City of Grand Island

Tuesday, August 22, 2006
Council Session

Item F3

#9064 - Consideration of Amending Chapter 15 of the City Code, Electric Rate

Staff Contact: Gary R. Mader

Council Agenda Memo

From: Gary R. Mader, Utilities Director

Meeting: August 22, 2006

Subject: Consideration of Amending Chapter 15 of the City Code**,** Electric Rate

Item #'s: F-3

Presenter(s): Gary R. Mader, Utilities Director

Background

After an extended period of relatively stable prices in the energy sector, things began to change approximately five years ago. In 2003, the Electric Department recognized that there had been a steady increase in costs of materials and fuels resulting in a corresponding decline in the cash reserves of that Department. That decline in financial condition resulted in the commission of the Electric Rate Study that was done in 2004, by Stanley Consultants. Historical cost and expense trends were projected to the future, and from those cost projections a coordinated rate increase schedule was developed. The results of the financial evaluation indicated a need for a revenue increase of 11.5%. At that time, after over 20 years of stable rates, it was decided that the rate increase would be phased in over a two year period, with rate changes programmed for January of 2005 and 2006. That same analysis, based on historical data, recommended that a third rate increase might be needed in 2008. The implemented rate increases had the predicted result and the downtrend in the reserves of the Electric Department was reversed.

Then in 2006, major changes occurred in the energy sector. Primary fossil fuels saw unprecedented increases in late 2005 and early 2006. The City's primary power plant fuel, coal, more than tripled in price from early 2005 to January 2006, with coal markets going from approximately $5.00 per ton to over $16.00 per ton. And during that same period freight costs to move the coal from the coal fields to the power plant increased over 20% because of the rapidly increasing price of the diesel fuel required to run the trains. 200% coal cost increases and 20% freight cost increases were not part of the rate study done in 2004. The Electric Department has not yet encountered the full impact of these large cost increases because of term contracts currently in place. The current coal contract expires December 13, 2006.

Additionally, the cost of materials for the Electric Department have increased rapidly over the last year. Power conductor, transformers, conduit, underground cable, and other materials necessary for the maintenance and growth of the electric system have increased from 40% to over 150%. There have been a number of theories put forth as to the cause of these steep increases metal products, but the Department has no control over these markets. The Rate Study anticipated continuing increasing costs, but not at the high rate seen recently, and included a provision for an additional rate increase in 2008. The timing of that change needs to be reconsidered.

Discussion

While the rate increases implemented as a result of the 2004 Rate Study accomplished the projected improvement in the finances of the Department, the recent increases in fuel and materials cost were not a part of than evaluation. In order to maintain the financial position of the Electric Department, a substantial rate increase will be required.

At the time of budget preparation in February, the coal and freight costs at that time were included in the budget projections. Since then, there have been some significant changes in the fuels and energy markets, and in the materials markets. Coal markets have moderated somewhat, but remain well above our current contract price. That moderation results in the ability to reduce the initially projected cost increase of $0.009 per kwh. But rail freight rates for coal transport have continued to increase as fuel oil prices have continued to increase. Materials prices have continued to increase steeply. Underground power cable, that was up 40% at the time of budget preparation, has now tripled in price. Additionally the Department was recently notified that the power purchased from the Western Area Power Administration (WAPA - the federal hydro projects on the Missouri River) will be increasing 6% next year, with 20 to 25% increases anticipated in the near future.

In anticipation of the expiration of the current coal contract later this year, bids for continued coal supply were solicited for 2007 and 2008. The softening coal markets resulted in a coal cost below that included in the initial budget preparation. Since the coal price in the largest impact component of the cost of providing electric power, that reduction has a major impact on the costs to the Department. With the coal costs now known, materials costs and WAPA purchase power costs adjusted for continued increases, the rate increase required to maintain the Electric Department's at this time is revised downward to $0.007 per kwh. That amount is included in the revised '06 - '07 Budget.

Attached for reference are copies of articles from across the country relating to the rapidly changing costs for electric utilities and copies of the presentation anticipated for the electric rate increase consideration.

Alternatives

It appears that the Council has the following alternatives concerning the issue at hand. The Council may:

1. Move to approve
2. Refer the issue to a Committee
3. Postpone the issue to future date
4. Take no action on the issue

Recommendation

City Administration recommends that the City Council approve the Electric rate change needed to compensate for the increased cost of fuel, power, and materials.

Sample Motion

Make a motion to approve Ordinance #9064.

Proposed Electric Rate Adjustment

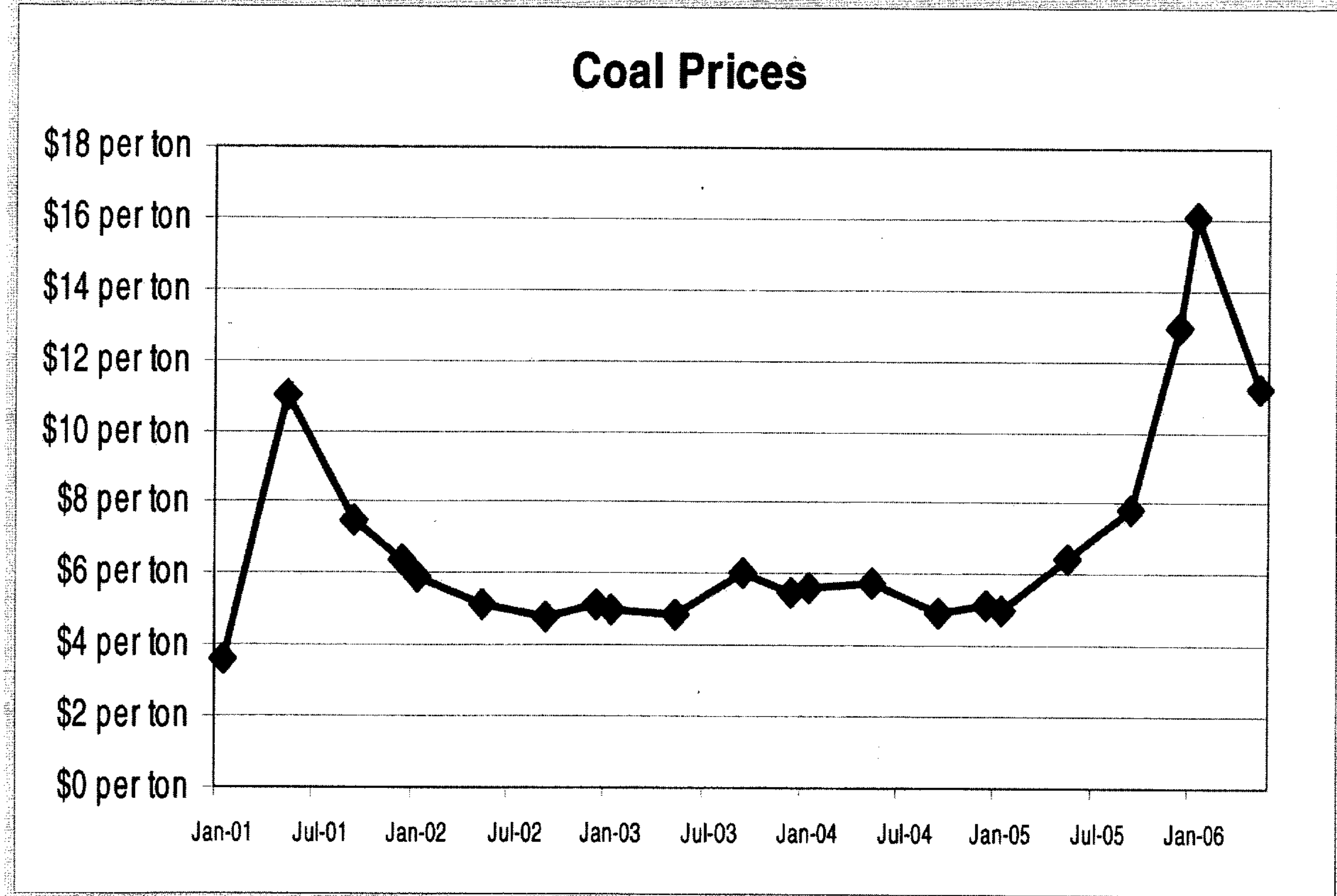
Relevant History

- 1973 Fuel Adjustment implemented
- 1982 Platte Generating Station
- 1988 Total Delivered Coal cost $30/ton
- 1989 Contract Buy-outs
- 1989 Total Delivered Coal cost $12/ton
- 1989 Rate Decrease
- 2004 Rate Study by Stanley Consultants
- 2006 Delivered Coal $17/ton
- 2006 Coal Contract expires, and the Freight Contract Cost Escalates in 2007
- Anticipated Delivered Coal Cost $22/ton in 2007

Current Coal Contract Expires

December 31, 2006

Coal Market Prices have More Than ***Tripled*** Since Early 2005

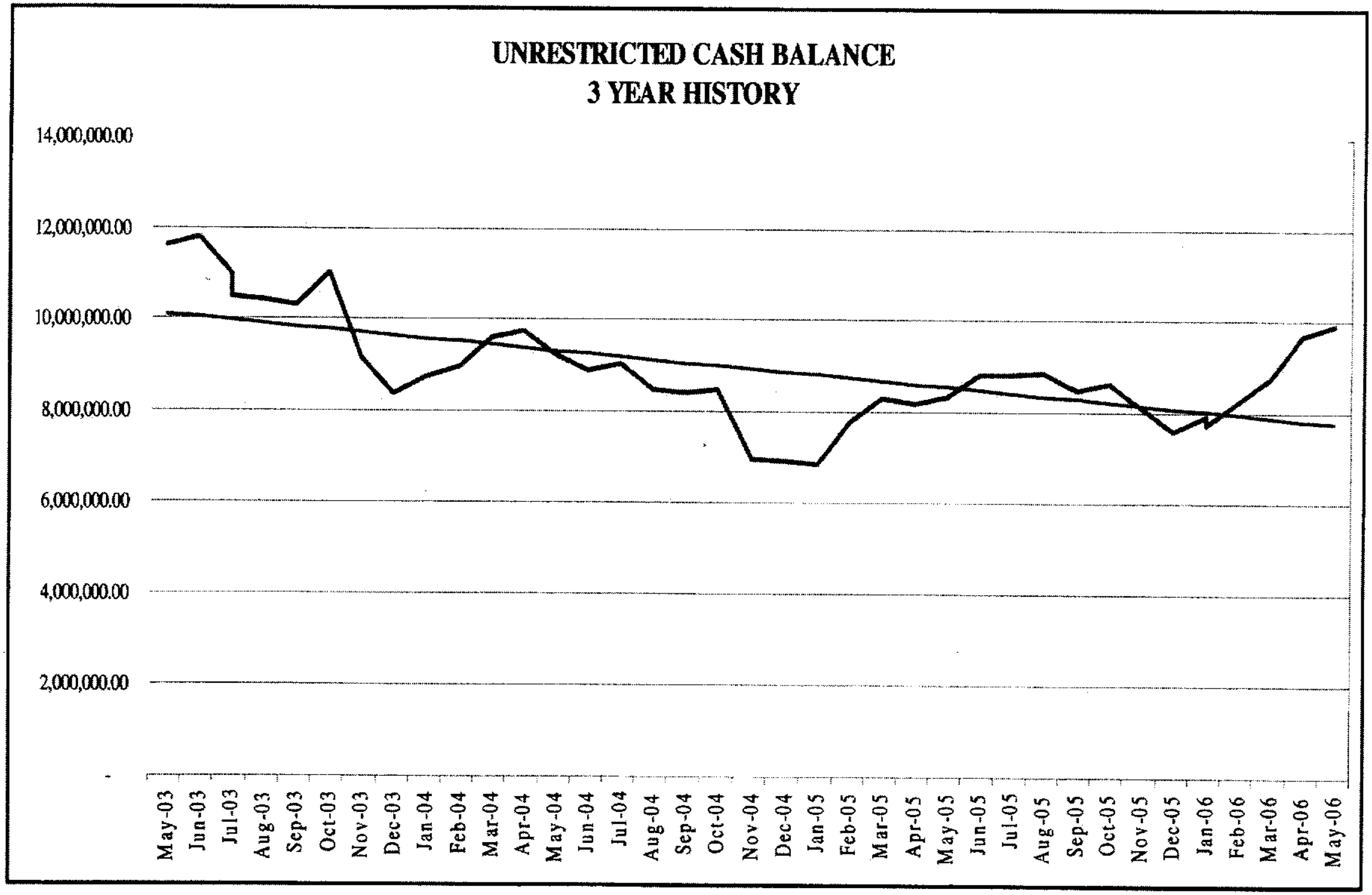

Coal Prices
$18 per ton
$16 per ton
$14 per ton
$12 per ton
$10 per ton
$8 per ton
$6 per ton
$4 per ton
$2 per ton
$0 per ton
Jan-01
Jul-01
Jan-02
Jul-02
Jan-03
Jul-03
Jan-04
Jul-04
Jan-05
Jul-05
Jan-06

Coal Freight Contract

3% Escalation

23% Fuel Adjustment

Total Increase in Coal Freight Price – ***25%***


UNRESTRICTED CASH BALANCE
3 YEAR HISTORY
14,000,000.00
12,000,000.00
10,000,000.00
8,000,000.00
6,000,000.00
4,000,000.00
2,000,000.00
May-03
Jun-03
Jul-03
Aug-03
Sep-03
Oct-03
Nov-03
Dec-03
Jan-04
Feb-04
Mar-04
Apr-04
May-04
Jun-04
Jul-04
Aug-04
Sep-04
Oct-04
Nov-04
Dec-04
Jan-05
Feb-05
Mar-05
Apr-05
May-05
Jun-05
Jul-05
Aug-05
Sep-05
Oct-05
Nov-05
Dec-05
Jan-06
Feb-06
Mar-06
Apr-06
May-06

Stanley Consultants Recommendations, Basic Rate Structure

- 2005 5% Revenue Increase
- 2006 5% Revenue Increase
- 2008 3% Revenue Increase

Study done 2004, Based on 2003 data

Stanley Consultants Recommendations, <u>Fuel Adjustment</u>

- Rename to Power Cost Adjustment (PCA)
- Increase Production Cost Base
- Old PCA Base $12/MWh
- New PCA Base $15/MWh
- Roll $3/MWh into Electric Rates
- $3/MWh equals 0.3¢/kWh

FUEL ADJUSTMENT SUMMARY FOR 2004

ENERGY	TOTAL COST	SOURCE
	GENERATION	
-287.508 MWh	$205,974.83	BURDICK STATION -- STEAM TURBINES
637,478.116 MWh	$6,390,905.73	PLATTE GENERATING STATION
680.460 MWh	$275,799.53	BURDICK STATION -- COMBUSTION TURBINES
637,871.068 MWh	$6,872,680.09	TOTAL GENERATION
	TRANSMISSION EXPENSE	
n/a	$140,600.00	WAPA FIRM
n/a	$741.25	NEBR. DISTRIBUTED WIND GENERATION
n/a	$217,829.51	MAPP Schedule F
-65.500 MWh	$15,206.17	ENERGY IMBALANCE, IMPORT & Transmission
	RECEIPTS	
33,522.000 MWh	$531,574.38	WAPA FIRM
49,133.000 MWh	$2,050,067.28	NPPD TYPE EA0
.000 MWh	$0.00	NPPD EMERGENCY
72.704 MWh	($578.67)	NEBR. DISTRIBUTED WIND GENERATION
82,727.704 MWh	$2,581,062.99	NET SCHEDULED RECEIPT
	DELIVERIES	
69,320.000 MWh	$1,821,205.00	NPPD TYPE EA0
263.000 MWh	$10,658.90	MAPP EMERGENCY
69,583.000 MWh	$1,831,863.90	NET SCHEDULED DELIVERY
650,950.272 MWh	**$7,996,256.11**	**SYSTEM TOTAL**
	$12.28 / MWh	**Average Cost**

FUEL ADJUSTMENT SUMMARY FOR 2005

ENERGY	TOTAL COST	SOURCE
	GENERATION	
-396.708 MWh	$206,983.36	BURDICK STATION -- STEAM TURBINES
659,723.068 MWh	$7,542,524.87	PLATTE GENRATING STATION
8,425.710 MWh	$1,263,810.63	BURDICK STATION -- COMBUSTION TURBINES
667,752.070 MWh	$9,013,318.86	TOTAL GENERATION
	TRANSMISSION EXPENSE	
n/a	$142,500.00	WAPA FIRM
n/a	$4,589.97	WIND GENERATION TRANSMISSION
n/a	$265,996.22	MAPP Schedule F
116.600 MWh	$32,542.90	ENERGY IMBALANCE, IMPORT & Transmission
	RECEIPTS	
33,428.000 MWh	$549,017.07	WAPA FIRM
48,432.000 MWh	$3,298,502.77	NPPD TYPE EA0
18.000 MWh	$424.62	NPPD EMERGENCY
1,039.132 MWh	$12,638.20	WIND GENERATION
82,917.132 MWh	$3,860,582.66	NET SCHEDULED RECEIPT
	DELIVERIES	
53,626.000 MWh	$1,709,903.50	NPPD TYPE EA0
.000 MWh	$0.00	NPPD OPERATIONAL CONTROL
153.000 MWh	$7,840.20	MAPP EMERGENCY
53,779.000 MWh	$1,717,743.70	NET SCHEDULED DELIVERY
697,006.802 MWh	**$11,601,786.91**	**SYSTEM TOTAL**
	$16.65 / MWh	**Average Cost**

EFFECT of ANTICIPATED COAL COST
PRODUCTION COST SUMMARY FOR 2005

July 26, 2006

ENERGY	HISTORICAL TOTAL COST	PROJECTED TOTAL COST	SOURCE
		GENERATION	
-396.708 MWh	$206,983.36	$206,983.36	BURDICK STATION -- STEAM TURBINES
659,723.066 MWh	**$7,542,524.87**	**$9,625,031.74**	**PLATTE GEN. STATION**
8,425.710 MWh	$1,263,810.63	$1,263,810.63	BURDICK STATION -- COMBUSTION TURBINES
667,752.070 MWh	$9,013,318.86	$11,095,825.73	TOTAL GENERATION
		TRANSMISSION EXPENSE	
n/a	$142,500.00	$142,500.00	WAPA FIRM
n/a	$4,589.97	$4,589.97	WIND GENERATION TRANSMISSION
n/a	$265,996.22	$265,996.22	MAPP Schedule F
116.600 MWh	$32,542.90	$32,542.90	ENERGY IMBALANCE, IMPORT & Transmission
		RECEIPTS	
33,428.000 MWh	**$549,017.07**	**$652,784.32**	**WAPA FIRM**
48,432.000 MWh	$3,298,502.77	$3,298,502.77	NPPD TYPE EA0
18.000 MWh	$424.62	$424.62	NPPD EMERGENCY
1,039.132 MWh	$12,638.20	$12,638.20	WIND GENERATION
.000 MWh	$0.00	$0.00	
	n.c.	n.c.	INADVERTENT PAYBACK
82,917.132 MWh	$3,860,582.66	$3,964,349.91	NET SCHEDULED RECEIPT
			INADVERTENT
		DELIVERIES	
53,626.000 MWh	$1,709,903.50	$1,709,903.50	NPPD TYPE EA0
.000 MWh	$0.00	$0.00	NPPD OPERATIONAL CONTROL
153.000 MWh	$7,840.20	$7,840.20	MAPP EMERGENCY
			INADVERTENT PAYBACK
53,779.000 MWh	$1,717,743.70	$1,717,743.70	NET SCHEDULED DELIVERY
			INADVERTENT
29,254.732 MWh	$2,588,468.05	$2,588,468.05	NET METERED IMPORT
697,006.802 MWh	**$11,601,786.91**	**$13,788,061.03**	**SYSTEM TOTAL**

Average Production Cost **$16.65 / MWh** **$19.78 / MWh**

Increase in Production Cost Above $15/MWh Base **$4.78 / MWh**

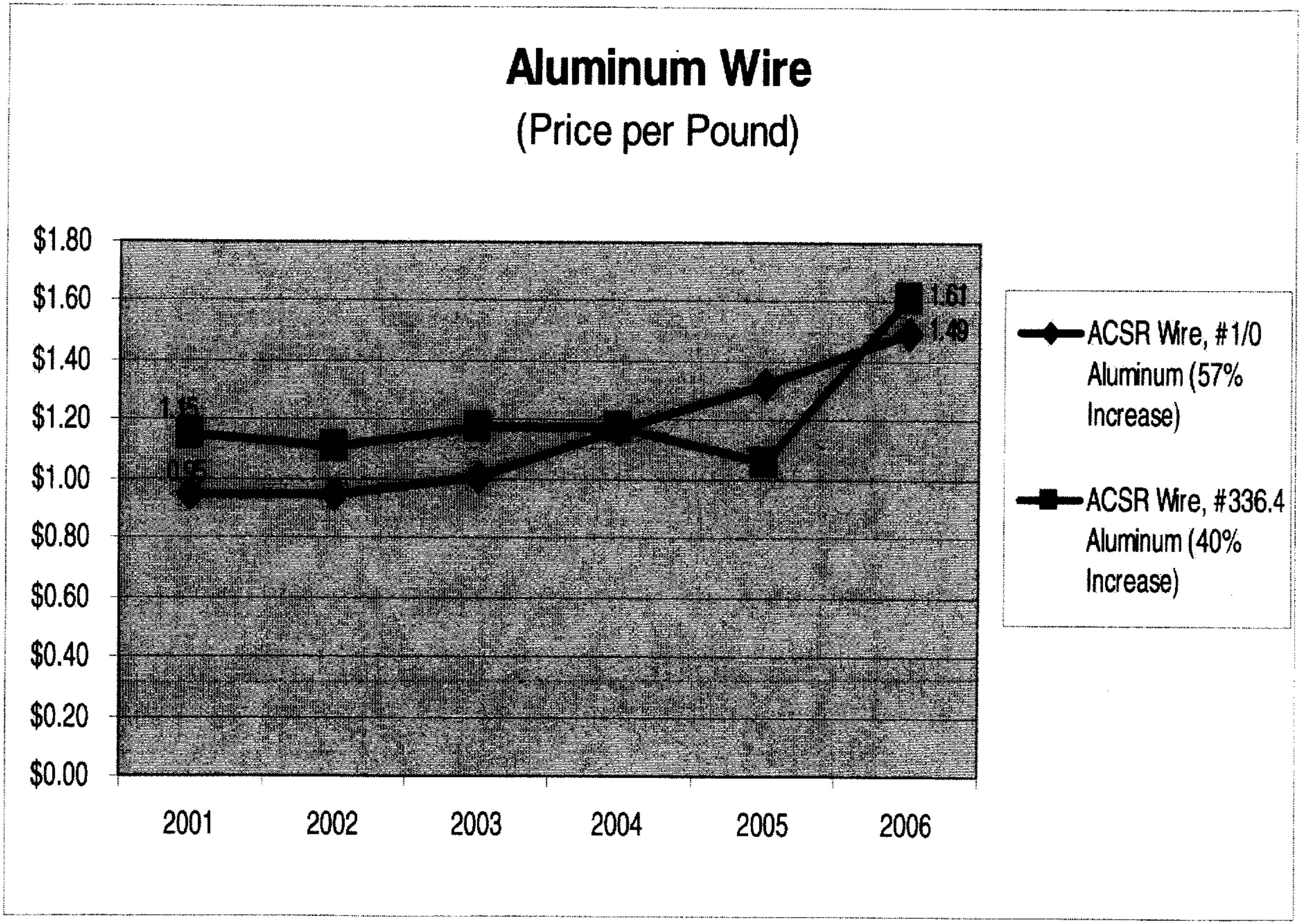
Production Cost Trends

- Calendar Year 2004 Average Power Costs, **$12.74/MWh** with a **$12/MWh** PCA Base
- 2004 Stanley Consultants recommends PCA Base be increased to **$15/MWh** for 2005
- Calendar Year 2005 Average Power Costs, **$16.65/MWh**.
- Costs anticipated to be nearly **$20/MWh** in Calendar Year 2007 with new coal contract and freight contract with fuel adjustment and escalation

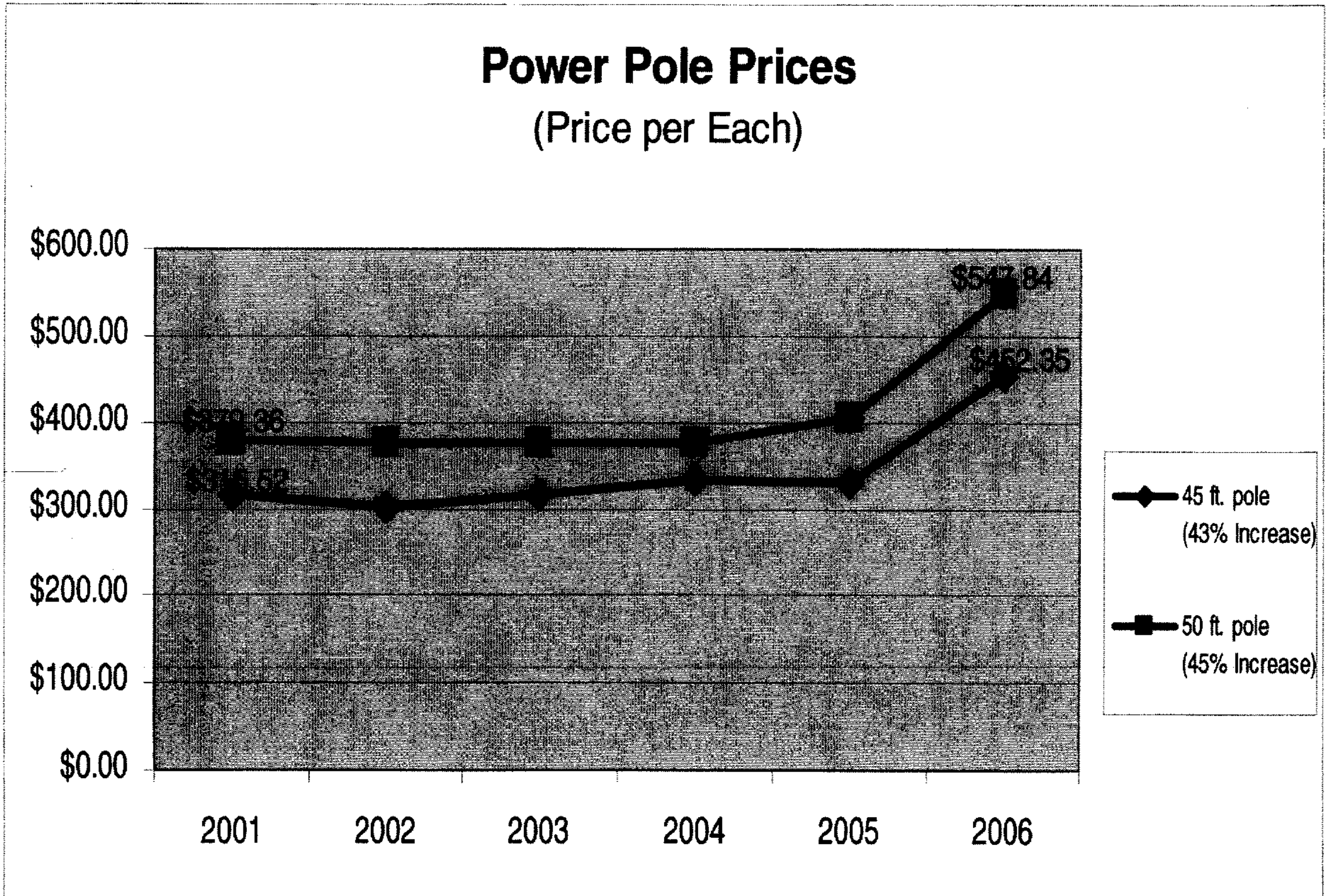
Fuel Cost Increase

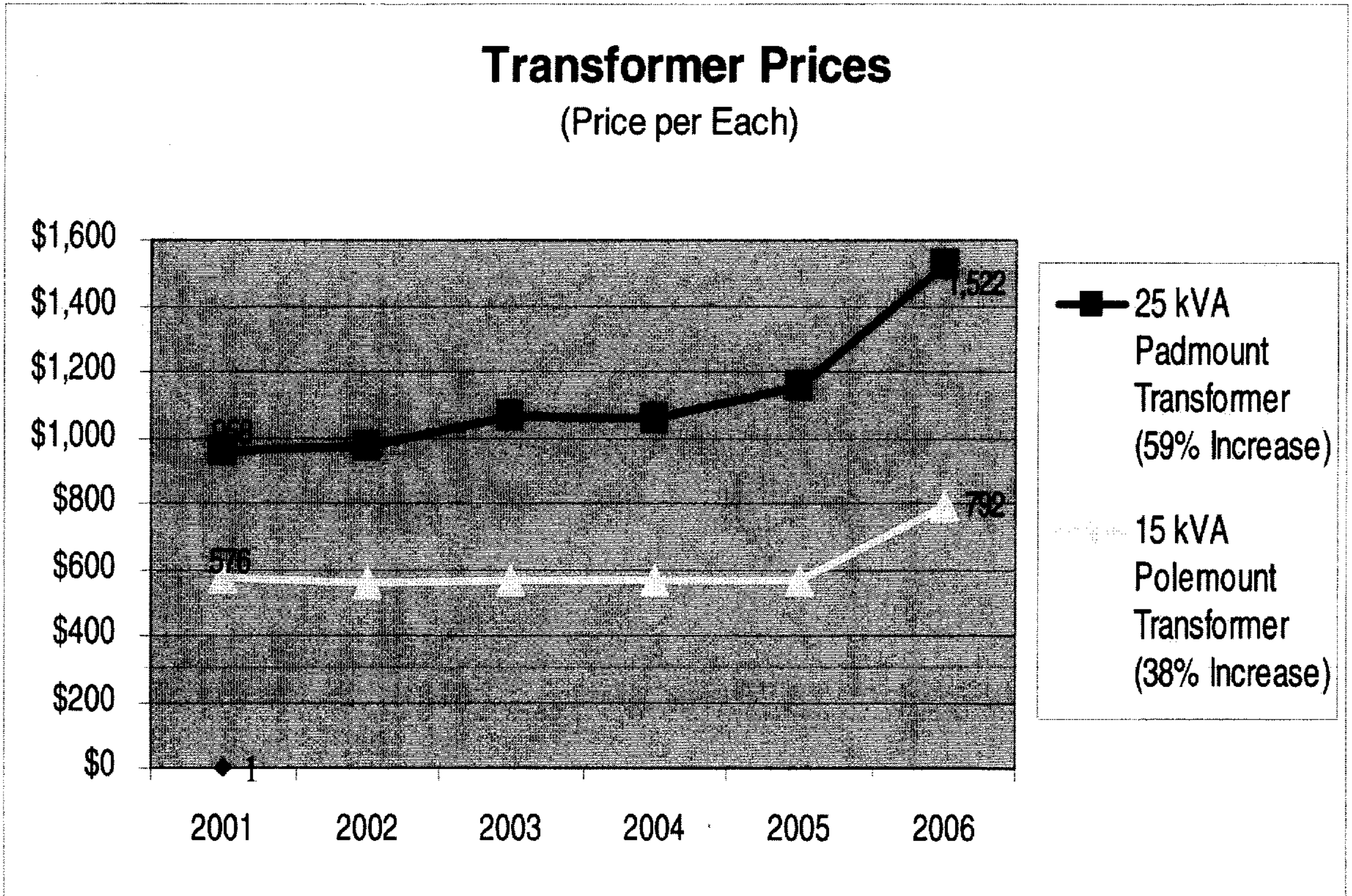
- Increase Production Cost Base to **$20/MWh**
- An increase of **$5/MWh** from the current **$15/MWh** Base
- Roll corresponding amount into the basic Electric Rates
- Energy blocks for all Electric **Rates increase by 0.5¢/kWh** Just to Cover fuel cost increase
- Begin with January 2007 billings, i.e. December 2006 consumption

Material Costs

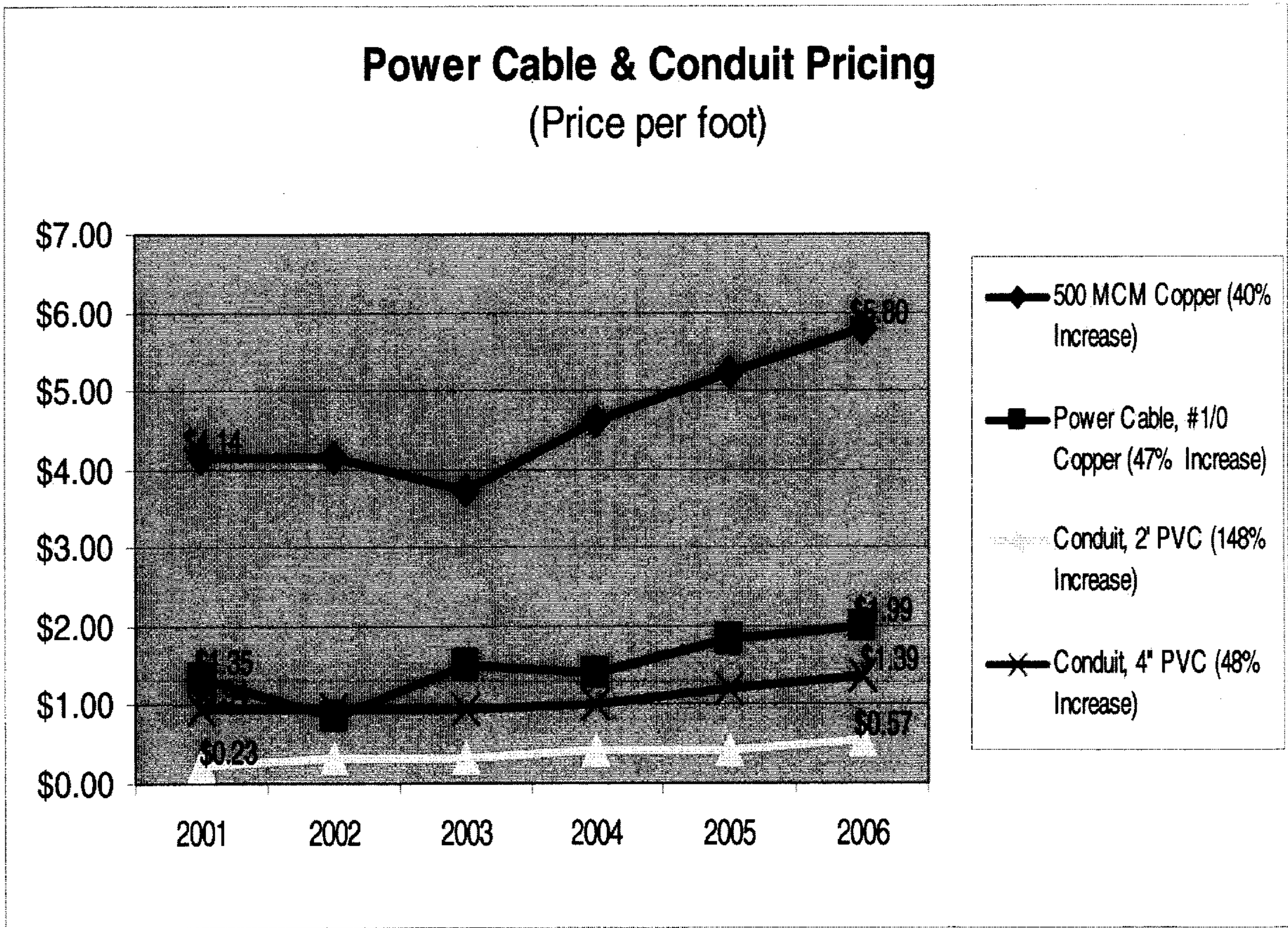


Aluminum Wire
(Price per Pound)
$1.80
$1.60
$1.40
$1.20
$1.00
$0.80
$0.60
$0.40
$0.20
$0.00
2001
2002
2003
2004
2005
2006
1.61
1.49
ACSR Wire, #1/0 Aluminum (57% Increase)
ACSR Wire, #336.4 Aluminum (40% Increase)


Power Pole Prices
(Price per Each)
$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$0.00
2001
2002
2003
2004
2005
2006
$547.84
$452.35
45 ft. pole
(43% Increase)
50 ft. pole
(45% Increase)



Transformer Prices
(Price per Each)
$1,600
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
576
1,522
792
1
2001
2002
2003
2004
2005
2006
25 kVA Padmount Transformer (59% Increase)
15 kVA Polemount Transformer (38% Increase)


Power Cable & Conduit Pricing
(Price per foot)
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
2001
2002
2003
2004
2005
2006
$1.35
$0.23
$1.99
$1.39
$0.57
500 MCM Copper (40% Increase)
Power Cable, #1/0 Copper (47% Increase)
Conduit, 2' PVC (148% Increase)
Conduit, 4" PVC (48% Increase)

Recommendation ’06 – ‘07

1) Stanley Consultants Recommendation of 3% Revenue Increase would add 0.17¢/kWH

2) Add 0.5¢/kWH For Increased Fuel Costs
   <u>Add 0.2¢/kWH For Increased Material Costs</u>

Total 0.7¢/kWH

3) Budget as proposed Includes Increased Expenses and 0.7¢/kWH Rate Increase

Background Information Regarding Increasing Coal, Freight, and Electricity Prices

The Kiplinger Letter

FORECASTS FOR MANAGEMENT DECISIONMAKING

1729 H St. NW, Washington, DC 20006-3938 • KiplingerForecasts.com • **Vol. 83, No. 24**

Mader
Gilpin
~~Riehle~~
Kortum
Strehle

~~Smith~~
Greer
Mayor
~~Albright~~

Dear Client:

Washington, June 16, 2006

On health care, there's cheering news. Employer cost-cutting is working, driving annual increases into single digits for the first time since 2000. Next year...9%.

HEALTH CARE

But keeping up momentum will be tough. The aging population and relentless push for tech advances exert upward pressure on costs. Savings from higher deductibles and copays for workers, more switching to generic drugs, fewer hospital stays, etc., will go only so far.

Employees need to make better choices about their health care treatments and providers as well as their lifestyles and health regimens.

And employers need to help them do it. Capturing the savings will require spoon-feeding, making sure workers get and grasp information about treatment options, results and trade-offs, and creating opportunities for healthier living.

Ratchet up preventive care and education. Every dollar spent on them saves nearly $3.50 in health care and about $5.80 in absenteeism.

... Individual health risk assessments for workers.

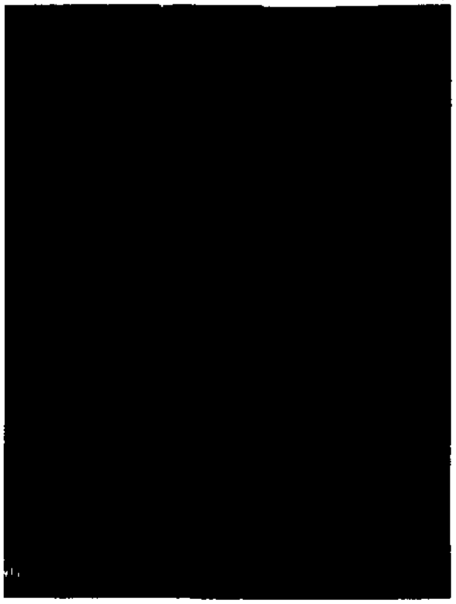
ENERGY FORECASTS

Energy Source	Current	Late Sept.	Jan. 2007
Crude oil (per barrel)	$69	$63	$55
Natural gas (per MMBtu at wellhead)	$7.15	$7.00	$9.50
Regular gasoline (per gallon)	$2.90	$2.75	$2.50
Diesel fuel (per gallon)	$2.98	$3.00	$2.75
Heating oil (per gallon)	$2.65	$2.90	$2.80
[illegible]	[illegible]	[illegible]	[illegible]

Grand Island at 5.24¢ in fiscal 04-05, the latest full audited data year.

POWER WEEKLY

Public Power Association No. 30 July 31, 2006



week, utilities asked their customers to
ace transformers that had self-destructed
attributed to the triple-digit temperatures.
nergy affairs, said this is the first time in 57
ern California have been hit by an extended

Six Iowa cities seek to create electric utilities

Six communities in Iowa have filed petitions with state regulators asking to establish city-owned electric utilities. The six—Everly, Kalona, Rolfe, Terril, Titonka and Wellman—filed their documents with the Iowa Utilities Board in early June. All are currently served by Alliant Energy, based in Madison, Wis., and all have held referendums in which residents voted in favor of unplugging the investor-owned utility and forming municipal electric systems.

Summer electric rates in Everly are now running 13.9 cents per kilowatt-hour, said Bruce Harden, the city's utility manager. Nearby cities that own their own electric utilities are charging in the six- to seven-cent range, he said.

GI at 8.24¢ for Last Fiscal Year

Everly, population 650, is prepared for a long fight with Alliant to take control of the community's distribution system, Harden said. It went through a similar struggle when it took over the local natural gas service from Peoples Natural Gas Co., he said. Residents voted in the mid-1980s to buy the natural gas system, but the private

(continued on page 3)

cess now moves :onsultants say

Buzz Canup, agreed with that observation. "You are on the short list before you even realize you were on someone's long list," he said. Canup is president of site selection services for Angelou Economics, an Austin, Texas, consulting firm.

The panelists spoke at July 24 session at the APPA meeting in Austin.

Asked what is the most important factor for companies seeking to site a new facility, all four members of the panel named the quality of the labor force. But, companies do their own research to determine how well a locality's work force matches its needs; they will not rely on local communities' marketing materials in making these assessments,

(continued on page 3)

Inside

The Grand Island Independent

Tuesday, July 25, 2006

SAN FRANCISCO

Sweltering California heat wave prompts power emergency, cited in at least four deaths

2 Power companies worked to restore electricity to thousands of customers throughout California early Monday as a scorching heat wave threatened to push the state into a power emergency with the potential for more blackouts.

Authorities were looking into several deaths possibly related to the high temperatures, which hit the triple digits in some areas on Sunday.

With temperatures again expected to top 100 degrees, power demand was projected to reach an all-time high Monday and prompt some voluntary blackouts, in which some businesses agree to have their power shut off temporarily in exchange for lower rates, according to the Independent System Operator, California's power grid manager.

Those blackouts could become involuntary if customers don't conserve electricity, said ISO spokesman Gregg Fishman.

"It's actually critical that people conserve power," Fishman said.

INTERοFFICE MEMORANDUM

CITY OF GRAND ISLAND

Working Together for a Better Tomorrow. Today.

DATE: April 10, 2006

TO: Gary Greer, City Administrator

FROM: Gary R. Mader, Utilities Director

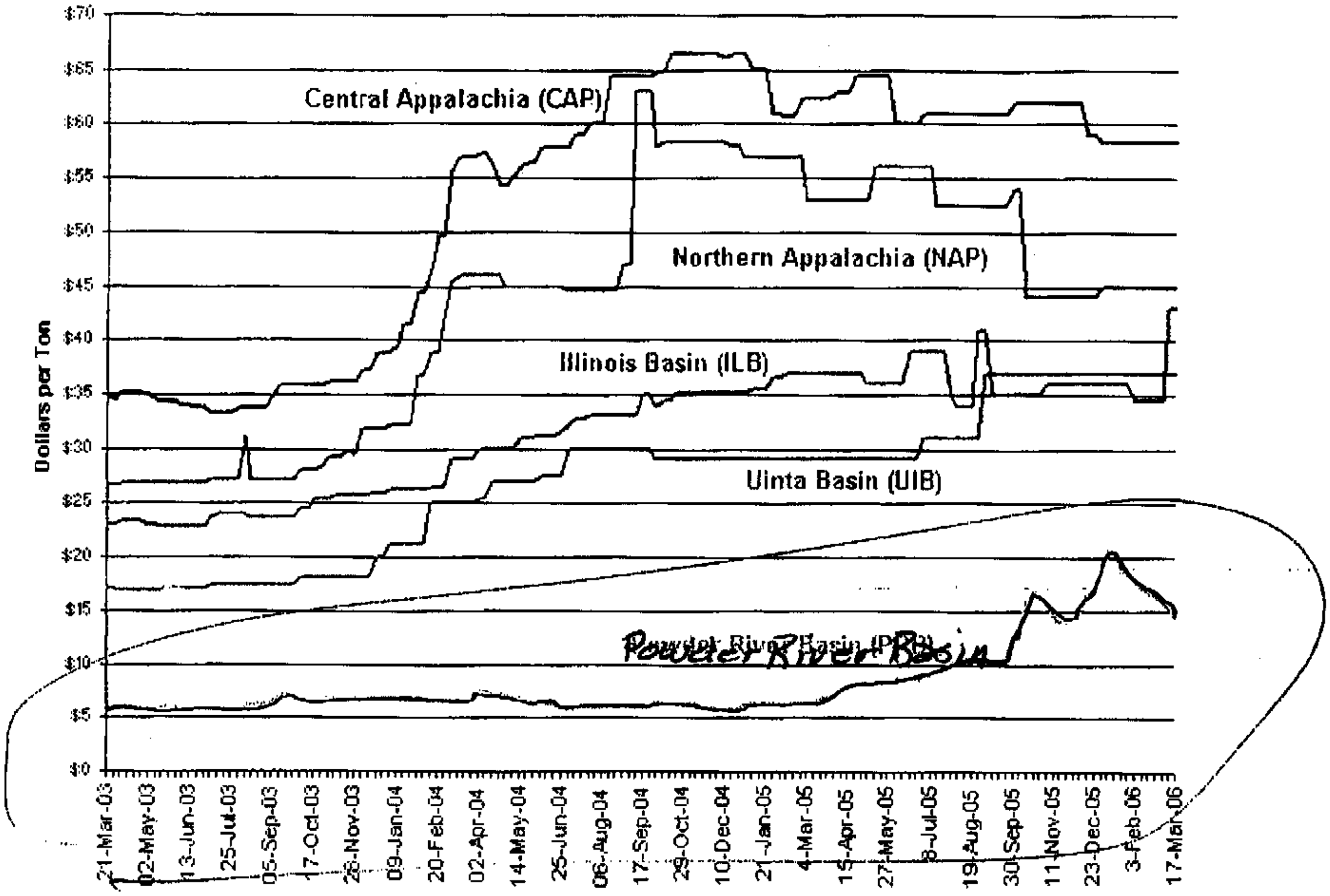
SUBJECT: Coal Prices

Grand Island is currently in the last year of a term contract for coal supply to PGS. That contract expires December 31, 2006. During the term of this current contract, coal prices more that tripled. The attached graph from the Federal Energy Information Administration provides a historical record of pricing since March 2003. The Electric Department's current pricing for coal is reflected in the '04, early '05, time line on the graph. And while there is at present a down trend in price, it remains nearly triple '04 levels, and is not expected to return to the '04 levels.

Additionally, the current ramp up of diesel fuel prices has increased the fuel adder in the coal transportation contract with Union Pacific, adding even more cost to the delivered coal price.

This sudden ramp up of the City's primary fuel cost will result in large increases in Electric Department operating expenses and will need to be reflected in increased electric rates in the '06 – '07 Budget.

GRM/pag



Key to Coal Commodities by Region'

Central Appalachia:	Big Sandy/Kanawha 12,500 Btu, 1.2 lbSO2/mmBtu	Powder River Basin:	8,800 Btu, 0.8 lb SO2/mmBtu
Northern Appalachia:	Pittsburgh Seam 13,000 Btu, <3.0 lbSO2/mmBtu	Uinta Basin in Colo.:	11,700 Btu, 0.8 lb SO2/mmBtu
Illinois Basin:	11,800 Btu, 5.0 lb SO2/mmBtu		

25

platts

www.platts.com

To: G. Greer
our current Contract
was effective Jan. 1, 2005
cc: Burhl Davis.
Tim Darren B.

Coal Outlook

Vol 30 / No 4 / January 23, 2006

Powder River Basin sets coal production record as prices, demand rise

Despite rail delivery problems last year, it appears the Powder River Basin continues to produce record amounts of low-sulfur coal that is in increasing demand and bringing higher prices.

According to preliminary estimates by the Energy Information Administration, the PRB produced a record 445.1 million tons of coal in 2005, with Wyoming contributing 407.3 million tons and Montana, the other 37.8 million tons.

That is a 2.0% increase from 2004, despite derailments caused by a mid-May snowstorm on the Joint Line operated by BNSF Railway and Union Pacific Railroad (*PCT 5/19/05*). The repairs lasted through mid-December (*PCT 12/14/05*).

The railroads also had to contend with a late November/early December snowstorm that slowed deliveries. Early January loadings were impacted by a conversion BNSF, which dispatches the line, made to a new dispatching system (*PCT 1/17*). But Dennis Duffy, UP's executive vice president of operations, said BNSF has temporarily returned to the prior dispatching system and operations have returned to a more normal state.

BNSF statistics show its PRB loadings averaged 46.14 trains/day the week ended Dec. 18, 46.43 the week ended Dec. 25, 50 the week ended Jan. 1, 49.71 the week ended Jan. 8 and 46.6 the week ended Jan. 15.

PRB production has grown 155.8%

(continued on page 12)

Production ... from page 1

since 1985 when, according to EIA data, it was 174.0 million tons. The EIA estimates that the United States will demand an additional 100 million tons of coal annually from the PRB by 2010.

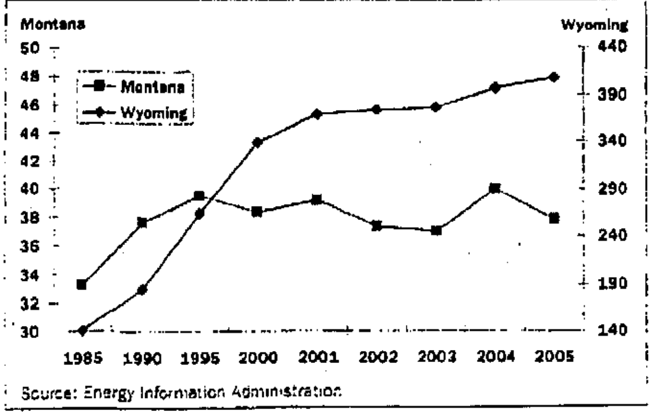
Montana's production has remained steady or fallen slightly while Wyoming's production has grown each year.

An estimated 2.4% increase in Wyoming coal production from 2004 would translate into good economic news for a state that receives most of its revenues from minerals. Severance taxes, federal mineral royalties and coal lease bonus bid payments from the coal industry in 2005 will exceeded $600 million, according to the state's economic analysis division. That does not include sales and use taxes, secondary business or the more than $600 million in annual payroll for the industry's 4,600 employees.

In Montana, Larry Finch, the state's tax policy and research administrator in the revenue department, told *Platts Coal Outlook* Jan. 17 that the coal severance tax brought in $29.3 million in 2003, $31.5 million in 2004, $37.6 million in 2005 and is expected to bring in $31.6 million in 2006 and $31.3 million in 2007. The mines also pay property taxes and royalties, which were not included.

The state's budget office based those numbers on production of 30.3 million tons in 2003, 31.9 million tons in 2004 and estimated production of 33.0 million tons in 2005, 32.2 million tons in 2006 and 32.8 million tons in 2007.

PRB coal production (millions of tons)



Source: Energy Information Administration

PRB prices on the rise

PRB 8,800 Btu/lb coal prices steadily increased during 2005, starting Jan. 3 at $5.65/ton — its lowest price of the year — and climbing to $22/ton on Dec. 27, according to *Platts Coal Trader's* OTC Broker Index. It ended the year at $21.85/ton.

According to the same index, the coal averaged $5.64/ton for January 2005 and had risen to an average of $21.85/ton for January 2006, pushed by increasing demand, rising emission credits and rising oil and gas prices.

In addition, the derailments prevented basin producers from meeting increased customer demand last year, leaving utility inventories at record lows. Utilities are trying to replenish their stocks and have been heard to be paying $25/ton or more.

Arch Coal spokesman Greg Schaefer stressed that $25/ton contracts are not the norm. About 85% of Arch's coal production is under contract and would be sold at lower prices.

Wall Street Journal
Wednesday, July 19, 2006

Nation's Power Grid Passes First Test of Summer

Heat Wave Exposes Shortage Of Reserves, Highlighting Urgency of System Overhaul

By John J. Fialka
And Rebecca Smith

North America's power-transmission system so far has passed the first major test of its reliability this summer during two days of Atlantic-to-Pacific heat, but it soaked up more electricity reserves than expected and spurred calls for strengthening the nation's power grid.

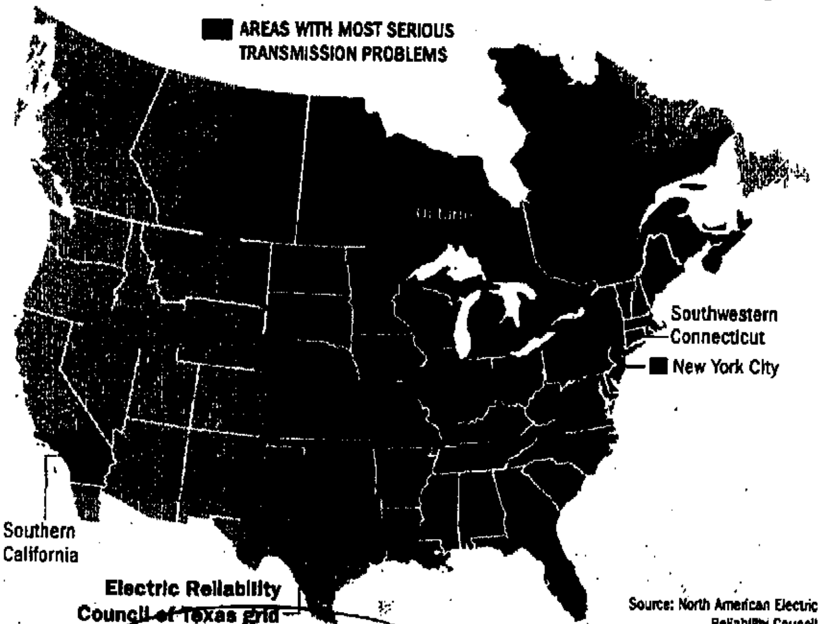
This week's heat wave brought record levels of electricity demand from California to New York to New England, and amounted to a giant stress test that the U.S. power grid—actually three interconnected grids that involve 3,500 utilities serving 283 million people—wasn't designed to handle.

Joseph T. Kelliher, chairman of the Federal Energy Regulatory Commission, said the two-day heat wave set record levels of demand in seven areas across the country. "You couldn't come up with a more serious test of the system," he said, adding that "we need adequate supplies, a more-robust grid and tough reliability standards."

Stephen Whitley, chief operating officer for ISO New England, which manages the grid there, called the heat wave "a major example" of why a bigger, more modern transmission system is needed. "Bulk-power helps us get through these events. We just need to have more of it," he said. He said that while New England was in desperate need of power, cooler weather was entering the Midwest, meaning there was excess electricity there. But the region lacks the connections to move much of the power east.

Taxing the Network

The Western, Eastern and Texas power grids make up the North American power-transmission system. The three grids are poorly connected, making it impossible to transfer large sums of power among them.



Source: North American Electric Reliability Council

The nation's energy infrastructure faces two challenges. The amount of backup power—needed to accommodate sudden spikes in usage caused by extremely hot weather—is adequate. But that amount has been in decline as a result of a growing economy and disruptions in energy markets that caused many firms to cancel new power-plant projects.

Also, the system is plagued by bottlenecks that prevent the movement of large blocks of power to areas that need it. Overhauls enacted in Washington after a major blackout in 2003 were supposed to start correcting those problems.

But progress has been slow. For example, implementing one of the 2003 recommendations, FERC is soon expected to select an industry group, the North American Electric Reliability Council, to enforce uniform, federally backed rules for the grid and to impose fines on violators.

For now, the grid operates under a system of voluntary rules, a kind of honor system for the utilities and grid operators that run high-voltage transmission systems. The U.S.-Canadian task force that investigated the August 2003 blackout cited violations of the voluntary standards, including the failure of utilities to conduct routine monitoring of transmission lines and inadequate pruning of trees along transmission corridors. The blackout caused between $4 billion and $10 billion of damage in parts of the Northeast, Midwest and Canada, according to the task force. Last year, Congress responded by passing an energy bill that requires mandatory standards, backed by monetary penalties, but the rules are months away from being finalized, though a draft has been sent to FERC for review.

Congress also required the Department of Energy to designate national "energy corridors" where congestion is bad and new high-voltage lines might be built. But the department's report isn't due out until next month. That will be the start of a more lengthy process that will allow the federal government to intervene where states cannot agree on the location of interstate power lines.

Craig Baker, senior vice president of American Electric Power Co., the Columbus, Ohio, utility that operates the nation's largest private transmission system, said that federal intervention will help, but that it still doesn't answer the question of who will pay for the multiple billions of dollars needed to build new transmission lines. "We're all looking at massive transmission expenses," he said. He told a forum of utilities and regulators yesterday that state regulators justify improvements that benefit local users, but sometimes reject changes that benefit regional movements on the grid.

FERC is reviewing plans from utilities for several major new interstate power lines. The agency has new powers to authorize higher electricity rates to help finance them, which could help stimulate new investment in the grid, but lead to higher power bills for consumers and businesses.

Yesterday, there were reports of isolated electric-system problems, some caused by overheating of equipment and others by equipment failures. But there weren't the major transmission-line failures that could cause widespread outages for protracted periods of time for millions of people. In New York, grid operators called on big energy users to voluntarily cut use.

It looked like several regions might set new records for electricity usage yesterday, in some cases beating records set the day before, including New York and California. New England, by 1 p.m. EDT, already had metered demand of 26,934 megawatts, narrowly beating a record of 26,885 megawatts set last July, according to ISO New England. One megawatt can power 500 to 1,000 homes.

One major problem is making sure there's enough power available to accommodate sudden spikes in usage caused by extremely hot weather. Backup power is especially needed in summer because electrical equipment is more prone to failure when plants are running hardest and power lines are fully loaded.

Reserve margins, a measure of the amount of surplus power available, in July were expected to be 17% for the U.S. as a whole and 23% for Canada, with the U.S. figure getting closer to the 15% reserve margin that's regarded as a minimum amount needed to assure reliability.

Nationally, the U.S. reserve margin hit 19.4% in 2003, and in some regions it was twice as great. But disruptions in energy markets caused many firms to cancel projects, and a growing economy has eaten up much of that reserve cushion. Even small swings can have a big impact on supplies. In 2000, the year an energy crisis in California began, the U.S. reserve margin slipped to 14.7%.

The electric system is susceptible to fuel problems, as well. Some companies continue to complain that they aren't getting sufficient coal deliveries out of Wyoming's Powder River Basin to keep their coal-fired plants running at maximum output. Rail problems from more than a year ago continue to cause delays as tracks are strengthened. Another type of fuel shortage could emerge, as well, if there are hurricanes along the Gulf Coast that disrupt natural-gas production, as they did last summer.

THE ECONOMY

Heat Blast Tests U.S. Electric System

Soaring Demand Underlines Regulatory, Industry Alerts On Need for More Capacity

By Rebecca Smith

Scorching temperatures strained electric systems throughout the nation as consumption broke records, underscoring warnings by regulators and industry officials that the nation isn't building enough power plants and transmission lines.

Grid officials in the most populous states asked consumers to trim electricity use to reduce the possibility of supply disruptions. Despite conservation efforts, records for electricity consumption were set in the Midwest and Texas and were expected in California.

In the Midwest, demand surged past the record of 131,435 megawatts by late afternoon and in Texas swept past the record of 60,279 megawatts by at least 3,000 megawatts, equivalent to six large power plants, according to the regions' grid operators. ISO New England, the grid operator for that six-state area, said demand nearly topped the record of 26,685 megawatts. In the mid-Atlantic region, demand was expected to shatter the record of 133,763 megawatts by late in the day.

The California Independent System Operator, a nonprofit corporation responsible for electric-system reliability, said demand likely would top 48,000 megawatts and beat a record set last July of 45,431 megawatts. Last week, the grid operator submitted a report to Congress in which it said the "most likely" summertime peak usage would be about 46,000 megawatts, a prediction based on normal summer temperatures.

Rising demand throughout the nation could reignite debate about how best to stimulate construction of plants in states that have deregulated their retail electricity markets, where regulators typically don't order utilities to build facilities. To encourage building plants, Texas gradually is raising its price caps for wholesale electricity. Those caps are reached periodically at times of high demand. The current cap of $1,000 a megawatt hour is expected to rise to $2,000 next March and to $3,000 by March 2009, making it the highest price ceiling in the nation.

Following a massive blackout in the Northeast and parts of the Midwest in August 2003, Congress in 2005 gave federal energy regulators more authority to intervene in cases where transmission lines are needed but aren't getting built because of disputes between states. Tight supplies this summer could prompt the Federal Energy Regulatory Commission to take a more aggressive stance and push development forward. Three new members join the five-member body this month.

FERC Chairman Joseph Kelliher last week warned a House energy subcommittee that trouble-prone areas include California, Connecticut and New York City. Although many generating plants were built in the U.S. in the late 1990s, the California energy crisis of 2000-2001 and bankruptcy of big power trader Enron Corp. in late 2001 shook up deregulated electricity markets and many projects were canceled.

Now, electricity supplies in some states are becoming uncomfortably tight at times of high demand. "This is not the time for complacency," Mr. Kelliher warned the House subcommittee, adding that electric system "vulnerability" is greatest in summer.

High energy demand this week will likely translate into big profits for some generators, especially those that use lower-cost coal or nuclear fuel to make electricity.

In California, as throughout the arid West, grid officials not only feared demand would outstrip resources but also worried high temperatures could prompt wildfires that could force major transmission lines out of service. Several fires were reported yesterday, but so far none have threatened essential transmission corridors. "That was our lucky break," said Stephanie McCorkle, spokeswoman for the California ISO in Folsom, Calif.

Unlike the East, where electric systems are tightly networked, utilities in the West more often rely on electricity that is carried long distances, making power supplies more vulnerable to disruption. The California ISO has said California needs at least $1.8 billion of additional transmission investments, mostly in the southern part of the state, the area that is the most stressed electrically. Northern California has been helped this year by hydro-electric resources that are the best in years.

Grid operators will likely be stressed again today with high temperatures expected to continue in most places. The longer a heat wave lasts, the more fragile the electric system becomes as older units succumb to mechanical breakdowns and as heavily laden power lines sag from heat, sometimes into trees, causing short-circuits or fires.

Stressing the Grid

Previous peak electricity consumption for U.S. grid operators, in megawatts

GRID OPERATOR	PREVIOUS PEAK
PJM Interconnection 13 states	133,763
Midwest Independent Transmission System Operator 15 states	131,434
Electric Reliability Council of Texas 1 state	60,274
California Independent System Operator 1 state	45,431*
New York ISO 1 state	32,075
ISO New England 6 states	26,885

*Adjusted for change in control-area size

Source: grid operators

Omaha World Herald
Tuesday, 7-11-2006

Another 'legacy' of Lay

If they sent his ashes into orbit, Ken Lay could never get around like he did on Earth.

One of humanity's great back-scratchers and influence-buyers is gone. But the events he set in motion will linger on, and on and on.

John Young
Waco (Texas) Tribune-Herald

Of course, there is the biggest corporate cataclysm in history: Enron. All the jobs lost, all the retirement funds squandered.

But something fartherreaching than even the Enron scandal is owed in large part to Ken Lay's influence.

It may not be accurate to say that electric deregulation was an Enron invention. But no one put a better shine on it than Lay and his partner in corporate crime, Jeffrey Skilling.

Back in the mid-1990s, Skilling and Lay, who had found a niche in trading energy futures, pushed for electric deregulation in the Lone Star State and the opportunity to make a mint. You might say Texas lawmakers were starry-eyed.

Our electricity at the time cost roughly half what it does today per kilowatt-hour. Skilling told lawmakers the marketplace could cut that price by 30 to 40 percent.

With Washington pushing and Enron-linked contributions warming political allies to the cause (Lay contributed $139,000 to candidate/governor/president George W. Bush, for one), these energy titans got a courteous airing before Texas lawmakers when electric deregulation came up in the late '90s.

"We consumer advocates had to wait until 2 in the morning to testify," recalled Randy Chapman of Texas Legal Services. The Enron boys? They testified on their time.

Not only did Lay and Skilling get what they wanted in electric deregulation, but they also got the guy they wanted to monitor things at the Public Utility Commission, Pat Wood. With Bush's rise, Wood also would rapidly ascend to head the Federal Energy Regulatory Commission.

Now Texas is five years into partial deregulation and is experiencing electric bills that in some cases have risen 70 to 100 percent.

Next year, former monopolies like TXU Energy won't be regulated at all, price-wise. Will that usher in the low, low rates touted by the Enron crowd? If it does signal lower rates by the big dogs, they could be the kinds that drive competition out.

Then there's the issue of companies that offer the service but never deliver.

One such company was called New Power. It got into the newly deregulated arena early, took on a customer base and then suddenly dumped customers and filed for bankruptcy. Only when consumer groups filed complaints did New Power honor refunds.

Oh, yes: New Power was a spinoff from that other energy company, Enron.

Texas has seen some benefits from deregulation, particularly among big purchasers and groups that have aggregated and found optimal deals.

But though the jury has spoken on the late Ken Lay, it is still out on his shining notion: deregulation. Will the wonders of the marketplace shower on us all? Or will it simply create more rampaging corporate behemoths like Enron?

PUBLIC POWER WEEKLY

A news summary for members of the American Public Power Association No. 26 July 3, 2006

Baltimore Public Works Director George Winfield (left) confers with Hugh Grunden, president and CEO of Easton Utilities in Maryland (right), and Joe Nipper, APPA's senior vice president of government relations, at last week's hearing. *Photo by John Whitman*

Baltimore leaders to propose feasibility study on public power

The president of the Baltimore City Council wants the city to conduct a feasibility study of public power for Baltimore. Council President Sheila Dixon said June 28 she expects a study would cost about $150,000.

"We need to look at all our options," agreed Councilman Bernard "Jack" Young.

Dixon said she, Young and Councilman James Kraft would propose the feasibility study when the City Council meets on July 10. She spoke toward the end of a hearing at City Hall on the possibility of the Maryland city creating a municipal electric utility.

The price of electricity has been making headlines in Maryland ever since investor-owned Baltimore Gas & Electric Co. announced earlier this year that it planned to raise rates by 72% starting in July. The state's deregulated retail electricity market has operated under a price freeze for the last six years, and the price controls expire this month.

In March, the Baltimore City Council directed the city's director of public works and its finance director to take an initial look at the feasibility of forming a municipal electric utility.

"Baltimore is not alone," Ursula Schryver, APPA's director of customer programs, told members of the City Council at last week's hearing. Several dozen cities in 20 states are looking into public power, she said. "Cities want more control over their electricity options," Schryver said.

(continued on page 4)

Draft report on competition misses the big picture, APPA tells FERC

The federal government's Electric Energy Market Competition Task Force should include in its final report a discussion of whether the intrinsic characteristics of the industry make it inherently difficult for electricity markets to be sufficiently competitive to set prices that are just and reasonable, APPA said in comments filed June 26 with the Federal Energy Regulatory Commission. That is the most important issue facing the electric utility industry, the association said.

The task force should include an overall assessment of how well wholesale and retail electricity markets are working and a comprehensive list of problems experienced in electricity markets, APPA recommended.

The task force's draft report omitted significant events in its historical review of the electricity industry, including the California and Western energy crisis, the bankruptcy of Enron and subsequent revelations of market manipulation, and the glut of generation capacity in 2002-2003, APPA said. Those events were a direct consequence of introducing competition into wholesale markets and need to be included in any comprehensive discussion of industry developments, APPA said.

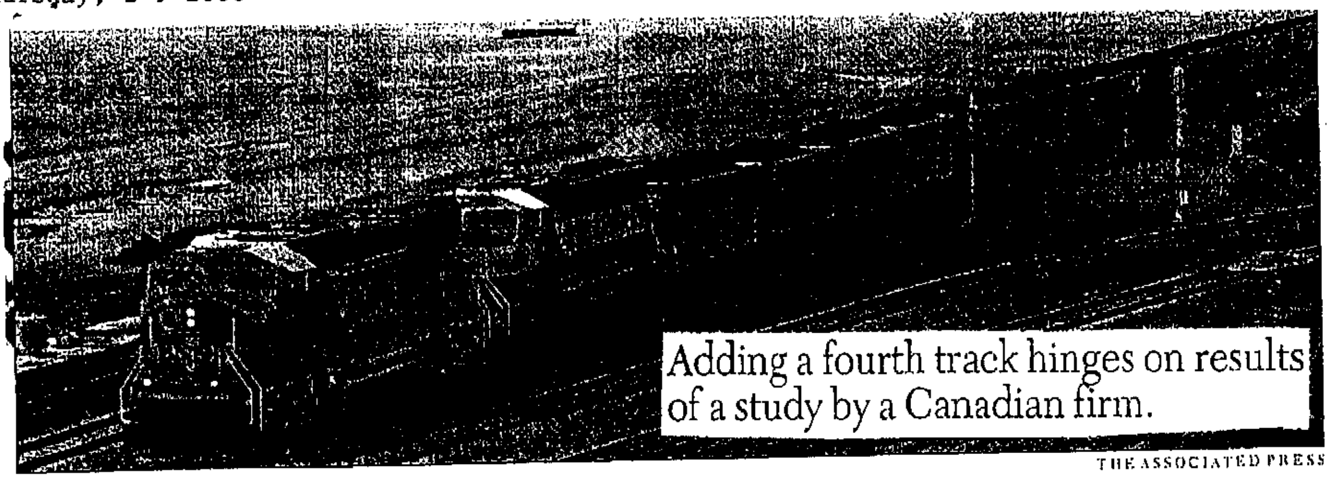
The draft report does not adequately portray the competitive features of more traditional wholesale markets, which include active trading hubs and the availability of indices to provide transparency, APPA said. However, APPA said it agrees that some wholesale customers in these markets are limited in their ability to shop for power because of inadequate access to transmission service.

APPA disagrees with the assertion that in regional transmission organization (RTO) markets, transparency of prices can give clear price signals on where and when new generation should be built. Even if that assertion were theoretically correct, "those signals have not often been received or acted upon," APPA said. It is unclear whether locational capacity markets will elicit additional capacity, but such markets are very likely to increase profits for generators, add new risks and burdens for load-serving

(continued on page 7)

Inside

Omaha World Herald
Thursday, 2-9-2006



Adding a fourth track hinges on results of a study by a Canadian firm.

THE ASSOCIATED PRESS

U.P., partner eye track expansion for coal region

By Stacie Hamel
WORLD-HERALD STAFF WRITER

A study of rail capacity in the Wyoming coal region could result in the addition of a fourth track to a line shared by Union Pacific and BNSF railroads.

U.P. President and Chief Executive James Young said in a recent interview that construction of a fourth track could begin as soon as next year, depending on the outcome of a study by CANAC, a Canadian railroad engineering company.

Multiple tracks increase the number of trains operating at the same time. Triple tracking, for example, would allow three trains to run side by side.

The railroads are nearly finished triple tracking their 102-mile joint line in the Southern Powder River Basin of Wyoming. About 18 more miles of the third track will be added this year, leaving about that much left to triple-track.

Demand for coal from Wyoming's Powder River Basin could increase by 100 million to 200 million tons over the next 10 years, one consultant said.

In 2005, more than 325 million tons of coal moved on the joint U.P.-BNSF rail line from the basin. U.P. and BNSF plan to increase that amount by about 10 percent this year, but it won't satisfy demand, Young said.

"We're well-positioned, but the whole logistics chain will be challenged — the mines, the railroads and the utilities," he said. "We'll have a record year for coal, but I don't think it will be enough."

The six-month study, jointly commissioned by the two railroads, began in late 2005 and is expected to be complete this spring. The study will identify how to increase rail capacity to 500 million to 600 million tons of coal per year.

In 2005, the joint line was affected several times by weather, maintenance and washouts, which limited its ability to move coal. Maintenance work increased after several derailments that were linked to an accumulation of dust that had weakened stability of rail beds after heavy precipitation.

Demand has been increasing for the low-sulfur PRB coal, which costs less than coal from other regions of the United States.

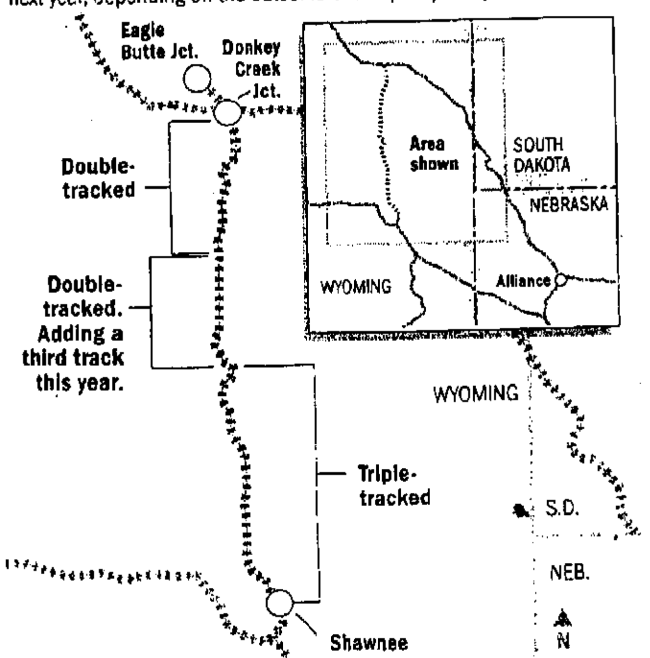
"I just spent time with utility customers in the mines," Young said recently. "We have to think differently, so we've got a full-court press on putting capacity in, bringing in locomotives, hiring and training people to meet that demand."

The study is focusing on transportation capacity but also will look at capacity within the mines, such as the mines' tracks, number of

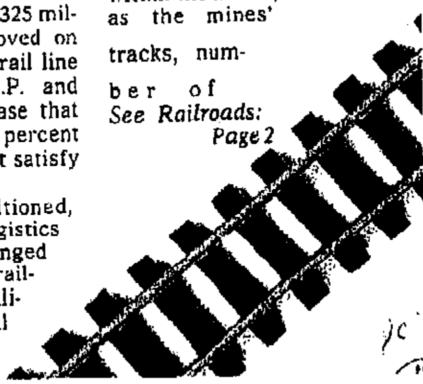
See Railroads: Page 2

Expanding rail capacity in Wyoming's coal region

Construction of a fourth railroad track on a stretch through Wyoming's coal region shared by Union Pacific and BNSF might begin as early as next year, depending on the outcome of a capacity study.



SOURCE: BNSF Railway Co.



jc 66

Railroads: U.P. may add track

Continued from Page 1
trains each mine can load now and how many more trains would be needed, said U.P. spokeswoman Kathryn Blackwell.

BNSF spokesman Pat Hiatte said a fourth line isn't assured, though that possibility will be part of the study's "capacity modeling phase."

"It would be premature to say that next capacity piece would be a fourth main," he said.

The joint line runs 102 miles north from where the U.P. and BNSF lines intersect to near Gillette, Wyo. BNSF also operates another rail line out of the mines.

Mines served by the joint rail line have a combined permitted capacity of 440 million tons per year, said Larry Metzroth, vice president of fuels advisory services for Global Energy Decisions. The Boulder, Colo.,-based consulting company forecasts energy pricing and supply and demand.

Moving as much coal as mines are capable of producing will require more rail capacity, he said.

If the railroads increase to 400 million tons or more a year, Metzroth said, "They are definitely going to have issues with the triple-track system."

Other parts of the railroads' coal routes also will need attention, he said, including U.P.'s line through western Nebraska to Kansas City, Mo., and BNSF's line that runs through Nebraska and on to St. Louis.

"They need more double- and triple-tracking in sections, need more signals installed, and to rehabilitate and expand their yards," he said. "There will be a need to invest in the system outside of the joint line as well to handle this increase in coal volume."

Both railroads announced 2006 capital projects recently, including projects for their coal routes outside the joint line.

U.P. will spend $700 million to $750 million on new capacity for coal this year, compared to $600 million to $700 million in recent years, Young said.

BNSF will add expand its Lincoln railyard and add another 32 miles of double- and triple-track to coal routes outside the Southern Powder River Basin.

3/24/06 To: G. Greer
Why coal & freight costs are going up rapidly.
G. M.

FEATURE-Coal is king at busiest U.S. rail yard

Wed Mar 15, 2006 1:32 PM ET

By Nick Carey

NORTH PLATTE, Neb., March 15 (Reuters) - Cameron Scott has no doubt about what comes first in his job as superintendent of the busiest rail yard in the United States.

"Coal is king," he said.

Union Pacific Corp.'s <UNP.N> yard in North Platte handles up to 170 trains a day. It expects coal to account for 70 percent of freight volume coming through there this year, up from 64 percent in 2005.

Forty percent of all of the Omaha-based company's business passes through this western Nebraska yard, which employs 2,700 people. Checking every foot of rail in sight, Scott said he must accommodate growing demand for coal as the No. 1 U.S. railroad tries to expand capacity.

Higher fuel prices -- which hurt the trucking industry more than railroads -- are prompting U.S. companies to shift ever more cargo to trains, while rising U.S. imports have further swelled orders. Customers have complained about the resulting delays.

Scott, 43, said he must balance utilities' need for coal with other services coming through the yard, but added his orders were clear from the day he started this job in November 2004.

"My main task was to keep the coal constantly moving," he said.

Union Pacific loads and sends out 35 to 40 full coal trains daily at North Platte, compared with five per day in 1985. To increase capacity, the company is laying a third through-line at the yard at a cost of $20 million, which will go into operation in October.

The coal moving though North Platte comes from the Powder River Basin in Wyoming and is popular with U.S. utilities because its low sulfur content helps them meet U.S. government emission requirements. It is also easier, thus cheaper, to mine than coal from other U.S. basins as its thick seams are close to the surface. High natural gas prices have made this coal even more attractive.

Demand for Powder River Basin coal doubled from 200 million tons in 1990 to 400 million in 2005.

Bottlenecks on Union Pacific's network, exacerbated last year by derailments on a 100-mile stretch of track out of the Powder River Basin that the company operates with No. 2 U.S. railroad Burlington Northern Santa Fe Corp. <BNI.N>, have led to complaints from customers -- including utilities -- of delays and unreliable service.

Superintendent Scott said that even more than rail capacity, he was short on locomotives. Union Pacific plans to add 200 to its fleet of 8,000 this year.

SURPRISING TURNAROUND

Chief Financial Officer Robert Knight said U.S. rail companies, which once had been plagued with overcapacity, scaled back their networks in the two decades following industry deregulation in 1980.

And since 2003, U.S. imports have been growing at double-digit annual percentage rates as manufacturers send more work to developing economies like China and India.

High fuel prices, plus a shortage of drivers, made the U.S. trucking industry less attractive. This pushed traffic onto the rails and raised Union Pacific revenues by 11 percent to $13.6 billion in 2005.

"We were surprised by how quickly things turned around," Knight said.

The company is not alone. Stephen Brown, a corporate finance director at rating agency Fitch Ratings, said for years the four main U.S. railroads - which also include CSX Corp. <CSX.N> and Norfolk Southern Corp. <NSC.N> -- couldn't justify making significant capacity investments because the returns weren't there.

"With the revenue picture improving dramatically over the past couple of years railroads are now in a position to make investments ... but it's going to take some time to get those investments in place," he added.

Union Pacific Chief Executive Jim Young said the company planned to ease network congestion by targeting the worst bottlenecks.

"If we focus on our (bottlenecks), we should see congestion easing across the entire network" Young said.

The company will invest $2.75 billion in maintaining and expanding capacity in 2006, compared with $2.7 billion last year.

Analysts say Union Pacific is taking the right approach.

"It's clear that UP takes the issue seriously," said Tony Hatch of ABH Consulting. "It takes time and money to lay new track, so they have to be sure of long-term returns."

CFO Knight said it cost the company between $1.5 million and $2 million to lay a mile of track, an investment that lasts decades, and $1.8 billion annually just to maintain the network.

Officials at both Burlington Northern and Union Pacific said they were boosting capacity to meet utilities' demand for Powder River Basin coal, but they were also looking at how that demand would change long term.

"We can't make investments (in new track) based just on demand today, but how it will look 10 years from now and beyond," said Thomas Kraemer, head of Burlington Northern's coal business.

While waiting for new capacity, Union Pacific managers like Scott say they are working with what they have to increase efficiency.

"I have to squeeze every inch of capacity out of the rails I have before I can ask for more," he said. "And although as superintendent I would always argue I need more rails, I have room to squeeze."

8

To: G. Grear, 1/12/06 p8
Others in the state are seeing the need to increase electric rates. G. M.

The total change in the below table is just under 15%

THURSDAY, JANUARY 12, 2006

OPPD proposes 3 years of rate hikes

■ Needed to pay for construction, the increases would begin with a 3% rise this spring.

BY NANCY GAARDER
WORLD-HERALD STAFF WRITER

The Omaha Public Power District is proposing rate increases totaling about 9 percent over the next three years as it takes on almost $2 billion in debt to upgrade its system.

The first portion of that increase, 3 percent, would take effect this spring, assuming board approval, Charles Moriarty, senior financial officer, said Tuesday.

The district also is contemplating a pass-through fuel charge that would allow for potentially more frequent, generally smaller, rate changes without a vote of the board.

The OPPD board will vote Thursday on a budget for this year that assumes the 3 percent rate increase goes into effect in April. The 2006 budget would total nearly $1 billion, with more than half of it devoted to construction projects.

The proposed rate increase will be the subject of four public hearings in February. The dates and locations of those hearings have yet to be set.

The average residential customer, whose monthly bill is $71.60, would see about a $2.15 increase in that bill, said spokesman Jeff Hanson.

For OPPD, the rate increase would bring in about $16 million a year, he said.

In March, the board also will vote on whether it is willing to commit to similar-sized rate increases in 2007 and 2008. The actual amounts of those two increases will be subject to further study and future separate votes by the board.

Board members reviewed the prospective rate increases at their committee meetings Tuesday.

The board long ago accepted the need for the increases when it embarked on the current construction plan.

Most of the debt is going toward the overhaul of Fort Calhoun Nuclear Station and the construction of a new coal plant near Nebraska City.

A substantial amount of work will be done on both projects in 2006, making this year's $538 million construction budget the largest in OPPD's history, Moriarty said. Without rate increases, OPPD calculates that it would have to go into debt in 2008.

OPPD needs to raise rates, not only because it is incurring these costs, but also because revenues are projected to drop as it takes power plants off line for retooling.

To reduce the size of the rate increases, the utility also is cutting expenses. By next year, it hopes to have completed about $20 million in permanent cuts.

OPPD rate hike schedule

January 2004	3.1 percent
May 2005/January 2006	1.7 percent total
April 2006	About 3 percent
[illegible] 2007	Up to 3 percent*
January 2008	Up to 3 percent*

*Estimate

GARY/

Nebraska utility to build 125-mile, 345-kV line

Responding to 2% load growth, the Nebraska Public Power District board Friday approved a 125-mile, 345-kV transmission project in east-central Nebraska.

The project includes upgrading to 345-kV a 230-kV line that runs about 60 miles from Norfolk, Nebraska, to Columbus, Nebraska, and then building a 345-kV line from Columbus to Lincoln, Nebraska, said Beth Boesch, utility spokeswoman. NPPD, based in Columbus, Nebraska, aims to have the line in service by 2010, she said.

The project was identified in NPPD's most recent long-range transmission planning study, Boesch said. The project is needed to improve reliability in light of sustained load growth, she said. Nebraska is seeing increased demand from farmers switching to electric pumps for irrigation, new ethanol plants and industry expansion, Boesch said. The utility doesn't have final cost estimates for the project, with design and line siting expected to start this year, she said.

The NPPD board also voted to spend $5.7 million to increase by 12 MW the capacity of the 778-MW Cooper Nuclear Station near Brownville, Nebraska, by installing "high-accuracy" monitoring equipment.

Also at Cooper, the NPPD board approved the first phase of building a dry-cask nuclear fuel storage system at the plant. The dry-cask nuclear fuel storage system involves transferring some used fuel from wet storage to dry storage in concrete and steel casks, the public utility said. NPPD expects to spend $45 million on the project.

NPPD management asked the board to consider a 3.5% average wholesale rate increase starting in 2007, due to rising fuel costs, equipment and power plant upgrades. The board is expected to vote on the rate hike by November.

NPPD serves about 1 million retail and wholesale customers.

Calpine quarterly loss balloons to $818 million

Bankrupt independent power producer Calpine said Friday its second-quarter net loss ballooned to $818 million, more than double its $298.5 million loss in the year-ago period, and the San Jose, California-based company delayed a formal filing with federal regulators for several days.

For the three months ended June 30, Calpine said it expected to incur net losses of about $818 million, swelling its total losses to $1.4 billion for the first half of 2006.

Calpine attributed the acceleration in quarterly net losses primarily to an ambitious reorganization program undertaken in concert with its December 20, 2005, Chapter 11 bankruptcy reorganization filing.

The company also advised the Securities and Exchange Commission it will need a five-day extension to submit its second-quarter report. Calpine spokesman Rick Barraza told Platts that means the report is expected to be filed with the federal agency during this week.

Calpine played down the delay. "This is not unusual for a

Weekend markets for delivery Aug 12 ($/MWh)

East	Index	Range	Deals	Volume
On-Peak				
Mass Hub	62.50	62.50 - 62.50	N.A.	N.A.
N.Y. Zone-G	65.75	65.75 - 65.75	N.A.	N.A.
N.Y. Zone-J	80.25	80.25 - 80.25	N.A.	N.A.
N.Y. Zone-A	51.50	51.50 - 51.50	N.A.	N.A.
Ontario*	45.00	45.00 - 45.00	N.A.	N.A.
PJM West	54.65	54.65 - 54.65	N.A.	N.A.
Dominion Hub	58.10	58.10 - 58.10	N.A.	N.A.
VACAR	65.00	65.00 - 65.00	N.A.	N.A.
Southern, into	67.00	67.00 - 67.00	N.A.	N.A.
Florida	77.00	77.00 - 77.00	N.A.	N.A.
TVA, into	64.50	64.50 - 64.50	N.A.	N.A.
Off-Peak				
Mass Hub	42.25	42.25 - 42.25	N.A.	N.A.
PJM West	25.00	25.00 - 25.00	N.A.	N.A.
Dominion Hub	28.45	28.45 - 28.45	N.A.	N.A.
VACAR	41.25	41.25 - 41.25	N.A.	N.A.
Southern, into	40.00	40.00 - 40.00	N.A.	N.A.
Florida	44.00	44.00 - 44.00	N.A.	N.A.
TVA, into	41.00	41.00 - 41.00	N.A.	N.A.
Central	**Index**	**Range**	**Deals**	**Volume**
On-Peak				
Michigan Hub	48.65	48.65 - 48.65	N.A.	N.A.
AD Hub	46.64	46.00 - 47.00	6	280
Cinergy Hub	44.00	44.00 - 44.00	N.A.	N.A.
Illinois Hub	46.75	46.75 - 46.75	N.A.	N.A.
NI Hub	46.65	46.65 - 46.65	N.A.	N.A.
Minnesota Hub	50.50	50.50 - 50.50	N.A.	N.A.
MAPP South	61.50	61.50 - 61.50	N.A.	N.A.
SPP North	62.50	62.50 - 62.50	N.A.	N.A.
Entergy, into	64.00	64.00 - 64.00	N.A.	N.A.
ERCOT	82.56	80.00 - 83.50	53	4,425
ERCOT, North	86.80	85.50 - 88.50	25	2,225
ERCOT, Houston	85.70	82.95 - 87.00	37	3,300
ERCOT, West	86.00	86.00 - 86.00	N.A.	N.A.
ERCOT, South	84.00	84.00 - 84.00	N.A.	N.A.
Off-Peak				
Michigan Hub	24.30	24.30 - 24.30	N.A.	N.A.
AD Hub	21.50	21.50 - 21.50	N.A.	N.A.
Cinergy Hub	23.15	23.15 - 23.15	N.A.	N.A.
Illinois Hub	23.20	23.20 - 23.20	N.A.	N.A.
NI Hub	21.50	21.50 - 21.50	N.A.	N.A.
Minnesota Hub	22.20	22.20 - 22.20	N.A.	N.A.
MAPP South	44.50	44.50 - 44.50	N.A.	N.A.
SPP North	45.00	45.00 - 45.00	N.A.	N.A.
Entergy, into	43.00	43.00 - 43.00	N.A.	N.A.
ERCOT	54.00	54.00 - 54.00	N.A.	N.A.
ERCOT, North	54.50	54.50 - 54.50	N.A.	N.A.
ERCOT, Houston	54.75	54.75 - 54.75	N.A.	N.A.
ERCOT, West	54.75	54.75 - 54.75	N.A.	N.A.
ERCOT, South	54.25	54.25 - 54.25	N.A.	N.A.
West†	**Index**	**Range**	**Deals**	**Volume**
On-Peak				
COB	75.50	74.00 - 77.00	15	400
Mid-C	73.42	71.00 - 74.50	156	4,425
Palo Verde	72.78	71.00 - 75.00	52	1,400
Mead	76.20	69.40 - 78.00	21	625
Mona	81.00	81.00 - 81.00	N.A.	N.A.
Four Corners	78.55	75.75 - 79.75	18	550
NP15	79.41	78.00 - 80.75	18	725
SP15	79.29	74.00 - 80.75	317	8,600
Off-Peak				
COB	60.97	58.00 - 63.25	16	450
Mid-C	60.90	59.00 - 62.25	83	2,275
Palo Verde	48.75	48.00 - 49.50	34	1,000
Mead	50.00	50.00 - 50.00	N.A.	N.A.
Mona	48.50	48.50 - 48.50	N.A.	49
Four Corners	48.67	48.00 - 49.25	30	750
NP15	53.50	52.75 - 49.25	62	1,750
SP15	53.26	51.50 - 54.50	88	2,350

*Ontario prices are in Canadian dollars

†West markets traded Thursday for Friday and Saturday delivery

ORDINANCE NO. 9064

An ordinance to amend Chapter 15 of the Grand Island City Code; to amend Sections 15-55, 15-57, 15-60, 15-63, and 15-68 pertaining to electric utility rates; to repeal Sections 15-55, 15-57, 15-60, 15-63, and 15-68 as now existing, and any ordinance or parts of ordinances in conflict herewith; and to provide for publication and the effective date of this ordinance.

BE IT ORDAINED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA:

SECTION 1. Section 15-55 of the Grand Island City Code is hereby amended to read as follows:

§15-55. 010 Residential Service

Applicable in urban and rural distribution areas. Available at single phase, through a single meter, to residential consumers for domestic use in a single-family dwelling unit; but is not available for commercial or non-domestic use.

Individual single-phase motors, not to exceed 10 HP each, may be connected; however, the City Utilities Department must be notified in writing, if a motor over 5 HP is installed.

This schedule has two sets of rates: one for the summer period of five months, beginning with the June billing; and the second for the winter season of seven months, beginning with the November billing.

~~Summer Rate for Calendar Year 2005~~

~~**Kilowatt-Hours Used Per Month**~~	~~**(June - October)**~~
~~First 300 KWH……………………………………….~~	~~$0.074 per KWH~~
~~Next 700 KWH……………………………………….~~	~~$0.049 per KWH~~
~~All additional KWH………………………………….~~	~~$0.055 per KWH~~

~~Plus a customer charge of $5.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge. The minimum monthly bill shall be $5.00 prior to the Power Cost Adjustment.~~

Summer Rate Beginning October 1, 2006 ~~Calendar Year 2006~~

Kilowatt-Hours Used Per Month	**(June – October)**
First 300 KWH……………………………………….	$0.084 per KWH ~~$0.077 per KWH~~
Next 700 KWH……………………………………….	$0.059 per KWH ~~$0.052 per KWH~~
All additional KWH………………………………….	$0.066 per KWH ~~$0.059 per KWH~~

Plus a customer charge of $5.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge. The minimum monthly bill shall be $5.00 prior to the Power Cost Adjustment.

Approved as to Form ¤ ___________
August 17, 2006 ¤ City Attorney

~~**Winter Rate for Calendar Year 2005**~~

~~**Kilowatt-Hours Used Per Month**~~	~~**(November - May)**~~
~~First 300 KWH……………………………………………~~	~~$0.074 per KWH~~
~~Next 700 KWH……………………………………………~~	~~$0.049 per KWH~~
~~Additional KWH…………………………………………..~~	~~$0.029 per KWH~~

~~Plus a customer charge of $5.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge. The minimum monthly bill shall be $5.00 prior to the Power Cost Adjustment.~~

Winter Rate Beginning October 1, 2006 ~~Calendar Year 2006~~

Kilowatt-Hours Used Per Month	**(November - May)**
First 300 KWH……………………………………………	$0.084 per KWH ~~$0.077 per KWH~~
Next 700 KWH……………………………………………	$0.059 per KWH ~~$0.052 per KWH~~
Additional KWH…………………………………………..	$0.038 per KWH ~~$0.031 per KWH~~

Plus a customer charge of $5.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge. The minimum monthly bill shall be $5.00 prior to the Power Cost Adjustment.

SECTION 2. Section 15-57 of the Grand Island City Code is hereby amended to read as follows:

§15-57. 030 Single-Phase Commercial Service

Applicable in urban and rural distribution areas. Available for commercial customers, for lighting and small appliances. Available for single meter apartment units, and combined residential-commercial use, where the Residential Rate is not applicable. Service shall be through a single meter.

Individual single-phase motors, not to exceed 10 HP each, may be connected; however, the City Utilities Department must be notified in writing, if a motor over 5 HP is installed.

Kilowatt-Hours Used Per Month	~~**Rates - 2005 Calendar Year**~~	**Rates Beginning October 1, 2006 ~~Calendar Year~~**
First 350 KWH………………………………………	~~$0.080 per KWH~~	$0.089 per KWH ~~$0.082 per KWH~~
Next 650 KWH………………………………………	~~$0.070 per KWH~~	$0.079 per KWH ~~$0.072 per KWH~~
Next 1,500 KWH…………………………………..	~~$0.064 per KWH~~	$0.073 per KWH ~~$0.066 per KWH~~
Next 2,500 KWH…………………………………..	~~$0.060 per KWH~~	$0.069 per KWH ~~$0.062 per KWH~~
Next 5,000 KWH…………………………………..	~~$0.053 per KWH~~	$0.063 per KWH ~~$0.056 per KWH~~
Over 10,000 KWH………………………………..	~~$0.050 per KWH~~	$0.060 per KWH ~~$0.053 per KWH~~

Plus a customer charge of $7.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Adjustment charge. The minimum monthly bill shall be $7.00 prior to the Power Adjustment.

SECTION 3. Section 15-60 of the Grand Island City Code is hereby amended to read as follows:

§15-60. 050 Three-Phase Commercial Service

Applicable in the territory served by the City of Grand Island; and is available through a single meter at three phase, for any electric service uses where three-phase service is available.

This schedule has two sets of rates: one for the summer period of five months, beginning with the June billing; and the second for the winter season of seven months, beginning with the November billing.

~~Summer Rate for Calendar Year 2005~~

~~Kilowatt-Hours Used Per Month~~	**~~(June - October)~~**
~~First 1,000 KWH…………………………~~	~~$0.075 per KWH~~
~~Next 1,500 KWH………………………...~~	~~$0.068 per KWH~~
~~Next 2,500 KWH………………………...~~	~~$0.064 per KWH~~
~~Next 15,000 KWH……………………….~~	~~$0.058 per KWH~~
~~Over 20,000 KWH……………………….~~	~~$0.055 per KWH~~

~~Plus a customer charge of $10.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge.~~

Summer Rate Beginning October 1, 2006 ~~Calendar Year~~

Kilowatt-Hours Used Per Month	**(June - October)**
First 1,000 KWH…………………………	$0.086 per KWH ~~$0.079 per KWH~~
Next 1,500 KWH………………………...	$0.078 per KWH ~~$0.071 per KWH~~
Next 2,500 KWH………………………...	$0.074 per KWH ~~$0.067 per KWH~~
Next 15,000 KWH……………………….	$0.068 per KWH ~~$0.061 per KWH~~
Over 20,000 KWH……………………….	$0.065 per KWH ~~$0.058 per KWH~~

Plus a customer charge of $10.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge.

~~Winter Rate for Calendar Year 2005~~

~~Kilowatt-Hours Used Per Month~~	**~~(November - May)~~**
~~First 500 KWH……………………………...~~	~~$0.075 per KWH~~
~~Next 1,000 KWH………………………...~~	~~$0.068 per KWH~~
~~Next 2,500 KWH………………………...~~	~~$0.055 per KWH~~
~~Over 4,000 KWH………………………...~~	~~$0.052 per KWH~~

~~Plus a customer charge of $10.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge.~~

Winter Rate Beginning October 1, 2006 ~~Calendar Year~~	
Kilowatt-Hours Used Per Month	**(November - May)**
First 500 KWH…………………………..	$0.086 per KWH ~~$0.079 per KWH~~
Next 1,000 KWH………………………..	0.078 per KWH ~~$0.071 per KWH~~
Next 2,500 KWH………………………..	$0.065 per KWH ~~$0.058 per KWH~~
Over 4,000 KWH………………………..	$0.062 per KWH ~~$0.055 per KWH~~

Plus a customer charge of $10.00 per month, in addition to that charged for the electrical energy used, plus the applicable Power Cost Adjustment charge.

Minimum

The minimum monthly charge shall be no less than $10.00. The minimum shall in no event be less than $0.70 per month per connected horsepower.

The billing horsepower shall be determined as follows:

1. Total connected horsepower, if total connected horsepower is less than 20 HP.
2. If total connected horsepower exceeds 20 HP, then the billing horsepower shall be the larger of 20 HP, or the largest single connected motor.
3. If questions arise as to the actual billing horsepower, the City Utilities Department may, at its option, install demand meters. The Kilowatt reading shall determine the billing horsepower on the basis of 0.75 Kilowatt = 1.0 HP.

It is the responsibility of the customer, to inform the City Utilities Department of changes that may effect minimum billings.

SECTION 4. Section 15-63 of the Grand Island City Code is hereby amended to read as follows:

§15-63. 100 Three-Phase Power Service

Applicable in the territory served by the City of Grand Island, available through a single meter at three phase. Available for any commercial or industrial use of energy.

~~**Calendar Year 2005**~~	**Beginning ~~2006~~ October 1, 2006 ~~Calendar Year~~**	
		Demand Charge
~~$8.00~~	$8.50	per KW of billing demand
		Energy Charge
~~$0.0265~~	$0.0345 ~~$0.0275~~	per KWH for the first 450 hours of monthly demand
~~$0.0200~~	$0.0280 ~~$0.0210~~	per KWH for all additional usage; plus applicable Power Cost Adjustment charge.
		Customer Charge
~~$300.00~~	$300.00	per month.

The minimum monthly bill shall be no less than $700. The Power Cost Adjustment charge is applied to energy consumption only.

SECTION 5. Section 15-68 of the Grand Island City Code is hereby amended to read as follows:

§15-68. 114 Area Floodlighting

Applicable in the territory served by the City of Grand Island; and is available for any outdoor area floodlighting of consumer's property from dusk to dawn, where such service can be rendered directly from existing secondary distribution lines of the City.

Luminare will be selected by Electric Department and provided from Electric Department stock. For installation on an existing wood pole, and connected to existing overhead secondary conductors on such pole, the rate is $0.76 per watt per year billed on a monthly basis beginning October 1, 2006. ~~$0.70 per watt per year, billed on a monthly basis for calendar year 2005; and $0.72 per watt per year billed on a monthly basis beginning calendar year 2006.~~

Power Cost Adjustment is not applicable to the Area Floodlighting Rate.

SECTION 6. Section section # as now existing, and any ordinances or parts of ordinances in conflict herewith be, and hereby are, repealed.

SECTION 7. The validity of any section, subsection, sentence, clause, or phrase of this ordinance shall not affect the validity or enforceability of any other section, subsection, sentence, clause, or phrase thereof.

SECTION 8. That this ordinance shall be in force and take effect from and after its passage and publication, in pamphlet form, within fifteen days in one issue of the Grand Island Independent as provided by law.

Enacted: August 22, 2006.

Jay Vavricek, Mayor

Attest:

RaNae Edwards, City Clerk