirect SG&A	($8)	($25)	($25)	($25)	($100)	($300)
Subtotal	$6	$111	$132	$213	$584	$1,387
Legacy Portfolio and Other Working Capital	$81	$204	$42	$42	$42	$101
Estimated Cash Flows	$87	$315	$174	$255	$626	$1,488

Note: Actual cash flows realized upon liquidation or sale of the portfolio may differ materially from those shown. Variability in actuals versus forecast is reflected in range of guidance provided.

Undiscounted Cash Flows
Line Item Clarification

- **Tolling cash flows associated with hedges**
  - Represents a percentage of the value of the underlying tolling option
  - Includes value associated with optionality, such as volatility, that is not effectively hedged with all products; thus, actual cash flows may vary from estimates provided
- **Merchant cash flows**
  - Represents unhedged cash flow from expected generation associated with underlying tolling option
  - Includes value associated with optionality, such as volatility; thus, actual cash flows may vary from estimates provided

Reported Segment Profit
Total Segment

1Q '04 Earnings Call

Williams

Dollars in millions	1Q04	4Q03	1Q03
Gross Margin	($2)	$40	($91)
SG&A	(16)	(17)	(36)
Op. Exp. & Other Inc / (Exp)	(15)	(124)	(9)
Reported Segment Profit	**($33)**	**($101)**	**($136)**
Includes:			
Impairments	-	89	-
Prior Period Adjustment	-	(12)	-
Cal. Refund & Other Accrual Adj.	-	33	-
Reduction in Force Costs	-	-	11
Recurring Segment Profit	**($33)**	**$9**	**($125)**

Segment Profit to Cash Flow
Total Segment 1Q04

Dollars in millions

	Power	Legacy	Other	Total
Gross Margin	**(93)**	**91**		**(2)**
SG&A	(16)			**(16)**
Oper Exp & Other Inc / (Exp)		(15)		**(15)**
Reported Segment Profit	**(109)**	**76**	-	**(33)**
Reverse: Unrealized MTM	47	(70)		**(23)**
Add: Realized Prior Period MTM	68	69		**137**
Proforma Accrual Basis	**6**	**75**	-	**81**
Working Capital & Other Changes			44	**44**
Exp not included in Segment Profit			(38)	**(38)**
Power Segment CFFO	6	75	6	**87**
Plus: Collateral paid for other Bus Units			76	**76**
Power Segment Standalone CFFO	6	75	82	**163**

Hedge Accounting Considerations

- Mark-to-market (MTM) volatility in earnings significantly reduced, but not eliminated
- GAAP earnings not likely to track cash flows due to MTM recognized prior to hedge accounting election date
- Legacy positions may not qualify for hedge accounting, thus will continue to be MTM
- Ineffectiveness in hedge portfolio still MTM

2004-2006 Guidance
Total Segment

1Q '04 Earnings Call

Williams

Dollars in millions	2004	2005	2006
Segment Profit*	$0-150	$50-150	$50-200
Capital Expenditures	$ 0	$ 0	$ 0
Cash Flows from Operations**	$150-350	$50-150	$50-200

** Assumes full year forward MTM gains or losses are zero*

*** Excludes commodity margin volatility*

Enterprise Risk Management

1Q '04 Earnings Call

Dollars in millions

- Margin volatility (99% confidence interval)
  - Incremental liquidity requirement

	3/31/04	12/31/03
– 30 days	($185)	($183)
– 180 days	($309)	($324)
– 360 days	($390)	($349)

- Incremental Margin requirement from historical price spike

2/27/03
($139)

Assumption: The margin numbers above consist of only the forward marginable position values, starting from May 2004.

Enterprise Risk Management

1Q '04 Earnings Call

Estimated dollars in millions

Sensitivities Analysis*

	Power West Spark Spread Power Price (Per MWh)
Price Increase	**$5.00**
2004	$0-5
2005	$5-10
2006	$5-15

* Assumes a non-correlated change in West power prices only, no change in power volatility, full extrinsic value not included. Heat rate and position change associated with Spark Spread increase is consistent across all months. Cash flow ranges are not linear.

Summary

Key Takeaways

- Daily / hourly power plant optimization creates significant value above the forward curve
- Sustained $5-$10 spark spreads are not realistic
- Long-term fundamentals favor tail risk
- Steam plants in California economically and operationally viable
- Confident in cash flow guidance

Summary

- **Operating business to**
  - Reduce risk
  - Generate cash
  - Meet contractual commitments
- **Continuing difficulty in exiting business**
- **Viable business fundamentals both short- and long-term**

Q&A

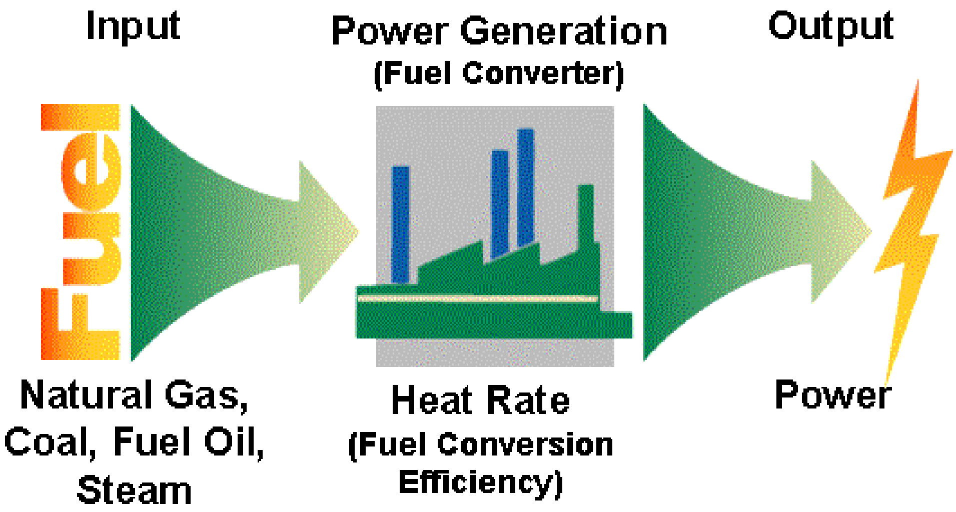
Appendix

Business Background

Tolling Concept

Williams

Tolling - Fuel conversion arrangement. Williams supplies fuel to plants and markets electricity output. Plant owner receives fixed fee and retains operational responsibility.



Heat Rate Concept

<u>**Heat rate**</u> – The amount of fuel a power plant requires to produce one unit of power. A measure of the efficiency of generating plants.

$$\frac{\textbf{MMBtu}}{\textbf{MWh}} = \textbf{Heat Rate}$$

Key concepts

- The lower the heat rate, the more efficient the power-generation unit.
- Heat rate, when considered in conjunction with a unit's input fuel, generally determines a power-generation unit's economic viability in a given market.

Spark Spread Concept

Spark spread - The difference between the price of power and the cost it takes to produce it at a given facility.

$$\text{Power Price} - \left[\begin{array}{c}\text{Power Cost:}\\ \text{Fuel Cost} \times \text{Heat Rate}\end{array}\right] = \text{Spark Spread}$$

Example:

$$\$42/\text{Mwh} - \left[\$4/\text{MMBtu} \times 10\text{MMBtu/MWh}\right] = \$2/\text{MWh}$$

Key concepts

- **The higher the spark spread, the higher the margin.**
- **A negative spark spread indicates it is more economical to purchase power to meet commitments than run generating facilities "out of the money."**

* Variable O&M costs typically included in spark-spread calculation, but not reflected here for sake of simplicity.

Tolling Cash Flows Assoc. with Hedges

- Represents the estimated tolling cash flows that have been hedged.

	Underlying Toll	Market	Hedge	Estimated Cash Flow *Associated w/ Toll**	*Associated w/ Hedge*	*Net*
Example 1	($25)	$35	$35	$10	$0	$10
Example 2	($25)	$30	$35	$5	$5	$10
Example 3	($25)	$20	$35	$0	$15	$15

* Both the hedge and the underlying toll are marked against current market prices.

Summary of NG Storage Agreements

Dollars in millions

Storage Agreements	MSQ*	Demand	Term
Clay	6.4	$3.7	Apr '08
Dawn	2.0	$0.9	Mar '13
NGPL Gulf Coast	1.6	$0.8	Mar '12
NGPL Midcontinent	0.8	$0.4	Mar '12
Transport Associated with Storage		$1.9	
Total	**10.9**	**$5.8**	

* Maximum Storage Quantity in Bcf

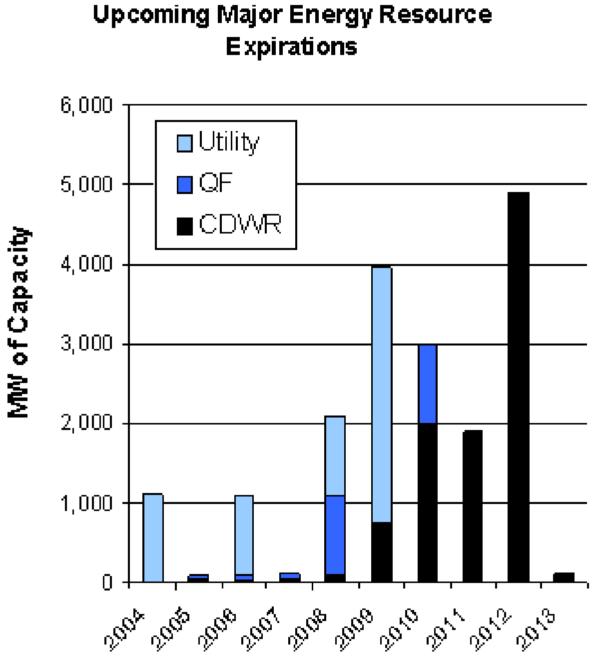
Summary of NG Transport Agreements

Transportation Agreements	Capacity	Demand	Term
Alliance	10,000	$3.4	Sep '15
CIG (Green River to Tomahawk/Cheyenne)	7,000	$0.8	Aug '09
CIG (Cave Gulch & Cyclone Ridge to WIC)	15,000	$0.4	Dec '07
CIG (CGF & Elk Basin to WIC)	15,000	$0.7	Dec '07
CIG (Bl Forest, King & Grn River to Lakin)	25,000	$2.9	Aug '09
CIG (Elk Basin to Lakin)	7,730	$0.9	Nov '05
CIG (Elk Basin to Baker)	10,000	$1.2	Dec '04
El Paso	5,484	$0.7	Jun '06
Transco - PG Energy	5,000	$0.8	Oct '04
Transco (6,880)	6,880	$0.8	Annual
WNG-CIG	29,494	$2.2	Dec '07
Total Transport	136,588	$14.7	

Capacity = MMBtu/d

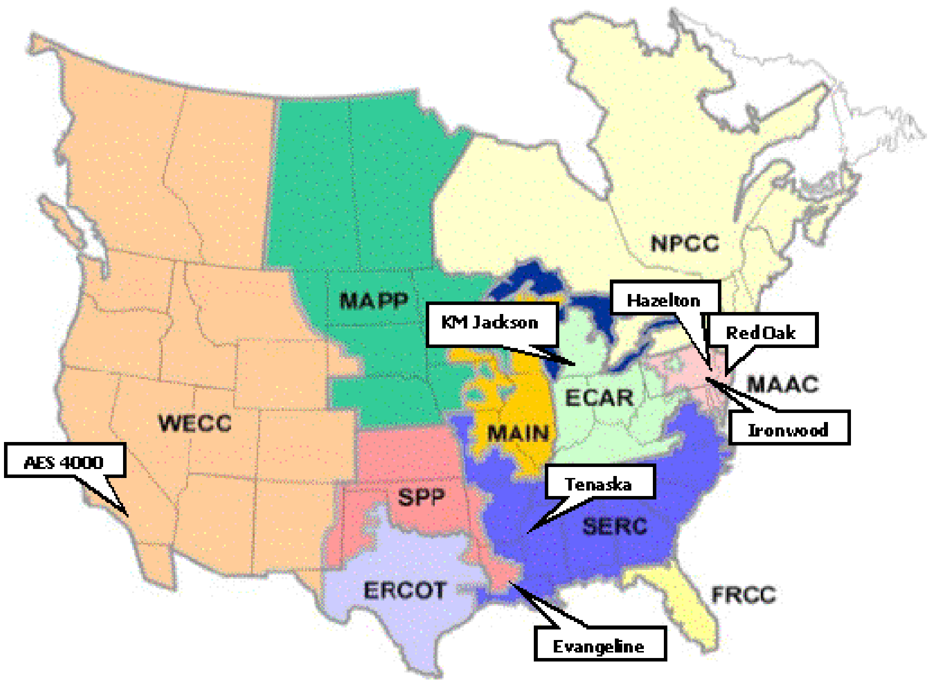
Demand = Dollars in millions per year

California Contract Expirations



Source: CA PUC Staff Report, A Core/Noncore Structure for Electricity on California. March 15th 2004. P.19

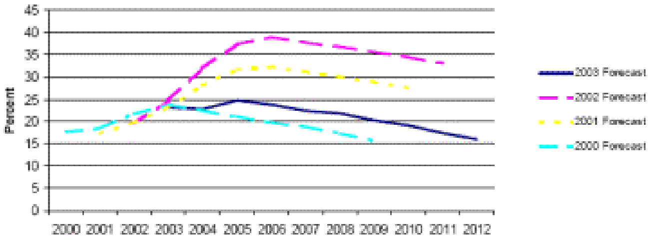
NERC Regions



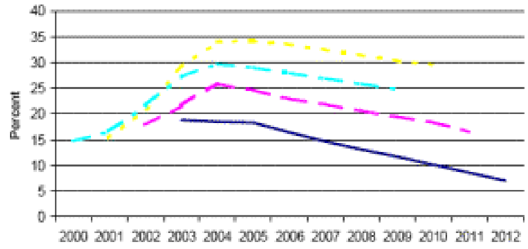
NERC Projected Capacity Margins

Williams

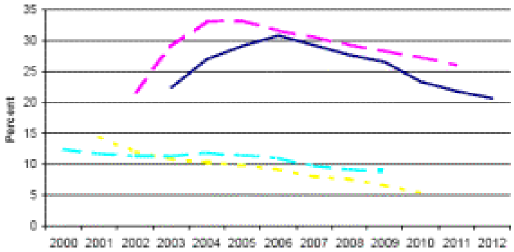
WECC



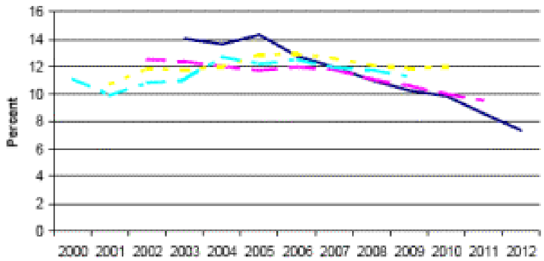
MACC



ECAR

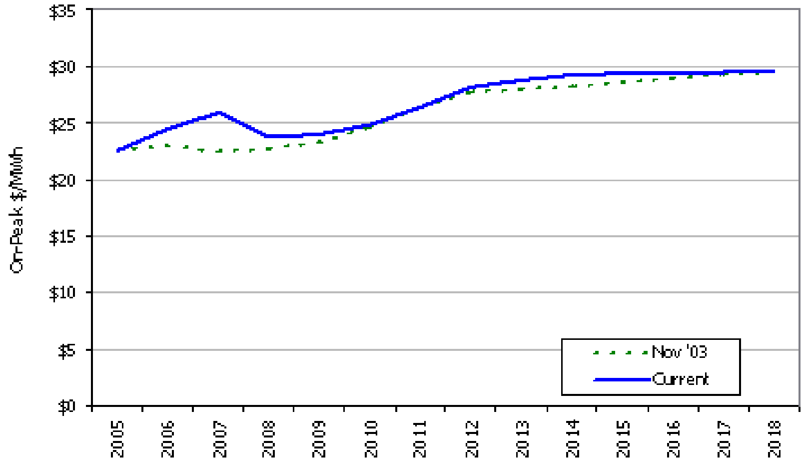


SERC



Source:Reliability Assessment 2003-2012. NERC Dec. 2003

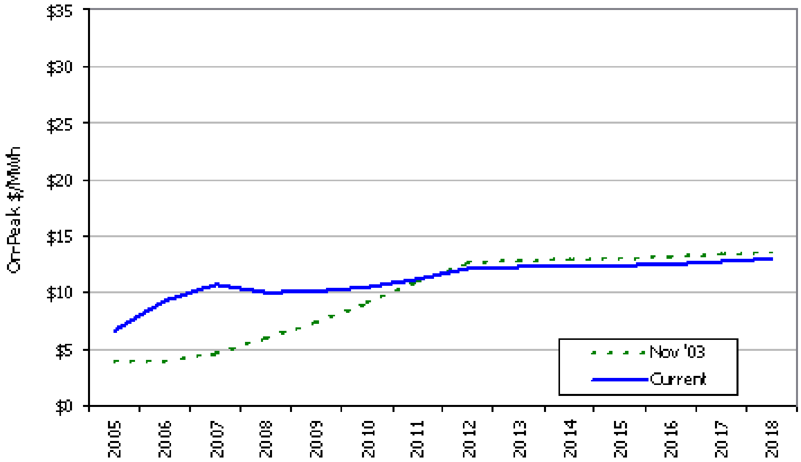
Forward Spark-Spreads
SP-15 (AES4000)



- Spark-spread represents the variable net margin per MWh of energy production
- Curve assumes a 7 heat rate conversion efficiency and assumes no VO&M
- Spark-Spread = Power Price – (7 × Gas Price)

Note: For consistency with Est. Cash Flow projections, Current curves presented above represent market conditions as of 3/31/2004

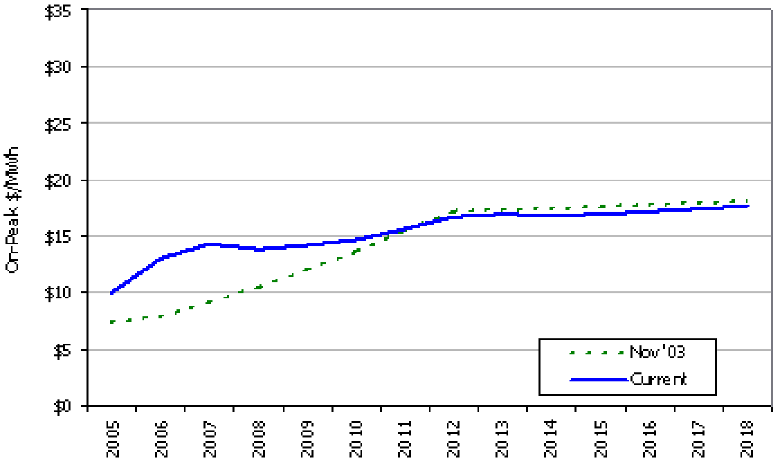
Forward Spark-Spreads
Entergy (Cleco Evangeline)



- Spark-spread represents the variable net margin per MWh of energy production
- Curve assumes a 7 heat rate conversion efficiency and assumes no VO&M
- Spark-Spread = Power Price – (7 × Gas Price)

Note: For consistency with Est. Cash Flow projections, Current curves presented above represent market conditions as of 3/31/2004

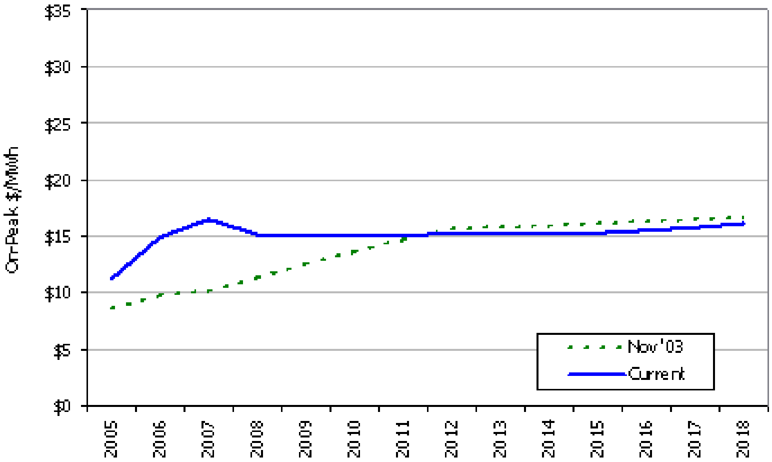
Forward Spark-Spreads
ECAR/MI (KM Jackson)



- Spark-spread represents the variable net margin per MWh of energy production
- Curve assumes a 7 heat rate conversion efficiency and assumes no VO&M
- Spark-Spread = Power Price – (7 × Gas Price)

Note: For consistency with Est. Cash Flow projections, Current curves presented above represent market conditions as of 3/31/2004

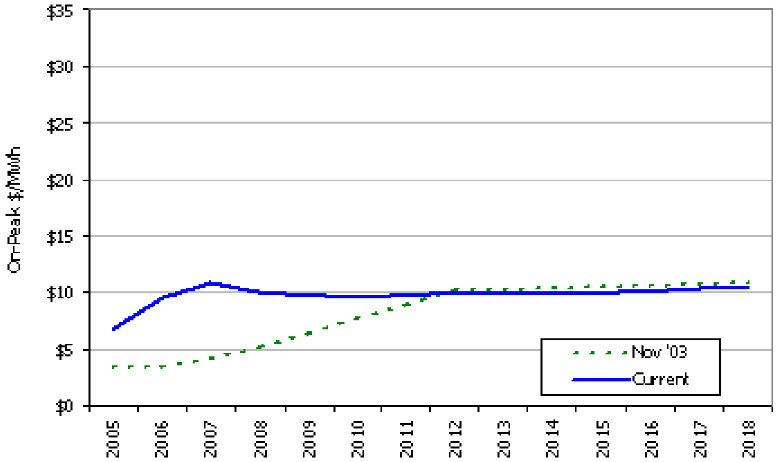
Forward Spark-Spreads
PJM-West (Red Oak / Ironwood)



- Spark-spread represents the variable net margin per MWh of energy production
- Curve assumes a 7 heat rate conversion efficiency and assumes no VO&M
- Spark-Spread = Power Price – (7 × Gas Price)

Note: For consistency with Est. Cash Flow projections, Current curves presented above represent market conditions as of 3/31/2004

Forward Spark-Spreads
Southern (Tenaska)



- Spark-spread represents the variable net margin per MWh of energy production
- Curve assumes a 7 heat rate conversion efficiency and assumes no VO&M
- Spark-Spread = Power Price – (7 × Gas Price)

Note: For consistency with Est. Cash Flow projections, Current curves presented above represent market conditions as of 3/31/2004

Financials & Accounting

Demand Payment Coverage

Dollars in millions

COMBINED	2004 A+F	2005	2006	2007-2010
Demand Payments	$ (395)	$ (397)	$ (401)	$ (1,637)
Resale of Tolling	$ 128	$ 97	$ 81	$ 190
Full Requirements	$ 15	$ 25	$ 22	$ 71
L-T Physical Fwd Power Sales	$ 92	$ 90	$ 68	$ 137
OTC Hedges	$ 156	$ 56	$ 89	$ (35)
Merchant Tolling Revenue Hedged	$ 179	$ 278	$ 299	$ 835
Total Hedged Cash Flows	**$ 570**	**$ 546**	**$ 559**	**$ 1,198**

Dmd Pmt Coverage through 2010	
Total Hedged in Cash Flows	**$ 2,872**
Total Demand Payments	**$ (2,830)**
Cost Coverage	**1.01**

Total Undiscounted Cash Flows
West Power Portfolio

Dollars in millions

West Power Portfolio *Estimated as of 3/31/04*	3 Mo. A	2004 A+F	2005 F	2006 F	2007-2010 F	2011-2018 F
Tolling Demand Payment Obligations	($39)	($154)	($154)	($156)	($639)	($1,243)
Resale of Tolling	$41	$128	$97	$81	$190	$0
Long-term Physical Forward Power Sales	$29	$93	$88	$68	$137	$0
OTC Hedges	$15	$98	$45	$72	($16)	($4)
Tolling Cash Flows Associated With Hedges	$12	$113	$169	$174	$532	$18
Subtotal	$58	$278	$245	$239	$204	($1,229)
Merchant Cash Flows	$0	$11	$37	$75	$675	$2,487
Estimated Cash Flows	$58	$289	$282	$314	$879	$1,258

Note: Actual cash flows realized upon liquidation or sale of the portfolio may differ materially from those shown. Also, please note that proprietary positions, storage, transportation, transmission, crude and refined products, interest rates, option premiums and margins are not included.

Total Undiscounted Cash Flows
Mid-Continent Power Portfolio

Dollars in millions

Mid-Continent Power Portfolio *Estimated as of 3/31/04*	3 Mo. A	2004 A+F	2005 F	2006F	2007-2010 F	2011-2022 F
Tolling Demand Payment Obligations	($13)	($87)	($88)	($89)	($363)	($837)
Long-term Physical Forward Power Sales	($2)	($1)	$2	$0	$0	$0
OTC Hedges	$1	$16	($16)	($14)	($18)	$0
Tolling Cash Flows Associated With Hedges	($3)	$16	$38	$24	$44	$0
Subtotal	($17)	($56)	($64)	($79)	($337)	($837)
Merchant Cash Flows	$0	$0	$0	$31	$276	$984
Estimated Cash Flows	($17)	($56)	($64)	($48)	($61)	$147

Note: Actual cash flows realized upon liquidation or sale of the portfolio may differ materially from those shown. Also, please note that proprietary positions, storage, transportation, transmission, crude and refined products, interest rates, option premiums and margins are not included.

Total Undiscounted Cash Flows
East Power Portfolio

Dollars in millions

East Power Portfolio *Estimated as of 3/31/04*	3 Mo. A	2004 A+F	2005 F	2006 F	2007-2010 F	2011-2022 F
Tolling Demand Payment Obligations	($36)	($154)	($154)	($157)	($635)	($1,780)
Full Requirements	($1)	$15	$25	$22	$71	$147
OTC Hedges	$19	$42	$27	$31	($1)	($29)
Tolling Cash Flows Associated With Hedges	($1)	$50	$71	$101	$259	$350
Subtotal	($19)	($47)	($31)	($3)	($306)	($1,312)
Merchant Cash Flows	$0	$0	$21	$25	$372	$2,096
Estimated Cash Flows	($19)	($47)	($10)	$22	$66	$784

Note: Actual cash flows realized upon liquidation or sale of the portfolio may differ materially from those shown. Also, please note that proprietary positions, storage, transportation, transmission, crude and refined products, interest rates, option premiums and margins are not included.

1Q04 Change in Power-Only Portfolio Cash Flows

1Q '04 Earnings Call

Williams

Dollars in millions

Combined Power Portfolio *1Q04 Change in Estimated Cash Flows*	**2004 F**	**2005 F**	**2006 F**
Tolling Demand Payment Obligations	($4)	($2)	($2)
Resale of Tolling	($15)	($20)	($23)
Full Requirements	($1)	($17)	($24)
Long-term Physical Forward Power Sales	($4)	($11)	($8)
OTC Hedges	($13)	$4	$12
Tolling Cash Flows Associated With Hedges	$71	$83	$49
Subtotal	$34	$37	$4
Merchant Cash Flows	$6	$9	$57
Est. Combined Power Portfolio Cash Flows	$40	$46	$61
Forecasted Direct SG&A	$0	$0	$0
Forecasted Indirect SG&A	$0	$0	$0
Estimated Cash Flows After SG&A	$40	$46	$61

Note: Represents change in estimated value over a 3 month time frame from 12/31/03 to 3/31/04

Undisc. Cash Flow Variance Analysis
Power-Only Portfolio

1Q '04 Earnings Call

Dollars in millions

Combined Power Portfolio	**Actual**	**Forecast**
Actual 1Q04 v. Forecast 1Q04	**1Q04**	**1Q04**
Tolling Demand Payment Obligations	$(88)	$(85)
Resale of Tolling	41	42
Full Requirements	(1)	(4)
Long-term Physical Forward Power Sales	27	22
OTC Hedges	36	46
Estimated Hedged Tolling Revenues	7	(0)
Total Cash Flows	22	21
Estimated Merchant Revenue Unhedged	-	-
Forecasted Direct SG&A	(8)	(13)
Forecasted Indirect SG&A	(8)	(6)
Estimated Cash Flows After SG&A	**$6**	**$2**

MTM Realizations
Power Segment

Dollars in millions

	Derivative Balances Expected to be Realized Based on 3/31/04 Fair Value
2Q 2004	$10
3Q 2004	63
4Q 2004	19
2005	188
2006	174
2007-2010	170
2011-2022	20

Revenue Recognition

EITF 02-3

- **Adoption of EITF 02-3 on Jan. 1, 2003, requires:**
  - Non-derivative contracts be reported on an accrual basis
  - Derivative contracts continue to be reported on a fair value basis under SFAS 133
- **Not currently qualified for cash flow hedge accounting under SFAS 133 due to stated intent to exit the business**

Revenue Recognition
EITF 02-3

- **Prohibits the use of fair-value accounting treatment for contracts that do not qualify as derivatives under FAS 133 "Accounting for Derivative Instruments and Hedging Activities"**
- **Derivative instruments:**
  – Underlying
  – Notional
  – Net settlement or instrument is readily convertible to cash
  – Minimal net initial investment

Revenue Recognition

EITF 02-3

- **Derivative instruments**
  - Financial transactions
    - Options
    - Swaps
    - Futures
  - Forward physical transactions
- **Non-derivative instruments**
  - Tolling
  - CDWR Product D
  - Full requirements
  - Storage
  - Transportation
  - Transmission
  - Transco Agency Service
  - Spot physical transactions

Revenue Recognition
EITF 02-3

- **Since not currently qualified for cash flow hedge accounting…**
  - Derivative instruments accounted for on a fair-value (MTM) basis
    - Changes in the forward value of these instruments are recorded as unrealized gains / losses on the income statement and balance sheet
  - Non-derivatives reported on an accrual basis

Revenue Recognition

EITF 02-3

- **GAAP earnings vary from economic results and cash flows:**
  - MTM gains or losses reflect change in fair value of derivative hedge portfolio, but not change in fair value of underlying non-derivative contracts such as tolling agreements
  - Accrual earnings reflect earnings from underlying non-derivative contracts, but do not include previously recognized unrealized gains or losses from derivative contracts
  - Normal purchases & sales contracts are no longer MTM but reflect realized accrual earnings offset by periodic reversal of previously recognized MTM earnings
- **GAAP earnings are volatile because hedges are MTM without offsetting impact of change in fair value of underlying contract**
- **Cash flows provide proxy for accrual-based economic results, but include changes in working capital**

Revenue Recognition

EITF 02-3

Other changes mandated by EITF 02-3

- **Before EITF 02-3**
  - Inventory accounted for on MTM basis
  - All trading revenues reported on a net basis
- **After EITF 02-3**
  - Inventory accounted for on a Lower of Cost or Market (LCM) basis
  - Revenue reporting mixed
    - Unrealized derivative revenues reported net
    - Financially settled realized derivative revenues reported net
    - Non-derivative revenues reported gross
    - Physically settled realized derivative revenues reported gross

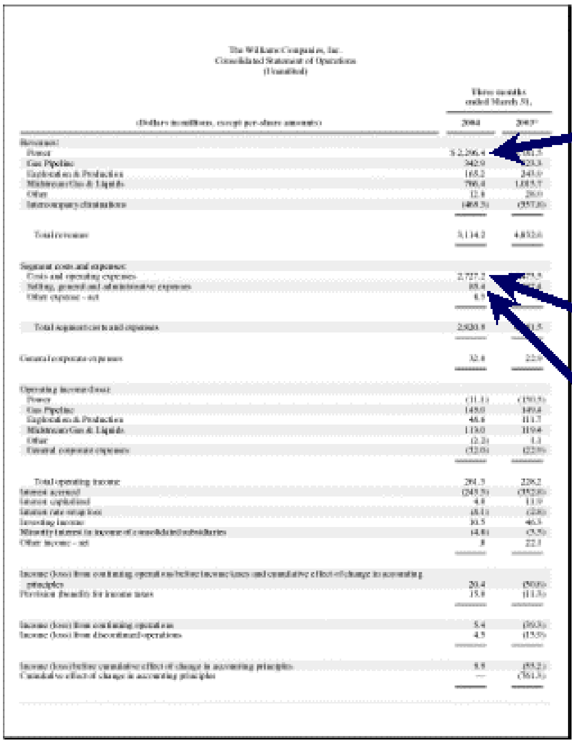
Revenue Recognition - EITF 02-3

Williams

Summary of Accounting Treatment by Contract type:

Contract Type	Acctg "Bucket"	Acctg Method	Income =Cash?	Revenues Gross/Net
Tolling	Non-Derivative	Accrual	Yes	Gross
Full Requirements	Non-Derivative	Accrual	Yes	Gross
Storage	Non-Derivative	Accrual	Yes	Gross
Transportation	Non-Derivative	Accrual	Yes	Gross
Transmission	Non-Derivative	Accrual	Yes	Gross
Firm Service	Non-Derivative	Accrual	Yes	Gross
CDWR Product D	Non-Derivative	Accrual	Yes	Gross
Spot Physical Trxs	Non-Derivative	Accrual	Yes	Gross
CDWR ABC	Derivative	Normal P&S	No	Gross & Net
OTC/NYMEX Fins	Derivative	MTM	No	Gross & Net
Forward Physicals	Derivative	MTM	No	Gross & Net

Income Statement: 1Q 2004 10-Q



The Williams Companies, Inc.
Consolidated Statement of Operations
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended March 31, 2004	2003*
Revenues:		
Power	$ 2,206.4	[illegible]
Gas Pipeline	342.9	[illegible]
Exploration & Production	165.2	243.0
Midstream Gas & Liquids	796.4	1,015.7
Other	12.4	28.0
Intercompany eliminations	(408.5)	(557.8)
Total revenues	3,114.2	4,832.6
Segment costs and expenses:		
Costs and operating expenses	2,727.2	[illegible]
Selling, general and administrative expenses	85.4	[illegible]
Other expense - net	8.9	
Total segment costs and expenses	2,820.8	[illegible]
General corporate expenses	32.0	22.9
Operating income (loss):		
Power	(11.1)	(150.5)
Gas Pipeline	145.0	149.4
Exploration & Production	48.6	111.7
Midstream Gas & Liquids	113.0	119.4
Other	(2.2)	1.1
General corporate expenses	(32.0)	(22.9)
Total operating income	261.3	228.2
Interest accrued	(245.5)	(352.0)
Interest capitalized	4.8	11.9
Interest rate swap loss	(8.1)	(2.8)
Investing income	10.5	46.3
Minority interest in income of consolidated subsidiaries	(4.8)	(5.5)
Other income - net	.8	22.1
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	20.4	(50.8)
Provision (benefit) for income taxes	15.0	(11.3)
Income (loss) from continuing operations	5.4	(39.5)
Income (loss) from discontinued operations	4.5	(15.5)
Income (loss) before cumulative effect of change in accounting principles	9.9	(55.2)
Cumulative effect of change in accounting principles	—	(761.3)

Revenues include:

- Gross revenue for non-derivative contracts (eg., tolling)
- Gross revenue for realization of physically settled forward sales contracts
- Net revenues for changes in fair value of derivatives (unrealized gains and losses)
- Note: Changes in fair value of non-derivatives no longer reported

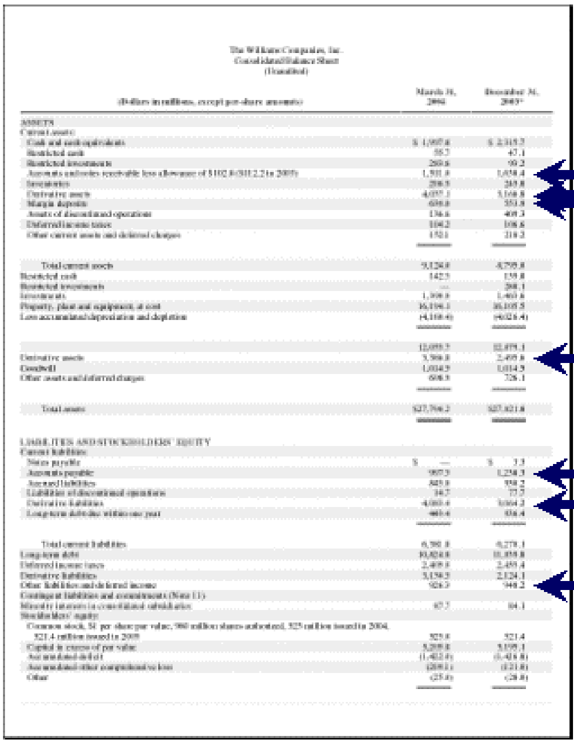
Costs & op exps include:

- Demand payments
- Gross purchases for realization of physically settled forward purchases

Selling, General & Administrative Expenses

Note: The full 1Q04 consolidated statement of operations is available on williams.com.

Balance Sheet: 1Q 2004 10-Q



Accounts Receivable: Commodity sales and derivative settlements

Derivative Assets: Fair value (unrealized gains) of derivatives

Margins: Margins, adequate assurance and prepays paid to others

Note: Fair value of non-derivative contracts no longer reported on the balance sheet

Accounts Payable: Commodity purchases

Derivative Liabilities: Fair value (unrealized losses) of derivatives

Note: The full 1Q04 consolidated balance sheet is available on williams.com.

Frequently Asked Questions

FAQ

What happens if a plant realizes a heat rate greater (or less) than what is provided under the contract?

Although the terms vary, all of the tolling agreements have "heat rate guarantees" that effectively put the risk and benefit of heat rates that differ from the guaranteed rates on the plant owner/operator. These contractual/financial guarantees by the owner/operator allow Williams to focus on market conditions in making dispatch decisions.

What happens if a plant exhibits low availability?

All of Williams' tolling agreements have availability guarantees, again with variations in terms, that provide for discounts to Williams' payments in the event target availabilities are not achieved. Availability bonuses are designed to give owner/operators incentives to achieve higher availabilities.

Please explain what re-powering (improvement) rights Williams has under the AES4000 agreement?

Subject to specified conditions, Williams has the right to cause unit repowering to achieve heat rate improvements. If the repowering is not pursued, Williams has a buy-out right for an amount equal to the outstanding debt attributable to the unit, plus costs, and equity (including ROE).

How does the Product D contract compare to the AES4000 PPA?

The Product D contract functions essentially as a "mirror image" of the the AES 4000 agreement: CDWR has tolling and dispatch rights to designated units that mirror Williams' rights with AES, subject to important exceptions, including price and volume.

Does Williams have any gas price risk associated with Product D?

CDWR is responsible for obtaining (at its cost) fuel for the designated units. Williams has supplied index-priced fuel to the CDWR for designated units under a fuel supply plan.

Note: All answers regarding Williams' contracts are necessarily summary in nature and subject to the specific provisions of the agreements.

FAQ (Cont.)

Is Williams required to supply energy for the CDWR contracts from the AES 4000 plants?

Product D is the only contract that requires delivery of energy from the AES 4000 plants. Energy for Products ABC can be supplied from the market and as long as it is scheduled to SP-15.

How do the ratings agencies calculate imputed debt for the power portfolio?

It is our understanding that S&P discounts the demand payments back at 10% and takes 70% of that number. While Moody's uses a similar methodology, they do not publish their calculated results.