RATE CASE APPLICATION

DOCKET NO. 12-KGSG-835-RTS

MAY 18, 2012

VOLUME I

KANSAS GAS SERVICE
A DIVISION OF ONEOK

RATE CASE APPLICATION
VOLUME I

KANSAS GAS SERVICE
A DIVISION OF ONEOK

John P. DeCoursey
Managing Attorney

MAY 18, 2012

Received
on

MAY 18 2012

by
State Corporation Commission
of Kansas

VIA HAND DELIVERY

Ms. Patrice Petersen-Klein
Executive Director
Kansas Corporation Commission
1500 S.W. Arrowhead Road
Topeka, Kansas 66604-4027

Re: Application of Kansas Gas Service, a Division of ONEOK, Inc.

Dear Ms. Petersen-Klein:

Kansas Gas Service hereby transmits an original and nine copies of its Application for Adjustment of its Natural Gas Rates in the State of Kansas, together with an electronic copy of the Application, all in accordance with K.A.R. 82-1-231.

Thank you for your consideration.

Sincerely,

John P. DeCoursey

John P. DeCoursey

7421 West 129th Street • Overland Park, KS 66213-2634
P.O. Box 25957 • Shawnee Mission KS 66225-5957
(913) 319-8617 • Fax (913) 319-8622
www.kansasgasservice.com

2012.05.18 15:09:43
Kansas Corporation Commission
/S/ Patrice Petersen-Klein
Received
on
MAY 18 2012
by
State Corporation Commission
of Kansas

BEFORE THE STATE CORORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas Gas Service, A Division of ONEOK, Inc. for Adjustment of its Natural Gas Rates in the State of Kansas	)	DOCKET NO. 12-KGSG-835-RTS

APPLICATION

COMES NOW Kansas Gas Service, a Division of ONEOK, Inc. ("Kansas Gas Service," "Company" or the "Applicant"), and files this Application to make changes for natural gas service under K.S.A. 66-117, K.S.A. 66-1,200 et seq. and K.A.R. 82-1-231. In support of the Application, Kansas Gas Service states:

1. Applicant is a natural gas public utility operating in the state of Kansas pursuant to certificates of convenience and necessity issued by the Commission. Applicant's principal place of business within the state of Kansas is located at 7421 West 129th Street, Overland Park, Kansas 66213.

2. The names, addresses and phone numbers of the persons authorized to receive notices and communications with respect to this Application on behalf of Kansas Gas Service are as follows:

Walker Hendrix
John P. DeCoursey
Kansas Gas Service
A Division of ONEOK, Inc.
7421 W. 129th Street
Overland Park, Kansas 66213

David N. Dittemore
Kansas Gas Service
A Division of ONEOK, Inc.
7421 W. 129th Street
Overland Park, Kansas 66213

James G. Flaherty
Anderson & Byrd LLP
216 South Hickory
P.O. Box 17
Ottawa, Kansas 66614

3. Applicant's current base rates were established in Docket No. 06-KGSG-1209-RTS ("1209 Docket"). The test period for that docket ended December 31, 2005. The test period in this Application is the twelve month period ending December 31, 2011. In the intervening six-year period, Kansas Gas Service has continued to make significant investments in plant totaling over $250 million to provide safe, reliable and efficient natural gas service to its customers. The Company has also experienced increases in wages, benefits, and pension expenses, and in material and supplier costs. During this same period, the Company has seen a decline in per capita residential consumption of natural gas because of more efficient gas usage by customers. The cumulative impact of these factors has necessitated the Company's request for an overall revenue increase of $32.7 million. This increase is the product of increasing base rates by $50.7 million and rebasing amounts currently collected through the Gas System Reliability Surcharge ("GSRS") ($10.9 million) and the Ad Valorem Tax Surcharge Rider ("ATSR") ($7.1 million).[1]

4. The testimony of eleven witnesses and the schedules required by K.A.R. 82-1-231 are filed in support of the Application. The witnesses and the subjects they address are identified in the testimony of Company witness and President Bradley O. Dixon. The testimony and schedules show that as of December 31, 2011, Applicant's adjusted rate base for Kansas operations was $772,431,396. The test year adjusted return on the Company's investment in

[1] Ms. Brenda Storbeck removes $8,005,229 test period GSRS revenues in Adjustment IS 5. The $10.9 million in GSRS revenue is the amount authorized for 2012. This larger amount is the appropriate measure of customer impact because it reflects amounts currently paid by customers.

rate base was 4.5515%. The schedules filed with the Application establish a gross revenue deficiency of $50,707,853 based upon normalized operating results for the 12 months ended December 21, 2011, adjusted for known and determinable changes in revenue, operating and maintenance expenses, cost of capital and taxes.

5. As part of the Application, the Company is seeking to recover costs associated with its Pension and Other Post Employment Benefits ("OPEB") which have been deferred for recovery as authorized in Docket No. 10-KGSG-130-ACT.

6. In this matter, Kansas Gas Service has commissioned a new study of its depreciation rates by Foster Associates, Inc. This study has recommended certain changes to the Company's depreciation rates, which are incorporated in this Application.

7. The Application makes an adjustment for the increase in *ad valorem* tax expenses the Company has been authorized to recover through the ATSR. Over the last six years, the Company's property taxes have increased by approximately $7.1 million. This increased property tax expense is included in the Application as part of the overall revenue requirement request. Similarly, since the end of the test year in the 1209 Docket, Kansas Gas Service has invested over $97 million in plant and equipment that is eligible for recovery pursuant to its GSRS tariff, the last such filing being made in Docket No. 12-KGSG-138-TAR (the "138 Docket"). Such investments are eligible for recovery between rate cases pursuant to the Gas Safety and Reliability Policy Act, K.S.A. 66-2201 through 2204. Pursuant to the Commission's Order in the 138 Docket, Kansas Gas Service is recovering $10.9 million on an annual basis. As with the ATSR, the GSRS expenses are included in the Application as part of the overall revenue requirement request. Since the increased expense is being moved from the GSRS calculation to base rates, it will also not require customers to pay more for this cost than they would pay under

current rates. In sum, after netting out the $18 million of GSRS and ATSR costs, the overall increase in the requested revenue request is $32.7 million above what customers are currently paying.

8. As stated earlier, one of the major factors requiring the filing of this request is a declining level of per capita consumption by residential customers because of more efficient gas usage. As shown in the testimony of Company witness David Dittemore, due to this impact, by 2011, Kansas Gas Service had experienced a decline of $7.7 million in annual revenue from residential customers compared to the level relied upon to set rates in the 1209 Docket. To address this problem, the Company is proposing a new tariff, the Revenue Normalization Adjustment Rider ("RNA"). The RNA will replace the Company's Weather Normalization Adjustment Rider ("WNA"). The RNA will continue the results achieved in the WNA in that customers will receive a credit following colder than normal years and the Company will receive revenue following warmer than normal years. Additionally, the RNA will allow the Company a more reasonable opportunity to achieve its authorized rate of return by adjusting revenues on a year to year basis to reflect either decreasing or increasing levels of consumption by customers on a year-to-year basis.

9. In addition to the requested RNA, the Company is proposing certain adjustments to its rate schedules. The Company is proposing to separate its General Sales Service rate schedule into three different rate schedules. Additionally, the Company is proposing to combine its STk and GTk rate schedules into a single rate schedule and to combine its STt and GTt rate schedule into another separate rate schedule. Finally, the Company is proposing miscellaneous revisions to certain sections of its General Terms and Conditions.

10. The total adjustment in rates requested in this Application is just and reasonable and in the public interest. The request to change the Company's schedules of charges is proposed to allow Applicant to maintain financial integrity and to continue to make investments in its distribution system and service offerings for the benefit of the public.

11. Applicant has on file with the Commission certain schedules of charges and rates for its natural gas service. The Company desires to withdraw certain of the schedules and file new ones, as reflected in Section 18 filed in support of this Application. The charges reflect the effects of the requested revenue increase and the proposed changes in rate design and General Terms and Conditions. Except as proposed in testimony with respect to the RNA/WNA, Applicant proposes that the revised schedules become effective thirty (30) days from the date of this filing, as permitted by law, or at such other date as the Commission may prescribe. Applicant's proposal for implementation of the RNA is set forth in the testimony of Company witness David Dittemore.

WHEREFORE, Kansas Gas Service, a Division of ONEOK, Inc., respectfully requests the approval and consent of the Commission to withdraw and cancel the referenced natural gas rate schedules and other provisions of its tariffs and to substitute therefore and place in effect the rate schedules and other provisions contained in Section 18 of the Application, which will provide an overall annual revenue increase of $32.7 million.

KANSAS GAS SERVICE,
A DIVISION OF ONEOK, INC.

Bradley O. Dixon
President
Kansas Gas Service,
A Division of ONEOK, Inc.
7421 W. 129th Street
Overland Park, Kansas 66213

VERIFICATION

STATE OF KANSAS)
) ss:
JOHNSON COUNTY)

Bradley O. Dixon, being duly sworn upon his oath deposes and says that he is President of Kansas Gas Service, a Division of ONEOK, Inc., that he has read and is familiar with the foregoing Application of Kansas Gas Service, a Division of ONEOK, Inc., filed herewith, and that the statements made therein are true to the best of his knowledge, information and belief.

Bradley O. Dixon

Bradley O. Dixon

Subscribed and sworn to before me this 14th day of May, 2012.

Jill Tennant

Notary Public

My Appointment Expires:

June 21, 2014

OFFICIAL SEAL
JILL TENNANT
MY COMMISSION EXPIRES
June 21, 2014

THIS SECTION SHOULD CONTAIN GENERAL INFORMATION ABOUT HOW COMPANY LET THE GENERAL PUBLIC WHICH IS AFFECTED BY THE FILING KNOW ABOUT THE FILING. IT SHALL INCLUDE GENERAL INFORMATION ABOUT THE FILING WHICH WILL BE OF INTEREST TO THE PUBLIC AND SUITABLE FOR PUBLICATION. INFORMATION SHALL INCLUDE:

i)	**ANNUAL REVENUE INCREASE PROPOSED IN THE FILING,**	Schedule 1, Col 6, Row 13
ii)	**AFFECTED COMMUNITIES**	Schedule 2
iii)	**NUMBER AND CLASSES OF CUSTOMERS AFFECTED,**	Schedule 1, Col 1 and Col 2
iv)	**AVERAGE MONTHLY INCREASE PER CUSTOMER,**	Schedule 1, Col 7
v)	**SUMMARY OF THE REASONS FOR THE FILING**	Schedule 3
vi)	**OTHER INFORMATION COMPANY WANTS OR KCC MAY REQUIRE, AND**	None
vii)	**COPIES OF PRESS RELEASES ISSUED PRIOR TO OR AT THE FILING DATE.**	Schedule 4

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
General Public Notification
Test Year Ended December 31, 2011

Line No.	Col. 1	Annualized Average Number of Customers Col. 2	Proforma MCF Col. 3	Base Revenues Col. 4	Proposed Revenues Col. 5	Proposed Revenue Increase Col. 6	Proposed Average Monthly Increase Per Customer Col. 7
1	Residential	575,841	43,365,197	$176,749,315	$227,457,168	$50,707,853	$7.34
2	General Service	49,366	11,270,958	$36,101,473	$36,101,473	$0	$0.00
3	Small Generator Sales Service	567	5,715	$345,629	$345,629	$0	$0.00
4	Irrigation Sales	228	224,746	$391,940	$391,940	$0	$0.00
5	KGSSD	1	56,988	$46,852	$46,852	$0	$0.00
6	Sales for Resale	4	18,096	$25,980	$25,980	$0	$0.00
7	Small Transportation	754	1,168,575	$2,337,926	$2,337,926	$0	$0.00
8	General Transportation	3,588	5,973,061	$10,271,501	$10,271,501	$0	$0.00
9	Compressed Natural Gas Transportation	1	13,036	$10,047	$10,047	$0	$0.00
10	Irrigation Transportation	459	1,132,170	$1,887,239	$1,887,239	$0	$0.00
11	Large Volume Transport	562	15,537,172	$15,987,787	$15,987,787	$0	$0.00
12	Wholesale Transport	27	1,192,821	$1,394,971	$1,394,971	$0	$0.00
13		631,398	79,958,535	$245,550,660	$296,258,513	$50,707,853	$6.69
14	Other Operating Revenue			$13,245,906	$13,245,906		
15				$258,796,566	$309,504,419		

The difference between the $7.34 shown in Col. 7, line 1 in this Schedule as the monthly increase to a typical residential customer and the $5.68 shown in the press release in Section 2 of the Application is due to the fact that the $7.34 amount includes GSRS, ATSR, and other surcharges that are being placed in base rates and are already being paid for by the residential customer. Since those customers are already paying for those surcharges they were not included in the annual increase shown in the press release.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Affected Communities
Test Year Ended December 31, 2011

	Community		Community		Community		Community		Community
1	Abilene	51	Carbondale	101	Esbon	151	Industry	200	Madison
2	Alden	52	Carlyle	102	Everest	152	Inman	201	Mahaska
3	Alma	53	Carona	103	Fairview	153	Iola Rural	202	Manhattan
4	Alta Vista	54	Cawker City	104	Fairway	154	Isabel	203	Mankato
5	Ames	55	Centralia	105	Formoso	155	Iuka	204	Marquette
6	Andover	56	Chapman	106	Fort Scott	156	Jamestown	205	Marysville
7	City	57	Chase	107	Frankfort	157	Jewell City	206	McPherson
8	Arlington	58	Cheney	108	Franklin	158	Johnson County	207	Acres
9	Arma	59	Cherokee	109	Frederick	159	Junction City	208	Lodge
10	Ashland	60	Cherryvale	110	Frontenac	160	Kanopolis	209	Medora
11	Assaria	61	Chicopee	111	Galena	161	Kansas City	210	Melvern
12	Atchison	62	Circleville	112	Galva	162	Kingman	211	Mentor
13	Atlanta	63	Claflin	113	Garden Plain	163	Kingman	212	Meridan
14	Energy	64	Clay Center	114	Gardner	164	Kingsdown	213	Merriam
15	Aubry	65	Clearwater	115	Garfield	165	Kinsley	214	Valley
16	Augusta	66	Clifton	116	Gas City	166	Kiowa	215	Energy, Inc.
17	Aurora	67	Clyde	117	Geneseo	167	Kirkwood	216	Milford
18	Axtell	68	Coldwater	118	Girard	168	Kiro	217	Miltonvale
19	Baileyville	69	Colony	119	Glasco	169	Kismet	218	Minneapolis
20	Baldwin	70	Columbus	120	Glen Elder	170	La Harpe	219	Minneola
21	Barnard	71	Colwich	121	Goddard	171	LaCrosse	220	Mission
22	Barnes	72	Concordia	122	Goessel	172	Lake Quivira	221	Mission Hills
23	Baxter Springs	73	Conway Springs	123	Gorham	173	Lake Waltana	222	Mission Woods
24	Beattie	74	Courtland	124	Grandview Plaza	174	Lancaster	223	Monticello
25	Bel Aire	75	Crestline	125	Grantville	175	Lane	224	Montrose
26	Plaine	76	Cuba	126	Great Bend	176	Langdon	225	Moran
27	Belleville	77	Cullison	127	Greeley	177	Langdon Lane	226	Morganville
28	Beloit	78	Cunningham	128	Greenleaf	178	Lansing	227	Morrill
29	Belpre	79	Delphos	129	Greensburg	179	Larned	228	Morrowville
30	Belvue	80	Dennis	130	Grenola	180	Leavenworth	229	Mount Hope
31	Bentley	81	Derby	131	Gypsum	181	Leawood	230	Vernon
32	Benton	82	Detroit	132	Haddam	182	Lebanon	231	Mullinville
33	Berryton	83	Dexter	133	Hamlin	183	Lecompton	232	Mulvane
34	Beverly	84	Douglass	134	Hanover	184	Lehigh	233	Munden
35	Bison	85	Downs	135	Harper	185	LeLoup	234	Muscotah
36	Black Hills Energy	86	Dwight	136	Hartford	186	Lenexa	235	Narka
37	Blaine	87	Eastborough	137	Haven	187	Leon	236	Nashville
38	Bloom	88	Easter's Addition	138	Haviland	188	Lewis	237	Netawaka
39	Mound	89	Edgerton	139	Haysville	189	Lincoln Center	238	Ozawkie
40	Rapids	90	Effingham	140	Hiawatha	190	Lindsborg	239	New Salem
41	Bronson	91	El Dorado	141	Highland	191	Linn	240	Newton
42	Bucklin	92	Elbing	142	Hoisington	192	Longford	241	Newton
43	Buhler	93	Ellinwood	143	Holton	193	Loretta	242	Nortonville
44	Burden	94	Ellsworth	144	Holyrood	194	Lorraine	243	Obeeville
45	Burns	95	Elmont	145	Home City	195	Louisville	244	Ogden
46	Burr Oak	96	Elwood	146	Hope	196	Lowell	245	Olmitz
47	Bushton	97	Emporia	147	Horton	197	Lucas	246	Olpe
48	Cambridge	98	Englewood	148	Hudson	198	Luray	247	Onaga
49	Canton	99	Enterprise	149	Huron	199	Lyndon	248	Osawatomie
50	Capaldo	100	Erie	150	Hutchinson	200	Macksville	249	Osborne

	Community		Community		Community
250	Oskaloosa	301	Heights	352	Wheaton
251	Oswego	302	Silver Lake	353	Whitewater
252	Otis	303	Smith Center	354	Whiting
253	Ottawa	304	Smolan	355	Wichita
254	Overbrook	305	Solomon	356	Williamsburg
255	Overland Park	306	Somerset	357	Willis
256	Oxford	307	Hutchinson	358	Addition
257	Ozawkie	308	South Mound	359	Winchester
258	Palmer	309	St. Benedict	360	Zarah
259	Paola	310	St. George		
260	Park City	311	St. John		
261	Parkerfield	312	St. Marys		
262	Parsons	313	St. Paul		
263	Partridge	314	Stafford		
264	Pauline	315	Stanley		
265	Perry	316	Stilwell		
266	Petrolia	317	Sylvan Grove		
267	Pfeiffer	318	Tecumseh		
268	Piqua	319	Tescott		
269	Pittsburg	320	Thayer		
270	Pomona	321	Timkin		
271	Potwin	322	Tonganoxie		
272	Prairie Village	323	Topeka		
273	Pratt	324	Towanda		
274	Preston	325	Est.		
275	Pretty Prairie	326	Troy		
276	Princeton	327	Turon		
277	Protection	328	Udall		
278	Quenemo	329	Valley Center		
279	Rantoul	330	Valley Falls		
280	Raymond	331	Vermillion		
281	Reserve	332	Vesper		
282	Richmond	333	Victoria		
283	Riverton	334	Vining		
284	Robinson	335	Vliets		
285	Roeland Park	336	Wakefield		
286	Rose Hill	337	Walker		
287	Roseland	338	Walnut		
288	Rossville	339	Wamego		
289	Roxbury	340	Washington		
290	Rozel	341	Waterville		
291	Russell	342	Wathena		
292	Sabetha	343	Waverly		
293	Salina	344	Weir		
294	Scammon	345	Welda		
295	Scandia	346	Wellington		
296	Scipio	347	Wellsville		
297	Scranton	348	West Mineral		
298	Sedgwick	349	Westmoreland		
299	Seneca	350	Westwood		
300	Shawnee	351	Westwood Hills		

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.

Summary of Reasons for Filing this Application

Kansas Gas Service, a Division of ONEOK, Inc. ("Company") files this rate application to give the Company an opportunity to earn its authorized rate of return. Kansas Gas Service's current base rates were last changed in January 2007 and were based upon a twelve month test year ending December 31, 2005. Kansas Gas Service has continued to devote capital to its operations resulting in increases in plant in service and depreciation expense. Although the Company has implemented measures to hold down costs and maximize efficiency in operations, it has experienced increases in labor, health care and pension costs. It has also experienced increases in other Operating and Maintenance costs. During this same period, the Company has seen a decline in per capita residential consumption of natural gas because of more efficient gas usage by customers. As a result, the Company does not have an opportunity to earn its authorized rate of return without an increase in its base rates. Kansas Gas Service is also filing this rate application to reset its Gas System Reliability Surcharge to zero as required by law. Additionally, Kansas Gas Service is filing this rate application seeking permission to implement a Revenue Normalization Adjustment ("RNA") mechanism in order to better match authorized revenue recovery with actual customer usage.

KANSAS GAS SERVICE
A DIVISION OF ONEOK

News

May 18, 2012

Analyst Contact: Andrew Ziola
918-588-7163

Contact: Dawn Ewing
913-319-8642

Kansas Gas Service Seeks Approval of New Rates

OVERLAND PARK, Kan. – May 18, 2012 – Kansas Gas Service, a division of ONEOK, Inc. (NYSE:OKE), announced today that it has filed a request with the Kansas Corporation Commission to increase its overall annual revenues by $32.7 million. The request includes a $50.7 million increase in base rates and an $18 million reduction in amounts currently recovered through surcharges.

Since its last adjustment in base rates in January 2007, Kansas Gas Service has invested more than $250 million in its natural gas distribution system, which stretches approximately 18,000 miles throughout Kansas and serves more than 630,000 customers.

"This rate request reflects the significant investment we have made in our Kansas pipeline infrastructure and facilities to deliver natural gas safely and reliably to our customers," said Brad Dixon, president of Kansas Gas Service.

Although the company has implemented measures to hold down costs and maximize efficiency in operations, Dixon also cited continuing increases in labor, health care and pension costs since the company's last rate case as contributing factors to the filing. "This request balances our customers' needs with the company's and its investors' needs to earn a fair and reasonable return on our investment in the natural gas distribution system."

If approved, this request would increase the typical residential customer's monthly natural gas bill by approximately $5.68, or 9.1 percent; the average commercial customer, who uses 288 thousand cubic feet (Mcf) of natural gas per year, would not experience an increase in their bill.

The Kansas Corporation Commission has 240 days to issue a ruling on Kansas Gas Service's application.

-more-

Kansas Gas Service provides clean, reliable natural gas to more than 630,000 customers in 337 communities in Kansas. It is a division of ONEOK, Inc. (NYSE: OKE), a diversified energy company. ONEOK is the general partner and owns 43.4 percent of ONEOK Partners, L.P. (NYSE: OKS), one of the largest publicly traded limited partnerships, which is a leader in the gathering, processing, storage and transportation of natural gas in the U.S. and owns one of the nation's premier natural gas liquids (NGL) systems, connecting NGL supply in the Mid-Continent and Rocky Mountain regions with key market centers. ONEOK is among the largest natural gas distributors in the United States, serving more than 2 million customers in Oklahoma, Kansas and Texas. Its energy services operation focuses primarily on marketing natural gas and related services throughout the U.S. ONEOK is a Fortune 500 company and is included in the Standard & Poor's 500 stock index.

For more information, visit the websites at www.kansasgasservice.com or www.oneok.com.

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KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3
	Rate Base		
1	Gas plant in service	3-B	$1,508,198,000
2	Less: Accumulated provision for depreciation and amortization	3-B	543,584,888
3	Net gas plant in service		$964,613,112
4	Working capital	3-B	(192,181,716)
5	Rate Base		$772,431,396
	Revenues and Expenses		
6	Total revenues	3-B	$258,796,565
7	Total expenses	3-B	223,639,079
8	Operating income		$35,157,486
	Rate of Return		
9	Return on present rates (Line 8 / Line 5)		4.5515%
10	Required return on rate base	7-A	8.5199%
11	Operating income requirement (Line 5 X Line 10)		$65,810,382
	Revenue Requirement to Earn Required Rate of Return		
12	Additional operating income (Line 11 - Line 8)		$30,652,896
13	Associated income taxes		20,054,955
14	Revenue increase required		$50,707,852

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Rate Base				
1	Gas plant in service	4-A	$1,474,614,559	$33,583,441	$1,508,198,000
2	Less: Accumulated provision for depreciation and amortization	5-A	534,291,084	9,293,804	543,584,888
3	Net gas plant in service		$940,323,475	$24,289,637	$964,613,112
4	Working capital	6-A	(233,791,063)	41,609,347	(192,181,716)
5	Rate Base		$706,532,412	$65,898,984	$772,431,396
	Revenues and Expenses				
6	Total revenues	9-A	$580,077,308	($321,280,743)	$258,796,565
7	Total expenses	9-A	537,965,653	(314,326,574)	223,639,079
8	Operating income		$42,111,655	($6,954,169)	$35,157,486

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Schedule Reference Col. 2	Amount Per Books Col. 3	PLT 1 CWIP Adjustment Col. 4	PLT 2 Corporate Assets Adjustment Col. 5	PLT 3 Asset Retirement Adjustment Col. 6
	Rate Base					
1	Gas plant in service	4-A	$1,474,614,559	$14,237,712	$27,214,749	($3,255,910)
2	Less: Accumulated provision for depreciation and amortization	5-A	534,291,084	0	0	0
3	Net gas plant in service		$940,323,475	$14,237,712	$27,214,749	($3,255,910)
4	Working capital	6-A	(233,791,063)	0	0	0
5	Rate Base		$706,532,412	$14,237,712	$27,214,749	($3,255,910)
	Revenues and Expenses					
6	Total revenues	9-A	$580,077,308	$0	$0	$0
7	Total expenses	9-A	537,965,653	0	0	0
8	Operating income		$42,111,655	$0	$0	$0

Line No.	Description	Schedule Reference	PLT 4 Adjustment Not Used & Useful Plant	PLT 5 Adjustment CNG	PLT 6 Adjustment Account Reclass	ADA-1 Corporate Assets ADA Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 4	Col. 5
	Rate Base					
1	Gas plant in service	4-A	($4,425,774)	($187,337)	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	15,113,866
3	Net gas plant in service		($4,425,774)	($187,337)	$0	($15,113,866)
4	Working capital	6-A	0	0	0	0
5	Rate Base		($4,425,774)	($187,337)	$0	($15,113,866)
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	0	0	0	0
8	Operating income		$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	ADA-2 Asset Retirement Adjustment	ADA-3 Not Used & Useful Plant Adjustment	WC 1 Prepayments	WC 2 Pension/OPEB Funding ADIT
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	(3,255,910)	(2,564,153)	0	0
3	Net gas plant in service		$3,255,910	$2,564,153	$0	$0
4	Working capital	6-A	0	0	1,360,076	33,759,366
5	Rate Base		$3,255,910	$2,564,153	$1,360,076	$33,759,366
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	0	0	0	0
8	Operating income		$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Schedule Reference Col. 2	WC 3 2011 Operations ADIT Col. 3	WC 4 COGR over/under ADIT Col. 4	WC 5 Corporate ADIT Col. 5	IS 1 Eliminate Accrued and Unbilled Revenues and Expenses Adjustment Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	10,382,007	140,671	(4,032,773)	0
5	Rate Base		$10,382,007	$140,671	($4,032,773)	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$8,754,035
7	Total expenses	9-A	0	0	0	7,611,194
8	Operating income		$0	$0	$0	$1,142,841

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 2 Eliminate Deferred WNA Revenues Adjustment	IS 3 Eliminate COGR Revenues and Expenses Adjustment	IS 4 ATSR Revenue and Adjust the Ad Valorem Adjustment	IS 5 Eliminate GSRS Revenue Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$4,311,866	($316,718,977)	($5,576,328)	($8,005,229)
7	Total expenses	9-A	0	(316,718,977)	1,570,697	0
8	Operating income		$4,311,866	$0	($7,147,026)	($8,005,229)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 6 As Available Gas Sales Adjustment	IS 7 Test Year Revenue Adjustments Adjustment	IS 8 Normalize Test Year Revenues- Adjustment	IS 9 Annualize Test Year Customers, Sales and Revenues Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	($1,337,471)	$327,929	($3,156,326)	$132,116
7	Total expenses	9-A	(1,327,523)	(45,482)	0	0
8	Operating income		($9,948)	$373,411	($3,156,326)	$132,116

Line No.	Description	Schedule Reference	IS 10 Eliminate CNG Revenue and Taxes Adjustment	IS 11 Adjustment for Non-Gas Portion of Uncollectible Adjustment	IS 12 Eliminate Royalty Fee Adjustment	IS 13 Pension & Benefits Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	($12,358)	$0	$0	$0
7	Total expenses	9-A	(7,902)	185,884	(8,116,302)	5,184,587
8	Operating income		($4,456)	($185,884)	$8,116,302	($5,184,587)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 14 Amortization of Deferred Pension & Benefits Adjustment	IS 15 Employee Medical Reserve Adjustment	IS 16 OPEB Amortization Adjustment	IS 17 Include Certain Donations from Account 426 and Eliminate Certain Dues and Donations Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	4,602,429	587,928	(2,937,792)	75,443
8	Operating income		($4,602,429)	($587,928)	$2,937,792	($75,443)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 18 Normalize Assessed Regulatory Costs Adjustment	IS 19 Income Taxes Adjustment	IS 20 Out of Period Adjustment	IS 21 Rate Case Expense Amortization Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	64,948	(4,501,925)	(225,411)	379,414
8	Operating income		($64,948)	$4,501,925	$225,411	($379,414)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 22 Payroll Adjustment Adjustment	IS 23 Annualize Depreciation on Pro-Forma Plant Adjustment	IS 24 Annualization Depreciation at Proposed Rates Adjustment	IS 25 Adjust Clearings Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	1,108,060	528,401	4,455,065	(249,361)
8	Operating income		($1,108,060)	($528,401)	($4,455,065)	$249,361

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 26 Annualize Cellnet Increase Adjustment	IS 27 Bill Print Vendor Change Adjustment Adjustment	IS 28 Reclassify Interest on Customer Deposits Adjustment	IS 29 Shared Services Contract Changes Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	22,681	270,819	21,097	38,491
8	Operating income		($22,681)	($270,819)	($21,097)	($38,491)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 30 Eliminate O&M costs related to plant Adjustment	IS 31 Annualized Corporate Depreciation Adjustment	IS 32 Normalized Compensation - STI/LTI/Deferred Compensation Adjustment	IS 33 Normalized Compensation - Share Awards Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	(82,357)	(34,635)	(1,924,470)	(2,367,236)
8	Operating income		$82,357	$34,635	$1,924,470	$2,367,236

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	IS 34 Adjustment for Change in Allocation Ratio Adjustment	IS 35 Adjustment for Miscellaneous Corporate Charges Adjustment	IS 36 Adjustment for OPEB, Pension, Health Benefits and Insurance Adjustment	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$33,583,441
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	9,293,804
3	Net gas plant in service		$0	$0	$0	$24,289,637
4	Working capital	6-A	0	0	0	41,609,347
5	Rate Base		$0	$0	$0	$65,898,984
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	($321,280,743)
7	Total expenses	9-A	(477,277)	(1,891,493)	(125,567)	(314,326,574)
8	Operating income		$477,277	$1,891,493	$125,567	($6,954,169)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Functional Classification of Plant in Service
Test Year Ended December 31, 2011

Line No.	Description	Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	Intangible plant	4-A	$68,559	$0	$68,559
2	Production plant	4-A	864,061	0	864,061
3	Storage plant	4-A	0	0	0
4	Transmission plant	4-A	232,415,468	(574,696)	231,840,772
5	Distribution plant	4-A	1,148,202,589	5,894,708	1,154,097,297
6	General plant	4-A	93,063,882	1,048,680	94,112,562
7	Corporate allocated plant	4-A	0	27,214,749	27,214,749
8	Total plant in service		$1,474,614,559	$33,583,441	$1,508,198,000

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Functional Classification of Plant in Service
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Amount Per Books (Schedule 4-B) Col. 2	Pro Forma Adjustments (Schedule 4-C) Col. 3	Pro Forma Adjusted Total Col. 4
		Intangible Plant			
1	302	Franchises and consents	$6,045	$0	$6,045
2	303	Intangible-miscellaneous	62,514	0	62,514
3		Total intangible plant	$68,559	$0	$68,559
		Natural Gas Production and Gathering Plant			
4	325.4	Rights-of-way	$232,567	$0	$232,567
5	327	Field compressor station structures	3,053	0	3,053
6	328	Field meas. and reg. station structures	44,026	0	44,026
7	332	Field lines	56,448	0	56,448
8	333	Field compressor station equipment	12,877	0	12,877
9	334	Field meas. and reg. station equipment	515,090	0	515,090
10		Total production and gathering plant	$864,061	$0	$864,061
		Underground Storage Plant			
11	350.1	Land & Land rights	$0	$0	$0
12	351.1	Structures and improvements	0	0	0
13	351.2	Structures and improvements	0	0	0
14	351.3	Structures and improvements	0	0	0
15	352	Wells	0	0	0
16	352.1	Storage Lease and Rights	0	0	0
17	352.2	Reservoirs	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0
19	353	Storage Lines	0	0	0
20	354	Compressor station equipment	0	0	0
21	355	Measuring and regulating station equipment	0	0	0
22	356	Purification equipment	0	0	0
23	357	Other equipment	0	0	0
24		Total Storage plant	$0	$0	$0

Line No.	Account Number	Description Col. 1	Amount Per Books (Schedule 4-B) Col. 2	Pro Forma Adjustments (Schedule 4-C) Col. 3	Pro Forma Adjusted Total Col. 4
		Transmission Plant			
1	365.1	Land and land rights	$826,470	$0	$826,470
2	365.2	Rights-of-way	11,672,850	168,964	11,841,814
3	366.1	Structures and imp. - compressor stations	4,140,389	1,758	4,142,147
4	366.2	Structures and imp. - meas. & reg. stations	1,137,206	0	1,137,206
5	367	Mains	178,365,385	3,539,160	181,904,545
6	368	Compressor station equipment	20,994,536	(3,995,847)	16,998,689
7	369	Measuring and regulating station equip.	15,278,632	(286,034)	14,992,598
8	371	Other Equipment	0	(2,697)	(2,697)
9		Total transmission plant	$232,415,468	($574,696)	$231,840,772
		Distribution Plant			
10	374.1	Land and land rights	$101,785	($4,220)	$97,565
11	374.2	Rights-of-way	1,832,554	0	1,832,554
12	375.1	Structures and improvements	860,867	(5,608)	855,259
13	376	Mains	287,155,624	2,380,594	289,536,218
14	376.5	Mains - Metallic	267,089,614	158,815	267,248,429
15	378	Meas. and reg. sta. equip. - general	21,366,421	158,743	21,525,164
16	379	Meas. and reg. sta. equip. - city gate	6,022,208	(56,074)	5,966,134
17	380	Services	332,686,616	2,171,650	334,858,266
18	380.5	Services - Metallic	31,461,187	(158,815)	31,302,372
19	381	Meters	96,912,722	965,481	97,878,203
20	382	Meter installations	87,849,166	203,465	88,052,631
21	383	House regulators	14,639,700	80,677	14,720,377
22	386	Other Property on Customer Premises	224,125	0	224,125
23	387	Other Equipment	0	0	0
24		Total distribution plant	$1,148,202,589	$5,894,708	$1,154,097,297

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Functional Classification of Plant in Service
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Amount Per Books (Schedule 4-B) Col. 2	Pro Forma Adjustments (Schedule 4-C) Col. 3	Pro Forma Adjusted Total Col. 4
		General Plant			
1	389.1	Land and land rights	$1,452,065	$0	$1,452,065
2	390.1	Structures and improvements - owned	29,227,370	268,522	29,495,892
3	390.2	Structures and improvements - leasehold	2,600,970	0	2,600,970
4	391.1	Office furniture and equipment - computers	4,853,880	170,940	5,024,820
5	391.9	Computers and other electronic equipment	6,148,309	0	6,148,309
6	392	Transportation equipment	20,489,618	329,159	20,818,777
7	393	Stores equipment	357,584	7,582	365,166
8	394	Tool, shop and garage equipment	8,062,508	8,986	8,071,494
9	395	Laboratory equipment	72,378	(796)	71,582
10	396	Power operated equipment	11,203,106	246,553	11,449,659
11	397	Communication equipment	8,459,089	16,956	8,476,045
12	398	Miscellaneous equipment	137,005	778	137,783
13		Total general plant	$93,063,882	$1,048,680	$94,112,562
14		Corporate allocated plant	$0	$27,214,749	$27,214,749
15		Total gas plant in service	$1,474,614,559	$33,583,441	$1,508,198,000

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Plant in Service by Primary Account
Test Year Ended December 31, 2011
Balance as of

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Intangible Plant				
1	302	Franchises and consents	$6,045	$6,045	$6,045	$6,045
2	303	Intangible-miscellaneous	827,258	52,535	62,514	62,514
3		Total intangible plant	$833,303	$58,580	$68,559	$68,559
		Natural Gas Production and Gathering Plant				
4	325.4	Rights-of-way	$232,567	$232,567	$232,567	$232,567
5	327	Field compressor station structures	3,053	3,053	3,053	3,053
6	328	Field meas. and reg. station structures	44,026	44,026	44,026	44,026
7	332	Field lines	559,783	558,800	558,800	56,448
8	333	Field compressor station equipment	117,939	117,939	12,877	12,877
9	334	Field meas. and reg. station equipment	515,090	515,090	515,090	515,090
10		Total production and gathering plant	$1,472,458	$1,471,475	$1,366,413	$864,061
		Underground Storage Plant				
11	350.1	Land & Land rights	$0	$0	$0	$0
12	351.1	Structures and improvements	0	0	0	0
13	351.2	Structures and improvements	0	0	0	0
14	351.3	Structures and improvements	0	0	0	0
15	352	Wells	0	0	0	0
16	352.1	Storage Lease and Rights	0	0	0	0
17	352.2	Reservoirs	0	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0	0
19	353	Storage Lines	0	0	0	0
20	354	Compressor station equipment	0	0	0	0
21	355	Measuring and regulating station equipment	0	0	0	0
22	356	Purification equipment	0	0	0	0
23	357	Other equipment	0	0	0	0
24		Total Storage plant	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Plant in Service by Primary Account
Test Year Ended December 31, 2011
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Transmission Plant				
1	365.1	Land and land rights	$826,491	$826,470	$826,470	$826,470
2	365.2	Rights-of-way	10,523,665	10,563,738	10,627,429	11,672,850
3	366.1	Compressor Station Structure	4,034,061	4,034,061	4,418,677	4,140,389
4	366.2	Measuring Station Structure	1,172,479	1,137,206	1,137,206	1,137,206
5	367	Mains	155,201,145	154,195,360	157,581,992	178,365,385
6	368	Compressor station equipment	20,529,445	19,598,363	22,010,987	20,994,536
7	369	Measuring and regulating station equip.	14,328,389	14,407,599	15,234,993	15,278,632
8	371	Other Equipment	27,439	40,328	24,447	0
9		Total transmission plant	$206,643,114	$204,803,125	$211,862,201	$232,415,468
		Distribution Plant				
10	374.1	Land and land rights	$101,763	$101,785	$101,960	$101,785
11	374.2	Rights-of-way	$1,550,030	$1,723,321	$1,858,489	$1,832,554
12	375.1	Structures and improvements	396,122	454,264	895,568	860,867
13	376	Mains	273,911,476	273,295,970	280,632,817	287,155,624
14	376.5	Mains - Metallic	251,382,931	255,376,926	261,428,656	267,089,614
15	378	Meas. and reg. sta. equip. - general	19,650,091	19,851,745	20,483,566	21,366,421
16	379	Meas. and reg. sta. equip. - city gate	5,719,869	5,848,301	6,354,324	6,022,208
17	380	Services	307,547,786	309,534,093	320,886,479	332,686,616
18	380.5	Services - Metallic	32,771,285	31,011,364	30,890,162	31,461,187
19	381	Meters	84,820,752	86,915,143	91,746,466	96,912,722
20	382	Meter installations	79,474,116	84,237,956	87,424,846	87,849,166
21	383	House regulators	14,758,472	15,239,754	15,668,329	14,639,700
22	386	Other Property on Customers Premises	224,125	224,125	224,125	224,125
23	387	Other Equipment	0	0	0	0
24		Total distribution plant	$1,072,308,818	$1,083,814,747	$1,118,595,787	$1,148,202,589

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Plant in Service by Primary Account
Test Year Ended December 31, 2011
Balance as of

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		General Plant				
1	389.1	Land and land rights	$1,468,978	$1,468,978	$1,468,978	$1,452,065
2	390.1	Structures and improvements - owned	25,278,136	25,935,208	27,687,750	29,227,370
3	390.2	Structures and improvements - leasehold	2,221,962	2,415,565	2,512,234	2,600,970
4	391.1	Office furniture and equipment	3,907,454	4,171,473	4,350,504	4,853,880
5	391.9	Computers and other electronic equipment	11,573,709	9,020,467	9,473,346	6,148,309
6	392	Transportation equipment	13,282,212	17,598,488	18,867,729	20,489,618
7	393	Stores equipment	488,410	420,435	338,182	357,584
8	394	Tool, shop and garage equipment	6,890,272	6,741,476	7,262,619	8,062,508
9	395	Laboratory equipment	525,391	105,356	77,305	72,378
10	396	Power operated equipment	8,555,003	8,691,866	9,699,644	11,203,106
11	397	Communication equipment	8,444,988	8,311,942	8,362,774	8,459,089
12	398	Miscellaneous equipment	128,120	130,095	132,195	137,005
13		Total general plant	$82,764,635	$85,011,349	$90,233,260	$93,063,882
14		Total gas plant in service	$1,364,022,328	$1,375,159,276	$1,422,126,220	$1,474,614,559

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Plant in Service (a)
Test Year Ended December 31, 2011

Line No.	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Corporate Assets	PLT 3 Pro Forma Adjustment Asset Retirement	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	Intangible plant	$0	$0	$0	$0	$0
2	Production and gathering plant	0	0	0	0	$0
3	Storage Plant	0	0	0	0	$0
4	Transmission plant	4,992,855	0	(1,141,777)	(4,425,774)	($574,696)
5	Distribution plant	7,642,386	0	(1,747,678)	0	$5,894,708
6	General plant	1,602,471	0	(366,455)	0	$1,236,016
7	Corporate Allocated Plant	0	27,214,749	0	0	$27,214,749
8	Total gas plant in service	$14,237,712	$27,214,749	($3,255,910)	($4,425,774)	$33,770,777

Note:
(a) See Schedule 4-D for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Plant in Service (a)
Test Year Ended December 31, 2011

Line No.	Description	PLT 5 Pro Forma Adjustment CNG	PLT 6 Pro Forma Adjustment Account Reclass	Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4
1	Intangible plant	$0	$0	$0
2	Production and gathering plant	0	0	$0
3	Storage Plant	0	0	$0
4	Transmission plant	0	0	($574,696)
5	Distribution plant	0	0	$5,894,708
6	General plant	(187,337)	0	$1,048,680
7	Corporate Allocated Plant	0	0	$27,214,749
8		($187,337)	$0	$33,583,441

Note:
(a) See Schedule 4-D for explanation of pro forma adjustments.

Line No.	Account Number	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Corporate Assets	PLT 3 Pro Forma Adjustment Asset Retirement	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Plant in Service To Section 10-E,F
		Col. 1	Col. 2	Col. 4	Col. 4	Col. 5	Col. 6
		Intangible Plant					
1	302	Franchises and consents	$0	$0	$0	$0	$0
2	303	Intangible-miscellaneous	0	0	0	0	0
3		Total intangible plant	$0	$0	$0	$0	$0
		Natural Gas Production and Gathering Plant					
4	325.4	Rights-of-way	$0	$0	$0	$0	$0
5	327	Field compressor station structures	0	0	0	0	0
6	328	Field meas. and reg. station structures	0	0	0	0	0
7	332	Field lines	0	0	0	0	0
8	333	Field compressor station equipment	0	0	0	0	0
9	334	Field meas. and reg. station equipment	0	0	0	0	0
10		Total production and gathering plant	$0	$0	$0	$0	$0
		Underground Storage Plant					
11	350.1	Land and Land Rights	$0	$0	$0	$0	$0
12	351.1	Structures and improvements	0	0	0	0	0
13	351.2	Structures and improvements	0	0	0	0	0
14	351.3	Structures and improvements	0	0	0	0	0
15	352	Wells	0	0	0	0	0
16	352.1	Storage Lease and Rights	0	0	0	0	0
17	352.2	Reservoirs	0	0	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0	0	0
19	353	Storage Lines	0	0	0	0	0
20	354	Compressor station equipment	0	0	0	0	0
21	355	Measuring and regulating station equipment	0	0	0	0	0
22	356	Purification equipment	0	0	0	0	0
23	357	Other equipment	0	0	0	0	0
24		Total Storage plant	$0	$0	$0	$0	$0

Line No.	Account Number	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Corporate Assets	PLT 3 Pro Forma Adjustment Asset Retirement	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Plant in Service To Section 10-E,F
		Col. 1	Col. 2	Col. 4	Col. 4	Col. 5	Col. 6
		Transmission Plant					
1	365.1	Land and land rights	$0	$0	$0	$0	$0
2	365.2	Rights-of-way	219,059	0	(50,095)	0	168,964
3	366.1	Structures and imp. - compressor stations	5,405	0	(1,236)	(2,412)	1,758
4	366.2	Structures and imp. - meas. & reg. stations	0	0	0	0	0
5	367	Mains	4,607,032	0	(1,053,546)	(14,326)	3,539,160
6	368	Compressor station equipment	66,372	0	(15,178)	(4,047,040)	(3,995,847)
7	369	Measuring and regulating station equip.	98,484	0	(22,522)	(361,996)	(286,034)
8	371	Other Equipment	(3,497)	0	800	0	(2,697)
9		Total transmission plant	$4,992,855	$0	($1,141,777)	($4,425,774)	($574,696)
		Distribution Plant					
10	374.1	Land and land rights	($5,471)	$0	$1,251	$0	($4,220)
11	374.2	Rights-of-way	0	0	0	0	0
12	375.1	Structures and improvements	(7,271)	0	1,663	0	(5,608)
13	376	Mains	2,997,702	0	(685,521)	0	2,312,181
14	376.5	Mains - Metallic	0	0	0	0	0
15	378	Meas. and reg. sta. equip. - general	205,808	0	(47,065)	0	158,743
16	379	Meas. and reg. sta. equip. - city gate	(72,699)	0	16,625	0	(56,074)
17	380	Services	2,904,202	0	(664,140)	0	2,240,062
18	380.5	Services - Metallic	0	0	0	0	0
19	381	Meters	1,251,729	0	(286,248)	0	965,481
20	382	Meter installations	263,789	0	(60,324)	0	203,465
21	383	House regulators	104,596	0	(23,919)	0	80,677
22	386	Other Property on Customer Premises	0	0	0	0	0
23	387	Other Equipment	0	0	0	0	0
24		Total distribution plant	$7,642,386	$0	($1,747,678)	$0	$5,894,708

Line No.	Account Number	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Corporate Assets	PLT 3 Pro Forma Adjustment Asset Retirement	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Plant in Service To Section 10-E,F
		Col. 1	Col. 2	Col. 4	Col. 4	Col. 5	Col. 6
		General Plant					
1	389.1	Land and land rights	$0	$0	$0	$0	$0
2	390.1	Structures and improvements - owned	348,134	0	(79,612)	0	268,522
3	390.2	Structures and improvements - leasehold	0	0	0	0	0
4	391.1	Office furniture and equipment	221,620	0	(50,680)	0	170,940
5	391.9	Computers and other electronic equipment	0	0	0	0	0
6	392	Transportation equipment	426,749	0	(97,590)	0	329,159
7	393	Stores equipment	9,830	0	(2,248)	0	7,582
8	394	Tool, shop and garage equipment	254,529	0	(58,206)	0	196,323
9	395	Laboratory equipment	(1,032)	0	236	0	(796)
10	396	Power operated equipment	319,651	0	(73,098)	0	246,553
11	397	Communication equipment	21,983	0	(5,027)	0	16,956
12	398	Miscellaneous equipment	1,008	0	(230)	0	778
13		Total general plant	$1,602,471	$0	($366,455)	$0	$1,236,016
14		Corporate Allocated Plant	$0	$27,214,749	$0	$0	$27,214,749
15		Total gas plant in service	$14,237,712	$27,214,749	($3,255,910)	($4,425,774)	$33,770,777

Line No.	Account Number	Description	PLT 5 Pro Forma Adjustment CNG	PLT 6 Pro Forma Adjustment Account Reclass	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4
		Intangible Plant			
1	302	Franchises and consents	$0	$0	$0
2	303	Intangible-miscellaneous	0	0	0
3		Total intangible plant	$0	$0	$0
		Natural Gas Production and Gathering Plant			
4	325.4	Rights-of-way	$0	$0	$0
5	327	Field compressor station structures	0	0	0
6	328	Field meas. and reg. station structures	0	0	0
7	332	Field lines	0	0	0
8	333	Field compressor station equipment	0	0	0
9	334	Field meas. and reg. station equipment	0	0	0
10		Total production and gathering plant	$0	$0	$0
		Underground Storage Plant			
11	350.1	Land & Land rights	0	0	0
12	351.1	Structures and improvements	0	0	0
13	351.2	Structures and improvements	0	0	0
14	351.3	Structures and improvements	0	0	0
15	352	Wells	0	0	0
16	352.1	Storage Lease and Rights	0	0	0
17	352.2	Reservoirs	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0
19	353	Storage Lines	0	0	0
20	354	Compressor station equipment	0	0	0
21	355	Measuring and regulating station equipment	0	0	0
22	356	Purification equipment	0	0	0
23	357	Other equipment	0	0	0
24		Total Storage plant	$0	$0	$0

Line No.	Account Number	Description Col. 1	PLT 5 Pro Forma Adjustment CNG Col. 2	PLT 6 Pro Forma Adjustment Account Reclass Col. 3	Total Pro Forma Adjustments Col. 4
		Transmission Plant			
1	365.1	Land and land rights	$0	$0	$0
2	365.2	Rights-of-way	0	0	168,964
3	366.1	Structures and imp. - compressor stations	0	0	1,758
4	366.2	Structures and imp. - meas. & reg. stations	0	0	0
5	367	Mains	0	0	3,539,160
6	368	Compressor station equipment	0	0	(3,995,847)
7	369	Measuring and regulating station equip.	0	0	(286,034)
8	371	Other Equipment	0	0	(2,697)
9		Total transmission plant	$0	$0	($574,696)
		Distribution Plant			
10	374.1	Land and land rights	$0	$0	($4,220)
11	374.2	Rights-of-way	0	0	0
12	375.1	Structures and improvements	0	0	(5,608)
13	376	Mains	0	68,412	2,380,594
14	376.5	Mains - Metallic	0	158,815	158,815
15	378	Meas. and reg. sta. equip. - general	0	0	158,743
16	379	Meas. and reg. sta. equip. - city gate	0	0	(56,074)
17	380	Services	0	(68,412)	2,171,650
18	380.5	Services - Metallic	0	(158,815)	(158,815)
19	381	Meters	0	0	965,481
20	382	Meter installations	0	0	203,465
21	383	House regulators	0	0	80,677
22	386	Other Property on Customer Premises	0	0	0
23	387	Other Equipment	0	0	0
24		Total distribution plant	$0	$0	$5,894,708

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	PLT 5 Pro Forma Adjustment CNG Col. 2	PLT 6 Pro Forma Adjustment Account Reclass Col. 3	Total Pro Forma Adjustments Col. 4
		General Plant			
1	389.1	Land and land rights	$0	$0	$0
2	390.1	Structures and improvements - owned	0	0	268,522
3	390.2	Structures and improvements - leasehold	0	0	0
4	391.1	Office furniture and equipment - computers	0	0	170,940
5	391.9	Computers and other electronic equipment	0	0	0
6	392	Transportation equipment	0	0	329,159
7	393	Stores equipment	0	0	7,582
8	394	Tool, shop and garage equipment	(187,337)	0	8,986
9	395	Laboratory equipment	0	0	(796)
10	396	Power operated equipment	0	0	246,553
11	397	Communication equipment	0	0	16,956
12	398	Miscellaneous equipment	0	0	778
13		Total general plant	($187,337)	$0	$1,048,680
14		Corporate allocated plant	$0	$0	$27,214,749
15		Total Plant in Service	($187,337)	$0	$33,583,441

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 1		
		0	0
	CWIP	0	0
1	Intangible plant	0	0
2	Production and gathering plant	4,992,855	0
3	Storage Plant	7,642,386	0
4	Transmission Plant	1,602,471	0
5	Distribution plant	0	0
6	General plant	0	0
7	Corporate Allocated Plant		
8	CWIP		

To include capital expenditures for projects underway at December 31, 2011 completed within one year after the end of the test year.

Line No.	Description	Increase	Decrease
	Adjustment PLT 2		
		0	0
	Corporate Assets	0	0
9	Intangible plant	0	0
10	Production and gathering plant	0	0
11	Storage Plant	0	0
12	Transmission Plant	0	0
13	Distribution plant	27,214,749	0
14	General plant	0	0
15	Corporate Allocated Plant		
16	CWIP		

To include Corporate assets providing service to Kansas Gas Service

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 3		
		0	0
	Asset Retirement	0	0
1	Intangible plant	0	0
2	Production and gathering plant	0	1,141,777
3	Storage Plant	0	1,747,678
4	Transmission Plant	0	366,455
5	Distribution plant	0	0
6	General plant	0	0
7	Corporate Allocated Plant		
8	CWIP		

To remove plant retirements in CWIP that will retire subsequent to the test year.

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 4		
		0	0
	Not Used & Useful Plant	0	0
9	Intangible plant	0	0
10	Production and gathering plant	0	4,425,774
11	Storage plant	0	0
12	Transmission plant	0	0
13	Distribution plant	0	0
14	General plant	0	0
15	Corporate Allocated Plant		
16	CWIP		

To remove the plant assets that are currently not used and useful.

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 5		
		0	0
	CNG	0	0
1	Intangible plant	0	0
2	Production and gathering plant	0	0
3	Storage Plant	0	0
4	Transmission Plant	0	187,337
5	Distribution plant	0	0
6	General plant	0	0
7	Corporate Allocated Plant		
8	CWIP		

To remove certain CNG assets pursuant to Brenda L. Storbeck testimony.

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 6		
		0	0
	Account Reclass	0	0
1	Intangible plant	0	0
2	Production and gathering plant	0	0
3	Storage Plant	0	0
4	Transmission Plant	0	0
5	Distribution plant	227,227	227,227
6	General plant	0	0
7	Corporate Allocated Plant		
8	CWIP		

To reclass plant between Services and Mains.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Description	Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Accumulated Provision For Depreciation				
1	Production and gathering plant	5-B	$597,410	$0	$597,410
2	Storage plant	5-B	0	0	0
3	Transmission plant	5-B	68,940,920	(3,705,930)	65,234,990
4	Distribution plant	5-B	428,594,784	(1,747,678)	426,847,106
5	General plant	5-B	33,887,108	(366,455)	33,520,653
6	Corporate allocated accumulated depreciation	5-B	0	15,113,866	15,113,866
7	Total accumulated provision for depreciation		$532,020,222	$9,293,804	$541,314,026
	Accumulated Provision For Amortization				
8	Total accumulated provision for amortization	5-B	2,270,862	0	2,270,862
9	Total accumulated provision for depreciation and amortization		$534,291,084	$9,293,804	$543,584,888

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Detail - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Amount Per Books Col. 2	Pro Forma Adjustments Col. 3	Pro Forma Adjusted Total Col. 4
		ACCUMULATED PROVISION FOR DEPRECIATION			
		Natural Gas Production and Gathering Plant			
1	325.4	Rights-of-way	$93,117	$0	$93,117
2	327	Field Compressor Station Structure	2,032	0	2,032
3	328	Field meas. and reg. station structures	55,464	0	55,464
4	332	Field lines	56,448	0	56,448
5	333	Field Compressor Station Equipment	12,877	0	12,877
6	334	Field meas. and reg. station equipment	377,472	0	377,472
7		Total production and gathering plant	$597,410	$0	$597,410
		Underground Storage Plant			
8	350.1	Land & Land rights	$0	$0	$0
9	350.2	Rights of way	0	0	0
10	351.1	Structures and improvements	0	0	0
11	351.2	Structures and improvements	0	0	0
12	351.3	Structures and improvements	0	0	0
13	352	Wells	0	0	0
14	352.1	Storage Lease and Rights	0	0	0
15	352.2	Reservoirs	0	0	0
16	352.3	Non-Recoverable Natural Gas	0	0	0
17	353	Storage Lines	0	0	0
18	354	Compressor station equipment	0	0	0
19	355	Measuring and regulating station equipment	0	0	0
20	356	Purification equipment	0	0	0
21	357	Other equipment	0	0	0
22		Total Underground storage plant	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Detail - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Amount Per Books Col. 2	Pro Forma Adjustments Col. 3	Pro Forma Adjusted Total Col. 4
		Transmission Plant			
1	365.2	Rights-of-way	$2,668,918	($50,095)	$2,618,823
2	366.1	Structures and imp. - compressor stations	3,728,296	(2,510)	3,725,786
3	366.2	Structures and imp. - meas. & reg. stations	900,604	0	900,604
4	367	Mains	42,744,519	(1,054,126)	41,690,393
5	368	Compressor station equipment	14,974,192	(2,499,796)	12,474,396
6	369	Measuring and regulating station equipment	3,924,391	(100,203)	3,824,188
7	371	Other Equipment	0	800	800
8		Total transmission plant	$68,940,920	($3,705,930)	$65,234,990
		Distribution Plant			
9	374.2	Rights-of-way	$376,128	$1,251	$377,379
10	375.1	Structures and improvements	268,885	1,663	270,548
11	376.1	Mains - Metallic	92,499,213	0	92,499,213
12	376.2	Mains - Plastic	87,341,158	(685,521)	86,655,637
13	378	Meas. and reg. sta. equip. - general	8,640,380	(47,065)	8,593,315
14	379	Meas. and reg. sta. equip. - city gate	3,753,915	16,625	3,770,540
15	380	Services	162,359,375	(664,140)	161,695,235
16	380.5	Services - Metallic	28,506,511	0	28,506,511
17	381	Meters	17,557,923	(286,248)	17,271,675
18	382	Meter installations	20,884,190	(60,324)	20,823,866
19	383	House regulators	6,239,474	(23,919)	6,215,555
20	386	Other Property Customer Premise	170,290	0	170,290
21	387	Other Equipment	(2,658)	0	(2,658)
22		Total distribution plant	$428,594,784	($1,747,678)	$426,847,106

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Detail - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Amount Per Books Col. 2	Pro Forma Adjustments Col. 3	Pro Forma Adjusted Total Col. 4
		General Plant			
1	389.1	Land	($14,378)	$0	($14,378)
2	390.1	Structures and improvements - owned	9,586,117	(79,612)	9,506,505
3	391.1	Office furniture and equipment	1,440,752	(50,680)	1,390,072
4	391.9	Computers and other electronic equipment	4,399,860	0	4,399,860
5	392	Transportation equipment	9,451,433	(97,590)	9,353,843
6	393	Stores equipment	471,031	(2,248)	468,783
7	394	Tools Shop and Garage Equipment	542,982	(58,206)	484,776
8	395	Laboratory equipment	(264,392)	236	(264,156)
9	396	Power operated equipment	3,564,730	(73,098)	3,491,632
10	397	Communication equipment	4,633,067	(5,027)	4,628,040
11	398	Miscellaneous equipment	75,906	(230)	75,676
12		Total general plant	$33,887,108	($366,455)	$33,520,653
13		Corporate Allocated	$0	$15,113,866	$15,113,866
14		Total accumulated provision for depreciation	$532,020,222	$9,293,804	$541,314,026
		ACCUMULATED PROVISION FOR AMORTIZATION			
15	302	Franchises and Consents	$0	$0	$0
16	303	Miscellaneous Intangible Plant	15,495	0	15,495
17	390.2	Structures and improvements - leasehold	2,255,367	0	2,255,367
18		Total accumulated provision for amortization	$2,270,862	$0	$2,270,862
19		Total accumulated provision for depreciation and amortization (a)	$534,291,084	$9,293,804	$543,584,887

Note:
(a) See Schedule 5-F for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Accumulated Provision for Depreciation and Amortization (a)
Test Year Ended December 31, 2011

Line No.	Description	ADA 1 Pro Forma Adjustment Corporate Assets	ADA 2 Pro Forma Adjustment Asset Retirement	ADA 3 Pro Forma Adjustment Not Used & Useful Plant	Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Accumulated Provision for Depreciation				
1	Production and gathering plant	$0	$0	$0	$0
2	Underground storage plant	0	0	0	0
3	Transmission plant	0	(1,141,777)	(2,564,153)	(3,705,930)
4	Distribution plant	0	(1,747,678)	0	(1,747,678)
5	General plant	0	(366,455)	0	(366,455)
6	Corporate Allocated	15,113,866	0	0	15,113,866
7	Total accumulated provision for depreciation Pro forma	$15,113,866	($3,255,910)	($2,564,153)	$9,293,804
	Accumulated Provision for Amortization				
8	Total accumulated provision for amortization	0	0	0	0
9	Total accumulated provision for depreciation and amortization	$15,113,866	($3,255,910)	($2,564,153)	$9,293,804

Note:
(a) See Schedule 5-F for explanation of pro forma adjustments.

Line No.	Account Number	Description	ADA 1 Pro Forma Adjustment Corporate Assets	ADA 2 Pro Forma Adjustment Asset Retirement	ADA 3 Pro Forma Adjustment Not Used & Useful Plant	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		ACCUMULATED PROVISION FOR DEPRECIATION				
		Natural Gas Production and Gathering Plant				
1	325.4	Rights-of-way	$0	$0	$0	$0
2	327	Field Compressor Station Structure	0	0	0	0
3	328	Field meas. and reg. station structures	0	0	0	0
4	332	Field lines	0	0	0	0
5	333	Field Compressor Station Equipment	0	0	0	0
6	334	Field meas. and reg. station equipment	0	0	0	0
7		Total production and gathering plant	$0	$0	$0	$0
		Underground Storage Plant				
8	350.1	Land & Land rights	$0	$0	$0	$0
9	350.2	Rights of way	0	0	0	0
10	351.1	Structures and improvements	0	0	0	0
11	351.2	Structures and improvements	0	0	0	0
12	351.3	Structures and improvements	0	0	0	0
13	352	Wells	0	0	0	0
14	352.1	Storage Lease and Rights	0	0	0	0
15	352.2	Reservoirs	0	0	0	0
16	352.3	Non-Recoverable Natural Gas	0	0	0	0
17	353	Storage Lines	0	0	0	0
18	354	Compressor station equipment	0	0	0	0
19	355	Measuring and regulating station equipment	0	0	0	0
20	356	Purification equipment	0	0	0	0
21	357	Other equipment	0	0	0	0
22		Total Underground storage plant	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Account Number	Description	ADA 1 Pro Forma Adjustment Corporate Assets	ADA 2 Pro Forma Adjustment Asset Retirement	ADA-3 Pro Forma Adjustment Not Used & Useful Plant	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Transmission Plant				
1	365.2	Rights-of-way	$0	($50,095)	$0	($50,095)
2	366.1	Structures and imp. - compressor stations	0	(1,236)	(1,274)	(2,510)
3	366.2	Structures and imp. - meas. & reg. stations	0	0	0	0
4	367	Mains	0	(1,053,546)	(580)	(1,054,126)
5	368	Compressor station equipment	0	(15,178)	(2,484,618)	(2,499,796)
6	369	Measuring and regulating station equipment	0	(22,522)	(77,681)	(100,203)
7	371	Other Equipment	0	800	0	800
8		Total transmission plant	$0	($1,141,777)	($2,564,153)	($3,705,930)
		Distribution Plant				
9	374.2	Rights-of-way	$0	$1,251	$0	$1,251
10	375.1	Structures and improvements	0	1,663	0	1,663
11	376.1	Mains - Metallic	0	0	0	0
12	376.2	Mains - Plastic	0	(685,521)	0	(685,521)
13	378	Meas. and reg. sta. equip. - general	0	(47,065)	0	(47,065)
14	379	Meas. and reg. sta. equip. - city gate	0	16,625	0	16,625
15	380	Services	0	(664,140)	0	(664,140)
16	380.5	Services - Metallic	0	0	0	0
17	381	Meters	0	(286,248)	0	(286,248)
18	382	Meter installations	0	(60,324)	0	(60,324)
19	383	House regulators	0	(23,919)	0	(23,919)
20	386	Other Property Customer Premise	0	0	0	0
21	387	Other Equipment	0	0	0	0
22		Total distribution plant	$0	($1,747,678)	$0	($1,747,678)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Account Number	Description	ADA 1 Pro Forma Adjustment Corporate Assets	ADA 2 Pro Forma Adjustment Asset Retirement	ADA-3 Pro Forma Adjustment Not Used & Useful Plant	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		General Plant				
1	389.1	Land	$0	$0	$0	$0
2	390.1	Structures and improvements - owned	0	(79,612)	0	(79,612)
3	391.1	Office furniture and equipment - computers	0	(50,680)	0	(50,680)
4	391.9	Computers and other electronic equipment	0	0	0	0
5	392	Transportation equipment	0	(97,590)	0	(97,590)
6	393	Stores equipment	0	(2,248)	0	(2,248)
7	394	Tool, shop and garage equipment	0	(58,206)	0	(58,206)
8	395	Laboratory equipment	0	236	0	236
9	396	Power operated equipment	0	(73,098)	0	(73,098)
10	397	Communication equipment	0	(5,027)	0	(5,027)
11	398	Miscellaneous equipment	0	(230)	0	(230)
12		Total general plant	$0	($366,455)	$0	($366,455)
13		Corporate Allocated	$15,113,866	$0	$0	$15,113,866
14		Total accumulated provision for depreciation	$15,113,866	($3,255,910)	($2,564,153)	$9,293,804
		ACCUMULATED PROVISION FOR AMORTIZATION				
15	302	Franchises and Consents	$0	$0	$0	$0
16	303	Miscellaneous Intangible Plant	0	0	0	0
17	390.2	Structures and improvements - leasehold	0	0	0	0
18		Total accumulated provision for amortization	$0	$0	$0	$0
19		Total accumulated provision for depreciation & Amortization	$15,113,866	($3,255,910)	($2,564,153)	$9,293,804

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Accumulated Provision for Depreciation and Amortization by Primary Account
Test Year Ended December 31, 2011
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		ACCUMULATED PROVISION FOR DEPRECIATION				
		Natural Gas Production and Gathering Plant				
1	325.4	Rights-of-way	$84,396	$87,303	$90,210	$93,117
2	327	Field Compressor Station Structure	1,767	1,855	1,944	2,032
3	328	Field meas. and reg. station structures	55,464	55,464	55,464	55,464
4	332	Field lines	559,784	558,800	558,800	56,448
5	333	Field Compressor Station Equipment	117,939	117,939	12,877	12,877
6	334	Field meas. and reg. station equipment	354,757	362,328	369,900	377,472
7		Total production and gathering plant	$1,174,106	$1,183,690	$1,089,195	$597,410
		Underground Storage Plant				
8	350.1	Land & Land Rights	$0	$0	$0	$0
9	350.2	Rights of way	0	0	0	0
10	351.1	Structures and Improvements	0	0	0	0
11	351.2	Structures and Improvements	0	0	0	0
12	351.3	Structures and Improvements	0	0	0	0
13	352	Wells	0	0	0	0
14	352.1	Storage Leaseholds and Rights	0	0	0	0
15	352.2	Reservoirs	0	0	0	0
16	352.3	Nonrecoverable Natural Gas	0	0	0	0
17	353	Storage Lines	0	0	0	0
18	354	Compressor Station Equipment	0	0	0	0
19	355	Measuring and Regulating Equipment	0	0	0	0
20	356	Purification Equipment	0	0	0	0
21	357	Other Equipment	0	0	0	0
22		Total Storage Facilities	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Accumulated Provision for Depreciation and Amortization by Primary Account
Test Year Ended December 31, 2011
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Transmission Plant				
1	365.2	Rights-of-way	$2,256,423	$2,389,426	$2,545,373	$2,668,918
2	366.1	Structures and imp. - compressor stations	3,770,653	3,922,745	4,060,147	3,728,296
3	366.2	Structures and imp. - meas. & reg. stations	884,039	857,410	885,729	900,604
4	367	Mains	41,369,081	39,624,014	42,285,813	42,744,519
5	368	Compressor station equipment	18,930,112	18,138,809	16,445,950	14,974,192
6	369	Measuring and regulating station equipment	1,475,875	1,662,010	4,031,245	3,924,391
7	371	Other Equipment	0	0	0	0
8		Total transmission plant	$68,686,183	$66,594,413	$70,254,258	$68,940,920
		Distribution Plant				
9	374.2	Rights-of-way	$299,413	$326,916	$350,794	$376,128
10	375.1	Structures and improvements	160,434	194,256	229,973	268,885
11	376.1	Mains - Metallic	67,666,033	73,774,330	80,586,959	92,499,213
12	376.2	Mains - Plastic	106,204,041	95,885,402	94,660,709	87,341,158
13	378	Meas. and reg. sta. equip. - general	7,707,583	7,995,738	8,247,866	8,640,380
14	379	Meas. and reg. sta. equip. - city gate	3,397,129	3,495,786	3,614,910	3,753,915
15	380	Services	158,924,192	158,178,776	159,206,965	162,359,375
16	380.5	Services - Metallic	29,269,878	27,654,105	28,190,631	28,506,511
17	381	Meters	16,298,154	14,732,013	16,060,659	17,557,923
18	382	Meter installations	16,986,338	18,021,182	19,221,807	20,884,190
19	383	House regulators	7,026,872	7,229,820	7,467,408	6,239,474
20	386	Other Property Customer Premise	105,227	126,512	148,180	170,290
21	387	Other Equipment	(2,665)	(2,653)	(2,652)	(2,658)
22		Total distribution plant	$414,042,630	$407,612,183	$417,984,208	$428,594,783

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Accumulated Provision for Depreciation and Amortization by Primary Account
Test Year Ended December 31, 2011
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		General Plant				
1	389.1	Land and land rights	$0	$0	$0	($14,378)
2	390.1	Structures and improvements - owned	8,361,752	8,682,012	9,112,339	9,586,117
3	391.1	Office furniture and equipment - computers	950,792	1,102,093	1,277,437	1,440,752
4	391.9	Computers and other electronic equipment	11,772,690	8,476,495	7,108,858	4,399,860
5	392	Transportation equipment	6,026,943	7,302,605	8,481,573	9,451,433
6	393	Stores equipment	255,368	177,292	108,246	471,031
7	394	Tool, shop and garage equipment	959,409	402,423	458,888	542,982
8	395	Laboratory equipment	229,042	(247,758)	(269,388)	(264,392)
9	396	Power operated equipment	1,594,785	1,879,791	2,752,351	3,564,730
10	397	Communication equipment	4,163,710	3,950,077	4,287,833	4,633,067
11	398	Miscellaneous equipment	63,826	65,917	69,122	75,906
12	399	Other Tangible Property	0	0	0	0
13		Total general plant	$34,378,318	$31,790,947	$33,387,259	$33,887,108
14		Total accumulated provision for depreciation	$518,281,236	$507,181,233	$522,714,920	$532,020,221
		ACCUMULATED PROVISION FOR AMORTIZATION				
15	302	Franchises and Consents	$0	$0	$0	$0
16	303	Miscellaneous Intangible Plant	802,751	2,189	8,928	15,495
17	390.2	Structures and improvements - leasehold	1,585,715	1,791,895	2,011,948	2,255,367
18		Total accumulated provision for amortization	$2,388,466	$1,794,084	$2,020,876	$2,270,862
19		Total accumulated provision for depreciation and amortization	$520,669,702	$508,975,317	$524,735,796	$534,291,083

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Explanation of Pro Forma Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment ADA 1		
	Corporate Assets		
1	Production and gathering plant	0	0
2	Underground storage plant	0	0
3	Transmission Plant	0	0
4	Distribution plant	0	0
5	General plant	0	0
6	Corporate Plant	15,113,866	0
	To include the accumulated depreciation reserve associated with Corporate assets providing service to Kansas Gas Service		
	Adjustment ADA 2		
	Asset Retirement		
7	Production and gathering plant	0	0
8	Underground storage plant	0	0
9	Transmission Plant	0	1,141,777
10	Distribution plant	0	1,747,678
11	General plant	0	366,455
12	Corporate Plant	0	0
	To remove accumulated depreciation related to plant retirements in CWIP that will retire subsequent to the test year.		
	Adjustment ADA 3		
	Not Used & Useful Plant		
13	Production and gathering plant	0	0
14	Underground storage plant	0	0
15	Transmission Plant	0	2,564,153
16	Distribution plant	0	0
17	General plant	0	0
18	Corporate Plant	0	0
	To remove the accumulated depreciation associated with assets that are currently not used and useful.		

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Working Capital and Rate Base Offsets
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	13 Month Avg. or Test Year End	Adjustment Reference	13 Month Average or TYE Per Books	Pro Forma Adjustments	Pro Forma Adjusted Average
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	Materials and supplies (154 - 163)	6-B	Avg.		$3,867,102	$0	$3,867,102
2	Gas storage inventory (164.1)	6-B	Avg.		41,153,564	0	41,153,564
3	Prepayments (165)	6-C	Avg.	WC 1	362,717	1,360,076	1,722,793
4	Accumulated Deferred Inc. Tax Liability	6-D	Year End	WC 2 - WC 4	(254,920,319)	44,282,044	(210,638,275)
5	Accumulated Deferred Inc. Tax Liab.- Corporate	6-D	Year End	WC 5	0	(4,032,773)	(4,032,773)
6	Customer Deposits (235)		Year End		(17,580,776)	0	(17,580,776)
7	Customer Advances (252)		Year End		(6,673,351)	0	(6,673,351)
8	Total Working Capital				($233,791,063)	$41,609,347	($192,181,716)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Working Capital
Gas Storage Inventory and Materials & Supplies
Test Year Ended December 31, 2011

		Gas Storage Inventory	Materials &Supplies		
		Amount Per Books	Amount Per Books		Per Books
Line No.	Date	Account 164.1	Account 154	Account 163	Total
	Col. 1	Col. 2	Col. 2	Col. 3	Col. 4
1	December	$47,738,365	$3,543,826	$113,257	$3,657,083
2	January	28,824,980	3,509,713	33,263	3,542,976
3	February	15,668,566	3,652,009	112,439	3,764,448
4	March	10,380,273	3,482,762	158,902	3,641,664
5	April	20,087,757	3,919,595	320,987	4,240,582
6	May	28,534,216	3,853,835	442,473	4,296,308
7	June	37,836,402	3,988,555	344,460	4,333,016
8	July	46,552,667	3,840,419	296,764	4,137,183
9	August	56,392,983	3,098,180	2,052	3,100,232
10	September	63,781,370	3,343,998	(258,897)	3,085,101
11	October	65,403,886	3,695,192	(227,743)	3,467,449
12	November	61,418,590	4,227,406	(51,984)	4,175,422
13	December	52,376,277	4,698,302	132,565	4,830,867
14	Total	$534,996,332	$48,853,791	$1,418,539	$50,272,330
15	13 month average	$41,153,564	$3,757,984	$109,118	$3,867,102

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Working Capital
Prepayments
Test Year Ended December 31, 2011

		Corporate			
Line No.	Date	Total Corporate Prepayments	Kansas Gas Service Allocated @ 12.47%	Account 165 Amount Per Books Direct 165	Per Books Average
	Col. 1	Col. 4 (Col 2 + Col. 3)	Col. 5	Col. 6	Col 7 (Col. 5 + Col. 6)
1	December	7,754,633	$967,003	$238,129	$1,205,132
2	January	6,914,934	862,292	281,257	1,143,549
3	February	5,763,941	718,764	324,024	1,042,787
4	March	5,620,183	700,837	339,884	1,040,720
5	April	10,148,343	1,265,498	300,816	1,566,315
6	May	11,568,082	1,442,540	450,581	1,893,121
7	June	12,816,642	1,598,235	494,095	2,092,331
8	July	11,933,610	1,488,121	458,724	1,946,845
9	August	11,202,548	1,396,958	413,598	1,810,556
10	September	15,575,206	1,942,228	456,034	2,398,262
11	October	14,781,877	1,843,300	347,890	2,191,190
12	November	14,388,963	1,794,304	305,081	2,099,384
13	December	13,319,238	1,660,909	305,210	1,966,119
14	Total	$141,788,201	$17,680,989	$4,715,323	$22,396,312
15	13 month average	$10,906,785	$1,360,076	$362,717	$1,722,793
16	Distrigas %	12.47%			
17	Kansas Gas Service Allocated Portion **(WC 1)**	$1,360,076			

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Working Capital
Deferred Taxes
Test Year Ended December 31, 2011

Line No.		Description Col. 1	12/31/2011 Balance Col. 2	Pro Forma Adjustments Col. 3	Pro Forma Balance Col. 4
	Kansas Gas Service				
1	283.0	Accumulated Deferred Taxes Current	($8,140,143)		($8,140,143)
2	283.0	Accumulated Deferred Federal/State Income Tax	(297,307,993)		(297,307,993)
3	283.0	Accumulated Deferred Federal/State ODC NOL	48,532,607		48,532,607
4	182.3	Regulatory Asset - Flow Through	1,995,210		1,995,210
6		ADIT associated with Pension/OPEB Funding **(WC 2)**		33,759,366	33,759,366
5		ADIT 2011 Reflect Test Year End Balance **(WC 3)**		10,382,007	10,382,007
7		ADIT associated with COGR Over/Under **(WC 4)**		140,671	140,671
8		Total Accumulated Deferred Income Taxes	($254,920,319)	$44,282,044	($210,638,275)
	ONEOK Corporate				
7		Accumulated Deferred Income Taxes **(WC 5)**	$0	Assignment	($4,032,773)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Test Year Ended December 31, 2011
ONEOK, INC., Capital Structure

Consolidated Capital Structure

Line No.	Description	Schedule Reference	ONEOK, Inc. March 31, 2012 Balance	Adjustment	Adjusted Balance	Capitalization Ratios	Related Costs	Cost of Capital
	Col. 1	Col. 2	Col. 3			Col. 4	Col. 5	Col. 6
1	Long term debt	7-B	$1,716,463,452	($28,748,452)	$1,687,715,000	41.1499%	5.3305%	2.1935%
2	Common equity	7-C	2,256,152,066	157,520,643	2,413,672,709	58.8501%	10.7500%	6.3264%
	Total Capitalization		$3,972,615,518	$128,772,191	$4,101,387,709	100%		8.5199%

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Test Year Ended December 31, 2011
ONEOK, INC. Cost of Debt

Line No.	Issue Date	Series	Gross Amount	Original Issuance Cost	Loss on Reacquired	Net Proceeds	Coupon Rate	Annual Interest	Effective Cost	Annual Cost
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Long-term Notes Payable								
1	26-Jan-12	4.25% Note due 2022	$700,000,000	$4,893,000	$0	$695,107,000	4.2500%	$29,750,000	4.2799%	$29,959,416
2	29-Sep-98	6.50% Note due 2028	87,715,000	4,327,553	9,927,102	73,460,344	6.5000%	5,701,475	7.7613%	6,807,821
3	30-Sep-98	6.875% Note due 2028	100,000,000	1,801,559	11,296,041	86,902,400	6.8750%	6,875,000	7.9112%	7,911,174
4	15-Jun-05	5.20% Note due 2015	400,000,000	3,189,387	0	396,810,613	5.2000%	20,800,000	5.2418%	20,967,181
5	15-Jun-05	6.00% Note due 2035	400,000,000	5,222,670	0	394,777,330	6.0000%	24,000,000	6.0794%	24,317,506
6		Total debt capital	$1,687,715,000	$19,434,169	$21,223,143	$1,647,057,688		$87,126,475		$89,963,098
7							Weighed Average Cost of Debt		**5.3305%**	

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Explanation of Pro Forma Adjustments to Cost of Capital
Test Year Ended December 31, 2011

Line No.	Adjustment No.	Category Col. 1	Increase Col. 2	Decrease Col. 3
1	1	Long Term Debt		$1,777,595
		To remove debt issuances specifically identifiable with non-Kansas Gas Service sources.		
2	2	Long Term Debt		26,970,857
		To remove debt associated swaps specifically associated with non-regulated operations		
		Total Adjustment to Long Term Debt		$28,748,452
3	3	Common Equity	$157,520,643	
		This adjustment is necessary to reflect the increase in common equity to remove the impact of Other Comprehensive Income associated with implementation of SFAS 158 as granted by the Kansas Corporation Commission in Docket No. 07-ATMG-387-ACT.		
4		Total Adjustment to Cost of Capital	$157,520,643	$28,748,452

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Historical Interest Coverage
12 Months Ending

Line No.	Description Col. 1	2008 Col. 2	2009 Col. 3	2010 Col. 4	2011 Col. 5
	Revenues				
1	Operating revenues	$799,366,887	$642,070,981	$635,425,587	$532,780,451
2	Non-operating revenues	48,690,648	46,667,261	48,944,446	47,296,857
3	Total	$848,057,535	$688,738,242	$684,370,033	$580,077,308
	Expenses				
4	Operating expenses	$794,258,121	$648,182,343	$634,306,305	$537,965,653
5	Miscellaneous deductions	(2,424,495)	(8,399,750)	(5,446,471)	(289,929)
6	Total	$791,833,626	$639,782,593	$628,859,834	$537,675,724
7	Net revenues	$56,223,909	$48,955,649	$55,510,199	$42,401,584
8	Income taxes included in line 4 above	17,020,343	27,726,508	26,160,914	16,498,578
9	Net earnings available for interest	$73,244,252	$76,682,157	$81,671,113	$58,900,162
10	Annual interest on bonds outstanding	$27,931,999	$24,585,538	$18,534,356	$19,999,632
11	Interest coverage (Line 9 / Line 10)	2.62	3.12	4.41	2.95

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Balance Sheet
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		ASSETS AND OTHER DEBITS				
		Utility Plant				
1	101-106	Utility plant	$1,364,022,327	$1,375,159,276	$1,422,126,220	$1,474,614,558
2	107	Construction work in progress	12,088,376	17,044,020	15,858,975	14,247,775
3	108,111	Less: Accumulated depreciation (a)	(520,669,702)	(508,975,317)	(524,735,796)	(534,291,083)
			855,441,001	883,227,979	913,249,399	954,571,250
4	114	Acquisition Adjustment	51,209,236	51,209,236	51,209,236	51,209,236
5	115	Accumulated Amortization of Acquisition	(1,270,429)	(1,270,429)	(1,270,429)	(1,270,429)
6		Net utility plant	$905,379,808	$933,166,786	$963,188,206	$1,004,510,057
7	117	Gas stored underground - noncurrent	$0	$0	$0	$0
8	121,122,123.1,124	Other Property and Investments	$0	$0	$0	$0
		Current and Accrued Assets				
11	131	Cash	($138,952,428)	($98,898,747)	($105,896,607)	($78,241,205)
12	134	Special deposits	0	0	0	0
13	135	Working funds	3,410	0	0	0
14	136	Temporary cash investments	0	0	0	0
15	141-146	Receivables (Less: Provision for uncollectible accounts)	143,947,998	102,172,065	93,703,174	93,007,537
16	154	Plant material and operating supplies	3,143,368	3,478,296	3,543,826	4,698,302
17	156	Other materials and supplies	0	0	0	0
18	163	Stores expense undistributed	(118,921)	229,219	113,257	132,565
19	164.1	Gas stored underground - current	98,054,083	42,317,777	47,738,365	52,376,277
20	165	Prepayments	317,946	391,967	238,129	305,210
21	174	Miscellaneous current and accrued assets	4,849,484	35,777,498	48,788,057	10,425,918
22		Total current and accrued assets	$111,244,940	$85,468,075	$88,228,201	$82,704,604

Note:
(a) Account 108 includes $1,352,741 Accumulated Depreciation Reserve/Regulatory Liability

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		ASSETS AND OTHER DEBITS (cont.)				
		Deferred Debits				
1	181	Unamortized debt discount and expense	$0	$0	$0	$0
2	182.1	Extraordinary property losses	0	0	0	0
3	182.3	Other regulatory assets	32,527,518	31,871,271	51,532,231	75,717,307
4	184	Clearing accounts	(183,920)	(588,216)	580,650	447,806
5	186	Miscellaneous deferred debits	40,274	64,982	19,865	10,413
6	189	Unamortized loss on reacquired debt	0	0	0	0
7	190	Accumulated deferred income taxes	0	0	0	0
8	191	Unrecovered purchased gas cost	40,966,880	20,516,136	2,593,188	5,884,139
9		Total deferred debits	$73,350,752	$51,864,173	$54,725,934	$82,059,665
10		Total assets and other debits	$1,089,975,500	$1,070,499,034	$1,106,142,341	$1,169,274,326
		LIABILITIES AND OTHER CREDITS				
		Proprietary Capital				
11	201	Common stock issued	$0	$0	$0	$0
12	204	Preferred stock issued	0	0	0	0
13	207	Premium on capital stock	0	0	0	0
14		Gain/(Loss) on reacquired stock	0	0	0	0
15	211	Other paid-in-capital	323,763,617	350,277,130	372,477,130	372,477,130
16	216	Retained earnings	39,839,935	41,496,533	78,472,376	82,484,673
17	217	Reacquired capital stock	0	0	0	0
18		Total proprietary capital	$363,603,552	$391,773,663	$450,949,506	$454,961,803
		Other Noncurrent Liabilities				
19	227	Obligations under capital leases	$0	$0	$0	$0
20		Total other noncurrent liabilities	$0	$0	$0	$0

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		LIABILITIES AND OTHER CREDITS (cont.)				
		Current and Accrued Liabilities				
1	231	Notes payable	$0	$0	$0	$0
2	232	Accounts payable	53,930,058	53,033,873	41,837,557	35,580,914
3	233	Long Term Debt	350,972,567	257,172,567	279,172,567	334,790,143
4	234	Accounts payable to associated companies	13,866,792	53,446,035	17,760,565	35,788,267
5	235	Customer deposits	17,457,151	18,038,238	18,131,203	17,580,776
6	236	Taxes accrued	9,323,933	10,912,036	10,783,470	11,497,237
7	237	Interest accrued	567	334	(1,727)	(214)
8	238	Dividends declared	0	0	0	0
9	239	Matured long-term debt	0	0	0	0
10	241	Tax collections payable	6,871,557	6,910,158	6,496,445	6,415,461
11	242	Miscellaneous current and accrued liabilities	14,530,316	10,503,612	4,443,874	5,480,760
12	243	Obligations under capital leases - current	0	0	0	0
13		Total current and accrued liabilities	$466,952,941	$410,016,853	$378,623,954	$447,133,344
		Deferred Credits				
14	252	Customer advances for construction	$10,767,334	$10,316,632	$8,455,029	$6,673,351
15	253	Other deferred credits	58,370,264	21,467,887	8,639,391	1,988,334
16	254	Other Regulatory Liabilities	0	0	0	0
17	255	Accumulated deferred investment tax credits	2,796,289	2,401,045	1,986,253	1,601,965
18		Total deferred credits	$71,933,887	$34,185,564	$19,080,673	$10,263,650
		Accumulated Deferred Income Taxes				
19	283	Other	$187,485,120	$234,522,954	$257,488,208	$256,915,529
20		Total accumulated deferred income taxes	$187,485,120	$234,522,954	$257,488,208	$256,915,529
21		Total liabilities and other credits	$1,089,975,500	$1,070,499,034	$1,106,142,341	$1,169,274,326

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Comparative Income Statement
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	400	Operating Revenues	$848,057,535	$688,738,242	$684,370,033	$580,077,308
		Operating Expenses				
2	401	Operation expense	$696,848,505	$537,082,017	$522,287,144	$433,720,296
3	402	Maintenance expense	20,167,643	19,740,111	18,645,181	19,211,942
4	403	Depreciation	37,570,100	38,011,741	39,343,073	40,484,479
5	404-405	Amortization and depletion	254,764	208,568	226,421	249,986
6	406	Amortization of utility plant acquisition. adj.	0	0	0	0
7	407	Other amortization	0	0	0	0
8	407.3	Regulatory debit	4,374,006	7,377,538	9,220,694	8,883,897
9	407.4	Regulatory credit	0	0	0	0
10	408.1	Taxes other than income taxes	18,440,276	18,431,104	18,837,670	19,300,763
11	409.1	Income taxes	6,034,584	(20,727,302)	2,176,692	(33,224,623)
12	410.1	Deferred income taxes (Dr.)	10,985,759	48,453,810	23,984,222	49,723,201
13	411.4	Investment tax credits, net	(417,516)	(395,244)	(414,792)	(384,288)
14		Total utility operating expenses	$794,258,121	$648,182,343	$634,306,305	$537,965,653
15		Net utility operating income	$53,799,414	$40,555,899	$50,063,728	$42,111,655
		Other Income and Deductions				
16	415	Revenues from merch., jobbing & contract	($3,326)	($20,205)	($21,811)	($22,100)
17	416	(Less)Costs & expense of merch, job. & cont.	7,208	2,415	1,758	2,969
18	417 - 417.6	Revenues from non-utility operations - net	5,876,335	6,889,623	5,079,141	1,267,944
19	418	Non operating rental income	0	0	0	0
20	418.1	Equity in earnings of subsidiary companies	0	0	0	0
21	419	Interest & dividend income	104	18,908	950	0
22	419.1	AFUDC	0	0	0	0
23	421	Misc non-operating income	378,132	2,303,244	1,390,201	(325,742)
24	421.1	Gain on disposition of property	0	0	0	0
25		Total other income before tax	$6,244,037	$9,189,155	$6,446,723	$917,133
26	421.2	Loss on disposition of property	$3,180	$0	$0	$0
27	425	Miscellaneous amortization	0	0	0	0
28	426	Misc Income deductions	3,816,362	789,405	1,000,252	627,204
29		Total other income deductions before tax	$3,819,542	$789,405	$1,000,252	$627,204

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Comparative Income Statement
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	409.1	Income taxes	$0	$0	$0	$0
2	410.1	Deferred taxes	0	0	0	0
3	411.2	Provision for deferred taxes - credit	0	0	0	0
4	411.4	ITC	0	0	0	0
5	420	Less: ITC credits	0	0	0	0
6		Total taxes on other inc & deductions	$0	$0	$0	$0
7		Total other income and deductions	$2,424,495	$8,399,750	$5,446,471	$289,929
8		Income before interest charges	$56,223,909	$48,955,649	$55,510,199	$42,401,584
		Interest Charges				
9	427	Interest on long-term debt	$0	$0	$0	$0
10	428	Amortization of debt discount and expense	447,061	439,244	375,854	379,322
11	429	Amortization of premium on debt (Cr.)	0	0	0	0
12	430	Interest on debt to assoc. companies	24,444,036	23,519,204	17,788,116	19,510,146
13	431	Other interest expense	3,578,844	884,166	721,839	624,560
14	432	Allowance for borrowed funds used during construction (Cr.)	(537,942)	(257,076)	(351,453)	(514,396)
15		Total interest charges	$27,931,999	$24,585,538	$18,534,356	$19,999,632
		Extraordinary Items				
16	434 - 435	Extraordinary income - net	$0	$0	$0	$0
17	409.3	Income taxes	0	0	0	0
18		Extraordinary Items after taxes	$0	$0	$0	$0
19		Net income	$28,291,910	$24,370,111	$36,975,843	$22,401,952

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Statement of Retained Earnings
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		RETAINED EARNINGS				
1	216	Retained earnings, beginning balance	$34,548,025	$39,839,935	$41,496,533	$78,472,376
		Additions:				
2	433	Net income	$28,291,910	$24,370,111	$36,975,843	$22,401,952
		Less:				
3	439	Adjustments to retained earnings	$0	$0	$0	$0
4	437	Dividends declared -preferred stock	0	0	0	0
4	438	Dividends declared - common stock	0	0	0	0
5	131	Dividends to parent	(23,000,000)	(22,713,513)	0	(18,389,655)
6		Total adjustment and dividends declared	($23,000,000)	($22,713,513)	$0	($18,389,655)
7	216	Retained earnings, ending balance	$39,839,935	$41,496,533	$78,472,376	$82,484,673

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Operating Revenues by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		OPERATING REVENUE				
		Gas Service Revenue				
1	480	Residential sales	$591,829,798	$488,563,957	$478,245,264	$428,069,067
		Commercial and industrial sales				
2	481.1	Commercial	155,396,792	121,850,506	120,239,846	102,710,210
3	481.2	Industrial	805,378	533,033	475,317	377,893
4		Total sales to ultimate customers	$748,031,968	$610,947,496	$598,960,427	$531,157,170
5	483	Sales for resale	$51,334,919	$31,123,485	$36,465,160	$1,623,281
6		Total gas service revenue	$799,366,887	$642,070,981	$635,425,587	$532,780,451
		Other Operating Revenue				
7	487	Forfeited discounts	$3,177,024	$2,377,361	$2,131,202	$1,852,483
8	488	Miscellaneous service revenues	2,267,786	1,988,603	1,814,993	1,755,017
9	489	Revenue from transmission of gas of others	40,976,137	40,877,345	43,350,210	42,383,959
10	491	Revenue from natural gas processed by others	2,034,511	888,543	1,164,465	820,664
11	493	Rent from gas property	163,530	482,687	474,954	476,289
12	495	Other gas revenue (inc. acct 412&414)	71,660	52,722	8,622	8,445
13		Total other operating revenue	$48,690,648	$46,667,261	$48,944,446	$47,296,857
14		Total gas operating revenue	$848,057,535	$688,738,242	$684,370,033	$580,077,308

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		OPERATIONS AND MAINTENANCE EXPENSES				
		Natural Gas Production and Gathering				
		Operation				
1	750	Operation supervision and engineering	$0	$36	$0	$0
2	751	Production maps and records	0	0	0	0
3	753	Field lines expense	0	0	0	0
4	754	Field compressor station expenses	50	0	0	28
5	755	Field compressor station fuel and power	0	0	0	0
6	756	Field measuring and regulating station expenses	0	0	0	0
7	757	Purification expenses	0	0	0	0
8	759	Other expenses	0	0	0	0
9	760	Rents	0	0	0	0
10		Total operation	$50	$36	$0	$28
		Maintenance				
11	761	Maintenance supervision and engineering	$0	$0	$0	$0
12	762	Maintenance of structures and improvements	0	0	0	0
13	764	Maintenance of field lines	0	0	0	0
14	765	Maintenance of field compressor station equip.	0	0	0	0
15	766	Maintenance of field meas. and reg. sta. equip.	0	0	0	0
16	767	Maintenance of purification equipment	0	0	0	0
17	769	Maintenance of other equipment	0	0	0	0
18		Total maintenance	$0	$0	$0	$0
19		Total natural gas production and gathering	$50	$36	$0	$28

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Products Extraction				
		Operation				
1	776	Operations and Supplies expense	$0	$0	$10	$0
2	777	Gas processed by others	1,435,913	$608,735	643,855	474,347
3		Total products extraction	$1,435,913	$608,735	$643,865	$474,347
		Other Gas Supply Expenses				
		Operation				
4	805	Other gas purchases	$581,658,742	$420,406,575	$407,681,239	$310,480,789
5		Total purchased gas	$581,658,742	$420,406,575	$407,681,239	$310,480,789
		Purchased Gas Expenses				
6	807.1	Well expenses- purchased gas	$0	$0	$0	$0
7	807.2	Operation of purchased gas measuring stations	0	$0	0	0
8	807.3	Maintenance of purchased gas measuring stations	0	$0	0	0
9	807.4	Purchased gas calculations expenses	24,457	$26,000	26,140	29,428
10	807.5	Other purchased gas expenses	1,040,099	$1,134,451	1,277,438	1,275,990
11		Total purchased gas expenses	$1,064,556	$1,160,451	$1,303,578	$1,305,418
		Gas Used in Utility Operations				
12	810	Gas used for compressor station fuel	($1,165,645)	($825,587)	($727,370)	($429,120)
13	811	Gas used for products extraction	(1,435,913)	(608,735)	(643,855)	(474,347)
14	812	Gas used for other utility operations	(87,835)	(49,245)	(46,189)	(107,051)
15		Total gas used in utility operations	($2,689,393)	($1,483,567)	($1,417,414)	($1,010,518)
16	813	Other gas supply expenses	$693,593	$827,379	$1,018,980	$1,068,573
17		Total other gas supply expenses	$580,727,498	$420,910,838	$408,586,383	$311,844,262
18		Total production expenses	$582,163,461	$421,519,609	$409,230,248	$312,318,637

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Underground Storage Expenses				
		Operation				
1	814	Operation, supervision and engineering	$0	$0	$0	$0
2	815	Maps and records	0	0	0	596
3	816	Wells expenses	0	0	0	0
4	817	Lines expenses	0	0	0	0
5	818	Compressor station expenses	0	0	0	21
6	819	Compressor station fuel and power	214,929	119,663	118,371	137,455
7	820	Measuring and regulating station expenses	0	0	0	0
8	821	Purification expenses	0	103	73	0
9	822	Exploration and development	0	0	0	0
10	823	Gas losses	0	0	0	0
11	824	Other expenses	21	0	0	37
12	825	Storage well royalties	0	0	0	0
13	826	Rents	0	0	0	0
14		Total operation	$214,950	$119,766	$118,444	$138,109
		Maintenance				
15	830	Maintenance, supervision and engineering	$0	$0	$0	$0
16	831	Maintenance of structures and improvements	0	0	0	0
17	832	Maintenance of reservoirs and wells	0	0	0	0
18	833	Maintenance of lines	0	0	0	0
19	834	Maintenance of compressor station equipment	0	0	0	0
20	835	Maintenance of measuring & reg. station equipment	0	0	0	0
21	836	Maintenance of purification equipment	0	0	0	0
22	837	Maintenance of other equipment	0	0	0	0
23		Total maintenance	$0	$0	$0	$0
24		Total underground storage expenses	$214,950	$119,766	$118,444	$138,109

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Transmission Expenses				
		Operation				
1	850	Operation supervision and engineering	$842,175	$771,633	$642,366	$584,908
2	851	System control and load dispatching	822,916	830,552	$946,845	1,432,836
3	852	Communication system expense	630,869	434,123	$93	0
4	853	Compressor station labor and expense	479,596	492,370	$598,105	725,323
5	854	Gas for compressor station fuel	950,717	705,924	$608,999	291,665
6	855	Other fuel and power for compressor stations	16,231	17,106	$10,303	13,513
7	856	Mains expenses	2,514,087	2,372,465	$2,591,495	2,472,903
8	857	Measuring and regulating station expenses	593,412	552,629	$617,543	606,055
9	858	Transmission and compression of gas by others	0	0	$0	0
10	859	Other expenses	108,065	102,300	$153,776	131,502
11	860	Rents	992	0	$2,638	4,095
12		Total operation	$6,959,060	$6,279,102	$6,172,163	$6,262,800
		Maintenance				
13	861	Maintenance supervision and engineering	$529,405	$435,406	$257,321	$182,785
14	862	Maintenance of structures and improvements	22,410	17,741	14,402	12,426
15	863	Maintenance of mains	752,408	742,766	670,781	698,372
16	864	Maintenance of compressor station equipment	473,840	410,192	315,164	433,987
17	865	Maintenance of meas. & regulating station equip.	343,570	339,083	344,909	459,896
18	866	Maintenance of communication equipment	2,341	303	289	403
19	867	Maintenance of other equipment	1,116	539	207	0
20		Total maintenance	$2,125,090	$1,946,030	$1,603,073	$1,787,869
21		Total transmission expenses	$9,084,150	$8,225,132	$7,775,236	$8,050,669

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Distribution Expenses				
		Operation				
1	870	Operation supervision and engineering	$3,799,891	$3,188,056	$2,121,201	$2,612,950
2	871	Distribution load dispatching	57,396	60,528	59,276	43,526
3	874	Mains and services expense	10,076,429	9,886,564	10,630,198	10,818,086
4	875	Meas. and reg. sta. expenses - general	1,561,372	1,475,447	1,498,281	1,436,392
5	876	Meas. and reg. sta. expenses - industrial	454,086	453,010	438,282	454,760
6	877	Meas. and reg. sta. expenses - city gate	58,074	59,492	268,294	329,236
7	878	Meter and house regulator expenses	9,413,288	9,599,437	9,712,763	9,624,534
8	879	Customer installations expenses	5,715,879	5,797,488	5,725,396	6,108,849
9	880	Other expenses	5,524,546	3,759,041	4,770,579	4,690,091
10	881	Rents	448,523	456,089	525,306	572,872
11		Total operation	$37,109,484	$34,735,152	$35,749,576	$36,691,296
		Maintenance				
12	885	Maintenance, supervision and engineering	$1,188,310	$1,031,791	$736,220	$745,267
13	886	Maintenance of structures and improvements	457,045	386,938	390,729	301,142
14	887	Maintenance of mains	9,786,655	9,525,182	9,062,605	8,854,481
15	889	Maint. of meas. and reg. sta. equip. - general	738,870	785,888	768,360	860,811
16	890	Maint. of meas. and reg. sta. equip. - industrial	66,899	165,033	269,587	314,086
17	891	Maint. of meas. and reg. sta. equip. - city gate	480	160	282,660	550,004
18	892	Maintenance of services	2,109,983	1,959,448	2,369,951	2,602,718
19	893	Maintenance of meters and house regulators	2,776,462	3,012,678	2,557,488	2,385,113
20	894	Maintenance of other equipment	42,405	31,381	3,672	1,030
21		Total Distribution	$17,167,109	$16,898,499	$16,441,272	$16,614,652
22	932	Maintenance of General Plant	875,444	$895,582	600,836	809,423
23		Total maintenance	$18,042,553	$17,794,081	$17,042,108	$17,424,075
24		Total distribution expenses	$55,152,037	$52,529,233	$52,791,684	$54,115,371

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Customer Accounts Expense				
1	901	Supervision	$739,626	$731,477	$1,111,234	$1,233,780
2	902	Meter reading expenses	5,345,314	5,261,069	5,000,588	5,034,827
3	903	Customer records and collection expense	17,744,010	17,727,909	16,170,507	16,453,067
4	904	Uncollectible accounts	3,748,248	1,760,810	2,334,795	2,000,000
5	905	Miscellaneous customer accounts expense	897,365	713,260	606,777	601,909
6		Total customer accounts expenses	$28,474,563	$26,194,525	$25,223,901	$25,323,583
		Customer Service and Informational Expenses				
7	907	Supervision	$0	$0	$0	$0
8	908	Customer assistance expenses	489	71	11	682
9	909	Informational and instructional expenses	6,729	1,850	4,079	0
10	910	Misc. customer service & informational expenses	0	0	0	0
11		Total customer. service and informational expenses	$7,218	$1,921	$4,090	$682
		Sales Expense				
12	911	Supervision	$4	$0	$212,305	$232,190
13	912	Demonstrating and selling expenses	618,794	720,795	944,835	993,672
14	913	Advertising expenses	60,801	22,749	700	0
15	916	Miscellaneous sales expenses	433,331	376,919	(5,601)	0
16		Total sales expenses	$1,112,930	$1,120,463	$1,152,239	$1,225,862

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Administrative and General Expenses				
		Operation				
1	920	Administrative and general salaries	$15,650,653	$18,369,792	$18,087,322	$21,312,979
2	921	Office supplies and expenses	4,547,609	4,516,601	4,478,986	4,462,414
3	922	Administrative expenses transferred	(1,294,700)	(1,207,000)	(1,182,000)	(1,960,201)
4	923	Outside services employed	747,774	852,646	1,102,483	1,229,107
5	924	Property insurance	0	0	0	0
6	925	Injuries and damages	942,171	763,075	407,135	1,030,775
7	926	Employee pensions and benefits	22,226,797	23,664,113	22,399,710	26,411,529
8	927	Franchise requirements	0	0	0	0
9	928	Regulatory commission expense	1,494,322	1,624,316	1,190,487	676,013
10	929	Duplicate expenses	(26,514,723)	(26,146,829)	(26,407,131)	(29,022,608)
11	930.1	General advertising expense	252,560	174,098	85,845	81,940
12	930.2	Miscellaneous general expenses	20,869,239	22,989,573	23,076,738	26,184,401
13	931	Rents	1,885,137	1,511,094	1,396,908	1,352,976
14		Total operation	$40,806,839	$47,111,479	$44,636,483	$51,759,325
15		Total administrative and general expenses	$40,806,839	$47,111,479	$44,636,483	$51,759,325
16		Total operation and maintenance expenses	$717,016,148	$556,822,128.00	$540,932,325	$452,932,238

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Sales Usage, Revenues, and Customer Data
Year Ending December 2008

Line No.	Description Col. 1	MCF Sales Col. 2	Revenue Col. 3	Average Number of Customers Col. 4	MCF Sales per Customer Col. 5	Revenue per MCF Sold ($) Col. 6
	Residential					
1	RSk - Residential Sales Service	39,405,825	$496,210,865	462,160	85	$12.5923
2	RSt - Residential Sales Service	8,444,877	108,654,610	112,393	75	12.8663
3	Revenue Accrual		(13,035,677)		N.A.	N.A.
4	Total Residential	47,850,702	$591,829,798	574,553	83	$12.3683
	Commercial					
5	GSk - General Sales Service	10,123,681	$119,969,838	37,814	268	$11.8504
6	GSt - General Sales Service	2,920,199	35,119,368	12,758	229	12.0264
7	GISt - Gas Irrigation Sales Service	174,131	2,221,489	258	674	12.7576
8	KGSSD - Kansas Gas Supply Sales Service D	138,284	1,412,421	2	69,142	10.2139
9	SGS-Small Generator Sales Service	23	1,783	3	9	76.2068
10	Revenue Accrual		(3,328,107)		N.A.	N.A.
11	Total commercial	13,356,319	155,396,792	50,835	263	$11.6347
	Industrial					
12	GSk - General Sales Service	18,516	$203,872	35	532	$11.0106
13	GSt - General Sales Service	52,900	591,312	48	1,104	11.1779
14	Revenue Accrual		10,194		N.A.	N.A.
15	Total Industrial	71,416	$805,378	83	863	$11.2773
	Sales for Resale					
16	Sales for Resale	153,015	$1,460,300	11	13,680	$9.5435
17	AAGS - As-Available Gas Sales Service	7,500,789	52,797,919	2	3,750,395	7.0390
18	Revenue Accrual		(2,923,300)		N.A.	N.A.
19	Total Sales for Resale	7,653,804	$51,334,919	13	580,476	$6.7071
20	Total Sales of Gas	68,932,241	799,366,887	625,484	110	$11.5964

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Sales Usage, Revenues, and Customer Data
Year Ending December 2009

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RSk - Residential Sales Service	36,943,674	$405,684,885	463,885	80	$10.9812
2	RSt - Residential Sales Service	7,970,981	89,200,802	112,695	71	11.1907
3	Revenue Accrual		(6,321,730)		N.A.	N.A.
4	Total Residential	44,914,654	$488,563,957	576,580	78	$10.8776
	Commercial					
5	GSk - General Sales Service	9,279,023	$94,107,079	37,663	246	$10.1419
6	GSt - General Sales Service	2,711,041	27,913,022	12,735	213	10.2961
7	GISt - Gas Irrigation Sales Service	167,817	1,193,227	247	680	7.1103
8	KGSSD - Kansas Gas Supply Sales Service D	87,422	675,871	2	43,711	7.7311
9	SGS-Small Generator Sales Service	29	4,186	7	4	145.8510
10	Revenue Accrual		(2,042,879)		N.A.	N.A.
11	Total commercial	12,245,332	$121,850,506	50,654	242	$9.9508
	Industrial					
12	GSk - General Sales Service	16,539	$160,945	33	496	$9.7311
13	GSt - General Sales Service	41,378	379,064	47	888	9.1611
14	Revenue Accrual		(6,976)		N.A.	N.A.
15	Total Industrial	57,917	$533,033	80	725	$9.2034
	Sales for Resale					
16	Sales for Resale	136,392	$1,093,859	11	12,443	$8.0200
17	AAGS - As-Available Gas Sales Service	9,897,636	30,029,626	2	4,948,818	3.0340
18	Revenue Accrual		0		N.A.	N.A.
19	Total Sales for Resale	10,034,028	$31,123,485	13	774,166	$3.1018
20	Total Sales of Gas	67,251,932	$642,070,981	627,327	107	$9.5472

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RSk - Residential Sales Service	37,558,887	$392,039,400	463,489	81	$10.4380
2	RSt - Residential Sales Service	8,079,736	86,406,924	112,985	72	10.6943
3	Revenue Accrual		(201,060)		N.A.	N.A.
4	Total residential	45,638,623	$478,245,264	576,474	79	$10.4790
	Commercial					
5	GSk - General Sales Service	9,350,180	$90,060,251	37,406	250	$9.6319
6	GSt - General Sales Service	2,779,290	27,213,276	12,692	219	9.7915
7	GISt - Gas Irrigation Sales Service	151,698	1,195,083	235	646	7.8780
8	KGSSD - Kansas Gas Supply Sales Service D	48,932	373,876	2	24,466	7.6407
9	SGS-Small Generator Sales Service	35	5,453	8	4	157.1331
10	Revenue Accrual		1,391,906		N.A.	N.A.
11	Total commercial	12,330,134	$120,239,846	50,343	245	$9.7517
	Industrial					
12	GSk - General Sales Service	16,189	147,318	31	526	$9.0998
13	GSt - General Sales Service	37,951	338,840	43	884	8.9283
14	Revenue Accrual		(10,841)		N.A.	N.A.
15	Total industrial	54,140	$475,317	74	735	$8.7793
	Sales for Resale					
16	Sales Service For Resale	115,365	$899,382	10	11,019	$7.7960
17	AAGS - As Available Gas Sales Service	10,472,726	35,565,778	2	5,236,363	3.3960
18	Revenue Accrual				N.A.	N.A.
19	Total Sales for Resale	10,588,091	$36,465,160	12	849,123	$3.4440
20	Total Sales of Gas	68,610,988	$635,425,587	626,904	109	$9.2613

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RSk - Residential Sales Service	36,358,640	$353,007,648	463,047	79	$9.7090
2	RSt - Residential Sales Service	8,040,050	79,775,045	113,271	71	9.9222
3	Revenue Accrual		(4,713,626)		N.A.	N.A.
4	Total residential	44,398,690	$428,069,067	576,318	77	$9.6415
	Commercial					
5	GSk - General Sales Service	8,852,551	$78,049,490	36,733	241	$8.8166
6	GSt - General Sales Service	2,662,175	24,039,505	12,684	210	9.0300
7	GISt - Gas Irrigation Sales Service	228,224	1,786,142	231	986	7.8263
8	KGSSD - Kansas Gas Supply Sales Service D	66,687	433,033	1	53,350	6.4935
9	SGS-Small Generator Sales Service	5,661	380,235	553	10	67.1645
10	Revenue Accrual		(1,978,195)		N.A.	N.A.
11	Total commercial	11,815,297	$102,710,210	50,203	235	$8.6930
	Industrial					
12	GSk - General Sales Service	16,148	$132,286	29	560	$8.1919
13	GSt - General Sales Service	31,191	254,388	40	772	8.1558
14	Revenue Accrual		(8,782)		N.A.	N.A.
15	Total industrial	47,340	$377,893	69	684	$7.9826
	Sales for Resale					
16	Sales Service For Resale	41,643	$285,810	17	2,414	$6.8633
17	AAGS - As Available Gas Sales Service	370,016	1,337,471	1	370,016	3.6146
18	Revenue Accrual		0		N.A.	N.A.
19	Total Sales for Resale	411,659	$1,623,282	18	22,557	$3.9433
20	Total sales of gas	56,672,986	$532,780,452	626,609	90	$9.4010

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	17,605,162	$756,987	10	1,760,516	$0.0430
2	Revenue Accrual		2,499		N.A.	N.A.
3	Total commercial	17,605,162	$759,486	10	1,760,516	$0.0431
	Distribution - Retail					
4	STk - Small Transportation Service	599,122	$1,167,701	338	1,770	$1.9490
5	STt - Small Transportation Service	154,886	322,097	104	1,491	2.0796
6	GTk - General Transportation Service	4,759,512	7,827,518	2,535	1,878	$1.6446
7	GTt - General Transportation Service	1,700,543	3,532,219	875	1,942	2.0771
8	GITt - Gas Irrigation Transportation Service	660,920	1,143,583	431	1,535	1.7303
9	LVTk - Large Volume Transportation Service	19,331,854	11,201,570	474	40,795	0.5794
10	LVTt - Large Volume Transportation Service	24,931,767	12,286,086	141	177,003	0.4928
11	Revenue Accrual		960,615		N.A.	N.A.
12	Total distribution - retail	52,138,604	$38,441,389	4,898	10,645	$0.7373
	Distribution - Sales for Resale					
13	WTt - Wholesale Transportation Service	2,612,367	$1,680,183	25	104,495	$0.6432
14	Revenue Accrual		(54,646)		N.A.	N.A.
15	Total distribution - sales for resale	2,612,367	$1,625,537	25	104,495	$0.6222
	Storage					
	Contract Storage	103,076	$149,725	1	103,076	$1.4526
	Revenue Accrual		0		N.A.	N.A.
	Total distribution - sales for resale	103,076	$149,725	1	103,076	$1.4526
16	Total gas transport	72,459,209	$40,976,137	4,934	14,686	$0.5655

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	18,501,941	$1,235,159	11.00	1,681,995	$0.0668
2	Revenue Accrual		27,771		N.A.	N.A.
3	Total commercial	18,501,941	$1,262,930	11	1,681,995	$0.0683
	Distribution - Retail					
4	STk - Small Transportation Service	674,246	$1,348,104	401	1,680	$1.9994
5	STt - Small Transportation Service	170,245	360,271	113	1,504	2.1162
6	GTk - General Transportation Service	4,488,796	7,676,508	2,611	1,719	1.7101
7	GTt - General Transportation Service	1,487,512	3,183,950	869	1,711	2.1405
8	GITt - Gas Irrigation Transportation Service	683,243	1,214,553	439	1,557	1.7776
9	LVTk - Large Volume Transportation Service	17,925,780	11,238,612	491	36,477	0.6270
10	LVTt - Large Volume Transportation Service	26,066,899	13,086,042	152	171,689	0.5020
11	Revenue Accrual		(337,486)		N.A.	N.A.
12	Total distribution - retail	51,496,721	$37,770,554	5,077	10,143	$0.7335
	Distribution - Sales for Resale					
13	WTt - Wholesale Transportation Service	2,465,038	$1,618,057	25	98,602	$0.6564
	Revenue Accrual		$85,896		N.A.	N.A.
14	Total distribution - sales for resale	2,465,038	1,703,953	25	98,602	$0.6912
	Storage					
15	Contract Storage	72,060	$139,909	1.00	72,060	$1.9416
16	Revenue Accrual				N.A.	N.A.
17	Total distribution - sales for resale	72,060	$139,909	1	72,060	$1.9416
18	Total gas transport	72,535,760	$40,877,345	5,114	14,183	$0.5635

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	12,776,625	$952,453	16.00	798,539	$0.0745
2	Revenue Accrual		2,052		N.A.	N.A.
3	Total commercial	12,776,625	$954,505	16	798,539	$0.0747
	Distribution - Retail					
4	STk - Small Transportation Service	739,895	$1,479,486	445	1,662	$1.9996
5	STt - Small Transportation Service	194,268	423,962	133	1,464	2.1824
6	GTk - General Transportation Service	4,523,681	8,265,872	2,661	1,700	1.8272
7	GTt - General Transportation Service	1,523,028	3,339,671	869	1,753	2.1928
8	GITt - Gas Irrigation Transportation Service	741,376	1,340,759	447	1,658	1.8085
9	LVTk - Large Volume Transportation Service	18,263,851	11,890,858	488	37,445	0.6511
10	LVTt - Large Volume Transportation Service	25,615,935	13,262,077	155	165,353	0.5177
11	Revenue Accrual		729,129		N.A.	N.A.
12	Total distribution - retail	51,602,033	$40,731,812	5,198	9,928	$0.7893
	Distribution - Sales for Resale					
13	WTt - Wholesale Transportation Service	2,513,565	$1,664,196	25	99,220	$0.6621
14	Revenue Accrual		($51,900)		N.A.	N.A.
15	Total distribution - sales for resale	2,513,565	$1,612,296	25	99,220	$0.6414
	Storage					
16	Contract Storage	106,802	$51,597	1	106,802	$0.4831
17	Revenue Accrual		0		N.A.	N.A.
18	Total distribution - sales for resale	106,802	$51,597	1	106,802	$0.4831
19	Total gas transport	66,999,025	$43,350,210	5,240	12,786	$0.6470

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Transport Usage, Revenues, and Customer Data
Year Ending December 2011

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	7,426,238	$724,466	11	655,256	$0.0976
2	Revenue Accrual		(7,329)		N.A.	N.A.
3	Total commercial	7,426,238	$717,136	11	655,256	$0.0966
	Distribution - Retail					
4	STk - Small Transportation Service	852,080	$1,772,737	544	1,567	$2.0805
5	STt - Small Transportation Service	231,742	509,011	156	1,482	2.1965
6	GTk - General Transportation Service	4,569,134	8,047,456	2,703	1,690	1.7613
7	GTt - General Transportation Service	1,538,017	3,403,257	870	1,768	2.2128
8	CNG - Compressed Natural Gas General Transp. Service	13,036	10,861	1	22,347	0.8331
9	GITt - Gas Irrigation Transportation Service	1,131,898	1,976,601	456	2,484	1.7463
10	LVTk - Large Volume Transportation Service	18,117,524	12,008,828	485	37,345	0.6628
11	LVTt - Large Volume Transportation Service	25,698,201	13,056,145	153	167,611	0.5081
12	Revenue Accrual		(826,406)		N.A.	N.A.
13	Total distribution - retail	52,151,631	$39,958,489	5,368	9,714	$0.7662
	Distribution - Sales for Resale					
14	WTt - Wholesale Transportation Service	2,790,112	$1,703,000	27	103,337	$0.6104
15	Revenue Accrual		5,334		N.A.	N.A.
16	Total distribution - sales for resale	2,790,112	$1,708,333	27	103,337	$0.6123
17	Total gas transport	62,367,981	$42,383,959	5,407	11,535	$0.6796

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Payroll Data
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Utility Plant Related Payroll				
1	106-107	Construction work in progress	$5,752,153	$4,933,180	$5,002,788	$4,887,476
2	108	Plant removal	926,046	2,305,012	2,324,861	2,298,033
3	154	Materials	0	0	0	5,957
4	163	Stores Expense	1,214,469	1,225,450	1,149,694	1,285,581
5	184	Clearing Accounts	8,036,620	8,282,748	8,014,783	8,506,191
6		Other	80,377	15,155	15,256	10,157
7		Total utility plant related payroll	$16,009,665	$16,761,545	$16,507,382	$16,993,395
		Operation and Maintenance Related Payroll Expenses				
		Natural Gas Production and Gathering				
		Operation				
8	750	Operation, supervision and engineering	$0	$0	$0	$0
9	751	Maps and records	0	0	0	0
10	753	Field lines expense	0	0	0	0
11	754	Field compressor station expenses	0	0	0	0
12	755	Field compressor station expenses	0	0	0	0
13	756	Field measuring and regulating station expenses	0	0	0	0
14	757	Purification expense	0	0	0	0
15	759	Other expenses	0	0	0	0
16	760	Rents	0	0	0	0
17		Total operation	$0	$0	$0	$0

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Natural Gas Production and Gathering (cont.)				
		Maintenance				
1	761	Maintenance, supervision and engineering	$0	$0	$0	$0
2	762	Maintenance of structures and improvements	0	0	0	0
3	764	Maintenance of field lines	0	0	0	0
4	765	Maintenance of field compressor station equipment	0	0	0	0
5	766	Maintenance of field measuring and regulating station equipment	0	0	0	0
6	767	Maintenance of purification equipment	0	0	0	0
7	769	Maintenance of other equipment	0	0	0	0
8		Total maintenance	$0	$0	$0	$0
9		Total natural gas production and gathering	$0	$0	$0	$0
		Other Gas Supply Expenses				
10	805.1	Other gas purchases-special contracts	$0	$0	$0	$0
11	807.1	Well expenses- purchased gas	0	0	0	0
12	807.2	Operation of purchased gas measuring stations	0	0	0	0
13	807.3	Maintenance of purchased gas measuring stations	0	0	0	0
14	807.4	Purchased gas calculations expenses	14,950	15,956	16,086	17,455
15	807.5	Other purchased gas expenses	0	0	0	0
16	810	Gas used for compressor station fuel- credit	0	0	0	0
17	813	Other gas supply expense	422,911	504,058	625,937	634,306
18		Total other gas supply expenses	$437,861	$520,014	$642,022	$651,762
19		Total production expenses	$437,861	$520,014	$642,022	$651,762

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Underground Storage Expenses				
		Operation				
1	814	Operation, supervision and engineering	$0	$0	$0	$0
2	815	Maps and records	0	0	0	0
3	816	Wells expenses	0	0	0	0
4	817	Lines expenses	0	0	0	0
5	818	Compressor station expenses	0	0	0	0
6	819	Compressor station fuel and power	0	0	0	0
7	820	Measuring and regulating station expenses	0	0	0	0
8	821	Purification expenses	0	0	0	0
9	822	Exploration and Development	0	0	0	0
10	823	Gas losses	0	0	0	0
11	824	Other expenses	0	0	0	0
12		Total operation	$0	$0	$0	$0
		Maintenance				
13	830	Maintenance, supervision and engineering	$0	$0	$0	$0
14	831	Maintenance of structures and improvements	0	0	0	0
15	832	Maintenance of reservoirs and wells	0	0	0	0
16	833	Maintenance of lines	0	0	0	0
17	834	Maintenance of compressor station equipment	0	0	0	0
18	835	Maintenance of measuring and regulating station equipment	0	0	0	0
19	836	Maintenance of purification equipment	0	0	0	0
20	837	Maintenance of other equipment	0	0	0	0
21		Total maintenance	$0	$0	$0	$0
22		Total underground storage expenses	$0	$0	$0	$0

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Transmission Expenses				
		Operation				
1	850	Operation, supervision and engineering	$466,042	$425,561	$349,101	$335,360
2	851	System control and load dispatching	498,898	502,453	577,323	844,309
3	852	Communication system expense	49	0	40	0
4	853	Compressor station labor and expense	197,865	220,100	240,657	298,117
5	854	Gas for Compressor Station Fuel	0	0	0	0
6	855	Other fuel and power for compressor stations	0	0	0	0
7	856	Mains expenses	907,948	874,167	936,636	914,531
8	857	Measuring and regulating station expenses	265,211	287,268	282,985	281,148
9	859	Other expenses	96	10,510	19,164	19,713
10	860	Rents	0	0	0	0
11		Total operation	$2,336,110	$2,320,059	$2,405,905	$2,693,177
		Maintenance				
12	861	Maintenance, supervision and engineering	$289,380	$233,614	$136,057	$104,408
13	862	Maintenance of structures and improvements	9,126	7,861	3,331	1,708
14	863	Maintenance of mains	312,523	346,032	311,620	313,441
15	864	Maintenance of compressor station equipment	196,213	192,144	145,141	180,211
16	865	Maintenance of measuring and regulating station equipment	153,580	165,046	143,227	188,758
17	866	Maintenance of communication equipment	1,141	0	0	0
18	867	Maintenance of other equipment	500	331	128	0
19		Total maintenance	$962,464	$945,028	$739,504	$788,525
20		Total transmission expenses	$3,298,574	$3,265,087	$3,145,409	$3,481,703

Line No.	Account Number	Description	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Distribution Expenses				
		Operation				
1	870	Operation, supervision and engineering	$2,085,306	$1,878,647	$1,243,345	$1,491,318
2	871	Distribution load dispatching	12	0	0	324
3	874	Mains and services expense	3,197,407	3,488,107	3,720,812	3,668,149
4	875	Measuring and regulating station expenses - general	705,242	719,069	648,368	583,586
5	876	Measuring and regulating station expenses - industrila	215,390	233,370	217,177	227,083
6	877	Measuring and regulating station expenses - city gate check station	26,692	30,342	143,724	167,586
7	878	Meter and house regulator expenses	4,667,003	4,795,009	4,896,652	4,603,705
8	879	Customer installations expenses	3,246,399	3,355,280	3,306,849	3,397,469
9	880	Other expenses	2,000,668	1,015,675	1,629,506	1,464,102
10	881	Rents	0	0	0	0
11		Total operation	$16,144,119	$15,515,499	$15,806,433	$15,603,321
		Maintenance				
12	885	Maintenance, supervision and engineering	$650,231	$586,172	$428,144	$415,023
13	886	Maintenance of structures and improvements	190,791	177,168	142,493	94,772
14	887	Maintenance of mains	4,044,266	3,968,871	3,783,272	3,526,140
15	889	Maintenance of measuring and regulating station expenses - general	285,420	324,396	326,484	363,058
16	890	Maintenance of measuring and regulating station expenses - industrial	28,867	87,736	148,309	162,283
17	891	Maintenance of measuring and regulating station expenses-city gate check	0	97	111,208	251,480
18	892	Maintenance of services	945,033	904,705	1,121,673	1,187,273
19	893	Maintenance of meters and house regulators	1,322,348	1,407,777	1,165,490	1,147,367
20	894	Maintenance of other equipment	15,620	11,088	83	0
21		Total maintenance	$7,482,578	$7,468,009	$7,227,156	$7,147,395
22		Total distribution expenses	$23,626,696	$22,983,508	$23,033,589	$22,750,717

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Customer Accounts Expense				
1	901	Supervision	$411,276	$423,586	$651,402	$690,035
2	902	Meter reading expenses	1,691,992	1,594,238	1,428,650	1,421,551
3	903	Customer records and collection expense	6,488,391	6,481,721	6,020,980	6,362,957
4	905	Miscellaneous customer accounts expense	307,525	230,348	180,422	164,183
5		Total customer accounts expenses	$8,899,184	$8,729,894	$8,281,454	$8,638,725
		Customer Service and Informational Expenses				
6	907	Supervision	$0	$0	$0	$0
7	908	Customer assistance expenses	255	38	0	0
8	909	Informational and instructional expenses	0	0	0	0
9	910	Miscellaneous customer service and informational expenses	0	0	0	0
10		Total customer service and informational expenses	$255	$38	$0	$0
		Sales Expense				
11	911	Supervision	$0	$0	$130,649	$137,707
12	912	Demonstrating and selling expenses	378,250	442,419	475,379	475,033
13	913	Advertising expenses	12,961	12,961	0	0
14	916	Miscellaneous sales expenses	147,886	126,478	0	0
15		Total sales expenses	$539,097	$581,857	$606,028	$612,740

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Payroll Data
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2008 Col. 2	December 31, 2009 Col. 3	December 31, 2010 Col. 4	December 31, 2011 Col. 5
		Administrative and General Expenses				
		Operation				
1	920	Administrative and general salaries	$7,793,811	$8,347,642	$8,517,230	$8,852,984
2	921	Office supplies and expenses	0	0	0	0
3	922	Administrative Expenses Transferred - Credit	0	0	0	0
4	923	Outside services employed	0	0	0	0
5	925	Injuries and damages	0	0	0	0
6	926	Employee pensions and benefits	0	0	0	0
7	927	Franchise requirements	0	0	0	0
8	930	Miscellaneous general expenses	0	0	0	0
9	931	Rents	0	0	0	0
10		Total operation	$7,793,811	$8,347,642	$8,517,230	$8,852,984
		Maintenance				
11	935	Maintenance of general plant	$0	$0	$0	$0
12		Total administrative and general expenses	$7,793,811	$8,347,642	$8,517,230	$8,852,984
13		Total O & M payroll expenses	$44,595,478	$44,428,042	$44,225,733	$44,988,631
14	417	Miscellaneous Non-Operating Income	$0	$0	$0	$0
15	426	Miscellaneous Income Deduction	$71,025	$56,038	$57,296	$59,283
16		Kansas gas operations payroll	$60,676,168	$61,245,625	$60,790,411	$62,041,309

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Operating Income Statement
Test Year Ended December 31, 2011

Line No.	Description	Schedule Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	8-D, 9-B	$532,780,451	($319,119,263)	$213,661,188
2	Service and other	8-D, 9-B	47,296,857	(2,161,480)	45,135,377
3	Total revenue		$580,077,308	($321,280,743)	$258,796,565
	Operating Expenses				
4	Production	8-E, 9-B	$312,318,637	($310,463,517)	$1,855,120
5	Underground storage	8-E, 9-B	138,109	0	138,109
6	Transmission	8-E, 9-B	8,050,669	18,183	8,068,852
7	Distribution	8-E, 9-B	53,305,948	493,275	53,799,223
8	Customer accounts	8-E, 9-B	25,323,583	722,603	26,046,186
9	Customer service and information	8-E, 9-B	682	0	682
10	Sales	8-E, 9-B	1,225,862	2,139	1,228,001
11	Administrative and general	8-E, 9-B	52,568,748	(9,086,813)	43,481,935
12	Total operating expenses	8-E, 9-B	$452,932,238	($318,314,129)	$134,618,109
13	Depreciation and amortization	8-B, 9-B	$49,618,362	$1,470,045	$51,088,407
14	Taxes other than income taxes	8-B, 9-B	19,300,763	7,019,435	26,320,198
15	Income taxes-current	8-B, 9-B	(33,224,623)	11,430,430	(21,794,193)
16	Income taxes-deferred	8-B, 9-B	49,723,201	(15,932,355)	33,790,846
17	Investment Tax Credits	8-B, 9-B	(384,288)	0	(384,288)
18	Total expenses	8-B, 9-B	$537,965,653	($314,326,574)	$223,639,079
19	Operating Income		$42,111,655	($6,954,169)	$35,157,486

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 1 Eliminate Accrued and Unbilled Revenues and Expenses	IS 2 Eliminate Deferred WNA Revenues	IS 3 Eliminate COGR Revenues and Expenses	IS 4 Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses
	Col. 1	Col. 3	Col. 4	Col. 5	Col. 2
	Operating Revenue				
1	Gas revenue	$7,925,634	$4,311,866	($316,477,067)	($3,706,513)
2	Service and other	828,401	0	(241,911)	(1,869,816)
3	Total revenue	$8,754,035	$4,311,866	($316,718,977)	($5,576,328)
	Operating Expenses				
4	Production	$7,611,194	$0	($316,718,977)	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	0	0
12	Total operating expenses	$7,611,194	$0	($316,718,977)	$0
13	Depreciation and amortization	$0	$0	$0	($5,522,836)
14	Taxes other than income taxes	0	0	0	7,093,533
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$7,611,194	$0	($316,718,977)	$1,570,697
19	Operating Income	$1,142,841	$4,311,866	$0	($7,147,026)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 5 Eliminate GSRS Revenue	IS 6 As Available Gas Sales	IS 7 Test Year Revenue Adjustments	IS 8 Normalize Test Year Revenues-
	Col. 1	Col. 3	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	($7,003,712)	($1,337,471)	$27,325	($2,659,708)
2	Service and other	(1,001,517)	0	300,603	(496,618)
3	Total revenue	($8,005,229)	($1,337,471)	$327,929	($3,156,326)
	Operating Expenses				
4	Production	$0	($1,327,523)	($45,482)	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	0	0
12	Total operating expenses	$0	($1,327,523)	($45,482)	$0
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$0	($1,327,523)	($45,482)	$0
19	Operating Income	($8,005,229)	($9,948)	$373,411	($3,156,326)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 9 Annualize Test Year Customers, Sales and Revenues	IS 10 Eliminate CNG Revenue and Taxes	IS 11 Adjustment for Non-Gas Portion of Uncollectible	IS 12 Eliminate Royalty Fee
	Col. 1	Col. 2	Col. 3	Col. 3	Col. 4
	Operating Revenue				
1	Gas revenue	($199,617)	$0	$0	$0
2	Service and other	331,734	(12,358)	0	0
3	Total revenue	$132,116	($12,358)	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	185,884	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	0	(8,116,302)
12	Total operating expenses	$0	$0	$185,884	($8,116,302)
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	(7,902)	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$0	($7,902)	$185,884	($8,116,302)
19	Operating Income	$132,116	($4,456)	($185,884)	$8,116,302

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 13 Pension & Benefits Adjustment	IS 14 Amortization of Deferred Pension & Benefits	IS 15 Employee Medical Reserve	IS 16 OPEB Amortization
	Col. 1	Col. 5	Col. 2	Col. 3	Col. 4
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	$0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	5,184,587	0	587,928	0
12	Total operating expenses	$5,184,587	$0	$587,928	$0
13	Depreciation and amortization	$0	$4,602,429	$0	($2,937,792)
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$5,184,587	$4,602,429	$587,928	($2,937,792)
19	Operating Income	($5,184,587)	($4,602,429)	($587,928)	$2,937,792

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 17 Donations from Account 426 and Eliminate Certain Dues and Donations	IS 18 Normalize Assessed Regulatory Costs	IS 19 Income Taxes	IS 20 Out of Period Adjustment
	Col. 1	Col. 5	Col. 2	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	(1,939)	0	0	0
8	Customer accounts	(20)	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	77,402	64,948	0	(83,103)
12	Total operating expenses	$75,443	$64,948	$0	($83,103)
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	(142,308)
15	Income taxes-current	0	0	11,430,430	0
16	Income taxes-deferred	0	0	(15,932,355)	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$75,443	$64,948	($4,501,925)	($225,411)
19	Operating Income	($75,443)	($64,948)	$4,501,925	$225,411

Line No.	Description	IS 21 Rate Case Expense Amortization	IS 22 Payroll Adjustment	IS 23 Annualize Depreciation on Pro-Forma Plant	IS 24 Annualization Depreciation at Proposed Rates
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$10,774	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	119,447	0	0
7	Distribution	0	707,954	0	0
8	Customer accounts	0	216,136	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	2,139	0	0
11	Administrative and general	0	(26,681)	0	0
12	Total operating expenses	$0	$1,029,769	$0	$0
13	Depreciation and amortization	$379,414	$0	$528,401	$4,455,065
14	Taxes other than income taxes	0	78,291	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$379,414	$1,108,060	$528,401	$4,455,065
19	Operating Income	($379,414)	($1,108,060)	($528,401)	($4,455,065)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 25 Adjust Clearings	IS 26 Annualize Cellnet Increase	IS 27 Bill Print Vendor Change Adjustment	IS 28 Reclassify Interest on Customer Deposits
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 2
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	(12,409)	0	0	0
7	Distribution	(212,740)	0	0	0
8	Customer accounts	(24,212)	22,681	274,888	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	(4,069)	21,097
12	Total operating expenses	($249,361)	$22,681	$270,819	$21,097
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($249,361)	$22,681	$270,819	$21,097
19	Operating Income	$249,361	($22,681)	($270,819)	($21,097)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 29 Shared Services Contract Changes	IS 30 Eliminate O&M costs related to plant	IS 31 Annualized Corporate Depreciation	IS 32 Compensation - STI/LTI/Deferred Compensation
	Col. 1	Col. 3	Col. 4	Col. 5	Col. 2
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$6,498	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	(88,856)	0	0
7	Distribution	0	0	0	0
8	Customer accounts	47,248	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	(8,756)	0	0	(1,922,290)
12	Total operating expenses	$38,491	($82,357)	$0	($1,922,290)
13	Depreciation and amortization	$0	$0	($34,635)	$0
14	Taxes other than income taxes	0	0	0	(2,180)
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$38,491	($82,357)	($34,635)	($1,924,470)
19	Operating Income	($38,491)	$82,357	$34,635	$1,924,470

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description	IS 33 Normalized Compensation - Share Awards	IS 34 Adjustment for Change in Allocation Ratio	IS 35 Adjustment for Miscellaneous Corporate Charges	IS 36 Adjustment for OPEB, Pension, Health Benefits and Insurance
	Col. 1	Col. 2	Col. 2	Col. 2	Col. 2
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	(2,367,236)	(477,277)	(1,891,493)	(125,567)
12	Total operating expenses	($2,367,236)	($477,277)	($1,891,493)	($125,567)
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($2,367,236)	($477,277)	($1,891,493)	($125,567)
19	Operating Income	$2,367,236	$477,277	$1,891,493	$125,567

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Total Adjustments Col. 3
	Operating Revenue	
1	Gas revenue	($319,119,263)
2	Service and other	(2,161,480)
3	Total revenue	($321,280,743)
	Operating Expenses	
4	Production	($310,463,517)
5	Underground storage	0
6	Transmission	18,183
7	Distribution	493,275
8	Customer accounts	722,603
9	Customer service and information	0
10	Sales	2,139
11	Administrative and general	(9,086,813)
12	Total operating expenses	($318,314,129)
13	Depreciation and amortization	$1,470,045
14	Taxes other than income taxes	7,019,435
15	Income taxes-current	11,430,430
16	Income taxes-deferred	(15,932,355)
17	Investment Tax Credits	0
18	Total expenses	($314,326,574)
19	Operating Income	($6,954,169)

Line No.	Adj. No.	Description	Increase	Decrease
	IS 1	Eliminate Accrued and Unbilled Revenues and Expenses		
1		Operating Revenue	$8,754,035	$0
2		Production Expenses	7,611,194	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate accrued and unbilled revenues and gas costs from test year operating results.		
	IS 2	Eliminate Deferred WNA Revenues		
13		Operating Revenue	$4,311,866	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate deferred WNA revenues		

Line No.	Adj. No.	Description	Increase	Decrease
	IS 3	Eliminate COGR Revenues and Expenses		
1		Operating Revenue	$0	$316,718,977
2		Production Expenses	0	316,718,977
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment eliminates the COGR revenues and the cost of gas expense to determine base rates.		
	IS 4	Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses		
13				
14		Operating Revenue	$0	$5,576,328
15		Production Expenses	0	0
16		Underground Storage Expenses	0	0
17		Transmission Expenses	0	0
18		Distribution Expenses	0	0
19		Customer Accounts Expenses	0	0
20		Cust. Service and Information Exp.	0	0
21		Sales and Advertising Expenses	0	0
22		Administration and General Expense	0	0
23		Depreciation and Amortization	0	5,522,836
24		Taxes Other Than Income Taxes	7,093,533	0
		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate Ad Valorem Tax Surcharge Revenues and annualize ad valorem expenses.		

Line No.	Adj. No.	Description	Increase	Decrease
	IS 5	Eliminate GSRS Revenue		
1		Operating Revenue	$0	$8,005,229
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate GSRS Revenues from test year revenues to determine base rate revenues.		
	IS 6	As Available Gas Sales		
13		Operating Revenue	$0	$1,337,471
14		Production Expenses	0	1,327,523
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate company retained AAGS from test year operating results.		

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Explanation of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2011

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 7	Test Year Revenue Adjustments		
1		Operating Revenue	$327,929	$0
2		Production Expenses	0	45,482
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize test year revenues and expenses for prior period adjustments, contract minimum quantities, and discounted rate annualization.		
	IS 8	Normalize Test Year Revenues-		
13		Operating Revenue	$0	$3,156,326
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Adjusts test year revenue had the weather been normal during the test year.		

Line No.	Adj. No.	Description	Increase	Decrease
		Col. 1	Col. 2	Col. 3
	IS 9	Annualize Test Year Customers, Sales and Revenues		
1		Operating Revenue	$132,116	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Adjustment annualizes sales to recognize change in customer count.		
	IS 10	Eliminate CNG Revenue and Taxes		
13		Operating Revenue	$0	$12,358
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	7,902
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is to remove revenue and taxes associated with the public sale of CNG.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 11	Adjustment for Non-Gas Portion of Uncollectible		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	185,884	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is to true up the bad debt expense for base rates.		
	IS 12	Eliminate Royalty Fee		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	8,116,302
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Eliminate the Royalty Fees from the test period.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 13	Pension & Benefits Adjustment		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	5,184,587	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust expenses for the increase in Pension and OPEB costs.		
	IS 14	Amortization of Deferred Pension & Benefits		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	4,602,429	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To amortize over 3 years the deferred Pension and OPEB expenses.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 15	Employee Medical Reserve		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	587,928	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust expenses for the increase in Medical Expenses.		
	IS 16	OPEB Amortization		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	2,937,792
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate OPEB amortization allowed pursuant to the 2003 rate case.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 17	Include Certain Donations from Account 426 and Eliminate Certain Dues and Donations		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	1,939
6		Customer Accounts Expenses	0	20
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	77,402	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate certain Dues, Donations and Membership Expenses by Account.		
	IS 18	Normalize Assessed Regulatory Costs		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	64,948	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize the costs associated with the KCC and CURB quarterly assessments.		

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Test Year Ended December 31, 2011

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 19	Income Taxes		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	4,501,925
		To adjust for the change in income taxes associated pro-forma changes to the test year.		
	IS 20	Out of Period Adjustment		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	83,103
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	142,308
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust the test year for out of period activity recorded during the test year.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 21	Rate Case Expense Amortization		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	379,414	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is for the amortization of the rate case costs in the current case.		
	IS 22	Payroll Adjustment		
13		Operating Revenue	$0	$0
14		Production Expenses	10,774	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	119,447	0
17		Distribution Expenses	707,954	0
18		Customer Accounts Expenses	216,136	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	2,139	0
21		Administration and General Expense	0	26,681
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	78,291	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize known changes to payroll expenses.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 23	Annualize Depreciation on Pro-Forma Plant		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	528,401	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize the change depreciation expense on the pro-forma plant in service.		
	IS 24	Annualization Depreciation at Proposed Rates		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	4,455,065	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize the change in depreciation rates on the pro-forma plant in service as a result of the depreciation study.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 25	Adjust Clearings		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	12,409
5		Distribution Expenses	0	212,740
6		Customer Accounts Expenses	0	24,212
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize test year clearing charges		
	IS 26	Annualize Cellnet Increase		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	22,681	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is made to calculate the annualized impact of the increase in Cellnet meter reading costs.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 27	Bill Print Vendor Change Adjustment		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	274,888	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	4,069
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is made to reflect the cost increase associated with the bill print vendor.		
	IS 28	Reclassify Interest on Customer Deposits		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	21,097	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To reclassify interest on customer deposits as an operating expense		

Line No.	Adj. No.	Description	Increase	Decrease
		Col. 1	Col. 2	Col. 3
	IS 29	Shared Services Contract Changes		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	47,248	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	8,756
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust for the changes in the Shared Services contract between Westar Energy and Kansas Gas Service.		
	IS 30	Eliminate O&M costs related to plant		
13		Operating Revenue	$0	$0
14		Production Expenses	6,498	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	88,856
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To remove the operation and maintenance costs associated with plant assets that are not currently used and useful.		

Line No.	Adj. No.	Description	Increase	Decrease
		Col. 1	Col. 2	Col. 3
	IS 31	Annualized Corporate Depreciation		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	34,635
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize the corporate depreciation expense.		
	IS 32	Normalized Compensation - STI/LTI/Deferred Compensation		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	1,922,290
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	2,180
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize the Other Compensation that was recorded during the test year.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 33	Normalized Compensation - Share Awards		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	2,367,236
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize the Share Awards that were recorded in the test year.		
	IS 34	Adjustment for Change in Allocation Ratio		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	477,277
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust for the reduction in the allocation percent in the Distrigas Allocation.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 35	Adjustment for Miscellaneous Corporate Charges		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	1,891,493
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate certain expense that were allocated through the Distrigas Methodology.		
	IS 36	Adjustment for OPEB, Pension, Health Benefits and Insurance		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	125,567
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To decreases expense by the increase of OPEB, Pension, Health Benefits and Insurance that are allocated through the Distragas Methodology.		

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Depreciation and Amortization Expense
Test Year Ended December 31, 2011

Line No.	Description	Amount Per Books (Schedule 10-B)	Pro Forma Adjustments (Schedule 10-C)	Pro Forma Total
	Col. 1	Col. 2	Col. 3	Col. 4
	Depreciation Expense			
1	Intangible plant	$0	$0	$0
2	Production and gathering	10,527	622	11,149
3	Underground storage	0	0	0
4	Transmission plant	4,777,167	987,354	5,764,521
5	Distribution plant	30,780,355	4,167,495	34,947,850
6	General plant	2,760,402	(172,005)	2,588,397
7	Corporate Allocated	2,156,028	(34,635)	2,121,393
8	Total depreciation expense	$40,484,479	$4,948,831	$45,433,310
	Amortization Expense			
9	Intangible plant	$249,986	$0	$249,986
10	Distribution plant	0	0	0
11	General plant	0	0	0
12	Utility plant acquisition premium	0	0	0
13	Regulatory debit	8,883,897	(3,478,786)	5,405,111
14	Total amortization expense	$9,133,883	($3,478,786)	$5,655,097
15	Total depreciation and amortization expense	$49,618,362	$1,470,045	$51,088,407

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Functional Classification Detail
Test Year Ended December 31, 2011

Line No.	Description	Depreciation Charged to Operating Expense	Depreciation Charged to Clearing Accounts	Total Expense
	Col. 1	Col. 2	Col. 3	Col. 4
	Depreciation Expense			
1	Intangible plant	$0	$0	$0
2	Production and gathering	10,527	0	10,527
3	Underground storage	0	0	0
4	Transmission plant	4,777,167	0	4,777,167
5	Distribution plant	30,780,355	0	30,780,355
6	General plant	4,952,749	(2,192,347)	2,760,402
	Corporate Allocated	2,156,028	0	2,156,028
7	Total depreciation expense	$42,676,826	($2,192,347)	$40,484,479
	Amortization Expense			
8	Intangible plant	$249,986	$0	$249,986
9	Distribution plant	0	0	0
10	General plant	0	0	0
11	Utility plant acquisition premium	0	0	0
12	Regulatory debit	8,883,897	0	8,883,897
13	Total amortization expense	$9,133,883	$0	$9,133,883
14	Total depreciation and amortization expense	$51,810,709	($2,192,347)	$49,618,362

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Depreciation and Amortization Expense (a)
Test Year Ended December 31, 2011

Line No.	Description	IS 4 Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses	IS 14 Amortization of Deferred Pension & Benefits	IS 16 OPEB Amortization	Sub Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Depreciation Expense				
1	Intangible plant	$0	$0	$0	$0
2	Production and gathering	0	0	0	0
3	Underground storage	0	0	0	0
4	Transmission plant	0	0	0	0
5	Distribution plant	0	0	0	0
6	General plant	0	0	0	0
7	Corporate Allocated	0	0	0	0
8	Total depreciation expense	$0	$0	$0	$0
	Amortization Expense				
9	Intangible plant	$0	$0	$0	$0
10	Distribution plant	0	0	0	0
11	General plant	0	0	0	0
12	Utility plant acquisition premium	0	0	0	0
13	Regulatory debit	(5,522,836)	4,602,429	(2,937,792)	(3,858,200)
14	Total amortization expense	($5,522,836)	$4,602,429	($2,937,792)	($3,858,200)
15	Total expense	($5,522,836)	$4,602,429	($2,937,792)	($3,858,200)

Note:
(a) See Schedule 9-C for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Depreciation and Amortization Expense (a)
Test Year Ended December 31, 2011

Line No.	Description	IS 21 Rate Case Expense Amortization	IS 23 Annualize Depreciation on Pro-Forma Plant	IS 24 Annualization Depreciation at Proposed Rates	Sub Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Depreciation Expense				
1	Intangible plant	$0	$0	$0	$0
2	Production and gathering	0	622	0	622
3	Underground storage	0	0	0	0
4	Transmission plant	0	279,375	707,979	987,354
5	Distribution plant	0	438,888	3,728,607	4,167,495
6	General plant	0	(190,484)	18,479	(172,005)
7	Corporate Allocated	0	0	0	0
8	Total depreciation expense	$0	$528,401	$4,455,065	$4,983,466
	Amortization Expense				
9	Intangible plant	$0	$0	$0	$0
10	Distribution plant	0	0	0	0
11	General plant	0	0	0	0
12	Utility plant acquisition premium	0	0	0	0
13	Regulatory debit	379,414	0	0	379,414
14	Total amortization expense	$379,414	$0	$0	$379,414
15	Total expense	$379,414	$528,401	$4,455,065	$5,362,880

Note:
(a) See Schedule 9-C for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Pro Forma Adjustments to Depreciation and Amortization Expense (a)
Test Year Ended December 31, 2011

Line No.	Description	IS 31 Annualized Corporate Depreciation	Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3
	Depreciation Expense		
1	Intangible plant	$0	$0
2	Production and gathering	0	622
3	Underground storage	0	0
4	Transmission plant	0	987,354
5	Distribution plant	0	4,167,495
6	General plant	0	(172,005)
7	Corporate Allocated	(34,635)	(34,635)
8	Total depreciation expense	($34,635)	$4,948,831
	Amortization Expense		
9	Intangible plant	$0	$0
10	Distribution plant	0	0
11	General plant	0	0
12	Utility plant acquisition premium	0	0
13	Regulatory debit	0	(3,478,786)
14	Total amortization expense	$0	($3,478,786)
15	Total expense	($34,635)	$1,470,045

Note:
(a) See Schedule 9-C for explanation of pro forma adjustments.

Line No.	Account Number	Description	Depreciation Rates Current Rates	Depreciation Rates Proposed Rates
		Col. 1	Col. 2	Col. 3
		Intangible Plant		
1	302	Franchise and Consents	0.00%	0.00%
2	303	Miscellaneous Intangible Plant	0.00%	0.00%
3		Total Intangible Plant		
		Production and gathering plant		
4	325.4	Rights of way	1.25%	1.25%
5	327	Field compressor station structures	2.89%	2.89%
6	328	Field measuring and regulating station	0.00%	0.00%
7	332	Field lines	0.80%	0.80%
8	333	Field compressor station equipment	1.01%	1.01%
9	334	Field measuring and regulating station equipment	1.47%	1.47%
10		Total Production and gathering plant		
		Underground storage plant		
11	350.1	Land & Land rights	0.00%	0.00%
12	351.1	Structures and improvements	0.00%	0.00%
13	351.2	Structures and improvements	0.00%	0.00%
14	351.3	Structures and improvements	0.00%	0.00%
15	352	Wells	0.00%	0.00%
16	352.1	Storage Lease and Rights	0.00%	0.00%
17	352.2	Reservoirs	0.00%	0.00%
18	352.3	Non-Recoverable Natural Gas	0.00%	0.00%
19	353	Storage Lines	0.00%	0.00%
20	354	Compressor station equipment	0.00%	0.00%
21	355	Measuring and regulating station equipment	0.00%	0.00%
22	356	Purification equipment	0.00%	0.00%
23	357	Other equipment	0.00%	0.00%
24		Total Underground storage plant	0.00%	0.00%

Line No.	Account Number	Description Col. 1	Depreciation Rates Current Rates Col. 2	Depreciation Rates Proposed Rates Col. 3
		Transmission plant		
1	365.1	Land & Land rights	0.00%	0.00%
2	365.2	Rights of way	1.36%	1.40%
3	366.1	Structures and improvements	2.88%	2.90%
4	366.2	Measuring and regulating station equipment	2.16%	2.32%
5	367	Mains	2.12%	2.40%
6	368	Compressor station equipment	2.85%	3.64%
7	369	Measuring and regulating station equipment	2.74%	3.12%
8		Total Transmission plant		
		Distribution plant		
9	374.1	Land & Land rights	0.00%	0.00%
10	374.2	Rights of way	1.39%	1.42%
11	375.1	Structures	4.40%	3.80%
12	376.1	Mains - Metallic	1.77%	2.19%
13	376.2	Mains - Plastic	2.79%	3.02%
14	376.4	Mains - Cathodic Protection	1.77%	7.15%
15	378	M&R station equipment - general	2.51%	2.47%
16	379	M&R station equipment - city gate	2.07%	1.99%
17	380	Services - Metallic	3.27%	2.77%
18	380.5	Services - Plastic	3.55%	3.49%
19	381	Meters	2.53%	2.61%
20	381.5	Meters - AMR	2.53%	6.67%
21	382	Meter installations	2.48%	3.14%
22	383	House regulators	1.79%	2.04%
23	386	Other Property on Customer Premises	9.79%	9.71%
24	387	Other equipment	0.00%	0.00%
25		Total Distribution plant		

Line No.	Account Number	Description	Depreciation Rates Current Rates	Depreciation Rates Proposed Rates
		Col. 1	Col. 2	Col. 3
		General Plant		
1	389.1	Land & Land rights	0.00%	0.00%
2	390.1	Structures	1.76%	1.61%
3	390.2	Leasehold Improvements (1)	0.00%	0.00%
4	391.1	Office furniture and equipment	4.97%	4.97%
5	391.25	Computers and other electronic equipment	14.16%	14.16%
6	392	Transportation equipment	7.08%	5.03%
7	393	Stores equipment	4.59%	4.59%
8	394	Tools, shop and garage equipment	6.66%	6.66%
9	395	Laboratory equipment	6.67%	6.67%
10	396	Power operated equipment	7.98%	6.20%
11	397	Communications equipment	4.30%	5.04%
12	398	Miscellaneous equipment	5.00%	5.00%
13		Total General Plant		

(1) Included in amortization expense

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Calculation of Pro-Forma Depreciation Expense - Existing Rates
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Intangible Plant			
1	302	Franchise and Consents	$6,045	0.00%	$0
2	303	Miscellaneous Intangible Plant	62,514	0.00%	0
3		Total Intangible Plant	$68,559		$0
		Production and gathering plant			
4	325.4	Rights of way	$232,567	1.25%	$2,907
5	327	Field compressor station structures	3,053	2.89%	88
6	328	Field measuring and regulating station	44,026	0.00%	0
7	332	Field lines	56,448	0.80%	452
8	333	Field compressor station equipment	12,877	1.01%	130
9	334	Field measuring and regulating station equipment	515,090	1.47%	7,572
10		Total Production and gathering plant	$864,061		$11,149
		Underground storage plant			
11	350.1	Land & Land rights	$0	0.00%	$0
12	351.1	Structures and improvements	0	0.00%	0
13	351.2	Structures and improvements	0	0.00%	0
14	351.3	Structures and improvements	0	0.00%	0
15	352	Wells	0	0.00%	0
16	352.1	Storage Lease and Rights	0	0.00%	0
17	352.2	Reservoirs	0	0.00%	0
18	352.3	Non-Recoverable Natural Gas	0	0.00%	0
19	353	Storage Lines	0	0.00%	0
20	354	Compressor station equipment	0	0.00%	0
21	355	Measuring and regulating station equipment	0	0.00%	0
22	356	Purification equipment	0	0.00%	0
23	357	Other equipment	0	0.00%	0
24		Total Underground storage plant	$0		$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Calculation of Pro-Forma Depreciation Expense - Existing Rates
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Transmission plant			
1	365.1	Land & Land rights	$826,470	0.00%	$0
2	365.2	Rights of way	11,841,814	1.36%	161,049
3	366.1	Structures and improvements	4,142,147	2.88%	119,294
4	366.2	Measuring and regulating station equipment	1,137,206	2.16%	24,564
5	367	Mains	181,904,545	2.12%	3,856,376
6	368	Compressor station equipment	16,998,689	2.85%	484,463
7	369	Measuring and regulating station equipment	14,992,598	2.74%	410,797
8	371	Other Equipment	(2,697)	0.00%	0
9		Total Transmission plant	$231,840,772		$5,056,542
		Distribution plant			
10	374.1	Land & Land rights	$97,565	0.00%	$0
11	374.2	Rights of way	1,832,554	1.39%	25,473
12	375.1	Structures	855,259	4.40%	37,631
13	376.1	Mains - Metallic	260,956,707	1.77%	4,618,934
14	376.2	Mains - Plastic	272,622,923	2.79%	7,606,180
15	376.4	Mains - Cathodic Protection	23,205,016	1.77%	410,729
16	378	M&R station equipment - general	21,525,164	2.51%	540,282
17	379	M&R station equipment - city gate	5,966,134	2.07%	123,499
18	380.0	Services - Metallic	31,302,372	3.27%	1,023,588
19	380.5	Services - Plastic	334,858,266	3.55%	11,887,468
20	381	Meters	87,128,287	2.53%	2,204,346
21	381.5	Meters - AMR	10,749,916	2.53%	271,973
22	382	Meter installations	88,052,631	2.48%	2,183,705
23	383	House regulators	14,720,377	1.79%	263,495
24	386	Other Property on Customer Premises	224,125	9.79%	21,942
25	387	Other equipment	0	0.00%	0
26		Total Distribution plant	$1,154,097,296		$31,219,243

Line No.	Account Number	Description Col. 1		Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		General Plant				
1	389.1	Land & Land rights		$1,452,065	0.00%	$0
2	390.1	Structures		29,495,892	1.76%	519,128
3	390.2	Leasehold Improvements (1)		2,600,970	0.00%	0
4	391.1	Office furniture and equipment		5,024,820	4.97%	249,734
5	391.9	Computers and other electronic equipment		6,148,309	14.16%	870,601
6	392	Transportation equipment		20,818,777	7.08%	1,473,969
7	393	Stores equipment		365,166	4.59%	16,761
8	394	Tools, shop and garage equipment		8,071,494	6.66%	537,562
9	395	Laboratory equipment		71,582	6.67%	4,774
10	396	Power operated equipment		11,449,659	7.98%	913,683
11	397	Communications equipment		8,476,045	4.30%	364,470
12	398	Miscellaneous equipment		137,783	5.00%	6,889
13		Total General Plant		$94,112,562		$4,957,570
14		Subtotal		$1,480,983,250		$41,244,504
		Less: Capitalized Depreciation				
15		392	Transportation Equipment			(1,473,969)
16		396	Power Operated Equipment			(913,683)
17		Pro-Forma Depreciation Expense				$38,856,852
18		Test Period Depreciation - Kansas Gas Service				38,328,451
19		Pro-Forma Depreciation Adjustment				$528,401

(1) Included in amortization expense

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Depreciation and Amortization Expense - Proposed Rates
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Intangible Plant			
1	302	Franchise and Consents	$6,045	0.00%	$0
2	303	Miscellaneous Intangible Plant	62,514	0.00%	0
3		Total Intangible Plant	$68,559		$0
4		Production and gathering plant			
5	325.4	Rights of way	$232,567	1.25%	$2,907
6	327	Field compressor station structures	3,053	2.89%	88
7	328	Field measuring and regulating station	44,026	0.00%	0
8	332	Field lines	56,448	0.80%	452
9	333	Field compressor station equipment	12,877	1.01%	130
10	334	Field measuring and regulating station equipment	515,090	1.47%	7,572
		Total Production and gathering plant	$864,061		$11,149
		Underground storage plant			
11	350.1	Land & Land rights	$0	0.00%	$0
12	351.1	Structures and improvements	0	0.00%	0
13	351.2	Structures and improvements	0	0.00%	0
14	351.3	Structures and improvements	0	0.00%	0
15	352	Wells	0	0.00%	0
16	352.1	Storage Lease and Rights	0	0.00%	0
17	352.2	Reservoirs	0	0.00%	0
18	352.3	Non-Recoverable Natural Gas	0	0.00%	0
19	353	Storage Lines	0	0.00%	0
20	354	Compressor station equipment	0	0.00%	0
21	355	Measuring and regulating station equipment	0	0.00%	0
22	356	Purification equipment	0	0.00%	0
23	357	Other equipment	0	0.00%	0
24		Total Underground storage plant	$0		$0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Depreciation and Amortization Expense - Proposed Rates
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Transmission plant			
1	365.1	Land & Land rights	$826,470	0.00%	$0
2	365.2	Rights of way	11,841,814	1.40%	165,785
3	366.1	Structures and improvements	4,142,147	2.90%	120,122
4	366.2	Measuring and regulating station equipment	1,137,206	2.32%	26,383
5	367	Mains	181,904,545	2.40%	4,365,709
6	368	Compressor station equipment	16,998,689	3.64%	618,752
7	369	Measuring and regulating station equipment	14,992,598	3.12%	467,769
8	371	Other Equipment	(2,697)	0.00%	0
9		Total Transmission plant	$231,840,772		$5,764,521
		Distribution plant			
10	374.1	Land & Land rights	$97,565	0.00%	$0
11	374.2	Rights of way	1,832,554	1.42%	26,022
12	375.1	Structures	855,259	3.80%	32,500
13	376.1	Mains - Metallic	260,956,707	2.19%	5,714,952
14	376.2	Mains - Plastic	272,622,923	3.02%	8,233,212
15	376.4	Mains - Cathodic Protection	23,205,016	7.15%	1,659,159
16	378	M&R station equipment - general	21,525,164	2.47%	531,672
17	379	M&R station equipment - city gate	5,966,134	1.99%	118,726
18	380.0	Services - Metallic	31,302,372	2.77%	867,076
19	380.5	Services - Plastic	334,858,266	3.49%	11,686,553
20	381	Meters	87,128,287	2.61%	2,274,048
21	381.5	Meters - AMR	10,749,916	6.67%	717,019
22	382	Meter installations	88,052,631	3.14%	2,764,853
23	383	House regulators	14,720,377	2.04%	300,296
24	386	Other Property on Customer Premises	224,125	9.71%	21,763
25		Total Distribution plant	$1,154,097,296		$34,947,850

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Depreciation and Amortization Expense - Proposed Rates
Test Year Ended December 31, 2011

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		General Plant			
1	389.1	Land & Land rights	$1,452,065	0.00%	$0
2	390.1	Structures	29,495,892	1.61%	474,884
3	390.2	Leasehold Improvements (1)	2,600,970	0.00%	0
4	391.1	Office furniture and equipment	5,024,820	4.97%	249,734
5	391.9	Computers and other electronic equipment	6,148,309	14.16%	870,601
6	392	Transportation equipment	20,818,777	5.03%	1,047,185
7	393	Stores equipment	365,166	4.59%	16,761
8	394	Tools, shop and garage equipment	8,071,494	6.66%	537,562
9	395	Laboratory equipment	71,582	6.67%	4,774
10	396	Power operated equipment	11,449,659	6.20%	709,879
11	397	Communications equipment	8,476,045	5.04%	427,193
12	398	Miscellaneous equipment	137,783	5.00%	6,889
13		Total General Plant	$94,112,562		$4,345,460
14		Subtotal	$1,480,983,250		$45,068,981
		Less: Capitalized Depreciation			
15		392 Transportation Equipment			(1,047,185)
16		396 Power Operated Equipment			(709,879)
17		Pro-Forma Depreciation Expense			$43,311,917
18		Less: Annualized Depreciation - Present Rates 10-E			38,856,852
19		Pro-Forma Depreciation Adjustment			$4,455,065

(1) Included in amortization expense

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Taxes Chargeable to Operations
Test Year Ended December 31, 2011

Line No.	Description	Schedule References	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Taxes other than income taxes:				
1	Payroll taxes	11-B	$3,766,328	$76,111	$3,842,440
2	Real estate and personal property taxes	11-B	15,377,655	7,093,533	22,471,188
3	Total other taxes	11-B	156,780	(150,210)	6,570
4	Total taxes other than income taxes		$19,300,763	$7,019,435	$26,320,198
	Income taxes:				
5	Income taxes - current	11-C	($33,224,623.0)	$11,430,429.6	($21,794,193.4)
6	Income taxes - deferred	11-E	49,723,201.0	(15,932,355.0)	33,790,846.0
7	Income taxes - amortization of ITC	11-E	(384,288.0)	0.0	(384,288.0)
8	Total income taxes		$16,114,290.0	($4,501,925.4)	$11,612,364.6
9	Total taxes chargeable to operations		$35,415,053	$2,517,509	$37,932,563

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Taxes Other Than Income Taxes
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Amount Per Books Col. 2	Pro Forma Adjustments (Schedule 9-B) Col. 3	Pro Forma Adjusted Total Col. 4
	Payroll taxes:			
1	Federal payroll taxes	$5,172,322	$76,111	$5,248,434
2	Federal unemployment (FUTA)	63,315	0	63,315
3	State unemployment (SUTA)	118,971	0	118,971
4	Capitalized payroll	(1,588,280)	0	(1,588,280)
5	Total payroll taxes	$3,766,328	$76,111	$3,842,440
6	General Tax Expense	$7,902	($7,902)	$0
7	General Tax Sales Tax Allowance	148,878	(142,308)	6,570
8	Real estate and personal property taxes	15,377,655	7,093,533	22,471,188
	Total non-payroll taxes	$15,534,435	$6,943,323	$22,477,758
9	Total taxes other than income taxes	$19,300,763	$7,019,435	$26,320,198

Line No.	Description Col. 1	Schedule Reference Col. 2	Amount Per Books Col. 3	Pro Forma Adjustments Col. 4	Pro Forma Adjusted Total Col. 5
	Provision for Kansas Income Tax:				
1	Taxable income	11-D	($44,836,281)	($9,479,407)	($54,315,688)
2	Kansas income tax		($3,193,821)	($663,558)	($3,857,379)
3	Adjustments [Provision-to-Return,Temp/Perm]		(2,686,643)	2,686,643	0
4	Kansas current income tax		($5,880,464)	$2,023,085	($3,857,379)
	Provision for Federal Income Tax:				
5	Taxable income		($44,836,281)	($9,479,407)	($54,315,688)
6	Less: Provision for				
	Kansas income tax (Line 2)		(3,193,821)	(663,558)	(3,857,379)
7	Federal taxable income		($41,642,460)	($8,815,848)	($50,458,308)
8	Federal income tax		($14,851,268)	($3,085,547)	($17,936,815)
9	Adjustments [Provision-to-Return,Temp/Perm]		(12,492,892)	12,492,892	0
10	Federal current income tax		($27,344,159)	$9,407,345	($17,936,815)
	Summary of Current Income Taxes				
11	Kansas income tax (Line 4)		($5,880,464)	$2,023,085	($3,857,379)
12	Federal income tax (Line 10)		(27,344,159)	9,407,345	(17,936,815)
13	Total current income taxes		($33,224,624)	$11,430,430	($21,794,193)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Taxable Income
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Schedule References Col. 2	Amount Per Books Col. 3	Pro Forma Adjustments Col. 4	Pro Forma Adjusted Total Col. 5
1	Operating revenues	9-A	$580,077,308	($321,280,743)	$258,796,565
2	Less: Operating expenses (accts. 431 and 432 included)	9-A	452,932,238	(318,314,129)	134,618,109
3	Depreciation and amortization	9-A	49,618,362	1,470,045	51,088,407
4	Taxes other than income taxes	9-A	19,300,763	7,019,435	26,320,198
5	Interest Expense	8-B	19,999,632	(3,056,349)	16,943,283
6	Other income & deductions	8-B	(289,929)	289,929	0
7	Total expenses before income taxes		$541,561,066	($312,591,069)	$228,969,997
8	Operating income before income taxes		$38,516,242	($8,689,674)	$29,826,568
	Increases/(decreases):				
9	Reverse Book Depreciation		$40,527,365	$0	$40,527,365
10	Other CIAC to Income		2,834,575	0	2,834,575
11	Line Ext Dep Rec'd-Net		(6,435)	0	(6,435)
12	Synthetic Lease		224,232	0	224,232
13	Bad Debts		297,765	0	297,765
14	Amortizations		249,986	0	249,986
15	Tight Sands Accrual-Net		(15,072)	0	(15,072)
16	Contingencies/Reserves		(1,087,967)	0	(1,087,967)
17	Pension: Book Accrual		(10,091,837)	0	(10,091,837)
18	OPEB: Book Accrual		(8,494,109)	0	(8,494,109)
19	Cost of Removal		(85,569)	0	(85,569)
20	Purchased Gas Adjustment		(4,587,546)	0	(4,587,546)
21	Tax Depreciation		(103,984,037)	0	(103,984,037)
22	Other (Eliminate below the line other income)		76,393	0	76,393
22	Total Temporary Differences increases/(decreases):		($84,142,256)	$0	($84,142,256)
23	Meal Disallowance - 50%		$159,419	($159,419)	$0
24	Lobbying Expenses		144,615	(144,615)	0
25	Civic Disallowance - 50%		34,034	(34,034)	0
26	Club Memberships		28,276	(28,276)	0
27	Penalty		120	(120)	0
28	Reverse Book Deductible GW		423,269	(423,269)	0
29	Permanent Differences		$789,733	($789,733)	$0
30	Taxable Income (Loss)		($44,836,281)	($9,479,407)	($54,315,688)

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Pro Forma Deferred Income Taxes
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Schedule Reference Col. 2	Amount Per Books Col. 3	Pro Forma Adjustments Col. 4	Pro Forma Adjusted Total Col. 5
	Provision for Deferred Income Taxes :				
1	Reverse Book Depreciation		($16,028,573)	$0	($16,028,573)
2	Other CIAC to Income		(1,121,074)	0	(1,121,074)
3	Line Ext Dep Rec'd-Net		2,545	0	2,545
4	Synthetic Lease		(88,684)	0	(88,684)
5	Bad Debts		(117,766)	0	(117,766)
6	Amortizations		(98,869)	0	(98,869)
7	Salvage Proceeds		0	0	0
8	Tight Sands Accrual-Net		5,961	0	5,961
9	Contingencies/Reserves		430,291	0	430,291
10	Pension: Book Accrual		7,350,742	0	7,350,742
11	Cost of Removal		33,843	0	33,843
12	Purchased Gas Adjustment		1,814,374	0	1,814,374
13	Tax Depreciation		41,125,687	0	41,125,687
14	Other (Eliminate below the line other income)		(30,213)	0	(30,213)
15	Sub-total Provision for deferred income taxes		$33,278,262	$0	$33,278,262
16	Adjustments, Provision/Return Temporary Differences		$15,932,355	($15,932,355)	$0
17	Adjustments, flow thru		359,716	0	359,716
18	Adjustments, flow thru offsets		0	0	0
19	Other		0	0	0
20	Sub-total Provision for deferred income taxes		$49,570,333	($15,932,355)	$33,637,978
21	Deferred investment tax credit		$152,868	$0	$152,868
22	Amortization of investment tax credit		(384,288)	0	(384,288)
23	Investment tax credit - net		($231,420)	$0	($231,420)
24	Total deferred income taxes		$49,338,913	($15,932,355)	$33,406,558

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Book depreciation** Depreciable plant in service is depreciated through account 403 for book purposes. Tax will reverse out the book depreciation expense.	40,527,365	0
2	**Contributions in Aid (CIAC)** Advance payments for a reimbursable construction job after 1986 are treated as contributions to capital for book purposes but are includible as taxable income for tax purposes.	2,834,575	0
3	**Line Extension Deposits - Received** Deposits received from the customers for line extensions are recorded as a deferred credit for book purposes. The deposits are taxable income for ratemaking purposes.	0	6,435
4	**Synthetic Leases** Book has vehicle operating leases which are treated as capital leases for tax purposes. Tax reverses the book synthetic lease expense, but recognizes the interest expense included in the book lease expense.	224,232	0
5	**Bad Debts** Tax reverses the book estimate of bad debt expense, then records a tax deduction for the actual net charge-offs/recoveries.	297,765	0
6	**Amortization-Leasehold Improvements** Cost associated with remodeling company facilities are being amortized for income tax purposes.	249,986	0

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Description of Increases/Decreases to
Operating Income Before Income Taxes
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Tight Sands** Payments are received from Amoco & Oxy and these reimbursements are credited to a deferred credit. As refunds are paid to customers, the refunds are debited to this same account. Book accrues interest expense on these refund payments and debits to an expense account. Tax reverses this interest accrual but deducts the actual interest paid to customers.	0	15,072
2	**Kansas Gas Service Reserve Accounts** Book accrues an expense or revenue each month for various contingent liabilities and deferred revenues. These accruals are reversed for tax purposes. Actual cash payments relating to the contingent liabilities or deferred revenue are recognized as a tax deduction or income for tax purposes.	0	1,087,967
3	**Pension - Book Accrual (FAS 87)** FAS 87 establishes standards for "pension benefits" to employees. The book accrual for pension benefits is reversed for tax purposes.	0	10,091,837
4	**Non-Pension - Book Accrual (Fas 106)** FAS 106 establishes standards for "postretirement benefits" other than pensions to employees. The book accrual for postretirement benefits is reversed for tax purposes.	0	8,494,109
5	**Cost of Removal**	0	85,569
6	**Purchased Gas Adjustment** A public utility that uses the accrual method of accounting is authorized to include fuel charges in its customers' bills for natural gas. The charges may be adjusted monthly and are trued up annually. These estimates are reversed for tax purposes.	0	4,587,546

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Description of Increases/Decreases to
Operating Income Before Income Taxes
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Tax Depreciation** The IRS allows depreciable plant in service to be depreciated for tax purposes at an accelerated rate. Therefore, tax depreciation as computed under IRS guidelines is recognized as a deduction for tax purposes.	0	103,984,037
2	**Other** Other miscellaneous deductions to eliminate below the line other income.	76,393	0
3	**50% Disallowed Meals** Book recognizes meals and entertainment expenses for GAAP purposes. disallow 50% of such expenses are disallowed per IRS guidelines.	159,419	0
4	**Lobbying Expenses** Book recognizes lobbying expenses for GAAP purposes. Lobbying expenses are disallowed per IRS guidelines; therefore, the book entry is reversed out for tax purposes.	144,615	0
5	**Civic Disallowance- 50%** Civic expenses are treated as such for book purposes, but only 50% of those expenses can be recognized as expense for tax purposes.	34,034	0
6	**Club Memberships** Employee costs related memberships in certain social clubs are not deductible for income tax purposes. Any expenses related to these items on the books are reversed for tax and not deductible.	28,276	0

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Tax Penalty** Penalties accrued determined to be non-deductible for tax purposes. The impact on income tax expense for this item has been eliminated.	120	0
2	**Goodwill - Reverse Nondeductible** Tax reverses non-deductible goodwill (permanent) for book purposes related to the Western Resources acquisition.	423,269	0
		45,000,049	128,352,572

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Composite Tax Rate
Test Year Ended December 31, 2011

Line No.	Description Col. 1		Tax Rates Col. 2
1	State Income Tax Rate		7.0000%
2	Federal Income Tax Rate		35.0000%
3	Less: State Tax Deductible for Federal (35.00%*7.00%)		-2.4500%
4	Effective Federal Income Tax Rate		32.5500%
5	Composite Income Tax Rate		39.5500%
6	Inverse Tax Rate (1- 39.5500%)		60.4500%
7	Reciprocal Tax Rate (tax / 1- tax)		65.4260%
8	Tax Gross-up		1.654260
9	Interest expense computation of synchronization:		
10	Rate Base	(Schedule 3A)	$772,431,396
11	Weighted Cost of Debt	(Schedule 7A)	2.1935%
12	Interest Expense		$16,943,283

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Accumulated Deferred Income Taxes
Accrual Charges and Credits to Account 283

Line No.	Year Col. 1	Income Taxes Deferred Col. 2	Credited to Income Col. 3	Adjustments Col. 4	Cumulative Balance Col. 5
1	1997	$104,786,340	($4,802,035)	$4,939,865	$104,924,170
2	1998	1,237,460	(4,227,624)	(2,720,972)	99,213,034
3	1999	(4,275,619)	(376,006)	4,932,767	99,494,176
4	2000	7,343,120	13,303,552	(4,334,787)	115,806,061
5	2001	5,805,215	7,224,635	(6,371,877)	122,464,034
6	2002	18,800,446	15,594,814	(14,345,950)	142,513,344
7	2003	6,564,788	(8,831,752)	(4,323,130)	135,923,250
8	2004	5,779,043	15,460,658	(11,101,266)	146,061,685
9	2005	$5,864,481	$12,675,978	($8,428,449)	$156,173,695

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Accumulated Deferred Income Taxes
Accrual Charges and Credits to Account 283

Line No.	Year	Income Taxes Deferred	Credited to Income	Adjustments	Cumulative Balance
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	2006	$17,646,429	($1,683,508)	($942,000)	$171,194,616
2	2007	7,448,708	(1,743,302)	1,261,054	178,161,076
3	2008	17,521,108	(7,086,508)	(1,110,556)	187,485,120
4	2009	20,682,151	(10,172,617)	36,528,301	234,522,954
5	2010	13,673,583	(4,870,182)	14,161,853	257,488,209
6	2011	35,072,154	(1,793,891)	14,681,666	305,448,137

Line No.	Year	Beginning Balance	Investment Credits Deferred	Credited to Income	Adjustments	Ending Balance
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	1997	$8,083,139	$0	($39,125)	$0	$8,044,014
2	1998	8,044,014	0	(307,981)	0	7,736,033
3	1999	7,736,033	0	(611,742)	0	7,124,291
4	1999SY	7,124,291	0	(180,656)	0	6,943,635
5	2000	6,943,635	0	(536,034)	0	6,407,601
6	2001	6,407,601	0	(501,120)	(247,755)	5,658,726
7	2002	5,658,726	0	(505,388)	457,650	5,610,988
8	2003	5,610,988	0	(444,807)	0	5,166,181
9	2004	5,166,181	0	(514,644)	0	4,651,537
10	2005	$4,651,537	$0	($499,464)	$0	$4,152,073

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Accumulated Deferred Investment Tax Credit
Accrual Charges and Credits to Account 255

Line No.	Year	Beginning Balance	Investment Credits Deferred	Credited to Income	Adjustments	Ending Balance
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	2006	$4,152,073	$0	($484,224)	$0	$3,667,849
2	2007	3,667,849	0	(454,044)	0	3,213,805
3	2008	3,213,805	0	(417,516)	0	2,796,289
4	2009	2,796,289	0	(395,244)	0	2,401,045
5	2010	2,401,045	0	(414,792)	0	1,986,253
6	2011	1,986,253	0	(384,288)	0	1,601,965

Line No.	Description Col. 1	Kansas Gas Service Col. 2	ONEOK, Inc Distribution Companies Col. 3	Kansas Gas Service Percentage Col. 4
	RATIO A - Distrigas Ratio 1007			
1	Gross Plant and Investment	$1,452,770,016	$3,800,674,901	38.22%
2	Operating Income	$89,280,332	$226,439,760	39.43%
3	Labor Expense	$44,283,030	$123,600,821	35.83%
4	Average Percentage			37.83%
	Effective 1st Quarter 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc	Kansas Gas Service Percentage
	RATIO B - Distrigas Ratio 1009			
1	Gross Plant and Investment	$1,452,770,017	$4,169,179,941	34.85%
2	Operating Income	$89,280,332	$357,877,803	24.95%
3	Labor Expense	$44,283,031	$132,112,526	33.52%
4	Average Percentage			31.10%
	Effective 1st Quarter 2011			

Line No.	Description Col. 1	Kansas Gas Service Col. 2	Total Company ONEOK, Inc and ONEOK Partners Col. 3	Kansas Gas Service Percentage Col. 4
	RATIO C - Distrigas Ratio 1011			
1	Gross Plant and Investment	$1,452,770,016	$11,656,997,018	12.46%
2	Operating Income	$89,280,332	$977,649,655	9.13%
3	Labor Expense	$44,283,030	$227,101,705	19.50%
4	Average Percentage			13.70%
	Effective 1st Quarter 2011			

Line No.	Description	Kansas Gas Service	ONEOK, Inc Distribution Companies	Kansas Gas Service Percentage
	RATIO A - Distrigas Ratio 1007			
1	Gross Plant and Investment	$1,458,735,209	$3,840,896,626	37.98%
2	Operating Income	$83,177,648	$217,532,497	38.24%
3	Labor Expense	$44,300,972	$123,480,471	35.88%
4	Average Percentage			37.36%
	Effective 2nd Quarter 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc	Kansas Gas Service Percentage
	Col. 1	Col. 2	Col. 3	Col. 4
	RATIO B - Distrigas Ratio 1009			
1	Gross Plant and Investment	$1,458,735,209	$4,210,548,451	34.64%
2	Operating Income	$83,177,648	$293,589,904	28.33%
3	Labor Expense	$44,300,972	$132,040,759	33.55%
4	Average Percentage			32.18%
	Effective 2nd Quarter 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc and ONEOK Partners	Kansas Gas Service Percentage
	RATIO C - Distrigas Ratio 1011			
1	Gross Plant and Investment	$1,458,735,209	$11,402,847,040	12.79%
2	Operating Income	$83,177,648	$940,898,643	8.84%
3	Labor Expense	$44,300,972	$226,544,110	19.56%
4	Average Percentage			13.73%
	Effective 2nd Quarter 2011			

Line No.	Description Col. 1	Kansas Gas Service Col. 2	ONEOK, Inc Distribution Companies Col. 3	Kansas Gas Service Percentage Col. 4
	RATIO A - Distrigas Ratio 1007			
1	Gross Plant and Investment	$1,468,654,906	$3,895,471,142	37.70%
2	Operating Income	$75,608,449	$206,071,993	36.69%
3	Labor Expense	$44,844,990	$123,880,902	36.20%
4	Average Percentage			36.86%
	Effective 3rd Quarter 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc	Kansas Gas Service Percentage
	RATIO B - Distrigas Ratio 1009			
1	Gross Plant and Investment	$1,468,654,906	$4,268,261,076	34.41%
2	Operating Income	$75,608,449	$275,759,019	27.42%
3	Labor Expense	$44,844,990	$132,437,465	33.86%
4	Average Percentage			31.90%
	Effective 3rd Quarter 2011			

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Allocation Ratios
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Kansas Gas Service Col. 2	Total Company ONEOK, Inc and ONEOK Partners Col. 3	Kansas Gas Service Percentage Col. 4
	RATIO C - Distrigas Ratio 1011			
1	Gross Plant and Investment	$1,468,654,906	$11,708,814,711	12.54%
2	Operating Income	$75,608,449	$988,413,367	7.65%
3	Labor Expense	$44,844,990	$228,541,483	19.62%
4	Average Percentage			13.27%
	Effective 3rd Quarter 2011			

		Kansas Gas Service	ONEOK, Inc Distribution Companies	Kansas Gas Service Percentage
	RATIO A - Distrigas Ratio 1007			
1	Gross Plant and Investment	$1,482,853,225	$3,950,243,204	37.54%
2	Operating Income	$74,206,918	$205,792,150	36.06%
3	Labor Expense	$44,941,170	$124,128,959	36.21%
4	Average Percentage			36.60%
	Effective 4th Quarter 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc	Kansas Gas Service Percentage
	Col. 1	Col. 2	Col. 3	Col. 4
	RATIO B - Distrigas Ratio 1009			
1	Gross Plant and Investment	$1,482,853,225	$4,327,295,411	34.27%
2	Operating Income	$74,206,918	$255,743,319	29.02%
3	Labor Expense	$44,941,170	$132,701,798	33.87%
4	Average Percentage			32.38%
	Effective 4th Quarter 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc and ONEOK Partners	Kansas Gas Service Percentage
	RATIO C - Distrigas Ratio 1011			
1	Gross Plant and Investment	$1,482,853,225	$12,100,332,305	12.25%
2	Operating Income	$74,206,918	$1,060,209,620	7.00%
3	Labor Expense	$44,941,170	$230,008,084	19.54%
4	Average Percentage			12.93%
	Effective 4th Quarter 2011			

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Allocation Ratios
Test Year Ended December 31, 2011

Line No.	Description Col. 1	Kansas Gas Service Col. 2	ONEOK, Inc Distribution Companies Col. 3	Kansas Gas Service Percentage Col. 4
	RATIO A - Distrigas Ratio 1007			
1	Gross Plant and Investment	$1,482,853,225	$3,949,579,668	37.54%
2	Operating Income	$74,206,918	$205,070,563	36.19%
3	Labor Expense	$44,941,170	$120,730,191	37.22%
4	Average Percentage			36.99%
	Effective December 1, 2011			
		Kansas Gas Service	Total Company ONEOK, Inc	Kansas Gas Service Percentage
	RATIO B - Distrigas Ratio 1009			
1	Gross Plant and Investment	$1,482,853,225	$4,326,631,875	34.27%
2	Operating Income	$74,206,918	$255,021,732	29.10%
3	Labor Expense	$44,941,170	$129,303,030	34.76%
4	Average Percentage			32.71%
	Effective December 1, 2011			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc and ONEOK Partners	Kansas Gas Service Percentage
	Col. 1	Col. 2	Col. 3	Col. 4
	RATIO C - Distrigas Ratio 1011			
1	Gross Plant and Investment	$1,482,853,225	$12,099,668,770	12.26%
2	Operating Income	$74,206,918	$1,059,488,032	7.00%
3	Labor Expense	$44,941,170	$226,609,317	19.83%
4	Average Percentage			13.03%
	Effective December 1, 2011			

Line No.	Description	Kansas Gas Service	ONEOK, Inc Distribution Companies	Kansas Gas Service Percentage
	RATIO A - Distrigas Ratio 1007			
1	Gross Plant and Investment	$1,503,622,764	$4,008,547,915	37.51%
2	Operating Income	$67,610,190	$197,550,011	34.22%
3	Labor Expense	$45,047,914	$121,087,870	37.20%
4	Average Percentage			36.31%
	Effective 1st Quarter 2012			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc	Kansas Gas Service Percentage
	Col. 1	Col. 2	Col. 3	Col. 4
	RATIO B - Distrigas Ratio 1009			
1	Gross Plant and Investment	$1,503,622,764	$4,388,408,220	34.26%
2	Operating Income	$67,610,190	$222,272,766	30.42%
3	Labor Expense	$45,047,914	$130,708,456	34.46%
4	Average Percentage			33.05%
	Effective 1st Quarter 2012			

Line No.	Description	Kansas Gas Service	Total Company ONEOK, Inc and ONEOK Partners	Kansas Gas Service Percentage
	RATIO C - Distrigas Ratio 1011			
1	Gross Plant and Investment	$1,503,622,764	$12,569,850,489	11.96%
2	Operating Income	$67,610,190	$1,184,602,506	5.71%
3	Labor Expense	$45,047,914	$228,359,728	19.73%
4	Average Percentage			12.47%
	Effective 1st Quarter 2012			

Line No.	Description Col. 1	Allocation Basis Col. 2	1st Quarter 2012 Percentage Col. 3
1	Power Plant	Gross PP&E	13.63%
2	Banner	Percentage of total customers as compared to all ONEOK Distribution Companies	30.26%
3	Dynamic Risk	Miles of Pipe	17.70%
4	Riskworks	Payroll Pro-rata	1.00%
5	ODC Executive	Evenly allocated between ONEOK Distribution Companies	33.33%
6	Billing Control	Percentage of KGS customers as compared to all ONEOK Distribution customers	30.26%
7	OKE Human Resources	Budgeted Headcount	21.74%
8	Maximo	User count	12.90%

Effective January 1, 2012

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Casual Allocation Ratios
Test Year Ended December 31, 2011

Allocation Percentages for 2011

Line No.	Description Col. 1	1st Quarter 2011 Col. 2	2nd Quarter 2011 Col. 3	3rd Quarter 2011 Col. 4	4th Quarter 2011 Col. 5
1	Power Plant	13.69%	14.72%	14.36%	14.04%
2	Banner	30.31%	30.31%	30.31%	30.31%
3	Dynamic Risk	17.70%	17.70%	17.70%	17.70%
4	Riskworks	1.00%	1.00%	1.00%	1.00%
5	ODC Executive	33.33%	33.33%	33.33%	33.33%
6	Billing Control	30.31%	30.31%	30.31%	30.31%
7	OKE Human Resources	21.74%	21.74%	21.74%	21.74%

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Labor Capitalization Ratio
Test Year Ended December 31, 2011

Line No.	Labor Capitalization Ratio for KGS	Labor	Labor % to Total
	Col. 1	Col. 2	Col. 3
1	Labor Expensed	$47,864,802	73.74%
2	Labor Capitalized	$17,047,152	26.26%
3	Total KGS	$64,911,954	

THIS SECTION CONTAINS THE 2011 ANNUAL REPORT

TOGETHER, WE ARE ONEOK.

ONEOK, INC. 2011 ANNUAL REPORT

- ONEOK, Inc. is the sole general partner and 43.4* percent owner of ONEOK Partners, L.P., a publicly traded master limited partnership engaged in the natural gas gathering and processing, natural gas pipelines and natural gas liquids businesses.
- ONEOK is three natural gas distribution companies serving more than 2 million customers in Oklahoma, Kansas and Texas.
- ONEOK is an energy services company marketing natural gas and related services to local distribution companies, industrial customers and power generators.

FINANCIAL HIGHLIGHTS

Year Ended December 31	2011	2010	2009
Consolidated financial information (millions of dollars)			
Net margin	$ 2,380.4	$ 2,062.2	$ 1,998.0
Operating income	$ 1,158.9	$ 942.7	$ 882.9
Net income	$ 759.7	$ 541.3	$ 491.2
Net income attributable to ONEOK, Inc.	$ 360.6	$ 334.6	$ 305.5
Total assets	$ 13,696.6	$ 12,499.2	$ 12,827.7
Stand-alone financial information**			
Debt capitalization	45 %	40 %	46 %
Capital expenditures (millions of dollars)	$ 272.7	$ 230.0	$ 175.6
Common stock data			
Shares outstanding at year-end	103,254,980	106,815,582	105,906,776
Data per common share			
Net earnings – basic	$ 3.44	$ 3.15	$ 2.90
Net earnings – diluted	$ 3.36	$ 3.10	$ 2.87
Dividends paid	$ 2.16	$ 1.82	$ 1.64
Market price range			
High	$ 86.70	$ 55.69	$ 44.57
Low	$ 55.38	$ 40.62	$ 18.19
Year-end	$ 86.69	$ 55.47	$ 44.57
Number of employees	4,795***	4,839	4,758

** As of March 2, 2012*

*** Excluding ONEOK Partners*

**** As of January 31, 2012*

LETTER TO SHAREHOLDERS

STRENGTH THROUGH UNITY

The phrase on the cover of this annual report – *Together, We Are ONEOK* – sounds good. But what do the words mean? And do they really matter?

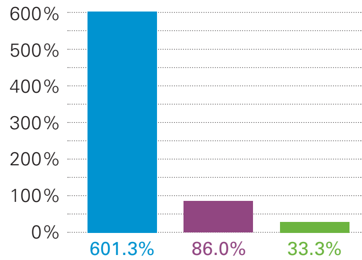
These questions can be answered, in part, by:

- Going back six years to see our vision of the future;
- Taking a look at what we've achieved since then;
- Previewing the level of performance and growth we expect to generate for you, our shareholders, in 2012 and beyond; and
- Describing the mutually beneficial relationship between ONEOK and our powerful growth engine, ONEOK Partners.

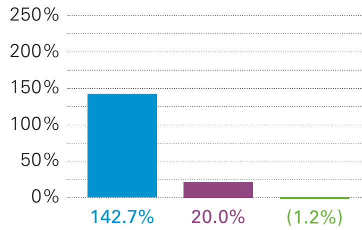
Prior to initial trading under the ONEOK Partners name in May 2006, we said that this new chapter in ONEOK's century of energy experience would provide shareholders with "immediate and long-term value." We explained that ONEOK Partners would be able to execute growth at a lower cost of capital because of the distinct tax structure of a master limited partnership. We also said that ONEOK's stock would become "more clearly valued."

This was only part of our expectations.

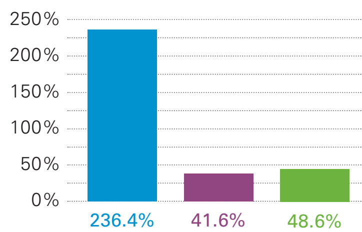
10-YEAR TOTAL RETURN*



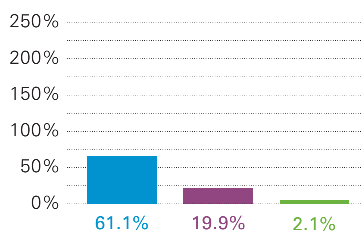
5-YEAR TOTAL RETURN*



3-YEAR TOTAL RETURN*



1-YEAR TOTAL RETURN*



ONEOK, Inc.

S&P 500 Utilities

S&P 500 Index

As of December 31, 2011

** Total return represents share-price appreciation and the reinvestment of dividends.*

We focused our skills and talents within the midstream natural gas and natural gas liquids (NGL) energy value chain, stretching from the wellhead to key markets and end-users. The natural gas and NGL assets and our team of people – including groups with a deep understanding of supply-and-demand dynamics on both ends of the pipeline – would enable us to deliver midstream solutions that generated long-term value to our customers and investors. One business would build off another. And new growth would open the way for still more, again and again.

This, in a nutshell, was our future vision of how ONEOK would create value for its shareholders.

Since then – from 2005 to January 2012 – our annualized dividend to ONEOK shareholders has more than doubled to $2.44 per share from $1.12; the share price has more than tripled to more than $88.00 from $26.63; and our total asset base has increased to $13.7 billion from $10.0 billion.

I'm pleased to report that ONEOK's 2011 performance was, overall, excellent.

And the future remains as bright as our past.

In January, a 9-percent increase in the quarterly dividend was announced. We expect to increase the dividend 50 percent by 2014 – when all of ONEOK Partners' large NGL and natural gas gathering and processing projects are in service for a full year. The partnership's current growth program, its second in five years, will total approximately $3 billion.

Incremental income from the partnership's current slate of projects will be the driving force behind those anticipated increases. More than half of the partnership's total $3 billion growth program will be invested in and related to the Bakken Shale play in the Williston Basin. There, its natural gas gathering and processing business' well-established service reputation with producers has opened great opportunities, not only for itself but also for its NGL business.

We also expect our natural gas distribution business to continue to improve operating income performance through steady rate-base growth, efficient capital allocation and operating efficiencies.

We remain on target with our cost-rebasing efforts at energy services, our natural gas marketing business, which has experienced an extremely challenging environment created by historically low natural gas prices and an absence of price volatility. It's our smallest business, accounting for approximately 2 percent of ONEOK operating income in 2011.

We were financially strong when our relationship with ONEOK Partners first began. We are much stronger today. Our investment-grade credit ratings, proven track record, excellent free cash flow and – most important – our reputation for *doing what we say we will do* keep the financial passageways open to capital-investment opportunities.

When we meet with shareholders and financial analysts, often we are asked about acquisition possibilities or what our next "big move" might be. Ideally, we would like to find an acquisition opportunity like we did nearly seven years ago when we bought the NGL business in the Mid-Continent. We've grown that business into one of the largest NGL midstream operations in the entire country – and now ONEOK Partners' largest income producer.

Such opportunities, however, are few and far between. And the returns on our internal-growth projects are much more attractive than the price tags we continue to see on acquisition prospects.

Our structure at ONEOK is working – providing us with increased cash and earnings from the growth at ONEOK Partners; it also gives us flexibility in terms of how we deploy that cash. We can make additional investments in the partnership (we own 43.4* percent), continue to increase our dividend and repurchase our own stock. Last August, we completed a $300 million repurchase of common shares as a part of a $750 million board-authorized program that concludes at year-end 2013.

When the partnership's current internal-growth program concludes in 2014, capital investments in the partnership will total well over $5 billion since we became sole general partner in 2006. At this time, we're surveying a "backlog" of more than $1 billion in additional growth opportunities, which we expect will continue to grow – and be funded – as we secure supply commitments from producers, processors or customers.

The most powerful definition and meaning of *Together, We Are ONEOK* resides with the nearly 4,800 men and women who make ONEOK and ONEOK Partners work – every day. Because we provide the management and the employees for the partnership, *they are us*. Our disciplines, values and goals are one and the same.

A former ONEOK leader many years ago observed that we are "in a constant state of becoming." This still remains true today as, together, we strive toward *Becoming ONE. ONE in*

** As of March 2, 2012*

SUCCESSION PLANNING AT WORK

Several key promotions became effective on January 1 of this year. Terry K. Spencer began serving as president of ONEOK and ONEOK Partners. He formerly was the chief operating officer of ONEOK Partners. Pierce H. Norton II began new duties as executive vice president and chief operating officer of ONEOK and ONEOK Partners. He formerly was chief operating officer of ONEOK. Robert F. Martinovich, formerly senior vice president, chief financial officer and treasurer of both companies, began serving as executive vice president, chief financial officer and treasurer of ONEOK and ONEOK Partners.

Responsibility. ONE in Value. ONE in Industry. Our dedicated drive toward these goals will be a continual process, just as it is in our expanded environmental, safety and health efforts, where we are making good progress – and have more work to do.

Numerous and diverse employee- and leadership-development efforts are under way throughout our organization. These efforts will sharpen our competitive edge, favorably impact our bottom line and deliver still-greater value to ONEOK shareholders. In January, three members of our senior management team were promoted to key positions as a part of our long-term succession-planning efforts to ensure that ONEOK has the leadership skills, talent and experience required for the rapid pace forward in the years ahead. (See sidebar on page 3.)

I hope that you are as excited about ONEOK's future as we are. We are grateful for, and mindful of, your continued trust and confidence in ONEOK.

John W. Gibson

John W. Gibson
Chairman and Chief Executive Officer
March 2, 2012

CLASSIFIED BOARD LEGISLATION

The Oklahoma legislature in 2012 amended the statute passed in 2010 that required all large, publicly traded companies that are incorporated in Oklahoma to have classified, or staggered, boards of directors. As a result, all ONEOK directors will be elected annually.

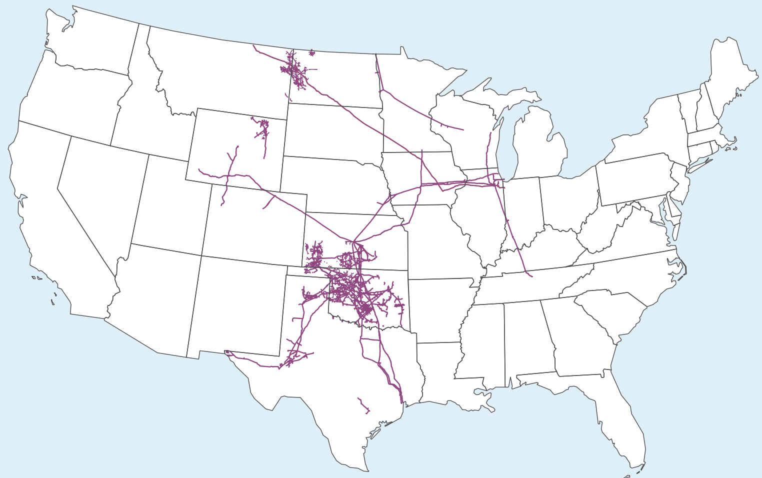
As you know, in 2008 our board recommended the elimination of our then existing classified board and the institution of the annual election of directors. This recommendation was approved overwhelmingly by our shareholders, and our certificate of incorporation was amended accordingly.

We are pleased that the legislature took this most recent action, as we continue to believe that your decision as a shareholder to have an annual election of all directors is consistent with best practices in corporate governance.

ONEOK ASSETS

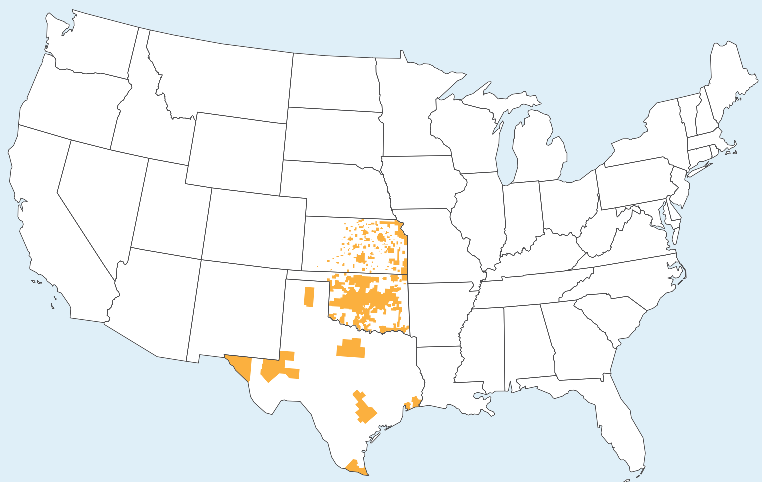
ONEOK PARTNERS

Natural Gas and
Natural Gas Liquids Assets



ONEOK NATURAL GAS DISTRIBUTION

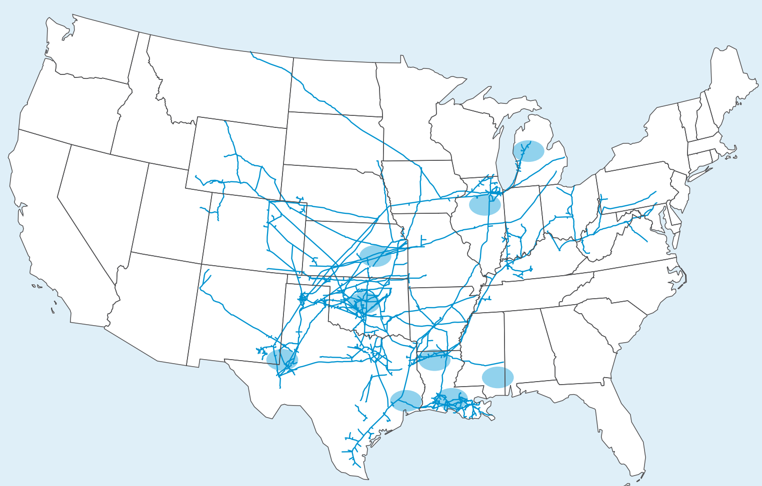
Natural Gas Distribution Assets



ONEOK ENERGY SERVICES

Leased Pipeline Capacity

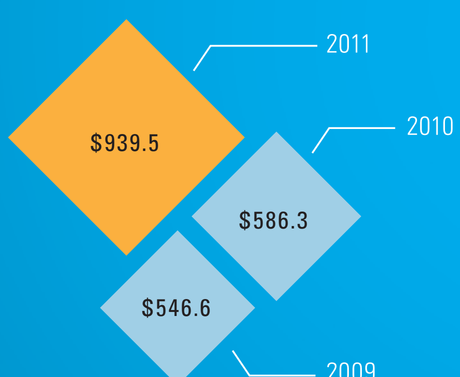
Leased Storage Capacity



ONEOK PARTNERS

OPERATING INCOME

MILLIONS OF DOLLARS



Variances:

- $363.6 million increase from higher optimization margins in the natural gas liquids business as a result of more favorable NGL price differentials and additional fractionation and transportation capacity available between the Mid-Continent and Gulf Coast markets.
- $32.6 million increase due to higher net realized NGL and condensate prices in the natural gas gathering and processing business.
- $32.5 million increase from higher NGL volumes gathered and fractionated in the natural gas liquids business.
- $26.4 million increase from higher isomerization margins.
- $19.4 million increase due to higher natural gas volumes processed in the Williston Basin.
- $42.8 million decrease from the deconsolidation of Overland Pass Pipeline Company.

CREATING VALUE THROUGH TEAMWORK

ONEOK Partners is our primary growth engine and largest business. We own 43.4* percent of the partnership and, as the general partner, manage and operate the assets.

The partnership strives to deliver consistent growth and sustainable earnings by connecting supplies of natural gas and natural gas liquids (NGLs) to key markets. Its disciplined growth is focused on building and integrating assets that provide exceptional value to customers, investors and other stakeholders on a long-term basis.

The partnership is in its second major growth phase since ONEOK became the sole general partner and a substantial owner in 2006. The first phase, which concluded in 2009, involved major projects, expansions and improvements totaling more than $2 billion. The current growth program – expected to total approximately $3 billion – got under way in 2011 and will continue through 2014.

We have secured multiyear supply commitments for all of the projects, whose capacities in most cases are already fully subscribed. The first of these projects was completed in December 2011, and several more are scheduled to be in service in 2012. Roughly two-thirds of the investment total is directed to the NGL business; the other one-third to the natural gas gathering and processing business.

Planned capital expenditures for 2012 are approximately $2 billion, the largest single-year investment in the partnership's history.

Over the past six years, the partnership's growth has come predominantly from internal projects that have expanded its footprint and integrated existing assets. We continue to look at acquisition opportunities, but they must be priced right and provide a platform for future growth. We remain disciplined and selective when looking at these opportunities – our most recent acquisition was in 2007.

Exceptional Value Creation

Since 2006, ONEOK Partners has increased the distribution to its unitholders by 53 percent – raising it in 21 of the last 24 quarters. Total cash distributions to ONEOK in 2011 were $333 million, representing a 10-percent increase over 2010. The 2011 amount includes $197 million from our limited partner interest and $136 million from our general partner interest.

Partnership distributions are expected to increase by 2.5 cents per unit each quarter in 2012 and grow *annually* by 15 to 20 percent in 2013 and 2014 when all of the announced projects are in service.

These increased cash distributions help ONEOK increase dividends to its shareholders. We expect to increase ONEOK's dividend by 50 percent over the 2011 to 2014 time period, based on the projected earnings and distribution growth at the partnership, combined with performance results at our natural gas distribution and energy services business segments.

Top-Down Tour

A top-down tour of the partnership's current $3 billion growth program reveals its strategic scope and value, which broaden and improve the partnership's natural gas liquids and natural gas gathering and processing businesses. The virtual tour begins in two states bordering Canada and concludes 1,400 miles south on the Texas Gulf Coast.

** As of March 2, 2012*

More than half of the $3 billion growth program is related to the Williston Basin's Bakken Shale in western North Dakota and eastern Montana. It's among the largest crude-oil plays in the nation, which also produces associated natural gas that's rich in NGLs. Approximately 2,000 wells were completed in the Bakken Shale in 2011 alone.

The partnership's natural gas gathering and processing business is working to keep pace with producer requirements in the Bakken Shale. It is investing approximately $1 billion for three new natural gas processing plants, nearly quadrupling its processing capacity there, and for well connections, gathering systems and compression facilities, as well as other infrastructure improvements.

The first of these new processing plants, Garden Creek, was completed in December 2011; the second one, Stateline I, is scheduled to start up in the third quarter of 2012; and the third, Stateline II, is expected to be on line in the first half of 2013. It takes 18 to 24 months to complete each of these processing plants, which are fabricated primarily in Tulsa, transported and assembled on site. Processing capacities at the Garden Creek and Stateline I plants are fully committed, and we expect the Stateline II facility soon will be.

Strong Production Economics

The natural gas gathering and processing business is ideally positioned to serve the intensely active play in the Williston Basin, having served producers there for a number of years prior to this recent crude-oil boom.

ONEOK Partners is the largest independent natural gas gatherer and processor in the basin. Williston Basin producers have dedicated their production from more than 1.9 million acres to the partnership's systems and services. These acreage dedications help ensure that the partnership will continue benefiting from the drilling activity. We expect the Williston Basin to deliver approximately 39 percent of this business segment's total gathered volumes by 2014 – the first full year of operation for *all* of the new processing plants – compared with 16 percent in 2011.

Currently, there is a backlog of Bakken Shale wells shut in and waiting for development of natural gas gathering and processing infrastructure. These wells otherwise would be flaring the natural gas and NGLs. Some producing wells, however, are still flared due to the lack of natural gas gathering and processing infrastructure. The partnership's new processing plants, and those of third parties, will serve to protect the environment and boost the economy as they reduce and eventually eliminate the flaring and deliver value from the natural gas stream. In 2011, ONEOK Partners connected approximately 600 new wells – predominantly in the Williston Basin – compared with approximately 300 in 2010.

During the next several years, we expect that production in the Williston and other basins served by ONEOK Partners' natural gas gathering and processing business will more than offset declines experienced in the "dry-gas" Powder River Basin in Wyoming. Dry-gas production contains very little or no NGLs, making this production less valuable and much less attractive to new drilling at the prevailing low natural gas prices. The partnership's natural gas gathering and processing business has approximately 2,000 contracts – with small, medium and large producers – and operates in six major basins, providing supply diversity and volume-growth opportunities.

Economic drivers for producers in the Bakken Shale play are predominantly crude oil, making up roughly 91 percent of the value. NGLs provide about 6 percent of the value; and natural gas accounts for approximately 3 percent of the total. Drilling remains attractive at crude-oil prices far lower than current prices, helping to ensure continued incremental production of this NGL-rich natural gas.

Synchronized Completions

There is sufficient interstate pipeline capacity to accommodate the Bakken Shale's current natural gas volumes, including the partnership's 50-percent-owned Northern Border Pipeline, which will transport much of the processed natural gas to Midwest markets. That's not the case with the NGLs, whose access to markets is limited currently to more costly and less reliable rail and truck transportation.

In the first half of 2013, we anticipate that the new Bakken Pipeline will begin transporting unfractionated NGLs from the partnership's new natural gas processing plants in the Willston Basin. Construction is scheduled to begin in the second quarter of 2012. Completion of the Bakken Pipeline, estimated to cost from $450 million to $550 million, will allow processors to economically extract ethane – a feedstock in high demand by the petrochemical industry.

Construction of two other NGL projects are being completed to handle the volume from this 525-mile, 60,000-barrel-per-day (bpd) NGL pipeline.

They are:

- The 50-percent-owned Overland Pass Pipeline, which went into service in 2008, will be expanded by 60,000 bpd to accommodate the Williston Basin NGLs. The partnership's share of this expansion cost is approximately $35 million to $40 million. The Bakken Pipeline will interconnect in northern Colorado with the Overland Pass Pipeline, which delivers to the partnership's Bushton, Kansas, fractionation and storage complex.

- Bushton's NGL fractionation capacity also will be expanded by 60,000 bpd, at a cost ranging from $110 million to $140 million, to accommodate the unfractionated Williston Basin NGL barrels. Once fractionated, NGL purity products will be transported on the partnership's fully integrated NGL system, arriving at the Conway, Kansas, and Mont Belvieu, Texas, NGL market centers. Some of these NGL purity products also will travel up the Midwest as far north as the Chicago area on the partnership's North System, an NGL and refined petroleum products pipeline with multiple storage and delivery facilities along the pipeline's route.

More NGL Supplies

We are expanding the partnership's Mid-Continent NGL infrastructure in the highly active Cana-Woodford Shale and Granite Wash production areas of western Oklahoma and the Texas Panhandle. This $180 million to $240 million project, which includes construction of 230 miles of NGL pipelines, will provide access to approximately 80,000 NGL bpd from three new and three expanded third-party natural gas processing plants. These barrels will be transported on the Arbuckle Pipeline to the partnership's NGL fractionation and storage facilities at Mont Belvieu, Texas, as well as to other fractionators.

The Cana-Woodford/Granite Wash expansion projects are scheduled for service early in the second quarter of 2012, when we also will complete the related 60,000 bpd expansion of the Arbuckle Pipeline, which was placed in service in 2009.

The Arbuckle Pipeline transports unfractionated NGLs from the partnership's Mid-Continent infrastructure, accesses additional unfractionated NGLs from the Arkoma-Woodford Shale in southeastern Oklahoma and the Barnett Shale in north Texas, and delivers them to fractionation and storage facilities on the Texas Gulf Coast. The expansion will bring the pipeline up to its full design capacity of 240,000 bpd.

Curtis Dinan *President, Natural Gas*

"The recent completion of the Garden Creek natural gas processing plant in North Dakota further solidifies our position as the midstream provider of choice in the Bakken Shale. With the scheduled completion of two additional plants in the next year and a half, we will continue to benefit from natural gas volume growth in this important region."

Optimizing Product Value

The strong "push" from NGL supplies continues to be balanced by an equally strong "pull" from robust demand for NGL products. The complete decoupling of crude-oil and natural gas prices several years ago (which make NGL feedstocks more economical to the petrochemical industry), combined with abundant supplies of natural gas from a multitude of shale plays, has resulted in increased demand for NGLs. About half of the unfractionated NGL barrel is ethane, which has a significant price advantage over petroleum-based feedstocks.

With ONEOK Partners' vertically integrated and strategically located assets, it is able to optimize the value of the NGL purity products by capturing price differentials between the Conway and Mont Belvieu markets. Ethane price differentials were historically high in 2011, averaging 28 cents per gallon, compared with 10 cents the previous year. During the late fall of 2011, the Mid-Continent-to-Gulf Coast price differentials reached more than 50 cents per gallon of ethane.

Through 2013, ONEOK Partners will invest from $910 million to $1.2 billion in projects to accommodate the growing NGL supplies in the Mid-Continent and elsewhere, while alleviating infrastructure constraints experienced between the Conway and Mont Belvieu markets. These projects include:

- Constructing a 570-mile pipeline – Sterling III – that can transport either unfractionated NGLs *or* NGL purity products from the Mid-Continent to the Texas Gulf Coast. Initial capacity on this new pipeline, due to be completed in late 2013, will be 193,000 bpd and can be expanded to 250,000 bpd. The Sterling III Pipeline will traverse the NGL-rich Arkoma-Woodford Shale play and provide additional transportation capacity for NGL production from the Cana-Woodford Shale and Granite Wash developments.

- Reconfiguring the existing Sterling I and Sterling II NGL distribution pipelines to transport either unfractionated NGLs or NGL purity products. Currently, these pipelines only transport NGL purity products. In November 2011, the partnership expanded capacity on the Sterling I Pipeline.

- Building a new 75,000 bpd fractionator – MB-2 – at Mont Belvieu, Texas. This plant, due for completion in mid-2013, is estimated to cost from $300 million to $390 million, and can be expanded to 125,000 bpd.

The partnership owns and operates an 80-percent interest in a 160,000 bpd fractionator, MB-1, at Mont Belvieu. In the second quarter of 2011, it gained direct access to an additional 60,000 bpd of fractionation capacity, also at Mont Belvieu, through a 10-year fractionation-services agreement with a third party. Fractionation capacity remains tight on the partnership's system and throughout the NGL industry in general.

Cost estimates for the construction of Sterling III and reconfigurations of the existing Sterling pipelines range from $610 million to $810 million.

The three pipelines, combined with expanded capacity on the Arbuckle Pipeline, will provide greater capacity, operational flexibility and redundancy between the partnership's Mid-Continent NGL infrastructure and the Texas Gulf Coast. This means greater service and fewer delays for petrochemical customers, who are expanding their facilities or converting them to use price-advantaged NGL feedstocks.

Sheridan Swords *President, Natural Gas Liquids*

"When completed and connected to our existing integrated NGL system, our current growth projects will enable us to access additional NGLs from liquids-rich regions and enhance our full-service capabilities."

Performance Highlights

ONEOK Partners' operating income increased by 60 percent in 2011, rising to a record $939.5 million. Here is a snapshot of the business-unit's performance:

- The partnership's natural gas gathering and processing business benefited primarily from higher net realized NGL and condensate prices and incremental natural gas volumes processed in the Williston Basin. During the year, approximately 600 new wells were connected to its systems, compared with approximately 300 in 2010, and processed volumes rose by 6 percent.

- ONEOK Partners' natural gas pipelines business, composed of interstate and intrastate pipelines and storage facilities, experienced lower transportation margins, primarily due to narrower natural gas price location differentials that reduced contracted transportation capacity on Midwestern Gas Transmission and reduced interruptible transportation volumes across several of its pipelines. Approximately 85 percent of this business' margin is from firm-demand contracts with utilities and industrial customers. The 50-percent-owned Northern Border Pipeline performed well, due primarily to higher contracted transportation volumes resulting from wider location price differentials between the markets it serves.

- The partnership's natural gas liquids business benefited primarily from exceptionally wide NGL price differentials between Conway, Kansas, and Mont Belvieu, Texas; increased NGL fractionation and transportation capacity available for that optimization activity; and higher overall gathered and fractionated volumes. Gathered volumes rose by 15 percent, and fractionated volumes increased by 5 percent.

Outlook

Driven by volumes from projects completed in this current growth program, ONEOK Partners' *annual* EBITDA (earnings before interest, taxes, depreciation and amortization), operating income and distributable cash flow are expected to increase substantially from 2012 through 2014.

The remarkable and disciplined growth continues to result in new opportunities as we expand the partnership's footprint and capacities. We currently are reviewing a backlog of additional growth opportunities totaling in excess of $1 billion.

We expect the natural gas gathering and processing business to increase its new well connections dramatically this year, primarily in the Williston Basin, and its year-over-year gathered and processed volumes will continue to grow.

ONEOK Partners' natural gas pipelines business is expected to continue to provide stable income and solid cash flow. Significant business-growth opportunities are expected to emerge if federal emission rules force power-generation utilities to retire coal-fired plants or convert existing plants to much cleaner-burning natural gas rather than undergo expensive emission-reduction upgrades.

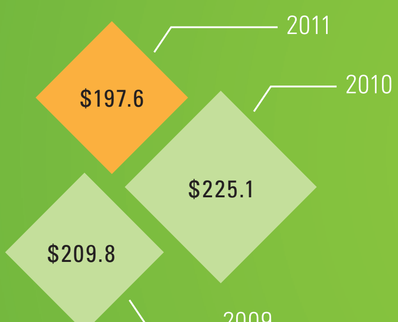
We anticipate that the NGL business will continue to set new-record levels of gathered and fractionated volumes during this year and beyond.

Prolific natural gas production from shale plays is beginning to change how this country views its uses of energy and holds the possibility of lowering our country's dependence on foreign oil. Advanced horizontal drilling and hydraulic fracturing technologies unlocking these vast shale natural gas reserves (and NGLs) are also delivering impressive volumes from conventional fields.

The Mississippian Lime, a promising crude-oil and NGL-rich conventional resource under development in southern Kansas and northern Oklahoma, and the Niobrara Shale in the Rockies are expected to demand new midstream services and are readily within our reach. When fully developed, these regions may provide increased connection opportunities for the partnership's existing infrastructure.

NATURAL GAS DISTRIBUTION

OPERATING INCOME
MILLIONS OF DOLLARS



Variances:

- Operating costs increased due to share-based compensation costs and employee-related incentive and benefit costs.

ALIGNED STRATEGY DRIVES COMPETITIVE ADVANTAGE

Our natural gas distribution business segment again delivered solid results in 2011, reflecting successful rates and risk-mitigation strategies, combined with targeted capital investments that provide value to our customers and investors. This business segment – composed of Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service – strives to maintain its competitive advantage by providing customers with safe, reliable and value-added services while operating efficiently.

This business segment provides sustainable earnings and excellent cash flow. The 12-percent operating income decline in 2011 is due primarily to share-based compensation awarded to the 2,800 employees who serve more than 2 million natural gas customers in Oklahoma, Kansas and Texas. Throughout ONEOK, one share of stock was given to eligible employees each time the closing share price rose by one dollar, which occurred 31 times in 2011. Our natural gas distribution segment has the largest number of employees and bore the largest portion of this expense.

Kansas Rate Case Being Prepared

Kansas Gas Service will file a rate case in 2012, our first filed there since May 2006. This new rate case will seek to, among other things, reduce earnings risk by increasing fixed charges.

Residential sales accounted for 67 percent of our margins. Of these, 73 percent are based on fixed fees, while the rest are based on volumetric fees. In Kansas, 49 percent of margins are based on volumes, compared with 13 percent in Oklahoma and 19 percent in Texas.

Because of the 240-day waiting period before new rates can take effect, the new Kansas rates are expected to impact earnings in 2013.

In Oklahoma and in most of our Texas service areas, annual rate reviews are allowed, providing for adjustments as necessary. Oklahoma Natural Gas operates under a dynamic, performance-based rate structure approved in late 2009. Texas Gas Service operates in 10 "home-rule" jurisdictions, which involve local regulatory bodies and include an appeals process at the state level.

We are the largest natural gas distributor in Oklahoma and Kansas, serving 836,000 and 632,000 customers, respectively. We are the third largest in Texas, with 621,000 customers, including service to Austin and El Paso.

Building on Success

Since 2006, operating income from this business – the eighth largest natural gas utility in the United States – has nearly doubled as a result of our unified efforts across the three operating divisions to:

- Reduce the regulatory lag-time associated with return on capital investments and increases in operating expenses;
- File rate cases more frequently, which results in more appropriate and timely returns while also avoiding customer "rate-shock" associated with large rate cases filed less frequently; and
- Increase efficiencies and maintain volumes across our assets.

During the past two years we have, in aggregate, delivered results at or near our allowed rate of return, essentially closing the gap between actual and allowed returns. That's a significant achievement, reflecting many changes and improvements. Going forward, we are focused on earning our allowed returns through capital expenditures – and timely regulatory filings – that provide safety, reliability, efficiency and value. These activities will grow our rate base and improve productivity, which allows us to reduce operating expenses.

Utilizing the Powerful Choice

We understand that customers *must* use electricity in homes, businesses and industries. The *choice* to use natural gas makes great economic and environmental sense. The current natural gas environment – with increasingly abundant supplies and historically low prices – further strengthens our natural gas distribution business segment's competitive advantage over electric power.

We expect the economic and environmental advantages of natural gas to become even more prominent over the next several years as environmental compliance issues bear heavily on electric utilities – particularly those with coal-fired power plants.

The advantages of natural gas over electricity are powerful. Here are a few examples:

- Natural gas is a bargain. When a kilowatt of energy is theoretically transformed into an equivalent Dekatherm of energy, natural gas enjoys a two-to-one retail-cost advantage – or greater – in most of our service territories.* That's important, especially when tens of millions of Americans are struggling to make ends meet.

- Natural gas, the cleanest of all the fossil fuels, is the most efficient form of fuel for 50 percent of a home's total energy needs.** In a full-cycle analysis, an all-electric home is only 27-percent energy efficient *before* it begins using the electricity. That's because 73 percent of the total energy has been lost generating the electricity and moving it over the transmission lines. By contrast, natural gas appliances – ranges, furnaces, water heaters and clothes dryers – receive 90 percent of the original energy.

- The average natural gas home emits 46 percent less carbon dioxide – a greenhouse gas that increases global warming – than an all-electric home.***

In September 2011, Oklahoma Natural Gas introduced a three-year, annually renewable energy-efficiency program offering attractive rebates on natural gas furnace checkups and on new natural gas furnaces, water heaters and clothes dryers – three of the four primary natural gas *touch points* in the home. Texas Gas Service also provides incentives and rebates in the Austin area. These programs strengthen our competitive advantage by ensuring our customers continue to choose natural gas as appliances are replaced in existing homes and new homes are built.

Judy Scott *Kansas Gas Service Meter Reader*

"The availability of automated meter-reading devices has decreased the mental and physical stress of daily meter reading. Not having to enter yards with unsafe access to the meter helps us complete our workday safely and with less stress."

** Source: Energy Information Administration*
*** Source: U.S. Department of Energy*
**** Source: Environmental Protection Agency*

CNG as a Transportation Fuel

With compressed natural gas (CNG) gaining more attention and support for use as a transportation fuel, we often are asked about our position and role in this market. We strongly support CNG, having used it in our Oklahoma fleet vehicles for many years but have no plans to enter the CNG retail marketing business. Our natural gas pipeline systems place us in an ideal position to *distribute* natural gas to CNG retail outlets within our service territories as demand increases and service opportunities arise. The annual energy usage of a CNG vehicle is generally equivalent to the amount of energy consumed in an average home.

The CNG transportation-fuel market is growing. Conversion of vehicle fleets to CNG from diesel and gasoline fuels is increasing. Motorists using this alternative fuel report annual cost savings of 50 percent or greater.*

CNG growth, however, is constrained by an absence of new-vehicle choices and a lack of fill stations, which thwarts CNG-vehicle purchases. Only one major car manufacturer currently offers a CNG-dedicated vehicle.

Our Kansas Gas Service division in 2011 assisted the Kansas City, Kansas, public school district as it introduced 47 CNG-fueled buses into its fleet, replacing nearly one-third of the district's diesel bus fleet. Kansas Gas Service served as an information resource for the school district throughout the project and completed necessary infrastructure upgrades, including an on-site fueling station. Kansas Gas Service currently delivers the natural gas to the school district's CNG fueling facility.

The environmental impact resulting from the converted buses equates to 1,700 fewer cars on the road and the elimination of 150,000 pounds of greenhouse gases every year.

Oklahoma Natural Gas has been using CNG in its work vehicles since 1990 and makes its 27 fill stations available to the public. At year-end 2011, there were fewer than 70 CNG fill sites in Kansas, Oklahoma and Texas; most of those are in Oklahoma.

It's More Than a Slogan

A year ago, we introduced ONEOK's *Becoming ONE* initiative that began in our natural gas distribution business segment and was spreading through the rest of the organization. Since then, it's become a successful branding tool. ONEOK employees are featured in our television commercials, telling the public how we are driven to become *"ONE in Responsibility, ONE in Value and ONE in Industry."*

Becoming ONE was always meant to be more than a catchy slogan. Here in the natural gas distribution business segment, we have developed a program that will help us align technology, the organization and our processes – how we think, decide and act – to create long-term competitive advantages that are driven by doing what is best for employees, shareholders, customers and the public. We intend to be the best natural gas distributor in the nation – by a variety of measures.

Our planned capital expenditures for 2012 are $270 million, including an estimated $40 million increase for pipeline-integrity and reliability programs. Installation of automated meter-reading devices, which increase safety and accuracy while reducing operating costs, will continue in 2012 – the third year for that program.

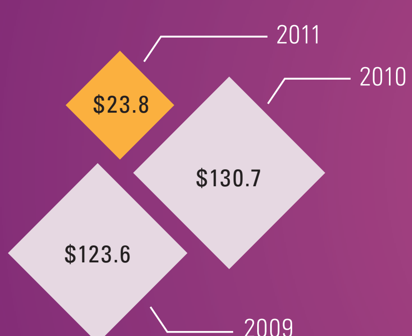
Exiting the Retail Natural Gas Marketing Business

In February 2012, we sold a subsidiary, ONEOK Energy Marketing Company, to Constellation Energy Group for $22.5 million plus working capital, after determining that retail natural gas marketing was no longer a core business to ONEOK. ONEOK Energy Marketing Company provides physical and financial natural gas products and services to retail customers primarily located in the Mid-Continent and Texas. The business was accounted for in the natural gas distribution business segment.

** Source: Consumer Reports*

ENERGY SERVICES

OPERATING INCOME
MILLIONS OF DOLLARS



Variances:

- $65.3 million decrease in transportation margins, net of hedging, due primarily to narrower realized natural gas price location differentials.
- $34.3 million decrease in storage and marketing margins, net of hedging, due primarily to lower realized seasonal natural gas storage price differentials.
- $7.3 million decrease in premium-services margins.

WORKING TOGETHER TO ADDRESS A CHALLENGING MARKET

Working in the most challenging natural gas marketing environment in a decade, our energy services business segment in 2011 produced results substantially below the earnings range we set more than two years ago as we initiated a multiyear cost-reduction program.

Historically low and stable natural gas prices – combined with greater availability, deliverability options and fierce competition – pressured margins across all aspects of this business. The primary drivers of the current market conditions are abundant supplies from natural gas shale plays across the country and interstate pipeline capacity increases in recent years, which have resulted in extremely narrow (and sometimes nonexistent) transportation margins between locations.

While energy services' 2011 results are disappointing, they have become an increasingly smaller percentage of ONEOK's total operating income, approximately 2 percent in 2011.

Rebasing Our Cost Structure

Late in 2009, we began reducing costs by lowering leased storage and transportation capacities while continuing to meet the needs of our premium-services customers. Representing the core of our business, these premium-services customers primarily are natural gas and electric-generation utilities, which pay a premium for callable, on-demand delivery of natural gas to meet their peaking requirements.

As contract terms allow, we are reducing our leased storage capacity to 65 billion cubic feet (Bcf) by the end of 2012 from 83 Bcf in 2009 and reducing our leased long-term transportation capacity to 1 Bcf per day by the end of 2012 from 1.5 Bcf per day in 2009. From 2012 through 2015, 78 percent of our current transportation contracts and 88 percent of our storage contracts will come up for renegotiations, allowing us the opportunity to achieve significant savings over this four-year time frame either through contract renegotiations at lower rates and shorter terms, or through non-renewals without affecting service to our premium-services customers.

The Work Ahead

As we continue to rebase our cost structure over the next several years, we will focus on:

- Retaining existing premium-services customers and attracting new ones. We have long-term relationships with these customers and maintain a 95-percent retention rate;
- Maximizing earnings through optimization activities that capture niche opportunities;
- Growing our market share with power-generation customers, including those facing compliance issues with existing coal-fired plants, by utilizing the ample-supply, low-cost and low-emission advantages of natural gas; and
- Working innovatively with natural gas producers to transport their supplies to market from transportation-constrained areas.

While reducing our costs going forward will help improve our performance, market conditions will continue to challenge this business.

Chris Snedden *Director of Origination, Mid-Continent*

"An oversupplied natural gas market has led to lower natural gas prices and reduced volatility – creating an increasingly challenging environment. However, we remain focused on providing reliable products and premium services to our expanding customer base."

FINANCIAL OVERVIEW

SUSTAINABLE GROWTH, STRONG BALANCE SHEET

Our continued earnings and cash flow growth has allowed us to increase the dividends we pay to our shareholders. In 2011, we increased the quarterly dividend in 4-cent increments on two separate occasions. In January 2012, we increased the dividend by 5 cents per share, and in February 2012, we announced that we intend to increase the dividend by another 5 cents per share in July 2012, subject to ONEOK board approval – higher than the 4-cent-per-share guidance increase we provided in September 2011 – reflecting strong earnings and cash generation at our ONEOK Partners and natural gas distribution segments.

The dividend has more than doubled since January 2006, and we expect it to grow an additional 50 percent by 2014, primarily as a result of the incremental earnings generated from the partnership's internal-growth program. Distribution increases at ONEOK Partners of 2.5 cents per quarter in 2012 will translate into approximately $100 million of incremental cash to ONEOK in 2012 because of our unit-ownership position and general partner interest.

Our balance sheet is strong, and our ability to access the capital markets has never been better.

In April 2011, we entered into a five-year, $1.2 billion unsecured revolving credit facility with a group of banks. The new credit facility replaced a $1.2 billion, five-year revolver that was scheduled to mature in June 2011. The new credit facility is being used to support our commercial paper program, working capital requirements and other general corporate purposes.

In August 2011, ONEOK completed a $300 million accelerated share-repurchase agreement under the company's previously approved three-year stock-repurchase program that runs through 2013 and received 4.3 million shares. The company's board of directors authorized the company to buy up to $750 million of the company's issued and outstanding common stock, subject to the limitation that purchases will not exceed $300 million in any one calendar year.

In January 2012, we issued $700 million in 4.25 percent senior notes due in 2022, using these proceeds to repay amounts outstanding under our $1.2 billion commercial paper program and for general corporate purposes, which may include one or more of the following: repurchase of ONEOK common stock under a previously approved share-repurchase program; purchase of additional common units of ONEOK Partners; and the payment of dividends.

In February 2012, the company's board of directors authorized a two-for-one stock split of ONEOK common stock, subject to shareholder approval, that will be voted on at the company's 2012 annual meeting on May 23, 2012, putting our stock price in a more attractive trading range for our investors. If approved, the additional shares are expected to be distributed on or about June 1, 2012.

In March 2012, we purchased 8.0 million common units from ONEOK Partners in a private placement that provided $459.8 million to the partnership. We also paid $19.1 million to maintain our 2-percent general partner interest. With this transaction, we increased our ownership in the partnership to 43.4* percent.

ONEOK Partners also completed a public offering of 8.0 million common units. The partnership expects to use the net proceeds from the common-unit public offering and private placement to repay amounts outstanding under its $1.2 billion commercial paper program, to repay amounts on the maturity of its $350 million 5.9 percent senior notes due April 2012, for capital expenditures and for other general partnership purposes.

ONEOK maintains an investment-grade credit rating and a strong balance sheet. At year-end 2011, our stand-alone debt-to-capitalization ratio was 45 percent.

** As of March 2, 2012*

CORPORATE RESPONSIBILITY

ONE TEAM, ONE GOAL

Over the last several years, as we have grown our business and operational footprint, we have also strengthened our commitment to improve our companywide environmental, safety and health (ESH) performance.

As we continue to grow, it becomes even more important for us to keep our focus in the right place – on our stakeholders and on our mission to operate reliably, safely and responsibly.

The following key ESH objectives drove our progress in 2011 and will serve as a guide for future ESH performance. By 2013, we will work to:

- Accomplish a 50-percent rate reduction from our 2009 safety performance in key areas (Total Recordable Incident Rate, Preventable Vehicle Incident Rate, agency-reportable events and pipeline hits);
- Achieve business-segment ESH performance in the top 25 percent of our peer companies;
- Develop initiatives to reduce our environmental footprint;
- Implement an ESH management system companywide;
- Establish a behavior-based safety program companywide;
- Review company resource use, such as water, electricity and fuel;
- Expand companywide ESH policies, procedures and training programs;
- Establish formal ESH audit and risk-assessment programs; and
- Establish an *interdependent* ESH culture, in which employees work together to strengthen and sustain company ESH initiatives.

These goals are components of our three-year ESH vision, developed by our Environment, Safety and Health Leadership Committee with input from business-unit leaders across the company. By setting these specific goals, we expect to build on the progress we have already made and will continue to make ESH improvements a priority.

A Focus on Safety

Our increased focus on safety is already contributing to improvements in our company's safety performance. In 2011, we decreased our Total Recordable Incident Rate by more than 15 percent and our Preventable Vehicle Incident Rate and number of agency-reportable events by nearly 20 percent each from our 2010 totals.

While we are pleased with these improvements and believe they represent progress across the company, we aren't focused only on statistics. Low incident rates alone can't prevent a large-scale incident. For this reason, we continue to focus on establishing and improving preventive safety programs, such as near-miss reporting, vehicle-safety monitoring and pipeline-integrity management.

In 2010, we introduced a behavior-based safety pilot program designed to reduce unsafe individual behaviors and prevent accidents. The program, which began with approximately 700 employees from our three natural gas distribution companies, teaches employees to identify and choose safe behaviors over unsafe behaviors by following a process of observation, discussion and positive reinforcement. Because of the pilot's success, we are now rolling out the program to additional natural gas distribution employees – nearly 1,800 employees across three states.

Our near-miss reporting system allows employees to report narrowly avoided incidents. The reported information serves as a resource for sharing lessons learned across the company and is an important learning tool for preventing future incidents. By proactively identifying and communicating the risks our employees are exposed to, we can limit potential incidents.

Business units across ONEOK participate regularly in safety-training exercises. Some are required annually, such as training on Occupational Safety and Health Administration (OSHA) standards, but many are developed and conducted by our own employees as a way to share best practices among work groups.

Our Oklahoma Natural Gas employees held safety conferences in early 2011 that provided hands-on safety training to nearly 1,000 field employees across its operating footprint. Our ONEOK Partners' natural gas pipelines business participated in a large-scale, emergency-response drill with local emergency responders, held a conference for business-unit safety representatives and provided more than 20,000 total hours of ESH training for its employees in 2011.

In early 2012, we plan to roll out our newly developed Environment, Safety and Health Management System Framework, which clearly defines ONEOK's ESH operating expectations and provides employees and business segments a roadmap for reaching ESH goals. This framework replaces and enhances our Operations Compliance Management Program and serves as the foundation of our companywide commitment to managing ESH risks and achieving excellence in ESH performance.

Pipeline Safety

We operate more than 70,000 miles of natural gas and natural gas liquids (NGL) pipelines in more than 16 states, and our business footprint continues to grow. Pipeline safety remains a significant priority for ONEOK. Focusing on accident prevention along our pipelines and on maintenance at our facilities and assets is an important part of reducing the risk of incidents.

We design, install, test and maintain new pipelines to meet federal and state regulations and industry standards. Our pipeline control centers monitor our pipelines 24 hours a day, seven days a week, and we conduct pipeline inspections according to federally required assessment time frames. Inspection techniques vary depending on the size and type of pipeline. We regularly use pressure testing, direct assessments and in-line inspection methods to examine and test the integrity of our pipelines.

In early 2012, new federal pipeline safety legislation was signed into law that will require enhanced safety, reliability and environmental protection measures for transporting oil, natural gas and NGLs by pipelines. As a result of this legislation, we expect expanded regulatory oversight, including new regulations for monitoring our pipelines.

Our compliance-audit program is another way we identify potential risks to our assets and the likelihood of an identified incident occurring. In early 2011, we redesigned this program to make it risk based rather than schedule based, helping us prioritize our audit schedules and focus on assets with the most potential ESH risk. In 2011, more than 25 ESH program and facility audits were conducted companywide.

Environmental Impact

We understand the potential impact our business operations can have on the environment, but we also recognize the environmental benefits of using natural gas relative to other types of energy. We believe the key is to find a balance and to continue focusing on taking steps to minimize those impacts.

Global concerns surrounding greenhouse gas emissions and the environment continue to be at the forefront of many government regulations. We continue to look for ways to reduce our environmental impact and help our customers do the same.

Our ONEOK Partners and natural gas distribution business segments also actively participate in the Environmental Protection Agency's Natural Gas STAR Program to reduce methane emissions. In 2010, ONEOK Partners was named the program's natural gas gathering and processing partner of the year.

Two of our natural gas distribution companies, Oklahoma Natural Gas and Texas Gas Service, participate in conservation and efficiency programs that offer customers rebates on natural gas appliances and energy-efficient home improvements.

Community Investments

We live in the communities where we operate, and we understand the importance of contributing to those communities – making them better places to live and do business. In 2011, our employees volunteered more than 9,000 hours to organizations in their communities.

Primary focus areas for our community investments are education, health and human services, arts and culture, and community improvement. We give priority consideration to educational programs and to health and human services organizations, particularly those with programs that help people become self-sufficient.

In 2011, the ONEOK Foundation contributed approximately $2.4 million in grants to support nonprofit organizations throughout our operating areas. Some grants approved in 2011 include:

- A technology boardroom for business students and support for the Shark Tank senior project program at Oral Roberts University in Tulsa, Oklahoma;

- A state-of-the-art natural gas compression training center at the Oklahoma State University Institute of Technology Energy Center in Okmulgee, Oklahoma;

- A contribution to Paso del Norte Children's Development Center in El Paso, Texas, to expand its services by renovating its current facility and building an additional one;

- A contribution to TLC Children and Families for a capital campaign to build the Families Institute and Wellness Center in Overland Park, Kansas;

- A contribution to the Trail Foundation of Austin, Texas, for its capital campaign to complete the trail by Lady Bird Lake;

- A contribution to the Food Bank of Rio Grande Valley in McAllen, Texas, for its capital campaign to purchase and renovate a new facility;

- A contribution to the Philbrook Museum of Art in Tulsa, Oklahoma, for a program that offers free public admission on the second Saturday of every month; and

- A state-of-the-art video board and technology upgrades at the University of Tulsa's Reynolds Center in Tulsa, Oklahoma.

Additionally, ONEOK gave $3.6 million in corporate contributions to support local nonprofit organizations, including funding flood-relief efforts in Minot, North Dakota, and donating to the Mont Belvieu, Texas, fire department for the purchase of a new ladder truck.

To strengthen our presence across our operating footprint, we have developed the "Powered by ONE" mobile unit – part of a new community education project. The mobile unit will travel throughout our operating areas sharing information about our company, how we operate, our ESH commitment and other industry-related facts.

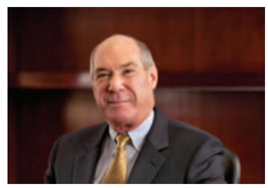
The mobile unit, which is partially powered by compressed natural gas, will be unveiled in the spring of 2012 and is expected to visit more than 20 communities across our operating footprint throughout the remainder of the year.

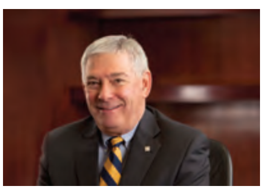
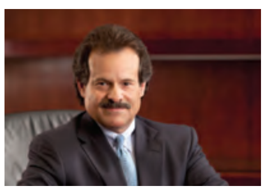
BOARD OF DIRECTORS

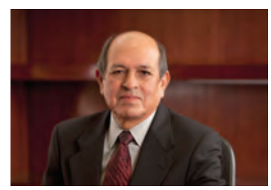










James C. Day
Retired Chairman,
Noble Corporation
Sugar Land, Texas

Bert H. Mackie
Trustee, Hamm Financial Group; *Vice Chairman,*
Security National Bank
Enid, Oklahoma

Gary D. Parker
President, Moffitt, Parker & Company, Inc.
Muskogee, Oklahoma

Julie H. Edwards
Former Chief Financial Officer, Southern Union Company; *Former Chief Financial Officer,* Frontier Oil Corporation
Houston, Texas

Steven J. Malcolm
Retired Chairman, President and Chief Executive Officer, The Williams Companies, Inc.
Tulsa, Oklahoma

Eduardo A. Rodriguez
President, Strategic Communications Consulting Group
El Paso, Texas

William L. Ford
President, Shawnee Milling Company
Shawnee, Oklahoma

Jim W. Mogg
Retired Chairman, DCP Midstream GP, L.L.C.
Hydro, Oklahoma

Gerald B. Smith
Chairman, Chief Executive Officer and Co-founder,
Smith, Graham & Company Investment Advisors L.P.
Houston, Texas

John W. Gibson
Chairman and Chief Executive Officer,
ONEOK, Inc. and ONEOK Partners, L.P.
Tulsa, Oklahoma

Pattye L. Moore
Chairman, Red Robin Gourmet Burgers;
Owner, Pattye L. Moore & Associates
Oklahoma City, Oklahoma

David J. Tippeconnic
Chief Executive Officer,
Arrow-Magnolia International, Inc.
Dallas, Texas

OFFICERS

ONEOK, INC. OFFICERS

John W. Gibson, 59
Chairman and Chief Executive Officer

Terry K. Spencer, 52
President

Pierce H. Norton II, 51
Executive Vice President and Chief Operating Officer

Robert F. Martinovich, 54
Executive Vice President, Chief Financial Officer and Treasurer

Stephen W. Lake, 48
Senior Vice President, General Counsel and Assistant Secretary

Derek S. Reiners, 40
Senior Vice President and Chief Accounting Officer

Robert S. Mareburger, 50
Senior Vice President, Corporate Planning and Development

David E. Roth, 56
Senior Vice President, Administrative Services

Dandridge L. Harrison, 58
Vice President, Investor Relations and Public Affairs

ONEOK NATURAL GAS DISTRIBUTION COMPANIES

Caron A. Lawhorn, 50
President

Kansas Gas Service Company
Bradley O. Dixon, 58
President

Oklahoma Natural Gas Company
Gregory A. Phillips, 48
President

Texas Gas Service Company
Kari L. French, 54
President

ONEOK ENERGY SERVICES

Patrick J. McDonie, 51
President

Charles M. Kelley, 53
Senior Vice President

ONEOK PARTNERS

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Chairman and Chief Executive Officer

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President

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Executive Vice President and Chief Operating Officer

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Senior Vice President, General Counsel and Assistant Secretary

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Senior Vice President, Operations

Derek S. Reiners, 40
Senior Vice President and Chief Accounting Officer

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Senior Vice President, Corporate Planning and Development

David E. Roth, 56
Senior Vice President, Administrative Services

Dandridge L. Harrison, 58
Vice President, Investor Relations and Public Affairs

CHAIRMAN EMERITUS

C.C. Ingram
ONEOK, Inc.
Tulsa, Oklahoma

Ages as of December 31, 2011

FORM 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

_X_ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011.
OR
__ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission file number **001-13643**

ONEOK, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1520922**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

Securities registered pursuant to Section 12(b) of the Act:

Common stock, par value of $0.01	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one) Large accelerated filer X Accelerated filer __ Non-accelerated filer __ Smaller reporting company __

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes__ No X

Aggregate market value of registrant's common stock held by non-affiliates based on the closing trade price on June 30, 2011, was $7.3 billion.

On February 14, 2012, the Company had 103,893,790 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 23, 2012, are incorporated by reference in Part III.

ONEOK, Inc.
2011 ANNUAL REPORT

As used in this Annual Report, references to “we,” “our” or “us” refer to ONEOK, Inc., an Oklahoma corporation, and its predecessors and subsidiaries, unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report are defined as follows:

AFUDC...Allowance for funds used during construction
Annual Report...Annual Report on Form 10-K for the year ended December 31, 2011
ASU ....Accounting Standards Update
Bbl ....Barrels, 1 barrel is equivalent to 42 United States gallons
Bbl/d ....Barrels per day
BBtu/d..Billion British thermal units per day
Bcf ....Billion cubic feet
Bcf/d ....Billion cubic feet per day
Btu(s) ....British thermal units, a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit
Bushton Plant..Bushton Gas Processing Plant
CFTC ....Commodities Futures Trading Commission
Clean Air Act..Federal Clean Air Act, as amended
Clean Water Act ....Federal Water Pollution Control Act Amendments of 1972, as amended
Dodd-Frank Act..Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
EBITDA..Earnings before interest expense, income taxes, depreciation and amortization
EPA...United States Environmental Protection Agency
Exchange Act..Securities Exchange Act of 1934, as amended
FASB ....Financial Accounting Standards Board
FERC ....Federal Energy Regulatory Commission
GAAP ....Accounting principles generally accepted in the United States of America
Guardian Pipeline ....Guardian Pipeline, L.L.C.
Intermediate Partnership.............................ONEOK Partners Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
IRS..Internal Revenue Service
KCC..Kansas Corporation Commission
KDHE ....Kansas Department of Health and Environment
LDCs...Local distribution companies
LIBOR ....London Interbank Offered Rate
MBbl...Thousand barrels
MBbl/d..Thousand barrels per day
Mcf ....Thousand cubic feet
MDth/d..Thousand dekatherms per day
Midwestern Gas Transmission....................Midwestern Gas Transmission Company
MMBbl ....Million barrels
MMBtu ....Million British thermal units
MMBtu/d ....Million British thermal units per day
MMcf..Million cubic feet
MMcf/d...Million cubic feet per day
Moody’s..Moody’s Investors Service, Inc.
Natural Gas Act ....Natural Gas Act of 1938, as amended
Natural Gas Policy Act ....Natural Gas Policy Act of 1978, as amended
NGL products ....Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
NGL(s)..Natural gas liquid(s)
Northern Border Pipeline............................Northern Border Pipeline Company
NYMEX..New York Mercantile Exchange
NYSE..New York Stock Exchange
OBPI ....ONEOK Bushton Processing, L.L.C., formerly ONEOK Bushton Processing, Inc.
OCC..Oklahoma Corporation Commission
ONEOK ....ONEOK, Inc.
ONEOK 2011 Credit Agreement................ONEOK’s five-year, $1.2 billion revolving credit agreement dated April 5, 2011
ONEOK Credit Agreement.........................ONEOK’s amended and restated $1.2 billion revolving credit agreement dated July 14, 2006
ONEOK Partners ....ONEOK Partners, L.P.

ONEOK Partners 2011 Credit Agreement...ONEOK Partners' five-year, $1.2 billion revolving credit agreement dated August 1, 2011
ONEOK Partners Credit Agreement...........ONEOK Partners' $1.0 billion amended and restated revolving credit agreement dated March 30, 2007
ONEOK Partners GP ....ONEOK Partners GP, L.L.C., a wholly owned subsidiary of ONEOK and the sole general partner of ONEOK Partners
OPIS ....Oil Price Information Service
OSHA ....Occupational Safety and Health Administration
Overland Pass Pipeline Company................Overland Pass Pipeline Company LLC
Quarterly Report(s).....................................Quarterly Report(s) on Form 10-Q
POP...Percent of Proceeds
RRC ....Railroad Commission of Texas
S&P...Standard & Poor's Rating Services
SEC...Securities and Exchange Commission
Securities Act...Securities Act of 1933, as amended
Viking Gas Transmission.............................Viking Gas Transmission Company
XBRL..eXtensible Business Reporting Language

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations and assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, "Risk Factors," and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation and "Forward-Looking Statements," in this Annual Report.

PART I

ITEM 1. BUSINESS

GENERAL

We are a diversified energy company and successor to the company founded in 1906 known as Oklahoma Natural Gas Company. We are a corporation incorporated under the laws of the state of Oklahoma and our common stock is listed on the NYSE under the trading symbol "OKE." We are the sole general partner and own 42.8 percent of ONEOK Partners, L.P. (NYSE: OKS), one of the largest publicly traded master limited partnerships. ONEOK Partners is a leader in the gathering, processing, storage and transportation of natural gas in the United States. In addition, ONEOK Partners owns one of the nation's premier natural gas liquids systems, connecting NGL supply in the Mid-Continent and Rocky Mountain regions with key market centers. We are the largest natural gas distributor in Oklahoma and Kansas and the third largest natural gas distributor in Texas, providing service as a regulated public utility to wholesale and retail customers. Our largest distribution markets are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita and Topeka, Kansas; and Austin and El Paso, Texas. Our energy services business is engaged in providing premium natural gas marketing services to its customers across the United States.

EXECUTIVE SUMMARY

North American natural gas production continues to increase at a faster rate than demand, primarily as a result of increased production from unconventional resource areas, such as shale plays. Because of the relatively higher market prices of crude oil and NGLs, drilling activity is especially robust in shale plays with crude oil and NGL-rich natural gas production. As a result, we expect producers to focus development efforts on crude oil and NGL-rich supply basins rather than areas with dry natural gas production. We expect inter-regional opportunities for midstream infrastructure development driven by producers who need to connect emerging production with end use markets where current infrastructure is either insufficient or nonexistent.

In 2011, producers continued to drill aggressively in a number of NGL-rich resource plays in the Mid-Continent and Rocky Mountain regions, creating a need for additional infrastructure to bring this new supply to market. The resulting increase in natural gas supply has caused lower natural gas prices, less volatility and narrower natural gas location and seasonal price differentials in the markets we serve.

Additionally, we have seen strong ethane demand from the petrochemical sector in the Gulf Coast, due to the price advantage ethane has over other feedstocks. Consequently, NGL pipeline capacity between the Conway, Kansas, and Mont Belvieu, Texas, market centers is constrained and contributes to wider location price differentials between those markets. The natural gas supply growth has also increased NGL supply in the Mid-Continent, coupled with increased demand in the Gulf Coast, resulting in decreased NGL prices in the Mid-Continent market center at Conway, Kansas, relative to prices in the Gulf Coast market center at Mont Belvieu, Texas.

Additional fractionation and pipeline capacity is needed to accommodate the growing NGL supply and demand, as well as new infrastructure to gather, process and transport growing natural gas production from both new and existing resource plays. In response to this increased production and demand for NGL products, ONEOK Partners is investing approximately $2.7 billion to $3.3 billion in new capital projects to meet the needs of oil and natural gas producers in the Bakken Shale, the Cana-Woodford Shale and the Granite Wash areas, and for additional NGL infrastructure in the Mid-Continent and Gulf Coast areas that will enhance the distribution of NGL products to meet the increasing petrochemical industry and NGL export demand. When completed, ONEOK Partners expects these projects to provide additional earnings and cash flows.

During 2011, we paid cash dividends of $2.16 per share, an increase of approximately 18.7 percent from the $1.82 per share paid during 2010. In January 2012, we declared a dividend of $0.61 per share ($2.44 per share on an annualized basis), an increase of approximately 17.3 percent from the $0.52 declared in January 2011.

During 2011, ONEOK Partners paid cash distributions to its limited partners of $2.325 per unit, an increase of approximately 4.3 percent from the $2.23 per unit paid during 2010. In January 2012, a cash distribution to ONEOK Partners' limited partners of $0.61 per unit ($2.44 per unit on an annualized basis) was declared, an increase of approximately 7.0 percent from the $0.57 declared in January 2011.

In January 2012, we completed an underwritten public offering of $700 million of 4.25-percent senior notes due 2022. The net proceeds from the offering, after deducting underwriting discounts and estimated expenses, of approximately $693.9 million were used to repay amounts outstanding under our $1.2 billion commercial paper program and for general corporate purposes, which may include one or more of the following: the repurchase of our common stock, the purchase of additional common units of ONEOK Partners and the payment of dividends.

During 2011, we relied primarily on operating cash flow, commercial paper and distributions from ONEOK Partners to fund our short-term liquidity and capital requirements, repay $400 million of maturing senior notes and redeem $90.5 million of 6.4-percent senior notes. In January 2011, ONEOK Partners completed an underwritten public offering of senior notes generating net proceeds of approximately $1.28 billion. ONEOK Partners utilized proceeds from its January 2011 debt issuance, its cash from operations and its commercial paper program, to repay $225 million of its maturing senior notes and to fund its capital projects and short-term liquidity needs.

In December 2011, we entered into a definitive agreement to sell ONEOK Energy Marketing Company to Constellation Energy Group, Inc. for $22.5 million plus working capital. The transaction closed on February 1, 2012. The financial information of ONEOK Energy Marketing Company is reflected as discontinued operations in this Annual Report. All prior periods presented have been recast to reflect the discontinued operations.

We anticipate that our cash flow generated from operations, existing capital resources, including proceeds from the issuance of our $700 million 4.25-percent senior notes issued in January 2012, and distributions from ONEOK Partners will enable us to maintain our current level of operations, our planned operations and fund the remainder of our three-year, $750 million stock repurchase program. ONEOK Partners anticipates that its cash flow generated from operations, existing capital resources and ability to obtain financing will enable it to maintain its current level of operations and its planned operations. Additionally, ONEOK Partners expects to fund its capital expenditures with short- and long-term debt, the issuance of equity and operating cash flows.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, for more information on our growth projects, results of operations, liquidity and capital resources.

BUSINESS STRATEGY

Our primary business strategy is to deliver consistent growth and sustainable earnings, while focusing on safe, reliable and environmentally responsible operations for our customers, employees, contractors and the public through the following:

- Operate in a safe, reliable and environmentally responsible manner - environmental, safety and health issues continue to be a primary focus for us; our emphasis on personal and process safety has produced improvements in the key indicators we track. We also continue to look for ways to reduce our environmental impact by conserving resources and utilizing more efficient technologies;
- Generate consistent growth and sustainable earnings - during 2011, ONEOK Partners' cash distributions increased by 9.5 cents, an approximate 4.3-percent increase compared with 2010; ONEOK Partners is investing approximately $2.7 billion to $3.3 billion in new capital projects to meet the needs of oil and natural gas producers in the Bakken Shale, the Cana-Woodford Shale and the Granite Wash areas, and to provide additional NGL infrastructure in the Mid-Continent and Gulf Coast areas that will enhance its ability to distribute NGL products to meet the increasing petrochemical industry and NGL export demand. When completed, these projects are anticipated to provide additional earnings and cash flows. Our Natural Gas Distribution segment benefits from rate strategies, including a performance-based rate mechanism in Oklahoma, capital-recovery mechanisms in Kansas and portions of Texas and cost-of-service adjustments in certain Texas jurisdictions that address investments in rate base and changes in expense; our Natural Gas Distribution segment's operating efficiencies include investments in automated meters in Oklahoma and Texas. Our Energy Services segment has undertaken several steps to realign fixed costs with its current business environment, including attempts to renegotiate various storage and transportation agreements and continuing to realign its contracted storage and transportation capacity with its customers' premium-service requirements;
- Execute strategic acquisitions that provide long-term value - we remain a disciplined buyer of assets and continue to evaluate assets that come to market. We did not consummate any acquisitions in 2011;
- Manage our balance sheet to maintain strong credit ratings - our balance sheet remains strong, ending 2011 with a capital structure of 45-percent debt and 55-percent equity, excluding the debt of ONEOK Partners. We will seek to maintain our investment-grade credit ratings; and
- Attract, develop and retain employees to support strategy execution - we continue to execute on our recruiting strategy that targets colleges, universities and vocational-technical schools in our operating areas. We also continue development efforts with our employees.

NARRATIVE DESCRIPTION OF BUSINESS

We report operations in the following business segments:

- ONEOK Partners;
- Natural Gas Distribution; and
- Energy Services.

ONEOK Partners

Overview - ONEOK Partners is a diversified master limited partnership involved in the gathering, processing, storage and transportation of natural gas in the United States. In addition, ONEOK Partners owns one of the nation's premier natural gas liquids systems, connecting NGL supply in the Mid-Continent and Rocky Mountain regions with key market centers.

We own approximately 84.8 million common and Class B limited partner units, and the entire 2-percent general partner interest, which, together, represent a 42.8-percent ownership interest in ONEOK Partners. We receive distributions from ONEOK Partners on our common and Class B units and our 2-percent general partner interest, which includes our incentive distribution rights. See Note P of the Notes to Consolidated Financial Statements in this Annual Report for discussion of our incentive distribution rights.

We and ONEOK Partners maintain significant financial and corporate governance separations. We seek to receive increasing cash distributions as a result of our investment in ONEOK Partners, and our investment decisions are made based on the anticipated returns from ONEOK Partners in total, not specific to any of ONEOK Partners' businesses individually. To aid in understanding the important business and financial characteristics of our ONEOK Partners segment, the following describes its business with reference to its underlying activities.

Natural gas gathering and processing business - ONEOK Partners' natural gas gathering and processing business provides nondiscretionary services to producers that include gathering and processing of natural gas produced from crude oil and natural gas wells. ONEOK Partners gathers and processes natural gas in the Mid-Continent region, which includes the NGL-rich Cana-Woodford Shale and Granite Wash formations; the Mississippian Lime formation of Oklahoma and Kansas; and the Hugoton and Central Kansas Uplift Basins of Kansas. It also gathers and/or processes natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana and North Dakota and includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations; and the Powder River Basin of Wyoming. In the Powder River Basin, the natural gas that ONEOK Partners gathers is coal-bed methane, or dry, natural gas that does not require processing or NGL extraction in order to be marketable; dry, natural gas is gathered, compressed and delivered into a downstream pipeline or marketed for a fee.

In the Mid-Continent region and the Williston Basin, unprocessed natural gas is compressed and transported through pipelines to processing facilities where volumes are aggregated, treated and processed to remove water vapor, solids and other contaminants, and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. The residue gas, which consists primarily of methane, is compressed and delivered to natural gas pipelines for transportation to end users. When the NGLs are separated from the unprocessed natural gas at the processing plants, the NGLs are in the form of a mixed, unfractionated NGL stream. ONEOK Partners' natural gas and NGLs are sold to affiliates and a diverse customer base.

Revenue from the natural gas gathering and processing business is derived primarily from the following three types of contracts:

- POP - ONEOK Partners retains a percentage of the NGLs and/or a percentage of the residue gas as payment for gathering, treating, compressing and processing the producer's natural gas. This type of contract represented approximately 37 percent and 35 percent of gathering and processing contracted volumes for 2011 and 2010, respectively.
- Fee - ONEOK Partners is paid a fee for the services it provides based on Btus gathered, treated, compressed and/or processed. This type of contract represented approximately 60 percent and 61 percent of gathering and processing contracted volumes for 2011 and 2010, respectively.
- Keep-whole - ONEOK Partners extracts NGLs from unprocessed natural gas and returns to the producer volumes of residue gas containing the same amount of Btus as the unprocessed natural gas that was originally delivered. This type of contract represented approximately 3 percent and 4 percent of gathering and processing contracted volumes for 2011 and 2010, respectively, with approximately 75 percent and 85 percent, respectively, of that volume under contracts that effectively convert into fee contracts when the gross processing spread is negative.

Natural gas pipelines business - ONEOK Partners' natural gas pipeline business owns and operates regulated natural gas transmission pipelines, natural gas storage facilities and natural gas gathering systems for unprocessed natural gas. ONEOK Partners also provides interstate natural gas transportation and storage services in accordance with Section 311(a) of the Natural Gas Policy Act.

ONEOK Partners' FERC-regulated interstate assets transport natural gas through pipelines that access supply from Canada and from the Mid-Continent, Rocky Mountain and Gulf Coast regions. ONEOK Partners' intrastate natural gas pipeline assets are located in Oklahoma, Texas and Kansas, and have access to major natural gas producing areas in those states. ONEOK Partners owns underground natural gas storage facilities in Oklahoma, Kansas and Texas.

ONEOK Partners' revenues from its natural gas pipelines are derived typically from fee-based services provided to its customers under the following types of fee-based contracts:

- Firm service - Customers can reserve a fixed quantity of pipeline or storage capacity for the terms of their contracts. Under firm-service contracts, the customer pays a fixed fee for a specified quantity regardless of their actual usage and is generally guaranteed access to the capacity they reserve; and
- Interruptible service - Customers may utilize available capacity after firm-service requests are satisfied or on an as-available basis. Under the interruptible service contract, the customer is provided capacity in of our pipelines and storage facilities on an interruptible basis.

Natural gas liquids business - ONEOK Partners' natural gas liquids business gathers, treats, fractionates, stores and transports NGLs and distributes and stores NGL products. ONEOK Partners' natural gas liquids gathering pipelines deliver unfractionated NGLs gathered from natural gas processing plants located in Oklahoma, Kansas, Texas and the Rocky Mountain region to fractionators it owns in Oklahoma, Kansas and Texas, as well as to third-party fractionators and pipelines. The NGLs are then separated through the fractionation process into the individual NGL products that realize the greater economic value of the NGL components. The individual NGL products are then stored or distributed to petrochemical manufacturers, heating-fuel users, refineries and propane distributors through ONEOK Partners' FERC-regulated distribution pipelines that move NGL products from Oklahoma and Kansas to the Mid-Continent and Gulf Coast NGL market centers, as well as the Midwest markets near Chicago, Illinois.

Revenue for the natural gas liquids business is derived primarily from fee-based services provided to ONEOK Partners' customers and physical optimization of its assets. The sources of revenue are categorized as follows:

- ONEOK Partners' exchange services business primarily collects fees to gather, fractionate and treat unfractionated NGLs, thereby converting them into marketable NGL products that are stored and shipped to a market center or customer-designated location.
- ONEOK Partners' optimization and marketing business utilizes our assets, contract portfolio and market knowledge to capture location and seasonal price differentials. ONEOK Partners transports NGL products between the Mid-Continent and Gulf Coast in order to capture the location price differentials between the two market centers. ONEOK Partners' natural gas liquids storage facilities are also utilized to capture seasonal price variances.
- ONEOK Partners' pipeline transportation business transports raw NGLs, finished NGL products and refined petroleum products primarily under our FERC-regulated tariffs. Tariffs specify the rates ONEOK Partners charges its customers and the general terms and conditions for NGL transportation service on its pipelines.
- ONEOK Partners' isomerization business captures the price differential when normal butane is converted into the more valuable iso-butane at its isomerization unit in Conway, Kansas. Iso-butane is used in the refining industry to increase the octane of motor gasoline.
- ONEOK Partners' storage business collects fees to store NGLs at its Mid-Continent and Gulf Coast facilities.

Market Conditions and Seasonality - Supply - Natural gas and NGL supply is affected by drilling rig availability, operating capability and producer drilling activity, which are sensitive to commodity prices, exploration success, the liquid content of the natural gas that is produced and processed, access to capital and regulatory control. Higher crude oil prices and advances in horizontal drilling and completion technologies are having a positive impact on drilling activity in the oil and NGL-rich shale areas and other resource plays, providing an offset to the less favorable supply projections in the dry gas areas. As new supply is developed, ONEOK Partners' customers may require incremental services to bring their production to market.

In the Rocky Mountain region, Williston Basin volumes continue to grow as drilling activity increases, driven primarily by producer development of Bakken Shale crude oil wells, which also produce associated natural gas containing significant amounts of NGLs. However, ONEOK Partners' natural gas gathering and processing business has seen declines in natural gas volumes gathered in the Powder River Basin, which is dry gas.

In the Mid-Continent region, ONEOK Partners expects increased drilling activity in the Cana-Woodford Shale and Granite Wash areas of western Oklahoma and the Mississippian Lime formation of Oklahoma and Kansas to more than offset the volumetric declines in most conventional wells that supply ONEOK Partners' natural gas gathering and processing facilities and intrastate natural gas pipelines and storage assets.

ONEOK Partners' interstate natural gas pipelines access supply from major producing regions in the Mid-Continent, Rocky Mountain, Gulf Coast and Canada.

ONEOK Partners expects the overall supply of NGLs to continue to increase as well as demand for fee-based services as a result of the development of shale areas and other resource plays. Many new natural gas processing plants are being constructed in Oklahoma and the Texas Panhandle to process NGL-rich natural gas being produced in the Cana-Woodford Shale, the Granite Wash, the Woodford Shale and the emerging Mississippian Lime formations. ONEOK Partners' NGL gathering and fractionation operations receive NGLs from a variety of processors and pipelines, including affiliates, located in these regions.

ONEOK Partners' natural gas gathering and processing and natural gas liquids businesses are also affected by operational or market-driven changes that impact the output of natural gas processing plants. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant NGL output. During 2011, ethane prices remained significantly above natural gas prices on a relative Btu basis, which resulted in an economic incentive for ethane recovery from ONEOK Partners' natural gas processing plants and third-party natural gas processing plants that deliver NGLs to ONEOK Partners' natural gas liquids gathering pipelines.

Demand - Demand for natural gas gathering and processing services is aligned typically with the production of natural gas from natural gas plays or the associated natural gas from wells drilled in crude oil plays. Gathering and processing are nondiscretionary services that producers require to market their natural gas and natural gas liquid production. As producers continue to develop shale and other resource plays, ONEOK Partners expects demand for its gathering and processing services to increase. ONEOK Partners' natural gas processing plant operations can be adjusted to respond to market conditions, such as demand for ethane. By changing operating parameters at certain plants, ONEOK Partners can reduce, to some extent, the amount of ethane and propane recovered in its processing plants if prices or processing margins are unfavorable.

Demand for natural gas pipeline transportation service and natural gas storage is related directly to demand for natural gas in the markets that the natural gas pipelines and storage facilities serve, and is affected by weather, the economy and natural gas price volatility. ONEOK Partners' natural gas pipelines primarily serve end-users, such as natural gas distribution companies and electric-generation companies, that require natural gas to operate their businesses and generally are not impacted by location price differentials. However, narrower location differentials may impact demand for ONEOK Partners' services from natural gas marketers as discussed below under "Commodity Prices." Demand for ONEOK Partners' natural gas pipelines services can also be impacted as coal-fired electric generators consider natural gas as an alternative fuel.

The strength of the economy directly impacts manufacturing and industrial companies that consume natural gas. Commodity price volatility can influence producers' decisions related to the production of natural gas, the level of NGLs processed from natural gas and natural gas storage injection and withdrawal activity.

Demand for NGLs and the ability of natural gas processors to sustain successfully and economically their operations impacts the volume of unfractionated NGLs produced by natural gas processing plants, thereby affecting the demand for NGL gathering, fractionation and distribution services. Natural gas and propane are subject to weather-related seasonal demand. Other NGL products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline, which are used by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil. Ethane, propane, normal butane and natural gasoline are used by the petrochemical industry to produce chemical products, such as plastics, rubber and synthetic fibers. During 2011, several petrochemical companies announced new plants, plant expansions, additions or enhancements that improve the light-NGL feed capability of their facilities due primarily to the increased supply and attractive price of ethane as a petrochemical feedstock in the United States. These projects are expected to increase significantly ethane demand over the next five years. In addition, international demand for propane is expected to impact the NGL market in the future. ONEOK Partners expects this increase in demand for NGLs to add incremental fee-based earnings to its natural gas liquids business.

Commodity Prices - Crude oil, natural gas and NGL prices can be volatile due to changes in market conditions. Commodity prices can also be impacted by demand for products from the petrochemical industry and other consumers, storage injection and withdrawal rates and available storage capacity. The increase in natural gas supply from shale gas development has caused natural gas prices to decline and natural gas location and seasonal price differentials to narrow across most of the regions where ONEOK Partners operates. However, an increase in crude oil prices and the abundance of NGLs produced from the development of NGL-rich shale resource plays have made producing NGL feedstocks for the petrochemical industry more profitable. ONEOK Partners is exposed to commodity price risk in its natural gas gathering and processing business, as a result of receiving commodities in exchange for services, primarily on POP contracts, and in its natural gas liquids business from the NGLs it purchases and sells. ONEOK Partners is also exposed to market risk associated with the price differentials between receipt and delivery points along its natural gas and natural gas liquids pipelines, also known as location differentials. Fluctuations in location differentials impact the rates its natural gas pipelines' customers with competitive alternatives are willing to pay and the optimization opportunities for its natural gas liquids business. ONEOK Partners' natural gas and NGL storage revenues are impacted by the differential between the forward price of natural gas and NGLs and the price of natural gas and NGLs on the spot market. Additionally, fluctuations in the relative price differential between natural gas, NGLs and individual NGL products impacts ONEOK Partners' natural gas liquids exchange services and transportation revenues and, to a lesser extent, margins on its natural gas gathering and processing keep-whole contracts.

Seasonality - Our ONEOK Partners segment's products are subject to weather-related seasonal demand. Cold temperatures typically increase demand for natural gas and propane, which are used to heat homes and businesses. Warm temperatures typically drive demand for natural gas used for natural gas-fired electric generation needed to meet the electricity-generation demand required to cool residential and commercial properties. Precipitation levels also can impact the demand for natural gas that is used to fuel irrigation activity in the Mid-Continent region and demand for propane used to fuel crop-drying activity. Demand for butane and natural gasoline, which are used primarily by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil, may also be subject to some variability as automotive travel increases and as seasonal gasoline formulation standards are implemented. During periods of peak demand for a certain commodity, prices for that product typically increase, which may influence processing and fractionation decisions.

Competition - ONEOK Partners' natural gas and natural gas liquids businesses compete directly with other companies for natural gas and NGL supplies, markets and services. Competition for natural gas transportation services continues to increase as new infrastructure projects are completed and the FERC and state regulatory bodies continue to encourage additional competition in the natural gas markets. Competition is based primarily on fees for services, quality of services provided, current and forward natural gas and NGL prices and proximity to supply areas and markets. ONEOK Partners believes that the location and integration of its assets enable it to compete effectively.

ONEOK Partners' natural gas gathering and processing business competes for natural gas supplies with independent exploration and production companies that have gathering and processing assets, pipeline companies and their affiliated marketing companies, national and local natural gas gatherers and processors, and marketers in the Mid-Continent and Rocky Mountain regions. ONEOK Partners' natural gas liquids business competes with other fractionators, storage providers, gatherers and transporters for NGL supplies in the Rocky Mountain, Mid-Continent and Gulf Coast regions. The factors that typically affect ONEOK Partners' ability to compete for natural gas and NGL supplies are:

- fees charged under its contracts;
- pressures maintained on its gathering systems;
- location of its assets relative to those of its competitors;
- location of its assets relative to drilling activity;
- efficiency and reliability of its operations; and
- receipt and delivery capabilities that exist in each system, plant, fractionator and storage location.

ONEOK Partners is responding to these factors by making capital investments to access new supplies; increasing gathering, fractionation, storage and transportation capacity; increasing storage, withdrawal and injection capabilities; and improving natural gas processing efficiency and reducing operating costs. ONEOK Partners' competitors have also recently announced plans for new natural gas gathering and processing facilities and natural gas liquids pipelines and fractionators to address the growing natural gas and NGL supply and petrochemical demand. When completed, ONEOK Partners' growth projects and those of its competitors are expected to impact NGL prices and narrow location differentials between the Mid-Continent and Gulf Coast market centers. ONEOK Partners is also evaluating asset consolidation opportunities to maximize earnings and renegotiating low-margin contracts. The principal goal of the contract renegotiation effort is to improve margins and reduce risk.

Government Regulation - The FERC traditionally has maintained that a natural gas processing plant is not a facility for the transportation or sale for resale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act. Although the FERC has made no specific declaration as to the jurisdictional status of ONEOK Partners' natural gas processing operations or facilities, ONEOK Partners' natural gas processing plants are primarily involved in extracting NGLs and, therefore, ONEOK Partners believes, its natural gas processing plants are exempt from FERC jurisdiction. The Natural Gas Act also exempts natural gas gathering facilities from the jurisdiction of the FERC. ONEOK Partners believes its natural gas gathering facilities and operations meet the criteria used by the FERC for nonjurisdictional gathering facility status. However, ONEOK Partners is subject to newly adopted FERC regulations that require it to post publicly certain natural gas flow information on ONEOK Partners' website. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has distinguished historically between these two types of facilities, either interstate or intrastate, on a fact-specific basis. ONEOK Partners also transports residue gas from its natural gas processing plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act.

Oklahoma, Kansas, Wyoming, Montana and North Dakota also have statutes regulating, in various degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

ONEOK Partners' interstate natural gas pipelines are regulated under the Natural Gas Act and Natural Gas Policy Act, which give the FERC jurisdiction to regulate virtually all aspects of the pipeline activities. ONEOK Partners' intrastate natural gas transportation assets in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively. ONEOK Partners has flexibility in establishing natural gas transportation rates with customers. However, there are maximum rates that ONEOK Partners can charge its customers in Oklahoma and Kansas.

ONEOK Partners' proprietary natural gas liquids gathering pipelines, fractionation and storage facilities in Oklahoma, Kansas and Texas are not regulated by the FERC or the states' respective corporation commissions. ONEOK Partners' remaining natural gas liquids pipelines are regulated by the FERC, which has authority over the terms and conditions of service, rates, including depreciation and amortization policies, and initiation of service. In Kansas and Texas, ONEOK Partners' intrastate natural gas liquids pipelines that provide common carrier services are subject to the jurisdiction of the KCC and RRC, respectively, which have oversight regarding services provided.

See further discussion in the "Environmental and Safety Matters" section.

Unconsolidated Affiliates - Our ONEOK Partners segment has investments in unconsolidated affiliates that include Northern Border Pipeline, Overland Pass Pipeline Company, three partnerships that operate natural gas gathering systems located primarily in the Powder River of Wyoming and other investments. Northern Border Pipeline is a leading transporter of natural gas imported from Canada into the United States. Overland Pass Pipeline Company operates an interstate natural gas liquids pipeline system that transports natural gas liquids from the Rocky Mountain region to the Mid-Continent NGL market center.

See Note O of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of ONEOK Partners' unconsolidated affiliates.

<u>Natural Gas Distribution</u>

Overview - Our Natural Gas Distribution segment provides natural gas distribution services to more than 2 million customers in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service. We serve residential, commercial, industrial and transportation customers in all three states. In addition, our LDCs serve wholesale and public authority customers. We operate subject to regulations and oversight of the state regulatory agencies. Our regulatory strategy incorporates features that reduce earnings lag, protect margin and mitigate risks.

Our strategies to reduce earnings lag include a performance-based rate mechanism in Oklahoma and capital-recovery mechanisms in Kansas and portions of Texas. In addition, we also have cost-of-service adjustments in certain Texas markets that address investments in rate base and changes in operating expenses.

Margin protection strategies include increasing the portion of our service fees that is fixed rather than volumetrically based. Customer consumption is a function of price levels and weather conditions. Weather normalization mechanisms limit our sensitivity to weather.

Risk mitigation strategies include mechanisms to recover the fuel-related component of bad debts in Oklahoma, Kansas and portions of Texas and pension and other post-retirement benefits and ad valorem taxes in Kansas.

Our operating results are affected primarily by the number of customers, usage and the ability to collect delivery rates that provide a reasonable rate of return on our investment and recovery of our cost of service. Natural gas costs are passed through to our customers based on the actual cost of natural gas purchased by the respective natural gas distribution companies and related expenses. Substantial fluctuations in natural gas sales can occur from year to year without materially or adversely impacting our net margin, since the fluctuations in natural gas costs affect natural gas sales and cost of gas by an equivalent amount. Higher natural gas costs may cause customers to conserve or use alternative energy sources. Higher natural gas costs may also impact adversely our accounts receivable collections, resulting in higher bad-debt expense. Recovery of the fuel-related portion of bad debts is allowed in all three states.

Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service distribute natural gas as public utilities to approximately 82 percent, 67 percent and 14 percent of the natural gas distribution markets for Oklahoma, Kansas and Texas, respectively. Natural gas sold to residential and commercial customers accounts for approximately 81 and 18 percent of our natural gas sales, respectively, in Oklahoma; 80 and 19 percent of our natural gas sales, respectively, in Kansas; and 69 and 23 percent of our natural gas sales, respectively, in Texas.

In December 2011, we entered into a definitive agreement to sell ONEOK Energy Marketing Company to Constellation Energy Group, Inc. for $22.5 million plus working capital. The transaction closed on February 1, 2012. The financial information of ONEOK Energy Marketing Company is reflected as discontinued operations in this Annual Report. All prior periods presented have been recast to reflect the discontinued operations.

Market Conditions and Seasonality - Supply - Our LDCs purchased 163 Bcf and 186 Bcf of natural gas supply in 2011 and 2010, respectively. Our natural gas supply portfolio consists of long-term, seasonal and short-term contracts from a diverse group of suppliers. These contracts are awarded through competitive-bidding processes to ensure reliable and competitively priced natural gas supply. Our Natural Gas Distribution segment's natural gas supply is acquired from natural gas processing plants, natural gas marketers and natural gas producers.

An objective of our supply-sourcing strategy is to provide value to customers through reliable, competitively priced and flexible gas supply and transportation purchases from multiple production areas and suppliers. This strategy is designed to protect receipt of supply from being curtailed by physical interruption, possible financial difficulties of a single supplier, natural disasters and other unforeseen force majeure events, as well as ensuring these resources are reliable and flexible to meet the variations of customer demands.

We do not anticipate problems with securing natural gas supply to satisfy customer demand; however, if supply shortages were to occur, each of our LDCs has curtailment tariff provisions in place that provide for: reducing or discontinuing natural gas service to large industrial users; and requesting that residential and commercial customers reduce their natural gas requirements to an amount essential for public health and safety. In addition, during times of critical supply disruptions, curtailments of deliveries to customers with firm contracts may be made in accordance with guidelines established by appropriate federal, state and local regulatory agencies.

Natural gas supply requirements are affected by weather conditions. In addition, economic conditions impact the requirements of our commercial and industrial customers. Natural gas usage per residential customer may decline as customers change their consumption patterns in response to: (i) more volatile and higher natural gas prices, as discussed above; (ii) customers' improving the energy efficiency of existing homes by replacing doors and windows and adding insulation, and retrofitting natural gas appliances with more efficient appliances; (iii) more energy-efficient construction; and (iv) fuel switching. In each jurisdiction in which we operate, changes in customer usage profiles are considered in the design of our rates.

In managing our natural gas supply portfolios, we partially mitigate price volatility using a combination of financial derivatives and fixed price contracts. We have natural gas hedging programs in each state that have been approved by the respective states' regulatory authorities. We do not utilize financial derivatives for speculative purposes nor do we have trading operations associated with our Natural Gas Distribution segment. In addition, we utilized 39.3 Bcf of contracted storage capacity in 2011, which allows gas to be purchased during the off-peak season and stored for use in the winter periods.

Demand - See discussion below under "Seasonality" and "Competition" for factors affecting demand for our services.

Seasonality - Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating. Accordingly, the volume of natural gas sales is higher normally during the months of November through March than in other months of the year. The impact on margins for our LDCs resulting from weather that is above or below normal is offset in part through weather-normalization adjustments (WNA). These adjustments have been approved by the regulatory authorities for our Oklahoma, Kansas and certain Texas service territories. WNA allows us to increase customer billing to offset lower gas usage when weather is warmer than normal and decrease customer billing to offset higher gas usage when weather is colder than normal.

Competition - We encounter competition based on customers' preference for natural gas, compared with other energy products and their comparative prices. The most significant product competition occurs between natural gas and electricity in the residential and small commercial markets. We compete for space and water heating, cooking, clothes drying and other general energy needs. Customers and builders typically make the decision on the type of equipment at initial installation and use the chosen energy source for the life of the equipment. The markets in our service territories have become increasingly competitive. Changes in the competitive position of natural gas relative to electricity and other energy products have the potential to cause a decline in consumption or in the number of natural gas customers.

However, recent studies have demonstrated that assessing energy efficiency in terms of full fuel-cycle analysis highlights the high overall efficiency of natural gas in residential and commercial uses, compared with electricity. The Department of Energy recently issued a statement of policy that it will use full fuel-cycle measures of energy use and emissions when evaluating energy-conservation standards for appliances. Further, independent studies show that natural gas provides a cost advantage over electricity for typical home and business applications.

We believe that we must maintain a competitive advantage in order to retain our customers, and, accordingly, we focus on providing safe, reliable and efficient service and controlling costs. Our Natural Gas Distribution segment is subject to competition from other pipelines for our existing industrial load. Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service compete for service to large industrial and commercial customers, and competition has and may continue to impact margins.

Under our transportation tariffs, qualifying industrial and commercial customers are able to purchase their natural gas commodity from the supplier of their choice and have us transport it for a fee. A portion of transportation services provided is at negotiated rates that are generally below the maximum approved transportation tariff rates. Reduced rate transportation service may be negotiated when a competitive pipeline is in proximity or another viable energy option is available. Increased competition could potentially lower these rates.

Government Regulation - Rates charged by LDCs in our Natural Gas Distribution segment for natural gas services are established by the OCC for Oklahoma Natural Gas and by the KCC for Kansas Gas Service. Texas Gas Service is subject to regulatory oversight by the various municipalities that it serves, which have primary jurisdiction in their respective areas. Rates in unincorporated areas of Texas and all appellate matters are subject to regulatory oversight by the RRC. Natural gas supply costs for our LDCs are passed on to our customers through a purchased-gas cost-adjustment mechanism. We do not make a profit on the cost of natural gas. Other changes in costs must be recovered through periodic rate adjustments approved by the OCC, KCC, RRC and various municipalities in Texas. See pages 52 for a detailed description of our various regulatory initiatives.

See further discussion in the "Environmental and Safety Matters" section.

Energy Services

Overview - Our Energy Services segment is a provider of non-uniform natural gas supply and risk-management services for natural gas and electric utilities and commercial and industrial customers with natural gas needs. We use a network of leased storage and transportation capacity to supply natural gas to our customers. This network connects the major supply and demand centers throughout the United States and into Canada and, coupled with our industry knowledge and market intelligence, allows us to provide our customers customized services in a more efficient and reliable manner than they can achieve independently.

Strategy - We follow a strategy of optimizing our storage and cross-regional transportation capacity through the application of market knowledge and effective risk management. We seek to maximize value by actively hedging the risks associated with seasonal and location price differentials that are inherent to storage and transportation contracts. At the same time, we attempt to capitalize on opportunities created by market volatility, weather-related events, supply-demand imbalances and market inefficiencies, which allow us to capture additional margin. Using market information, we manage these asset-based positions and seek to provide incremental margin in our trading portfolio.

To ensure natural gas is available when our customers need it, we offer premium services and products that satisfy our customers' non-uniform supply needs such as swing and peaking natural gas load requirements on a year-round basis. Types of premium services include next-day and no-notice services. Next-day services allow our customers to call on additional gas supply, up to an amount agreed upon in a service contract, and expect delivery the following day. No-notice services allow customers to call on additional gas supply and expect immediate delivery. We also provide weather-related protection and other custom solutions based on our customers' specific needs. Our storage and transportation assets enable us to provide these services and provide us with opportunities to capture daily, monthly and seasonal value due to market inefficiencies.

As a result of significant increases in the supply of natural gas, primarily from shale production across North America, location and seasonal differentials have significantly narrowed, resulting in reduced opportunities to optimize our firm transportation and storage capacity. Additionally, price volatility in the natural gas markets has diminished, which further limits opportunities to optimize our assets. We have undertaken several steps to better align fixed costs with the current business environment, including attempts to renegotiate various natural gas storage and transportation contracts. Contract renegotiation activities that we have taken or expect to consider further include renewing contracts at current market prices at contract expiration, extending contracts in order to negotiate a more favorable rate or paying to terminate contracts in areas that are no longer strategic to our business. It is possible that we may recognize charges to our earnings as a result of certain of these actions. These changes would result in a better alignment of our contracted natural gas transportation and storage capacity with the needs of our premium-services customers. We also expect the effect of these strategies to be a reduction in our contracted natural gas transportation and storage capacity, which should reduce our operating costs and working-capital requirements primarily through a reduction in natural gas inventory levels.

Approximately 14 percent of our transportation capacity and approximately 20 percent of our storage capacity expire by the end of 2012, and an additional amount of approximately 64 percent of our transportation capacity and an additional amount of approximately 68 percent of our storage capacity expires by the end of 2015.

Derivatives - It is our intention to minimize the mark-to-market earnings impact that our forward hedges have on current period earnings. When possible, we implement hedging strategies using derivative instruments that qualify as hedges for accounting purposes. We actively manage the commodity price and volatility risks associated with providing energy risk-management services to our customers by executing derivative instruments in accordance with the parameters established in our commodity risk-management policy. The derivative instruments consist of over-the-counter transactions such as forward, swap and option contracts, and NYMEX futures and option contracts.

We utilize our experience to optimize the value of our contracted assets and use our risk management and marketing capabilities to both manage risk and generate additional margins. We apply a combination of cash flow and fair value hedge accounting when implementing hedging strategies that take advantage of favorable market conditions. See Note D of the Notes to Consolidated Financial Statements in this Annual Report for additional information. Additionally, certain non-trading transactions, which are economic hedges of our accrual transactions such as certain of our storage and transportation contracts, will not qualify for hedge accounting treatment. These economic hedges receive mark-to-market accounting treatment, as they are derivative contracts and are not designated as part of a hedge relationship. As a result, the underlying risk being hedged receives accrual accounting treatment, while we use mark-to-market accounting treatment for the economic hedges. We cannot predict the earnings fluctuations from mark-to-market accounting, and the impact on earnings could be material.

In prior years, we were able to hedge location differentials and seasonal storage differentials at more favorable levels compared with opportunities currently available to us. These factors have impacted negatively our Energy Services segment's results of operations in 2011, and we anticipate these factors will persist throughout 2012 and potentially into 2013. A significant amount of our storage and transportation hedges that were entered into at favorable levels were realized by the end of 2011.

Working Capital - Our Energy Services segment requires working capital to purchase natural gas inventory, to reserve transportation and storage capacity and to meet cash collateral requirements associated with our risk-management activities. Our inventory purchases and hedging strategies are implemented with consideration given to ONEOK's overall working capital requirements and liquidity. Restrictions on our access to working capital may impact our inventory purchases and risk-management activities, which could impact our results. Our working capital costs would be impacted by a change in ONEOK's current investment-grade credit ratings or a significant increase in commodity prices. See discussion under "Credit Risk" of Note D of the Notes to Consolidated Financial Statements in this Annual Report for additional information about the impact of a change in ONEOK's credit rating.

Our working capital requirements related to our inventory in storage were as high as $297.9 million during 2011 and had decreased to $215.0 million by December 31, 2011. In addition, margin requirements can result in increased working capital requirements. During 2011, the amount we were required to post with counterparties to meet our margin requirements ranged from zero to $22.6 million, and the amount posted for our benefit by our counterparties ranged from zero to $60.5 million.

Sales with Affiliates - Our Energy Services segment conducts business with our ONEOK Partners and Natural Gas Distribution segments. These services are provided under agreements with market-based terms. Additionally, business with our LDCs is awarded through a competitive-bidding process. We provide supply and risk-management service to certain retail marketing operations, including the retail marketing portion of our Natural Gas Distribution segment that was sold in February 2012.

Market Conditions and Seasonality - Supply - Our Energy Services segment maintains a natural gas supply portfolio consisting of various term-length contracted supply in all of the major producing regions, including the Rocky Mountain, Mid-Continent and Gulf Coast. During periods of high natural gas demand, we utilize storage capacity that allows us to supplement natural gas supply volumes to meet our peak day demand obligations or market needs.

An increase in shale natural gas production and related pipeline construction across North America has resulted in greater natural gas supply, putting downward pressure on natural gas prices and narrowing the price differentials between regions. The impact of lower natural gas prices and price volatility and narrower location and seasonal price differentials has resulted in reduced opportunities to capture incremental margin through optimization efforts.

Demand - Demand under our swing and peaking natural gas requirements contracts in our wholesale operation usually is driven by the extent to which temperatures vary from normal levels. A significant portion of this business is contracted during the winter period of November through March.

The displacement of electric power-generation plants from coal to natural gas is resulting in a slight increase in demand for natural gas. These displacements are being driven by the cost of natural gas relative to coal and to a lesser extent due to potential government regulations.

Customers continue to contract for storage, transportation and premium services but at lower prices due to lower natural gas prices resulting from the increased supply and lower natural gas price volatility. Although future improvements in the U.S. economy, coupled with the depressed natural gas price environment, could increase modestly customer demand, we do not anticipate a significant change in customer demand in 2012.

Seasonality - Due to the seasonality of natural gas consumption, storage withdrawals and demand for our products and services, earnings are higher normally during the winter months than the summer months. Natural gas sales volumes are higher typically in the winter heating months than in the summer months, reflecting increased demand due to greater heating requirements and, typically, higher natural gas prices.

Increased natural gas supply is also impacting negatively the seasonal price differentials. There could be situations where winter prices are lower, due to mild weather and abundant supply, than the prices in the upcoming summer. These changes could result in unfavorable pricing between periods that could result in losses on the withdrawal of natural gas from inventory.

Competition **-** In response to a challenging marketing environment, our strategy is to concentrate our efforts on providing reliable service during peak-demand periods. We can compete effectively in the market by utilizing our contracted storage and transportation assets. We continue to focus on building and strengthening supplier and customer relationships to execute our strategy and increase our market presence.

Government Regulation - Our Energy Services segment purchases natural gas for resale at negotiated rates in interstate commerce. As such, it has been granted by FERC an automatic blanket certificate of public convenience and necessity authorizing such sales. This is a limited certificate that does not subject our Energy Services segment to any other regulation of FERC under its Natural Gas Act jurisdiction. Holders of blanket marketing certificates are subject to certain reporting and document retention requirements.

Market conditions and uncertainties associated with the implementation of financial reform through the Dodd-Frank Act have reduced liquidity in the financial derivatives markets, particularly for basis swaps, which make it difficult to implement forward hedges around our transportation and storage positions. See “Financial Markets Legislation” for discussion of the Dodd-Frank Act.

SEGMENT FINANCIAL INFORMATION

Operating Income, Customers and Total Assets - See Note R of the Notes to Consolidated Financial Statements in this Annual Report for disclosure by segment of our operating income and total assets and for a discussion of revenues from external customers.

Other

Through ONEOK Leasing Company, L.L.C., and ONEOK Parking Company, L.L.C., we own a parking garage and an office building (ONEOK Plaza) in downtown Tulsa, Oklahoma, where our headquarters are located. ONEOK Leasing Company, L.L.C., leases excess office space to others and operates our headquarters office building. ONEOK Parking Company, L.L.C. owns and operates a parking garage adjacent to our headquarters.

FINANCIAL MARKETS LEGISLATION

The Dodd-Frank Act represents a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the CFTC has issued final regulations for certain provisions of the Dodd-Frank Act, many remain outstanding. In November 2011, the CFTC published final rules on speculative position limits, which we do not expect to impact directly our current risk-management practices. In December 2011, the CFTC issued an order that further defers the effective date of the provisions of the Dodd-Frank Act that require a rulemaking, such as definitions of certain terms, until the earlier of the effective date of the final rule defining the reference terms or July 16, 2012. Until the remaining final regulations are established, we are unable to ascertain how we may be affected by them. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We also may incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations; however, we do not believe the costs will be material. These requirements could affect adversely market liquidity and pricing of derivative contracts making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

ENVIRONMENTAL AND SAFETY MATTERS

Additional information about our environmental matters is included in Note Q of the Notes to Consolidated Financial Statements in this Annual Report.

Environmental Liabilities - We are subject to multiple historical and wildlife preservation laws and environmental regulations affecting many aspects of our present and future operations. Regulated activities include those involving air emissions; storm water and wastewater discharges; handling and disposal of solid and hazardous wastes; hazardous materials transportation; and pipeline and facility construction. These laws and regulations require us to obtain and comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If a leak or spill of hazardous substances or petroleum products occurs from pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and cleanup costs, which could affect materially our results of operations and cash flows. In addition, emission controls required under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Pipeline Safety - We are subject to Pipeline and Hazardous Materials Safety Administration regulations, including integrity-management regulations. The Pipeline Safety Improvement Act of 2002 requires pipeline companies operating high-pressure pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. The new law contains numerous requirements for the Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include but are not limited to:

- an evaluation on whether hazardous natural gas liquid and natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a review of all natural gas and hazardous natural gas liquid gathering pipeline exemptions;
- a verification of records for pipelines in Class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test pipelines previously untested in high-consequence areas operating above 30-percent yield strength.

The potential capital and operating expenditures related to this legislation, the associated regulations or other new pipeline safety regulations are unknown.

Air and Water Emissions - The Clean Air Act, the Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air-pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge.

Federal, state and regional initiatives to measure and regulate greenhouse gas emissions are under way. We are monitoring federal and state legislation to assess the potential impact on our operations. The EPA's Mandatory Greenhouse Gas Reporting rule, released in September 2009, requires greenhouse gas emissions reporting for affected facilities on an annual basis and requires us to track the emission equivalents for the natural gas delivered by us to our distribution customers and emission equivalents for all NGLs delivered to customers of ONEOK Partners. Our 2010 total reported emissions were less than 66.6 million metric tons of carbon dioxide equivalents. This total includes direct emissions from the combustion of fuel in our equipment, such as compressor engines and heaters, and carbon dioxide equivalents from NGL products and natural gas delivered to customers, as if all such fuel and NGL products were combusted and carbon dioxide injected directly into disposal wells. The next required reporting period for 2011 greenhouse gas emissions will be due March 31, 2012. Also, the EPA released a subpart to the Mandatory Greenhouse Gas Reporting Rule that will require the reporting of vented and fugitive emissions of methane from our facilities. The new requirements began in January 2011, with the first reporting of fugitive emissions due September 30, 2012. We do not expect the cost to gather this emission data to have a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. At this time, no rule or legislation has been enacted that assesses any costs, fees or expenses on any of these emissions.

In May 2010, the EPA finalized the "Tailoring Rule" that will regulate greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities will be required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. Since January 2011, the rule has been in the process of being phased in, and at current emission threshold levels, we believe it will have a minimal impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In addition, the EPA issued a rule on air-quality standards, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, with a compliance date in 2013. The rule will require capital expenditures over the next two years for the purchase and installation of new emissions-control equipment. We do not expect these expenditures to have a material impact on our results of operations, financial position or cash flows.

On July 28, 2011, the EPA issued a proposed rule package that would change the air emission New Source Performance Standards and Maximum Achievable Control Technology requirements applicable to natural gas production, processing, transmission and underground storage. The proposed rules would impact emission limits for specific equipment through the use of controls; however, potential costs associated with the proposed rules currently are unknown.

Superfund - The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or Superfund, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a facility where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies. In 2011, ONEOK Partners received notice from the EPA of potential liability for the U.S. Oil Recovery Superfund Site location in Harris County, Texas. ONEOK Partners is named a potentially responsible party as a result of waste disposal at the now-abandoned site. Neither we nor ONEOK Partners expect our respective current responsibilities under CERCLA, for this facility and any other, to have a material impact on our respective results of operations, financial position or cash flows.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. We completed the Homeland Security assessments, and our facilities subsequently were assigned one of four risk-based tiers ranging from high (Tier 1) to low (Tier 4) risk, or not tiered at all due to low risk. To date, four of our facilities have been given a Tier 4 rating. Facilities receiving a Tier 4 rating are required to complete Site Security Plans and possible physical security enhancements. We do not expect the Site Security Plans and possible security enhancements cost to have a material impact on our results of operations, financial position or cash flows.

Pipeline Security - Homeland Security's Transportation Security Administration and the United States Department of Transportation have completed a review and inspection of our "critical facilities" and identified no material security issues. Also, the Transportation Security Administration has released new pipeline security guidelines that include broader definitions for the determination of pipeline "critical facilities." We have reviewed our pipeline facilities according to the new guideline requirements and there have been no material changes required to date.

Environmental Footprint - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (i) developing and maintaining an accurate greenhouse gas emissions inventory, according to current rules issued by the EPA; (ii) improving the efficiency of our various pipelines, natural gas processing facilities and natural gas liquids fractionation facilities; (iii) following developing technologies for emission control; and (iv) following developing technologies to capture carbon dioxide to keep it from reaching the atmosphere.

ONEOK Partners participates in the EPA's Natural Gas STAR Program to reduce voluntarily methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for natural gas through expanded implementation of best practices to limit the release of natural gas during pipeline and facility maintenance and operations. Our most recent calculation of our annual lost-and-unaccounted-for natural gas, for all of our business operations, is less than 1 percent of total throughput.

EMPLOYEES

We employed 4,795 people at January 31, 2012, including 694 people at Kansas Gas Service who are subject to collective bargaining contracts. The following table sets forth our contracts with collective bargaining units at January 31, 2012:

Union	Employees	Contract Expires
The United Steelworkers	388	October 28, 2016
International Brotherhood of Electrical Workers (IBEW)	306	June 30, 2014

EXECUTIVE OFFICERS

All executive officers are elected annually by our Board of Directors, and each serves until such person resigns, is removed or is otherwise disqualified to serve, or until such officer's successor is duly elected. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 executive officers.

Name and Position	Age		Business Experience in Past Five Years
John W. Gibson	59	2012 to present	Chairman and Chief Executive Officer, ONEOK and ONEOK Partners
Chairman and Chief Executive Officer		2011	Chairman, President and Chief Executive Officer, ONEOK
		2011	Vice Chairman of the Board of Directors, ONEOK
		2010 to 2011	President and Chief Executive Officer, ONEOK
		2010 to 2011	Chairman, President and Chief Executive Officer, ONEOK Partners
		2007 to 2009	Chief Executive Officer, ONEOK
		2007 to 2009	Chairman and Chief Executive Officer, ONEOK Partners
		2006 to present	Member of the Board of Directors, ONEOK and ONEOK Partners
Terry K. Spencer	52	2012 to present	President, ONEOK and ONEOK Partners
President		2010 to present	Member of the Board of Directors, ONEOK Partners
		2009 to 2011	Chief Operating Officer, ONEOK Partners
		2007 to 2009	Executive Vice President, Natural Gas Liquids, ONEOK Partners
Pierce H. Norton II	52	2012 to present	Executive Vice President and Chief Operating Officer, ONEOK and ONEOK Partners
Executive Vice President and		2011	Chief Operating Officer, ONEOK
Chief Operating Officer		2009 to 2011	President, ONEOK Distribution Companies, ONEOK
		2007 to 2009	Executive Vice President, Natural Gas, ONEOK Partners
		2006 to 2007	President, Gathering and Processing, ONEOK Partners
Robert F. Martinovich	54	2012 to present	Executive Vice President, Chief Financial Officer and Treasurer, ONEOK and ONEOK Partners
Executive Vice President, Chief Financial Officer		2011 to present	Member of the Board of Directors, ONEOK Partners
and Treasurer		2011	Senior Vice President, Chief Financial Officer and Treasurer, ONEOK and ONEOK Partners
		2009 to 2011	Chief Operating Officer, ONEOK
		2007 to 2009	President, Gathering and Processing, ONEOK Partners
		2006 to 2007	Group Vice President, EHS, Operations & Technical Services, DCP Midstream LLC
Stephen W. Lake	48	2012 to present	Senior Vice President, General Counsel and Assistant Secretary, ONEOK and ONEOK Partners
Senior Vice President, General Counsel and		2011	Senior Vice President, Associate General Counsel and Assistant Secretary, ONEOK and ONEOK Partners
Assistant Secretary		2008-2011	Executive Vice President and General Counsel, McJunkin Red Man Corporation
		1998-2008	Partner, GableGotwals
Derek S. Reiners	40	2009 to present	Senior Vice President and Chief Accounting Officer, ONEOK and ONEOK Partners
Senior Vice President and Chief Accounting Officer		2004 to 2009	Partner, Grant Thornton LLP

No family relationships exist between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.oneok.com) copies of our Annual Reports, Quarterly Reports, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct, Corporate Governance Guidelines and Director Independence Guidelines are also available on our website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including "Forward-Looking Statements," which are included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

RISK FACTORS INHERENT IN OUR BUSINESS

Market volatility and capital availability could affect adversely our business.

The capital and credit markets have experienced volatility and disruption in the past. In many cases during these periods, the capital markets have exerted downward pressure on equity values and reduced the credit capacity for certain companies. Our ability to grow could be constrained if we do not have regular access to the capital and credit markets. Similar or more severe levels of market disruption and volatility may have an adverse affect on us resulting from, but not limited to, disruption of our access to capital and credit markets, difficulty in obtaining financing necessary to expand facilities or acquire assets, increased financing cost and increasingly restrictive covenants.

Our operating results may be affected materially and adversely by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in the oil and natural gas industry, as well as in the specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region. Volatility in commodity prices may have an impact on many of our customers, which, in turn, could have a negative impact on their ability to meet their obligations to us. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the United States or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition, results of operations and liquidity.

Our cash flow depends heavily on the earnings and distributions of ONEOK Partners.

Our partnership interest in ONEOK Partners is one of our largest cash-generating assets. Therefore, our cash flow is heavily dependent upon the ability of ONEOK Partners to make distributions to its partners. A significant decline in ONEOK Partners' earnings and/or cash distributions would have a corresponding negative impact on us. For information on the risk factors inherent in the business of ONEOK Partners, see the section below entitled "Additional Risk Factors Related to ONEOK Partners' Business" and Item 1A, Risk Factors in the ONEOK Partners' Annual Report.

Some of our nonregulated businesses have a higher level of risk than our regulated businesses.

Some of our nonregulated operations, which include ONEOK Partners' natural gas gathering and processing business, most of its natural gas liquids business and our energy services business, have a higher level of risk than our regulated operations, which include the LDCs in our distribution business, ONEOK Partners' natural gas pipelines business and a portion of its natural gas liquids business. We and ONEOK Partners expect to continue investing in natural gas and natural gas liquids projects and other related projects, some or all of which may involve nonregulated businesses or assets. These projects could involve risks associated with operational factors, such as competition and dependence on certain suppliers and customers, and financial, economic and political factors, such as rapid and significant changes in commodity prices, the cost and availability of capital and counterparty risk, including the inability of a counterparty, customer or supplier to fulfill a contractual obligation.

Our LDCs have recorded certain assets that may not be recoverable from our customers.

Accounting principles that govern our LDCs permit certain assets that result from the regulatory process to be recorded on our balance sheet that could not be recorded under GAAP for nonregulated entities. We consider factors such as rate orders from regulators, previous rate orders for substantially similar costs, written approval from the regulators and analysis of recoverability from internal and external legal counsel to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time.

Terrorist attacks aimed at our facilities could affect adversely our business.

Since the September 11, 2001, terrorist attacks, the United States government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments may subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Our businesses are subject to market and credit risks.

We are exposed to market and credit risks in all of our operations. To minimize the risk of commodity price fluctuations, we periodically enter into derivative transactions to hedge anticipated purchases and sales of natural gas, NGLs, crude oil, fuel requirements and firm transportation commitments. Interest-rate swaps are also used to manage interest-rate risk. Currency forward contracts are used to mitigate unexpected changes that may occur in anticipated revenue streams of our Canadian natural gas sales and purchases driven by currency rate fluctuations. However, financial derivative instrument contracts do not eliminate the risks. Specifically, such risks include commodity price changes, market supply shortages, interest rate changes and counterparty default. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts, or increased interest expense.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by customers and counterparties of our Energy Services segment. The customers of our Energy Services segment are predominantly LDCs, industrial customers, natural gas producers and marketers that may experience deterioration of their financial condition as a result of changing market conditions or financial difficulties that could impact their creditworthiness or ability to pay for our services. If we fail to assess adequately the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting nonpayment and/or nonperformance could adversely impact results of operations for our Energy Services segment. In addition, if any of our Energy Services segment's customers or counterparties filed for bankruptcy protection, we may not be able to recover amounts owed, which could impact materially and adversely the results of operations for our Energy Services segment.

Increased competition could have a significant adverse financial impact on us.

The natural gas and natural gas liquids industries are expected to remain highly competitive. The demand for natural gas and NGLs is primarily a function of commodity prices, including prices for alternative energy sources, customer usage rates, weather, economic conditions and service costs. Our ability to compete also depends on a number of other factors, including competition from other companies for our existing customers, the efficiency, quality and reliability of the services we provide, and competition for throughput at ONEOK Partners' gathering systems, pipelines, processing plants, fractionators and storage facilities.

We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of operations or cash flows. There are no assurances that our business will be positioned to effectively compete in the future.

We may not be able to make additional strategic acquisitions.

Our ability to make strategic acquisitions and investments will depend on: (i) the extent to which acquisitions and investment opportunities become available; (ii) our success in bidding for the opportunities that do become available; (iii) regulatory approval, if required, of the acquisitions on favorable terms; and (iv) our access to capital, including our ability to use our equity in acquisitions or investments, and the terms upon which we obtain capital. If we are unable to make strategic investments and acquisitions, we may be unable to grow.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per-share basis.

Any acquisition involves potential risks that may include, among other things:

- inaccurate assumptions about volumes, revenues and costs, including potential synergies;
- an inability to integrate successfully the businesses we acquire;
- decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified, our indemnity is inadequate or our insurance policies may exclude from coverage;
- an inability to hire, train or retain qualified personnel to manage and operate the acquired business and assets;
- limitations on rights to indemnity from the seller;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas;
- increased regulatory burdens;
- customer or key employee losses at an acquired business; and
- increased regulatory requirements.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and investors will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of our resources to future acquisitions.

We may engage in acquisitions, divestitures and other strategic transactions, the success of which may impact our results of operations.

We may engage in acquisitions, divestitures and other strategic transactions. If we are unable to integrate successfully businesses that we acquire with our existing business, our results of operations may be affected materially and adversely. Similarly, we may from time to time divest portions of our business, which may also affect materially and adversely our results of operations.

Any reduction in our credit ratings could affect materially and adversely our business, financial condition, liquidity and results of operations.

Our long-term senior unsecured debt has been assigned an investment-grade rating by S&P of "BBB" (Stable) and Moody's of "Baa2" (Stable); however, we cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if S&P or Moody's were to downgrade our long-term rating, particularly below investment grade, our borrowing costs would increase, which would affect adversely our financial results, and our potential pool of investors and funding sources could decrease. Further, if our short-term ratings were to fall below A-2 or Prime-2, the current ratings assigned by S&P and Moody's, respectively, it could limit significantly our access to the commercial paper market. Any such downgrade of our long- or short-term ratings could increase significantly our cost of capital and reduce the availability of capital and, thus, have a material adverse effect on our business, financial condition, liquidity and results of operations. Ratings from credit agencies are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

A downgrade in our credit ratings below investment grade would affect negatively the operations of our Energy Services segment. If our credit ratings fall below investment grade, ratings triggers and/or adequate assurance clauses in many of our financial and wholesale physical contracts would be in effect. A ratings trigger or adequate assurance clause gives a counterparty the right to suspend or terminate the agreement unless margin thresholds are met. Margin requirements related to the trading activities of our Energy Services segment may also increase as a result of market volatility without regard to our credit rating. The additional increase in capital required to support our Energy Services segment would impact materially and adversely our ability to compete, as well as our ability to manage actively the risk associated with existing storage and transportation contracts.

Our established risk-management policies and procedures may not be effective, and employees may violate our risk management policies.

We have developed and implemented a comprehensive set of policies and procedures that involve both our senior management and the Audit Committee of our Board of Directors to assist us in managing risks associated with, among other things, the marketing, trading and risk-management activities associated with our business segments. Our risk policies and procedures are intended to align strategies, processes, people, information technology and business knowledge so that risk is managed throughout the organization. As conditions change and become more complex, current risk measures may fail to assess adequately the relevant risk due to changes in the market and the presence of risks previously unknown to us. Additionally, if employees fail to adhere to our policies and procedures or if our policies and procedures are not effective, potentially because of future conditions or risks outside of our control, we may be exposed to greater risk than we had intended. Ineffective risk-management policies and procedures or violation of risk-management policies and procedures could have an adverse affect on our earnings, financial position or cash flows.

Our indebtedness could impair our financial condition and our ability to fulfill our obligations.

As of December 31, 2011, we had total indebtedness for borrowed money of approximately $1.8 billion, which excludes the debt of ONEOK Partners. Our indebtedness could have significant consequences. For example, it could:

- make it more difficult for us to satisfy our obligations with respect to our senior notes and our other indebtedness due to the increased debt-service obligations, which could, in turn, result in an event of default on such other indebtedness or our senior notes;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general business purposes;
- diminish our ability to withstand a downturn in our business or the economy;
- require us to dedicate a substantial portion of our cash flow from operations to debt-service payments, reducing the availability of cash for working capital, capital expenditures, acquisitions, or general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared with our competitors that have proportionately less debt.

We are not prohibited under the indentures governing our senior notes from incurring additional indebtedness, but our debt agreements do subject us to certain operational limitations summarized in the next paragraph. If we incur significant additional indebtedness, it could worsen the negative consequences mentioned above and could affect adversely our ability to repay our other indebtedness.

Our revolving debt agreements with banks contain provisions that restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, certain of these agreements contain provisions that, among other things, limit our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, grant liens, or make negative pledges. Certain agreements also require us to maintain certain financial ratios, which limit the amount of additional indebtedness we can incur, as described in the "Liquidity and Capital Resources" section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash. Future financing agreements we may enter into may contain similar or more restrictive covenants.

If we are unable to meet our debt-service obligations, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

We are subject to comprehensive energy regulation by governmental agencies, and the recovery of our costs is dependent on regulatory action.

We are subject to comprehensive regulation by several federal, state and municipal utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility regulatory authorities in Oklahoma, Kansas and Texas regulate many aspects of our utility operations, including customer service and the rates that we can charge customers. Federal, state and local agencies also have jurisdiction over many of our other activities, including regulation by the FERC of our storage and interstate pipeline assets. The profitability of our regulated operations is dependent on our ability to pass through costs related to providing energy and other commodities to our customers by filing periodic rate cases. The regulatory environment applicable to our regulated businesses could impair our ability to recover costs historically absorbed by our customers.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operating results. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition and results of operations. Further, the results of our LDCs' operations could be impacted negatively if the cost recovery mechanisms authorized by our rate cases do not function as anticipated.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, the Dodd-Frank Act was enacted, which provides for new statutory and regulatory requirements for certain swap transactions. Certain financial transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. However, the Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users and includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and to the parties to those transactions. Additionally, the Dodd-Frank Act calls for various regulatory agencies, including the SEC and the CFTC, to establish regulations for implementation of many of the provisions of the act. It also requires the CFTC to establish new position trading limits.

We expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional record-keeping, reporting and disclosure obligations. These requirements could affect adversely the liquidity and pricing of derivative contracts making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties will likely be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

The volatility of natural gas prices may impact negatively LDC customers' perception of natural gas.

Natural gas costs are passed through to the customers of our LDCs based on the actual cost of the natural gas purchased by the particular LDC. Substantial fluctuations in natural gas prices can occur from year to year. Sustained periods of high natural gas prices or of pronounced natural gas price volatility may impact negatively our LDC customers' perception of natural gas, which could lead to customers selecting other energy alternatives, such as electricity, and to difficulties in the rate-making process. Additionally, high natural gas prices may cause customers to conserve more and may also impact adversely our accounts receivable collections, resulting in higher bad-debt expense.

Our business is subject to regulatory oversight and potential penalties.

The natural gas industry historically has been subject to heavy state and federal regulation that extends to many aspects of our businesses and operations, including:

- rates, operating terms and conditions of service;
- the types of services we may offer our customers;
- construction of new facilities;
- the integrity, safety and security of facilities and operations;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- maintenance of accounts and records; and
- relationships with affiliate companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. Future changes to laws, regulations and policies in these areas may impair our ability to compete for business or to recover costs and may increase the cost and burden of operations.

We cannot guarantee that state or federal regulators will authorize any projects or acquisitions that we may propose in the future. Moreover, there can be no guarantee that, if granted, any such authorizations will be made in a timely manner or will be free from potentially burdensome conditions.

Failure to comply with all applicable state or federal statutes, rules and regulations and orders, could bring substantial penalties and fines. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1.0 million per day for each violation.

Finally, we cannot give any assurance regarding future state or federal regulations under which we will operate or the effect such regulations could have on our business, financial condition and results of operations.

Demand for services of our Natural Gas Distribution and Energy Services segments and for certain of ONEOK Partners' products is highly weather sensitive and seasonal.

The demand for natural gas in our Natural Gas Distribution, Energy Services and ONEOK Partners' segments and for certain of ONEOK Partners' products, such as propane, is weather sensitive and seasonal, with a significant portion of revenues derived from sales for heating during the winter months. Weather conditions influence directly the volume of, among other things, natural gas and propane delivered to customers. Deviations in weather from normal levels and the seasonal nature of certain of our segments' business can create large variations in earnings and short-term cash requirements.

Compliance with environmental regulations that we are subject to may be difficult and costly.

We are subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid and hazardous wastes and hazardous material and substance management. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If a leak or spill of hazardous substance occurs from our lines or facilities in the process of transporting natural gas or NGLs or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean-up costs, which could affect materially our results of operations and cash flows. In addition, emission controls required under the federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. In addition, the EPA issued a rule on air-quality standards, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, with a compliance date in 2013. The rule will require capital expenditures over the next three years for the purchase and installation of new emissions-control equipment. We do not expect these expenditures to have a material impact on our results of operations, financial position or cash flows. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations. For further discussion on this topic, see Note Q of the Notes to Consolidated Financial Statements in this Annual Report.

We are subject to risks that could limit our access to capital, thereby increasing our costs and affecting adversely our results of operations.

We have grown rapidly in the past as a result of acquisitions. Future acquisitions may require additional capital. If we are not able to access capital at competitive rates, our strategy of enhancing the earnings potential of our existing assets, including through acquisitions of complementary assets or businesses, will be affected adversely. A number of factors could affect adversely our ability to access capital, including: (i) general economic conditions; (ii) capital market conditions; (iii) market prices for natural gas, NGLs and other hydrocarbons; (iv) the overall health of the energy and related industries; (v) our ability to maintain our investment-grade credit ratings; and (vi) our capital structure. Much of our business is capital intensive, and achievement of our long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes constrained significantly, our interest costs will likely increase and our financial condition and future results of operations could be harmed significantly.

Energy efficiency and technological advances may affect the demand for natural gas and affect adversely our operating results.

The national trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, may decrease the demand for natural gas by residential customers. More strict conservation measures in the future or technological advances in heating, conservation, energy generation or other devices could affect adversely our operations.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may increase.

We have a defined benefit pension plan for certain employees and postretirement welfare plans that provide postretirement medical and life insurance benefits to certain employees who retire with at least five years of service. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension and postretirement benefit plan assets, changing demographics, including longer life expectancy of plan participants and their beneficiaries and changes in health care costs. For further discussion of our defined benefit pension plan, see Note M of the Notes to Consolidated Financial Statements in this Annual Report.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension and postretirement benefit plan assets. In these circumstances, additional cash contributions to our pension plans may be required.

Our business could be affected adversely by strikes or work stoppages by our unionized employees.

As of January 31, 2012, 694 of our 4,795 employees were represented by collective bargaining units under collective bargaining agreements. We are involved periodically in discussions with collective bargaining units representing some of our employees to negotiate or renegotiate labor agreements. We cannot predict the results of these negotiations, including whether any failure to reach new agreements will have a negative effect on our business, financial condition and results of operations or whether we will be able to reach any agreement with the collective bargaining units. Any failure to reach agreement on new labor contracts might result in a work stoppage. Any future work stoppage could, depending on the operations and the length of the work stoppage, have a material adverse effect on our business, financial condition and results of certain operations.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Greenhouse gas emissions originate primarily from combustion engine exhaust, heater exhaust and fugitive methane gas emissions. Various federal and state legislative proposals have been introduced to regulate the emission of greenhouse gases, particularly carbon dioxide and methane, and the United States Supreme Court has ruled that carbon dioxide is a pollutant subject to regulation by the EPA. In addition, there have been international efforts seeking legally binding reductions in emissions of greenhouse gases.

We believe it is possible that future governmental legislation and/or regulation may require us either to limit greenhouse gas emissions from our operations or to purchase allowances for such emissions that are actually attributable to our distribution customers or attributable to NGL customers of ONEOK Partners. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations, or when they will become effective. Several legislative bills have been introduced in the United States Congress that would require carbon dioxide emission reductions. Previously considered proposals have included, among other things, limitations on the amount of greenhouse gases that can be emitted (so called “caps”) together with systems of emissions allowances. This system could require us to reduce emissions, even though the technology is not currently available for efficient reduction, or to purchase allowances for such emissions. Emissions also could be taxed independently of limits.

In addition to activities on the federal level, state and regional initiatives could also lead to the regulation of greenhouse gas emissions sooner and/or independent of federal regulation. These regulations could be more stringent than any federal regulation or legislation that is adopted.

Future legislation and/or regulation designed to reduce greenhouse gas emissions could make some of our activities uneconomic to maintain or operate. Further, we may not be able to pass on the higher costs to our customers or recover all costs related to complying with greenhouse gas regulatory requirements. Our future results of operations, cash flows or financial condition could be adversely affected if such costs are not recovered through regulated rates or otherwise passed on to our customers.

We continue to monitor legislative and regulatory developments in this area. Although the regulation of greenhouse gas emissions may have a material impact on our operations and rates, we are unable to quantify the potential costs of the impacts at this time.

We do not hedge fully against commodity price changes, time differentials or locational differentials. This could result in decreased revenues and increased costs, thereby resulting in lower margins and adversely affecting our results of operations.

Certain of our nonregulated and regulated businesses are exposed to market risk and the impact of market price fluctuations of natural gas, NGLs and crude oil. Market risk refers to the risk of loss of cash flows and future earnings arising from adverse changes in commodity prices. Our Energy Services segment's primary exposures arise from seasonal and locational price differentials and our ability to execute hedges. Our ONEOK Partners segment's primary exposures arise from the value of the NGL and natural gas it receives in exchange for the natural gas gathering and processing services it provides; the differentials between commodity prices with respect to its keep-whole contracts and the differentials between NGL and natural gas prices and their impact on our natural gas and NGL transportation, fractionation and exchange throughputs; the differentials between the individual NGL products; differentials between NGL prices at different locations; the seasonal differentials impacting the volume of natural gas and NGLs stored; and the fuel costs and the value of the retained fuel in-kind in ONEOK Partners' natural gas pipelines and storage operations. Our ONEOK Partners and Energy Services segments are also exposed to the risk of changing prices or the cost of transportation resulting from purchasing natural gas or NGLs at one location and selling it at another (referred to as basis risk). To minimize the risk from market price fluctuations of natural gas, NGLs and crude oil, we use physical forward transactions and commodity derivative instruments such as futures contracts, swaps and options to manage market risk of existing or anticipated purchases and sales of natural gas, NGLs and crude oil. We adhere to policies and procedures that monitor our exposure to market risk from open positions. However, we do not hedge fully against commodity price changes, and therefore, we retain some exposure to market risk. Accordingly, any adverse changes to commodity prices could result in decreased revenue and/or increased costs.

Our Natural Gas Distribution segment uses storage to minimize the volatility of natural gas costs for our customers by storing natural gas in periods of low demand for consumption in peak demand periods. In addition, various natural gas supply contracts allow us the option to convert index-based purchases to fixed prices. Also, we use derivative instruments to hedge the cost of anticipated natural gas purchases during the winter heating months to protect customers from upward volatility in the market price of natural gas.

Federal, state and local jurisdictions may challenge our tax return positions.

The positions taken in our federal and state tax return filings require significant judgments, use of estimates and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite management's belief that our tax return positions are fully supportable, certain positions may be successfully challenged by federal, state and local jurisdictions.

Although we control ONEOK Partners, we may have conflicts of interest with ONEOK Partners that could subject us to claims that we have breached our fiduciary duty to ONEOK Partners and its unitholders.

We are the sole general partner and own 42.8 percent of ONEOK Partners. Conflicts of interest may arise between us and ONEOK Partners and its unitholders. In resolving these conflicts, we may favor our own interests and the interests of our affiliates over the interests of ONEOK Partners and its unitholders as long as the resolution does not conflict with the ONEOK Partners' partnership agreement or our fiduciary duties to ONEOK Partners and its unitholders.

We are subject to physical and financial risks associated with climate change.

There is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate change creates physical and financial risk. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes may require us to invest in more pipelines and other infrastructure to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues. Severe weather impacts our operating territories primarily through hurricanes, thunderstorms, tornadoes and snow or ice storms. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could affect negatively our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change.

Both our and ONEOK Partners' operations are subject to operational hazards and unforeseen interruptions, which could affect materially and adversely our and ONEOK Partners' business and for which neither we nor ONEOK Partners may be insured adequately.

Our and ONEOK Partners' operations are subject to all of the risks and hazards typically associated with the operation of natural gas and natural gas liquids gathering, transportation and distribution pipelines, storage facilities and processing and fractionation plants. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes, and the performance of pipeline facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment with our or ONEOK Partners' pipeline facilities (for example, this may occur if a third party were to perform excavation or construction work near our or ONEOK Partners' facilities) and catastrophic events such as tornados, hurricanes, earthquakes, floods or other similar events beyond our or ONEOK Partners' control. It is also possible that our or ONEOK Partners' facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred and interruptions to the operations of our or ONEOK Partners' pipelines or other facilities caused by such an event could reduce revenues generated by us or ONEOK Partners and increase expenses, thereby impairing our or ONEOK Partners' ability to meet our respective obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost, and neither we nor ONEOK Partners are fully insured against all risks inherent in our respective businesses.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and, in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Consequently, neither we nor ONEOK Partners may be able to renew existing insurance policies or purchase other desirable insurance on commercially reasonable terms, if at all. If either we or ONEOK Partners were to incur a significant liability for which either we or ONEOK Partners was not insured fully, it could have a material adverse effect on our or ONEOK Partners' financial position and results of operations. Further, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Our use of financial instruments to hedge market risk may result in reduced income.

We utilize financial instruments to mitigate our exposure to commodity price and interest-rate fluctuations. Hedging arrangements that are used to reduce our exposure to commodity price fluctuations may limit the benefit we would otherwise receive if market prices for natural gas, crude oil and NGLs exceed the stated price in the hedge instrument for these commodities. Hedging instruments that are used to reduce our exposure to interest-rate fluctuations could expose us to risk of financial loss where we have contracted for variable-rate swap instruments to hedge fixed-rate instruments and the variable rate exceeds the fixed rate. In addition, these hedging arrangements may limit the benefit we would otherwise receive if we had contracted for fixed-rate swap agreements to hedge variable-rate instruments and the variable rate falls below the fixed rate.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may affect adversely our financial results.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings, our financial results could be affected adversely. Our financial results could also be affected adversely if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our businesses. We use computer programs to help run our financial and operations sectors, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse on our businesses. In addition, cyber attacks on our customer and employee data may result in a financial loss and may impact negatively our reputation.

Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt one or more of our businesses, result in potential liability or reputational damage or otherwise have an adverse affect on our financial results.

Increases in interest rates could affect adversely our business.

We use both fixed- and variable-rate debt, and we are exposed to market risk due to the floating interest rates on our short-term borrowings. From time to time we use interest-rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. These hedges may be ineffective, and our results of operations, cash flows and financial position could be affected adversely by significant increases in interest rates above current levels.

We do not own all of the land on which our pipelines and facilities are located, and we lease certain facilities and equipment, which could disrupt our operations.

We do not own all of the land on which certain of our pipelines and facilities are located, and are, therefore, subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts on acceptable terms or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs, which could affect operations and cash flows available for distribution.

Our operations require skilled and experienced workers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the midstream energy business has caused us to conduct certain operations without full staff, thus hiring outside resources, which may decrease productivity and increase costs. This shortage of trained workers is the result of experienced workers reaching retirement age, and increased competition for workers in certain areas, combined with the difficulty of attracting new workers to the midstream energy industry. This shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our products and services, which could adversely affect operations and cash flows available for distribution to unitholders.

Pipeline-integrity programs and repairs may impose significant costs and liabilities.

Pursuant to a United States Department of Transportation rule, pipeline operators are required to develop integrity-management programs for intrastate and interstate natural gas and natural gas liquids pipelines that could affect high-consequence areas in the event of a release of product. As defined by applicable regulations, high-consequence areas include areas near the route of a pipeline with high population densities, facilities occupied by persons of limited mobility or indoor or outdoor areas where at least twenty people gather periodically. The rule requires operators to identify to pipeline segments that could impact a high-consequence area; improve data collection, integration and characterization of threats applicable to each segment, implement preventive and mitigating actions, perform ongoing assessments of pipeline integrity and repair and remediate as necessary. These testing programs could cause us and ONEOK Partners to incur significant capital and operating expenditures to make repairs or remediate, as well as initiate preventive or mitigating actions that are determined to be necessary.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could affect adversely financial results.

The workplaces associated with our facilities are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. The failure to comply with OSHA requirements or general industry standards, including keeping adequate records or occupational exposure to regulated substances could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties and could have a material adverse effect on our business, financial position, results of operations and cash flow.

Measurement adjustments on our pipeline system can be impacted materially by changes in estimation, type of commodity and other factors.

Natural gas and natural gas liquids measurement adjustments occur as part of the normal operating conditions associated with our assets. The quantification and resolution of measurement adjustments are complicated by several factors including: (1) the significant quantities (*i.e.*, thousands) of measurement meters that we use throughout our natural gas systems; (2) varying qualities of natural gas in the streams gathered and processed and the mixed nature of NGLs gathered and fractionated through ONEOK Partners' systems; and (3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that can occur on our systems, which could affect negatively our earnings and cash flows.

ADDITIONAL RISK FACTORS RELATED TO ONEOK PARTNERS' BUSINESS

The volatility of natural gas, crude oil and NGL prices could affect adversely ONEOK Partners' cash flow.

A significant portion of ONEOK Partners' revenues are derived from the sale of commodities that are received as payment for natural gas gathering and processing services, for the transportation and storage of natural gas, and for the sale of purity NGL products in ONEOK Partners' natural gas liquids business. Commodity prices have been volatile and are likely to continue to be so in the future. The prices ONEOK Partners receives for its commodities are subject to wide fluctuations in response to a variety of factors beyond ONEOK Partners' control, including, but not limited to, the following:

- overall domestic and global economic conditions;
- relatively minor changes in the supply of, and demand for, domestic and foreign energy;
- market uncertainty;
- the availability and cost of third-party transportation, natural gas processing and natural gas liquids fractionation capacity;
- the level of consumer product demand;
- geopolitical conditions impacting supply and demand for natural gas, NGLs and crude oil;
- weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- speculation in the commodity futures markets;
- overall domestic and global economic conditions;
- the price of natural gas, crude oil, NGL and liquefied natural gas imports and exports;
- the effect of worldwide energy conservation measures; and
- the impact of new supplies, new pipelines, processing and fractionation facilities on location price differentials.

These external factors and the volatile nature of the energy markets make it difficult to estimate reliably future prices of commodities and the impact commodity price fluctuations have on our customers and their need for our services. As commodity prices decline, ONEOK Partners is paid less for its commodities, thereby reducing its cash flow. In addition, production could also decline.

ONEOK Partners' inability to develop and execute growth projects and acquire new assets could result in reduced cash distributions to its unitholders and to ONEOK.

ONEOK Partners' primary business objectives are to generate cash flow sufficient to pay quarterly cash distributions to unitholders and to increase quarterly cash distributions over time. ONEOK Partners' ability to maintain and grow its distributions to unitholders, including ONEOK, depends on the growth of its existing businesses and strategic acquisitions. Accordingly, if ONEOK Partners is unable to implement business development opportunities and finance such activities on economically acceptable terms, its future growth will be limited, which could adversely impact its and our results of operations and cash flows.

Growing ONEOK Partners' business by constructing new pipelines and plants or making modifications to its existing facilities subjects ONEOK Partners to construction risks and supply risks should adequate natural gas or NGL supplies be unavailable upon completion of the facilities.

One of the ways ONEOK Partners intends to grow its business is through the construction of new pipelines and new gathering, processing, storage and fractionation facilities and through modifications to ONEOK Partners' existing pipelines and existing gathering, processing, storage and fractionation facilities. The construction and modification of pipelines and gathering, processing, storage and fractionation facilities may require significant capital expenditures, which may exceed ONEOK Partners' estimates, and involves numerous regulatory, environmental, political, legal and weather-related uncertainties. Construction projects in ONEOK Partners' industry may increase demand for labor, materials and rights of way, which, may, in turn, impact ONEOK Partners' costs and schedule. If ONEOK Partners undertakes these projects, it may not be able to complete them on schedule or at the budgeted cost. Additionally, ONEOK Partners' revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if ONEOK Partners builds a new pipeline, the construction will occur over an extended period of time, and ONEOK Partners will not receive any material increases in revenues until after completion of the project. ONEOK Partners may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Additionally, ONEOK Partners may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. ONEOK Partners may also rely on estimates of proved reserves in its decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas or NGLs to achieve ONEOK Partners' expected investment return, which could affect materially and adversely ONEOK Partners' results of operations and financial condition.

If the level of drilling and production in the Mid-Continent, Rocky Mountain, Texas and Gulf Coast regions declines substantially near its assets, ONEOK Partners' volumes and revenue could decline.

ONEOK Partners' ability to maintain or expand its businesses depends largely on the level of drilling and production by third parties in the Mid-Continent, Rocky Mountain, Texas and Gulf Coast regions. Drilling and production are impacted by factors beyond ONEOK Partners' control, including:

- demand and prices for natural gas, NGLs and crude oil;
- producers' finding and developing costs of reserves;
- producers' desire and ability to obtain necessary permits in a timely and economic manner;
- natural gas field characteristics and production performance;
- surface access and infrastructure issues; and
- capacity constraints on natural gas, crude oil and natural gas liquids pipelines from the producing areas and ONEOK Partners' facilities.

If production from the Western Canada Sedimentary Basin remains flat or declines, and demand for natural gas from the Western Canada Sedimentary Basin is greater in market areas other than the Midwestern United States, demand for ONEOK Partners' interstate gas transportation services could decrease significantly.

ONEOK Partners depends on natural gas supply from the Western Canada Sedimentary Basin for some of ONEOK Partners' interstate pipelines, primarily Viking Gas Transmission and ONEOK Partners' investment in Northern Border Pipeline, that transport Canadian natural gas from the Western Canada Sedimentary Basin to the Midwestern United States market area. If demand for natural gas increases in Canada or other markets not served by ONEOK Partners' interstate pipelines and/or production remains flat or declines, demand for transportation service on ONEOK Partners' interstate natural gas pipelines could decrease significantly, which could impact adversely ONEOK Partners' results of operations and cash flows available for distributions.

ONEOK Partners' regulated pipelines' transportation rates are subject to review and possible adjustment by federal and state regulators.

Under the Natural Gas Act, which is applicable to interstate natural gas pipelines, and the Interstate Commerce Act, which is applicable to crude oil and natural gas liquids pipelines, ONEOK Partners' interstate transportation rates, which are regulated by the FERC, must be just and reasonable and not unduly discriminatory.

Shippers may protest ONEOK Partners' pipeline tariff filings, and the FERC and/or state regulatory agencies may investigate tariff rates. Further, the FERC may order refunds of amounts collected under newly filed rates that are determined by the FERC to be in excess of a just and reasonable level. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC and/or state regulatory agencies may also investigate tariff rates absent shipper complaint. Any finding that approved rates exceed a just and reasonable level on the natural gas pipelines would take effect prospectively. In a complaint proceeding challenging natural gas liquids pipeline rates, if the FERC determines existing rates exceed a just and reasonable level, it could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Any such action by the FERC or a comparable action by a state regulatory agency could affect adversely ONEOK Partners' pipeline businesses' ability to charge rates that would cover future increases in costs, or even to continue to collect rates that cover current costs and provide for a reasonable return. We can provide no assurance that ONEOK Partners' pipeline systems will be able to recover all of their costs through existing or future rates.

ONEOK Partners' regulated pipeline companies have recorded certain assets that may not be recoverable from its customers.

Accounting policies for FERC-regulated companies permit certain assets that result from the regulated ratemaking process to be recorded on ONEOK Partners' balance sheet that could not be recorded under GAAP for nonregulated entities. ONEOK Partners considers factors such as regulatory changes and the impact of competition to determine the probability of future recovery of these assets. If ONEOK Partners determines future recovery is no longer probable, ONEOK Partners would be required to write off the regulatory assets at that time.

ONEOK Partners' operations are subject to federal and state laws and regulations relating to the protection of the environment, which may expose it to significant costs and liabilities.

The risk of incurring substantial environmental costs and liabilities is inherent in ONEOK Partners' business. ONEOK Partners' operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into, or otherwise relating to the protection of, the environment. Examples of these laws include:

- the Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the Clean Water Act and analogous state laws that regulate discharge of waste water from ONEOK Partners' facilities to state and federal waters;
- the federal CERCLA and analogous state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by ONEOK Partners or locations to which ONEOK Partners has sent waste for disposal;
- the federal Resource Conservation and Recovery Act and analogous state laws that impose requirements for the handling and discharge of solid and hazardous waste from ONEOK Partners' facilities; and
- the EPA has issued a rule on air-quality standards, known as RICE NESHAP, with a compliance date in 2013.

Various federal and state governmental authorities, including the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them. Violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under the CERCLA, Resource Conservation and Recovery Act and analogous state laws for the remediation of contaminated areas.

There is an inherent risk of incurring environmental costs and liabilities in ONEOK Partners' business due to its handling of the products it gathers, transports, processes and stores, air emissions related to its operations, past industry operations and waste disposal practices, some of which may be material. Private parties, including the owners of properties through which ONEOK Partners' pipeline systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from ONEOK Partners' operations. Some sites ONEOK Partners operates are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ONEOK Partners' sites. In addition, increasingly strict laws, regulations and enforcement policies could increase significantly ONEOK Partners' compliance costs and the cost of any remediation that may become necessary, some of which may be material. Additional information is included under Item 1, Business under "Environmental and Safety Matters" and in Note Q of the Notes to Consolidated Financial Statements in this Annual Report.

ONEOK Partners' insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against ONEOK Partners. ONEOK Partners' business may be affected materially and adversely by increased costs due to stricter pollution-control requirements or liabilities resulting from noncompliance with required operating or other regulatory permits. New environmental regulations might also materially adversely affect ONEOK Partners' products and activities, and federal and state agencies could impose additional safety requirements, all of which could affect materially ONEOK Partners' profitability.

In the competition for customers, ONEOK Partners may have significant levels of uncontracted or discounted capacity on its natural gas and natural gas liquids pipelines, processing, fractionation and storage assets.

ONEOK Partners' natural gas and natural gas liquids pipelines, processing, fractionation and storage assets compete with other pipelines, processing, fractionation and storage facilities for natural gas and NGL supplies delivered to the markets it serves. As a result of competition, at any given time ONEOK Partners may have significant levels of uncontracted or discounted capacity on its pipelines, processing, fractionation and in its storage assets, which could have a material adverse impact on ONEOK Partners' results of operations.

ONEOK Partners is exposed to the credit risk of its customers or counterparties, and its credit risk management may not be adequate to protect against such risk.

ONEOK Partners is subject to the risk of loss resulting from nonpayment and/or nonperformance by ONEOK Partners' customers or counterparties. ONEOK Partners' customers or counterparties may experience rapid deterioration of their financial condition as a result of changing market conditions or financial difficulties that could impact their creditworthiness or ability to pay ONEOK Partners for its services. ONEOK Partners assesses the creditworthiness of its customers or counterparties and obtains collateral as it deems appropriate. If ONEOK Partners fails to assess adequately the creditworthiness of existing or future customers or counterparties, unanticipated deterioration in their creditworthiness and any resulting nonpayment and/or nonperformance could adversely impact ONEOK Partners' results of operations. In addition, if any of ONEOK Partners' customers or counterparties files for bankruptcy protection, this could have a material negative impact on ONEOK Partners' results of operations.

Any reduction in ONEOK Partners' credit ratings could affect materially and adversely its business, financial condition, liquidity and results of operations.

ONEOK Partners' senior unsecured long-term debt has been assigned an investment-grade rating by Moody's of "Baa2" (Stable) and by S&P of "BBB" (Stable); however, we cannot provide assurance that any of its current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if Moody's or S&P were to downgrade ONEOK Partners' long-term debt rating, particularly below investment grade, its borrowing costs would increase, which would affect adversely its financial results, and its potential pool of investors and funding sources could decrease. Ratings from credit agencies are not recommendations to buy, sell or hold ONEOK Partners' securities. Each rating should be evaluated independently of any other rating.

An event of default may require ONEOK Partners to offer to repurchase certain of its senior notes or may impair its ability to access capital.

The indentures governing ONEOK Partners' senior notes include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of ONEOK Partners' outstanding senior notes to declare those senior notes immediately due and payable in full. ONEOK Partners may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause ONEOK Partners to borrow money under its credit facilities or seek alternative financing sources to finance the repurchases and repayment. ONEOK Partners could also face difficulties accessing capital or its borrowing costs could increase, impacting its ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill its debt obligations.

ONEOK Partners has adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of its limited partner units.

When ONEOK Partners issues additional units or engages in certain other transactions, ONEOK Partners determines the fair market value of its assets and allocates any unrealized gain or loss attributable to its assets to the capital accounts of its unitholders and its general partner. ONEOK Partners' methodology may be viewed as understating the value of its assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under ONEOK Partners' current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to ONEOK Partners' tangible assets and a lesser portion allocated to ONEOK Partners' intangible assets. The IRS may challenge ONEOK Partners' valuation methods or ONEOK Partners' allocation of the Section 743(b) adjustment attributable to ONEOK Partners' tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of ONEOK Partners' unitholders.

A successful IRS challenge to these methods or allocations could affect adversely the amount of taxable income or loss being allocated to ONEOK Partners' unitholders. It also could affect the amount of gain from ONEOK Partners unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to ONEOK Partners unitholders' tax returns without the benefit of additional deductions.

ONEOK Partners' treatment of a purchaser of common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of the common units.

Because ONEOK Partners cannot match transferors and transferees of common units, ONEOK Partners is required to maintain the uniformity of the economic and tax characteristics of these units in the hands of the purchasers and sellers of these units. ONEOK Partners does so by adopting certain depreciation conventions that do not conform to all aspects of existing United States Treasury regulations. A successful IRS challenge to these conventions could affect adversely the tax benefits to a unitholder of ownership of the common units and could have a negative impact on their value or result in audit adjustments to ONEOK Partners unitholders' tax returns.

Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, which could impact adversely ONEOK Partners' revenues by decreasing the volumes of unprocessed natural gas transported on its or its joint ventures natural gas pipelines.

The natural gas industry is relying increasingly on natural gas supplies from unconventional sources, such as shale, tight sands and coal-bed methane gas. Natural gas extracted from these sources frequently requires hydraulic fracturing, which involves the pressurized injection of water, sand, and chemicals into the geologic formation to stimulate natural gas production. Recently, there have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing, and several states have adopted regulations that impose more stringent permitting, disclosure and well-completion requirements on hydraulic fracturing operations. Legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of unprocessed natural gas and, in turn, adversely affect ONEOK Partners' revenues and results of operations by decreasing the volumes of unprocessed natural gas gathered, treated, processed and transported on ONEOK Partners' or its joint ventures' natural gas pipelines, several of which gather unprocessed natural gas from areas where the use of hydraulic fracturing is prevalent.

Continued development of new supply sources could impact demand.

The discovery of nontraditional natural gas production areas nearer to certain of the market areas that we serve may compete with natural gas originating in production areas connected to our systems. For example, the Marcellus Shale in Pennsylvania, New York, West Virginia and Ohio, may cause natural gas in supply areas connected to our systems to be diverted to markets other than our traditional market areas and may affect capacity utilization adversely on our pipeline systems and our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows. In addition, supply volumes from these nontraditional natural gas production areas may compete with and displace volumes from the Mid-Continent, Rocky Mountains and Canadian supply sources in certain of our markets. The displacement of natural gas originating in supply areas connected to our pipeline systems by these new supply sources that are closer to the end-use markets could result in lower transportation revenues, which could have a material adverse impact on our business, financial condition, results of operations and cash flows.

An impairment of goodwill, long-lived assets, including intangible assets, and equity-method investments could reduce our earnings.

Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP require us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization.

A court may use fraudulent conveyance considerations to avoid or subordinate ONEOK Partners Intermediate Limited Partnership's guarantee of certain of ONEOK Partners' senior notes.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. A court may use fraudulent conveyance laws to subordinate or avoid the guarantee of certain of ONEOK Partners' senior notes issued by ONEOK Partners Intermediate Limited Partnership. It is also possible that under certain circumstances, a court could hold that the direct obligations of the Intermediate Partnership could be superior to the obligations under that guarantee.

A court could avoid or subordinate the Intermediate Partnership's guarantee of certain of ONEOK Partners' senior notes in favor of the Intermediate Partnership's other debts or liabilities to the extent that the court determined either of the following were true at the time the Intermediate Partnership issued the guarantee:

- the Intermediate Partnership incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or the Intermediate Partnership contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or
- the Intermediate Partnership did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, the Intermediate Partnership:
    - was insolvent or rendered insolvent by reason of the issuance of the guarantee;

- was engaged or about to engage in a business or transaction for which its remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if:

- the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

Among other things, a legal challenge of the Intermediate Partnership's guarantee of certain of ONEOK Partners' senior notes on fraudulent conveyance grounds may focus on the benefits, if any, realized by the Intermediate Partnership as a result of ONEOK Partners' issuance of such senior notes. To the extent the Intermediate Partnership's guarantee of certain of ONEOK Partners' senior notes is avoided as a result of fraudulent conveyance or held unenforceable for any other reason, the holders of such senior notes would cease to have any claim in respect of the guarantee.

ONEOK Partners may be unable to cause its joint ventures to take or not to take certain actions unless some or all of its joint-venture participants agree.

ONEOK Partners participates in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100 percent) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint-venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint-venture participants with enough voting interests, ONEOK Partners may be unable to cause any of its joint ventures to take or not to take certain actions, even though those actions may be in the best interest of ONEOK Partners or the particular joint venture.

Moreover, any joint-venture owner generally may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint-venture owners. Any such transaction could result in ONEOK Partners being required to partner with different or additional parties.

ONEOK Partners' operating cash flow is derived partially from cash distributions it receives from its unconsolidated affiliates.

ONEOK Partners' operating cash flow is derived partially from cash distributions it receives from its unconsolidated affiliates, as discussed in Note O of the Notes to Consolidated Financial Statements. The amount of cash that ONEOK Partners' unconsolidated affiliates can distribute principally depends upon the amount of cash flow these affiliates generate from their respective operations, which may fluctuate from quarter to quarter. ONEOK Partners does not have any direct control over the cash distribution policies of its unconsolidated affiliates. This lack of control may contribute to ONEOK Partners' not having sufficient available cash each quarter to continue paying distributions at its current levels.

Additionally, the amount of cash that ONEOK Partners has available for cash distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by noncash items such as depreciation, amortization and provisions for asset impairments. As a result, ONEOK Partners may be able to make cash distributions during periods when it records losses and may not be able to make cash distributions during periods when it records net income.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

DESCRIPTION OF PROPERTIES

ONEOK Partners

Property - Our ONEOK Partners segment owns the following assets:

- approximately 10,300 miles and 5,600 miles of natural gas gathering pipelines in the Mid-Continent and Rocky Mountain regions, respectively;
- nine natural gas processing plants, with approximately 645 MMcf/d of processing capacity, in the Mid-Continent region, and five natural gas processing plants, with approximately 215 MMcf/d of processing capacity, in the Rocky Mountain region;
- approximately 24 MBbl/d of natural gas liquids fractionation capacity at various natural gas processing plants in the Mid-Continent and Rocky Mountain regions;
- approximately 1,500 miles of FERC-regulated interstate natural gas pipelines with approximately 3.1 Bcf/d of peak transportation capacity;
- approximately 5,600 miles of intrastate natural gas gathering and state-regulated intrastate transmission pipelines with approximately 3.4 Bcf/d of peak transportation capacity;
- approximately 51.7 Bcf of total active working natural gas storage capacity;
- approximately 2,500 miles of natural gas liquids gathering pipelines with peak gathering capacity of approximately 629 MBbl/d;
- approximately 160 miles of natural gas liquids distribution pipelines with approximately 66 MBbl/d of peak transportation capacity;
- two natural gas liquids fractionators with approximately 260 MBbl/d of combined operating capacity, which are located in Oklahoma and Kansas;
- a natural gas liquids fractionator with operating capacity of 150 MBbl/d located at the Bushton facility in Kansas, portion of which prior to June 30, 2011, was leased through an affiliate;
- 80-percent ownership interest in one natural gas liquids fractionator in Texas with ONEOK Partners' proportional share of operating capacity of approximately 128 MBbl/d;
- interest in one natural gas liquids fractionator in Kansas with ONEOK Partners' proportional share of operating capacity of approximately 11 MBbl/d;
- one isomerization unit in Kansas with 9 MBbl/d of operating capacity;
- six natural gas liquids storage facilities and other leased facilities in Oklahoma, Kansas and Texas with approximately 23.2 MMBbl of total operating underground NGL storage capacity;
- approximately 780 miles of FERC-regulated natural gas liquids gathering pipelines with approximately 213 MBbl/d of peak capacity;
- approximately 3,500 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with approximately 708 MBbl/d of peak capacity;
- eight natural gas liquids product terminals in Missouri, Nebraska, Iowa and Illinois; and
- above- and below-ground storage facilities associated with its FERC-regulated natural gas liquids pipeline operations in Iowa, Illinois, Nebraska and Kansas with 978 MBbl of combined operating capacity.

ONEOK Partners owns or leases five underground natural gas storage facilities in Oklahoma, three underground natural gas storage facilities in Kansas and three underground natural gas storage facilities in Texas. One of its natural gas storage facilities in Kansas has been idle since 2001. In compliance with a KDHE order, ONEOK Partners began injecting brine into that facility in the first quarter of 2007 in order to ensure the long-term integrity of the idled facility. ONEOK Partners expects to complete the injection process by the end of 2012. Monitoring of the facility and review of the data for the geo-engineering studies are ongoing, in compliance with a KDHE order while ONEOK Partners evaluates the alternatives for the facility. Following the testing of the gathered data, ONEOK Partners expects that the facility will be returned to storage service, although most likely for a product other than natural gas. The return to service will require KDHE approval. It is possible, however, that testing could reveal that it is not safe to return the facility to service or that the KDHE will not grant the required permits to resume service.

Utilization - The utilization rates for ONEOK Partners' various assets for 2011 and 2010 were as follows:

- natural gas processing plants were approximately 71 percent and 69 percent utilized, respectively;
- natural gas pipelines were approximately 83 percent and 87 percent subscribed, respectively, and storage facilities were fully subscribed both years;
- non-FERC-regulated natural gas liquids pipelines were approximately 71 percent and 56 percent subscribed, respectively;

- average contracted natural gas liquids storage volumes were approximately 63 percent and 64 percent of storage capacity, respectively;
- natural gas liquids fractionators were approximately 89 percent and 93 percent utilized, respectively;
- FERC-regulated natural gas liquids gathering pipelines were approximately 97 percent and 70 percent utilized, respectively; and
- FERC-regulated natural gas liquids distribution pipelines were approximately 65 percent and 63 percent utilized, respectively.

ONEOK Partners calculates utilization on its assets using a weighted-average approach, adjusting for the dates that assets were placed in service. The utilization rate of ONEOK Partners' FERC-regulated natural gas liquids gathering pipelines reflect Overland Pass Pipeline and its related lateral pipelines until Overland Pass Pipeline Company was deconsolidated in September 2010. The utilization rate of ONEOK Partners' fractionation facilities reflects leased capacity and the approximate proportional capacity associated with ONEOK Partner's ownership interests.

Natural Gas Distribution

Property - We own approximately 18,600 miles of pipeline and other natural gas distribution facilities in Oklahoma; approximately 12,800 miles of pipeline and other natural gas distribution facilities in Kansas; and approximately 9,800 miles of pipeline and other natural gas distribution facilities in Texas. In addition, we have 39.3 Bcf of natural gas storage capacity under lease with maximum withdrawal capacity of approximately 1.0 Bcf/d.

Energy Services

Property - Our total natural gas storage capacity under lease is 75.6 Bcf, with maximum withdrawal capability of 2.4 Bcf/d and maximum injection capability of 1.3 Bcf/d. At December 31, 2011, our natural gas transportation capacity was 1.2 Bcf/d, of which 1.1 Bcf/d was contracted under long-term natural gas transportation contracts. Our contracted storage and transportation capacity connects major supply and demand centers throughout the United States and into Canada. We have 22 different storage leases throughout the United States.

Other

Property - We own the 17-story ONEOK Plaza office building, with approximately 517,000 square feet of net rentable space, and an associated parking garage.

ITEM 3. LEGAL PROCEEDINGS

Thomas F. Boles, et al. v. El Paso Corporation, et al. (f/k/a Will Price, et al. v. Gas Pipelines, et al., f/k/a Quinque Operating Company, et al. v. Gas Pipelines, et al.), 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 99C30 ("Boles I"). Plaintiffs brought suit on May 28, 1999, against us and our division, Oklahoma Natural Gas, four subsidiaries of ONEOK Partners, Mid-Continent Market Center, L.L.C., ONEOK Field Services Company, L.L.C., ONEOK WesTex Transmission, L.L.C. and ONEOK Hydrocarbon, L.P. (formerly Koch Hydrocarbon, LP, successor to Koch H`ydrocarbon Company), as well as approximately 225 other defendants. Plaintiffs sought class certification for their claims for monetary damages, alleging that the defendants had underpaid gas producers and royalty owners throughout the United States by intentionally understating both the volume and the heating content of purchased gas. After extensive briefing and a hearing, the Court refused to certify the class sought by plaintiffs. Plaintiffs then filed an amended petition limiting the purported class to gas producers and royalty owners in Kansas, Colorado and Wyoming and limiting the claim to undermeasurement of volumes. On September 18, 2009, the Court denied the plaintiffs' motions for class certification, which, in effect, limits the named plaintiffs to pursuing individual claims against only those defendants who purchased or measured their gas. The plaintiffs' motion for reconsideration of the Court's denial of class certification was denied on March 31, 2010. This case continues but is now limited to the individual claims of the two named plaintiffs.

Thomas F. Boles, et al. v. El Paso Corporation, et al. (f/k/a Will Price and Stixon Petroleum, et al. v. Gas Pipelines, et al.), 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 03C232 ("Boles II"). This action was filed by the plaintiffs on May 12, 2003, after the Court denied class status in Boles I. Plaintiffs are seeking monetary damages based upon a claim that 21 groups of defendants, including us and our division, Oklahoma Natural Gas, four subsidiaries of ONEOK Partners, Mid-Continent Market Center, L.L.C., ONEOK Field Services Company, L.L.C., ONEOK WesTex Transmission, L.L.C. and ONEOK Hydrocarbon, L.P. (formerly Koch Hydrocarbon, LP, successor to Koch Hydrocarbon Company), intentionally underpaid gas producers and royalty owners by understating the heating content of purchased gas in Kansas, Colorado and Wyoming. Boles II has been consolidated with Boles I for the determination of whether either or both cases may be certified properly as class actions. On September 18, 2009, the Court denied the plaintiffs' motions for class certification, which, in effect, limits the named plaintiffs to pursuing individual claims against only those defendants who purchased or measured their gas. The plaintiffs' motion for reconsideration of the Court's denial of class certification was denied on March 31, 2010. This case continues but is now limited to the individual claims of the two named plaintiffs.

Gas Index Pricing Litigation: We, ONEOK Energy Services Company, L.P. ("OESC") and one other affiliate are defending, either individually or together, against the following lawsuits that claim damages resulting from the alleged market manipulation or false reporting of prices to gas index publications by us and others: *Sinclair Oil Corporation v. ONEOK Energy Services Corporation, L.P., et al.* (filed in the United States District Court for the District of Wyoming in September 2005, transferred to MDL-1566 in the United States District Court for the District of Nevada); *Reorganized FLI, Inc. (*formerly *J.P. Morgan Trust Company) v. ONEOK, Inc., et al.* (filed in the District Court of Wyandotte County, Kansas, in October 2005, transferred to MDL-1566 in the United States District Court for the District of Nevada); *Learjet, Inc., et al. v. ONEOK, Inc., et al.* (filed in the District Court of Wyandotte, Kansas, in November 2005, transferred to MDL-1566 in the United States District Court for the District of Nevada); *Breckenridge Brewery of Colorado, LLC, et al. v. ONEOK, Inc., et al.* (filed in the District Court of Denver County, Colorado, in May 2006, transferred to MDL-1566 in the United States District Court for the District of Nevada); *Arandell Corporation, et al. v. Xcel Energy, Inc., et al.* (filed in the Circuit Court for Dane County, Wisconsin, in December 2006, transferred to MDL-1566 in the United States District Court for the District of Nevada); *Heartland Regional Medical Center, et al. v. ONEOK, Inc., et al.* (filed in the Circuit Court of Buchanan County, Missouri, in March 2007, transferred to MDL-1566 in the United States District Court for the District of Nevada); *NewPage Wisconsin System v. CMS Energy Resource Management Company, et al.* (filed in the Circuit Court for Wood County, Wisconsin, in March 2009, transferred to MDL-1566 in the United States District Court for the District of Nevada and now consolidated with the *Arandell* case). In each of these lawsuits, the plaintiffs allege that we, OESC and one other affiliate and approximately ten other energy companies and their affiliates engaged in an illegal scheme to inflate natural gas prices by providing false information to gas price index publications. All of the complaints arise out of a CFTC investigation into and reports concerning false gas price index-reporting or manipulation in the energy marketing industry during the years from 2000 to 2002.

On July 18, 2011, the trial court granted judgments in favor of ONEOK, Inc., OESC and other unaffiliated entities in the following cases: *Reorganized FLI, Learjet, Arandell, Heartland,* and *NewPage.* A final judgment in favor of all defendants was also granted in the *Breckenridge* case. The court also granted a final judgment in favor of OESC on all state law claims asserted in the *Sinclair* case. The plaintiffs in those cases case have appealed the judgments entered by the trial court to the United States Court of Appeals for the Ninth Circuit. All of the appeals have been consolidated for briefing purposes by the Ninth Circuit. On August 18, 2011, the trial court entered an order approving a stipulation by the plaintiffs and our affiliate, Kansas Gas Marketing Company ("KGMC"), for a dismissal without prejudice of the plaintiffs' claims against KGMC in the *Learjet* and *Heartland* cases.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND HOLDERS

Our common stock is listed on the NYSE under the trading symbol "OKE." The corporate name ONEOK is used in newspaper stock listings. The following table sets forth the high and low closing prices of our common stock for the periods indicated:

	Year Ended December 31, 2011		Year Ended December 31, 2010	
	High	**Low**	**High**	**Low**
First Quarter	**$ 66.88**	**$ 55.38**	$ 47.15	$ 40.62
Second Quarter	**$ 74.01**	**$ 64.23**	$ 50.72	$ 42.00
Third Quarter	**$ 75.95**	**$ 59.31**	$ 47.91	$ 42.29
Fourth Quarter	**$ 86.70**	**$ 64.21**	$ 55.69	$ 45.64

At February 14, 2012, there were 14,583 holders of record of our 103,893,790 outstanding shares of common stock.

DIVIDENDS

The following table sets forth the quarterly dividends declared and paid per share of our common stock during the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
First Quarter	**$ 0.52**	$ 0.44	$ 0.40
Second Quarter	**$ 0.52**	$ 0.44	$ 0.40
Third Quarter	**$ 0.56**	$ 0.46	$ 0.42
Fourth Quarter	**$ 0.56**	$ 0.48	$ 0.42
Total	**$ 2.16**	$ 1.82	$ 1.64

In January 2012, we declared a dividend of $0.61 per share ($2.44 per share on an annualized basis) for the fourth quarter of 2011, which was paid on February 14, 2012, to shareholders of record as of January 31, 2012.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table sets forth information relating to our purchases of our common stock for the periods shown:

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Be Purchased Under the Plans or Programs
October 1-31, 2011	6,660	$28.15	-	
November 1-30, 2011	5,744	$18.10	-	
December 1-31, 2011	-	-	-	
Total	12,404	$23.49	-	$ 450,000,000 (b)

(a) - Includes shares withheld pursuant to attestation of ownership and deemed tendered to us in connection with the exercise of stock options under the ONEOK, Inc. Long-Term Incentive Plan.

(b) - The maximum approximate dollar value of shares that may yet be purchased pursuant to our approximately $750 million stock repurchase program that was announced on October 21, 2010, subject to the limitation that purchases will not exceed $300 million in any one calendar year. The program will terminate upon the completion of the repurchase of $750 million of common stock or on December 31, 2013, whichever occurs first.

EMPLOYEE STOCK AWARD PROGRAM

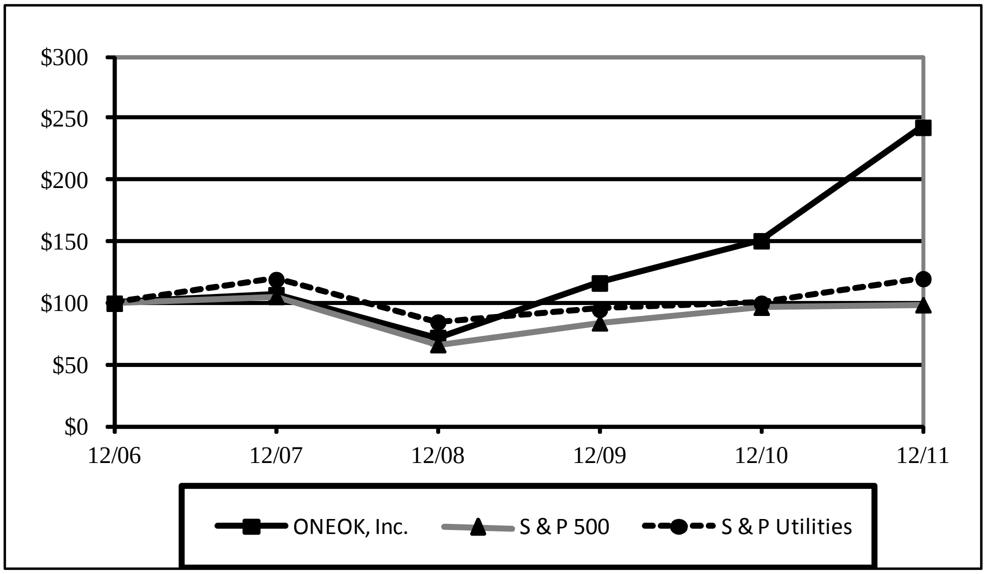
Under our Employee Stock Award Program, we issued, for no monetary consideration, to all eligible employees one share of our common stock when the per-share closing price of our common stock on the NYSE was for the first time at or above $26 per share. Shares issued to employees under this program during 2011 totaled 147,847, and compensation expense related to the Employee Stock Award Plan was $16.0 million. For 2010, the number of shares issued under this program was immaterial, and there were no shares issued in 2009.

The total number of shares of our common stock available for issuance under this program was 300,000. During 2011, the number of shares of our common stock available for distribution under this program was met. Shareholder approval is required for further stock awards to be issued under the program. The shares issued under this program have not been registered under the Securities Act, in reliance upon the position taken by the SEC (see Release No. 6188, dated February 1, 1980) that the issuance of shares to employees pursuant to a program of this kind does not require registration under the Securities Act. See Note L of the Notes to Consolidated Financial Statements in this Annual Report for additional information.

PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock with the S&P 500 Index and the S&P Utilities Index during the period beginning on December 31, 2006, and ending on December 31, 2011. The graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

Value of $100 Investment Assuming Reinvestment of Dividends
at December 31, 2006, and at the End of Every Year Through December 31, 2011,
Among ONEOK, Inc., The S&P 500 Index and The S&P Utilities Index



	Cumulative Total Return				
	Years Ended December 31,				
	2007	2008	2009	2010	2011
ONEOK, Inc.	$ 106.90	$ 72.16	$ 116.45	$ 150.65	**$ 242.74**
S&P 500 Index	$ 105.49	$ 66.47	$ 84.06	$ 96.74	**$ 98.76**
S&P Utilities Index (a)	$ 119.36	$ 84.75	$ 94.87	$ 100.08	**$ 119.98**

(a) - The Standard & Poors Utilities Index is comprised of the following companies: AES Corp.; AGL Resource, Inc.; Ameren Corp.; American Electric Power Co., Inc.; Centerpoint Energy, Inc.; CMS Energy Corp.; Consolidated Edison, Inc.; Constellation Energy Group, Inc.; Dominion Resources, Inc.; DTE Energy Co.; Duke Energy Corp.; Edison International; Entergy Corp.; Exelon Corp.; FirstEnergy Corp.; Integrys Energy Group, Inc.; NextEra Energy, Inc.; NiSource, Inc.; Northeast Utilities; NRG Energy, Inc.; Pepco Holdings, Inc.; PG&E Corp.; Pinnacle West Capital Corp.; PPL Corp.; Progress Energy, Inc.; Public Service Enterprise Group, Inc.; SCANA Corp.; Sempra Energy; Southern Co.; TECO Energy, Inc.; Wisconsin Energy Corp.; and Xcel Energy, Inc.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for each of the periods indicated:

	Years Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
	(Millions of dollars except per share amounts)				
Revenues	**$ 14,805.8**	$ 12,678.8	$ 10,805.8	$ 15,514.3	$ 12,936.9
Income from continuing operations	**$ 757.5**	$ 540.1	$ 483.7	$ 595.0	$ 493.1
Income from continuing operations attributable to ONEOK	**$ 358.4**	$ 333.4	$ 297.9	$ 306.4	$ 299.9
Net income attributable to ONEOK	**$ 360.6**	$ 334.6	$ 305.5	$ 311.9	$ 304.9
Total assets	**$ 13,696.6**	$ 12,499.2	$ 12,827.7	$ 13,126.1	$ 11,062.0
Long-term debt, including current maturities	**$ 4,893.9**	$ 4,329.8	$ 4,602.2	$ 4,230.8	$ 4,635.5
Earnings per share - continuing operations					
Basic	**$ 3.42**	$ 3.14	$ 2.83	$ 2.94	$ 2.79
Diluted	**$ 3.34**	$ 3.09	$ 2.80	$ 2.91	$ 2.74
Earnings per share - total					
Basic	**$ 3.44**	$ 3.15	$ 2.90	$ 2.99	$ 2.84
Diluted	**$ 3.36**	$ 3.10	$ 2.87	$ 2.95	$ 2.79
Dividends declared per common share	**$ 2.16**	$ 1.82	$ 1.64	$ 1.56	$ 1.40

The financial information of ONEOK Energy Marketing Company is reflected as discontinued operations in this Annual Report. All prior periods presented have been recast to reflect the discontinued operations. See Note B of The Notes to Consolidated Financial Statements in this Annual Report for additional information on our discontinued operations.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and the Notes to Consolidated Financial Statements in this Annual Report.

RECENT DEVELOPMENTS

The following discussion highlights some of our planned activities, recent achievements and significant issues affecting us. Please refer to the "Financial Results and Operating Information," and "Liquidity and Capital Resources" sections of Management's Discussion and Analysis of Financial Condition and Results of Operation and our consolidated financial statements and Notes to Consolidated Financial Statements for additional information.

Growth Projects - Drilling rig counts are higher compared with 2010, and related development activities continue to progress in many regions of ONEOK Partners' operations. Increasing natural gas and NGL production resulting from these activities and higher petrochemical industry demand for NGL products have required additional capital investments to increase the capacity of the infrastructure to bring these commodities from supply basins to market. In response to this increased production and demand for NGL products, ONEOK Partners is investing approximately $2.7 billion to $3.3 billion in capital projects to meet the needs of oil and natural gas producers in the Bakken Shale, the Cana-Woodford Shale, the Granite Wash and Mississippian Lime areas, and to provide additional NGL infrastructure in the Rocky Mountain, Mid-Continent and Gulf Coast regions that will enhance its ability to distribute NGL products to meet the increasing petrochemical industry and NGL export demand. When completed, these projects are anticipated to provide additional earnings and cash flows. See discussion of ONEOK Partners' growth projects in the "Financial Results and Operating Information" section for our ONEOK Partners segment.

Stock Repurchase Program - In 2011, we repurchased approximately 4.3 million shares of our common stock for approximately $300 million pursuant to an accelerated stock repurchase agreement. This stock repurchase was part of our three-year stock repurchase program to buy up to $750 million of our common stock that was authorized by our Board of Directors in October 2010.

Dividends/Distributions - During 2011, we paid dividends totaling $2.16 per share, an increase of approximately 18.7 percent over the $1.82 per share paid during 2010. We declared a quarterly dividend of $0.61 per share ($2.44 per share on an annualized basis) in January 2012, an increase of approximately 17.3 percent over the $0.52 declared in January 2011. During 2011, ONEOK Partners paid cash distributions totaling $2.325 per unit, an increase of approximately 4.3 percent over the $2.23 per unit paid during 2010. ONEOK Partners paid total cash distributions to us in 2011 of $333 million, which includes $197 million resulting from our limited-partner interest and $136 million related to our general-partner interest. A cash distribution from ONEOK Partners of $0.61 per unit ($2.44 per unit on an annualized basis) was declared in January 2012, an increase of approximately 7.0 percent over the $0.57 declared in January 2011.

Credit Agreements - In April 2011, ONEOK entered into the ONEOK 2011 Credit Agreement, which is a $1.2 billion revolving credit facility scheduled to expire in April 2016. In August 2011, ONEOK Partners entered into the ONEOK Partners 2011 Credit Agreement, which is a $1.2 billion revolving credit facility scheduled to expire in August 2016.

Debt Issuance and Maturities - In January 2011, ONEOK Partners completed an underwritten public offering of $1.3 billion of senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering of approximately $1.28 billion were used to repay amounts outstanding under ONEOK Partners' commercial paper program, to repay $225 million of ONEOK Partners' senior notes that matured in March 2011 and for general partnership purposes, including capital expenditures.

In 2011, ONEOK repaid $400 million of maturing senior notes and redeemed $90.5 million of 6.4-percent senior notes with available cash and short-term borrowings.

In January 2012, we completed an underwritten public offering of $700 million of 4.25-percent senior notes due 2022. The net proceeds from the offering, after deducting underwriting discounts and offering expenses, of approximately $693.9 million were used to repay amounts outstanding under our $1.2 billion commercial paper program and for general corporate purposes, which may include one or more of the following: the repurchase of our common stock, the purchase of additional common units of ONEOK Partners and the payment of dividends.

Unit Split - In July 2011, ONEOK Partners completed a two-for-one split of our common and Class B units by a distribution of one unit for each unit outstanding and held by unitholders of record on June 30, 2011. In July 2011, ONEOK Partners' partnership agreement was amended to adjust the formula for distributing available cash among the general partner and limited partners to reflect the unit split. As a result of this unit split, we have adjusted all unit and per-unit amounts contained herein to be presented on a post-split basis.

Stock Split - On February 15, 2012, our Board of Directors authorized a two-for-one split of our common stock, subject to shareholder approval of a proposal to increase the number of authorized shares of our common stock to 600 million from 300 million. The proposal will be voted on at our 2012 annual meeting of shareholders on May 23, 2012.

Retail Marketing Sale - In December 2011, we entered into a definitive agreement to sell ONEOK Energy Marketing Company to Constellation Energy Group, Inc. for $22.5 million plus working capital. The transaction closed on February 1, 2012. As a result, we expect to recognize a pre-tax gain of approximately $20 million to $23 million in the first quarter of 2012. The financial information of ONEOK Energy Marketing Company is reflected as discontinued operations in this Annual Report. All prior periods presented have been recast to reflect the discontinued operations.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

Selected Financial Results - The following table sets forth certain selected financial results for the periods indicated:

Financial Results	Years Ended December 31, 2011	2010	2009	Variances 2011 vs. 2010 Increase (Decrease)		Variances 2010 vs. 2009 Increase (Decrease)	
	(Millions of dollars)						
Revenues	$14,805.8	$12,678.8	$10,805.8	$ 2,127.0	17%	$ 1,873.0	17%
Cost of sales and fuel	12,425.4	10,616.6	8,807.8	1,808.8	17%	1,808.8	21%
Net margin	2,380.4	2,062.2	1,998.0	318.2	15%	64.2	3%
Operating costs	908.3	830.9	831.0	77.4	9%	(0.1)	(0%)
Depreciation and amortization	312.2	307.2	288.9	5.0	2%	18.3	6%
Gain (loss) on sale of assets	(1.0)	18.6	4.8	(19.6)	*	13.8	*
Operating income	$ 1,158.9	$ 942.7	$ 882.9	$ 216.2	23%	$ 59.8	7%
Equity earnings from investments	$ 127.2	$ 101.9	$ 72.7	$ 25.3	25%	$ 29.2	40%
Interest expense	$ (297.0)	$ (292.2)	$ (300.8)	$ 4.8	2%	$ (8.6)	(3%)
Net income	$ 759.7	$ 541.3	$ 491.2	$ 218.4	40%	$ 50.1	10%
Net income attributable to noncontrolling interests	$ 399.2	$ 206.7	$ 185.8	$ 192.5	93%	$ 20.9	11%
Net income attributable to ONEOK	$ 360.6	$ 334.6	$ 305.5	$ 26.0	8%	$ 29.1	10%
Capital expenditures	$ 1,336.1	$ 582.7	$ 791.2	$ 753.4	*	$ (208.5)	(26%)

* Percentage change is greater than 100 percent.

2011 vs. 2010 - NGL and condensate prices were higher while natural gas prices decreased during 2011, compared with 2010. These changes in commodity prices had a direct impact on our revenues and cost of sales and fuel.

Operating income increased 23 percent in 2011 reflecting higher results from our ONEOK Partners segment, offset partially by lower operating income from our Distribution and Energy Services segments. Our ONEOK Partners segment’s operating income significantly increased due primarily to more favorable NGL location differentials and higher NGL volumes gathered and fractionated, offset partially by the deconsolidation of Overland Pass Pipeline in September 2010 in its natural gas liquids business and lower natural gas transportation margins due to narrower natural gas price location differentials in its natural gas pipelines business.

Our Natural Gas Distribution segment’s operating income decreased 12 percent in 2011 due to increased operating costs.

Our Energy Services segment’s operating income decreased significantly in 2011 due primarily to lower transportation margins and storage and marketing margins, net of hedging activities.

Operating costs increased in 2011 due primarily to higher short-term incentive and share-based compensation and other labor and benefit costs for all segments and higher materials and outside services expenses in our ONEOK Partners segment.

Gain (loss) on sale of assets decreased from 2010, which reflected a $16.3 million gain on the sale of a 49-percent interest of Overland Pass Pipeline Company.

Equity earnings from investments increased in 2011, compared with the same period last year, due to the impact of accounting for Overland Pass Pipeline Company as an equity method investment beginning in September 2010 and increased contracted capacity on Northern Border Pipeline.

Net income attributable to noncontrolling interests, primarily reflects the portion of ONEOK Partners that we do not own and reflects higher earnings in our ONEOK Partners segment during 2011.

Capital expenditures increased during 2011 due primarily to the growth projects in ONEOK Partners’ natural gas gathering and processing and natural gas liquids businesses.

2010 vs. 2009 - Commodity prices were generally higher during 2010, compared with 2009, which had a direct impact on our revenues and cost of sales and fuel. Our operating results include the benefits from a full year of ONEOK Partners' more than $2.0 billion of completed growth projects that were placed in service in 2009.

Operating income increased 7 percent in 2010, when compared with 2009, reflecting higher NGL volumes, higher contracted natural gas transportation capacity, an increase in natural gas processing volumes, higher natural gas and NGL storage margins and a gain on the sale of a 49-percent ownership interest in Overland Pass Pipeline Company in our ONEOK Partners segment. These increases were offset partially by ONEOK Partners' lower NGL optimization margins. Our Distribution segment benefited from new rates in Oklahoma that increased fixed fees and lowered our volumetric sensitivity, providing more consistent revenues each month. Our Energy Services segment's results were consistent with the prior year, with higher realized seasonal storage price differentials and marketing margins offset by lower realized Mid-Continent-to-Gulf Coast transportation margins and lower premium-services margins.

Operating costs increased due primarily to the recognition of previously deferred integrity-management costs in our Natural Gas Distribution segment that are now being recovered through rates, offset partially by lower than estimated ad valorem taxes in our ONEOK Partners segment and lower legal-related costs in our Energy Services segment.

Our results were also favorably impacted by increased equity earnings from investments in our ONEOK Partners segment. The overall increase was due primarily to increased contracted capacity on Northern Border Pipeline, which benefited from wider natural gas price differentials between the markets it serves, and as a result of accounting for ONEOK Partners' 50-percent investment in Overland Pass Pipeline Company as an equity investment beginning September 2010.

More information regarding our results of operations is provided in the following discussion of operating results for each of our segments.

ONEOK Partners

Growth Projects - Natural gas gathering and processing business - ONEOK Partners' natural gas gathering and processing business is investing approximately $950 million to $1.1 billion in growth projects in the Williston Basin and Cana-Woodford Shale areas that will enable ONEOK Partners to meet the rapidly growing needs of crude oil and natural gas producers in those areas.

Williston Basin Processing Plants and related projects - ONEOK Partners projects in this basin include three 100 MMcf/d natural gas processing facilities: the Garden Creek plant in eastern McKenzie County, North Dakota, and the Stateline I and II plants in western Williams County, North Dakota. ONEOK Partners has multi-year supply commitments and acreage dedications for all the capacity of the Garden Creek and Stateline I plants and for approximately 75 percent of the Stateline II plant's capacity. In addition, ONEOK Partners will expand and upgrade its existing gathering and compression infrastructure and add new well connections associated with these plants. The Garden Creek plant, which was placed in service in December 2011, and related infrastructure projects are expected to cost approximately $350 million to $415 million, excluding AFUDC. The Stateline I plant, which is expected to be in service by the third quarter of 2012, and related infrastructure projects are expected to cost approximately $300 million to $355 million, excluding AFUDC. The Stateline II plant, which is expected to be in service during the first half of 2013, and related infrastructure projects are expected to cost approximately $260 million to $305 million, excluding AFUDC.

Horizontal wells drilled in the Williston Basin are economically justified by producers primarily by crude oil economics. Accordingly, ONEOK Partners' growth in this area is expected to shift our supply exposure from natural gas production economics toward crude oil production economics. In addition, ONEOK Partners expects its commodity price exposure to increase particularly to NGLs and natural gas, as equity volumes increase under its POP contracts with its customers in the Williston Basin.

Cana-Woodford Shale projects - In 2010, ONEOK Partners completed projects totaling approximately $38 million in the Cana-Woodford Shale development in Oklahoma, which included the connection of its western Oklahoma natural gas gathering system to its Maysville natural gas processing facility in central Oklahoma, as well as new well connections to gather and process additional Cana-Woodford Shale natural gas volumes.

In both the Williston Basin and Cana Woodford Shale project areas, nearly all of the new gas production is from horizontally drilled and completed wells. These wells tend to produce at higher initial volumes; however, they generally have higher initial decline rates than conventional vertical wells, but the decline curves flatten out. These wells are expected to have long-lasting reserves. ONEOK Partners expects the routine growth capital needed to connect to new wells and expand its infrastructure to be higher compared with its previous experience.

Natural gas liquids business - The growth strategy in ONEOK Partners' natural gas liquids business is focused around the oil and natural gas drilling activity in shale and other resource plays from the Rocky Mountain region through the Mid-Continent region down into Texas. Increasing natural gas and NGL production resulting from this activity and higher petrochemical industry demand for NGL products have required ONEOK Partners to make additional capital investments to increase the capacity of its infrastructure to bring these commodities from supply basins to market. ONEOK Partners' natural gas liquids business is investing approximately $1.7 billion to $2.2 billion through 2014. This investment will accommodate the gathering and fractionation of growing NGL supplies from the shale and other resource plays across ONEOK Partners' asset base and alleviate infrastructure constraints between the Mid-Continent and Texas Gulf Coast regions that will enhance its ability to distribute NGL products to meet the increasing petrochemical industry and NGL export demand in the Gulf Coast. ONEOK Partners' supply commitments from producers and natural gas processors associated with these growth projects will provide incremental and long-term fee-based earnings to its NGL business. Over time, these growing fee-based volumes will fill a portion of the capacity used in 2011 to capture the price differentials between the Mid-Continent and Gulf Coast market centers. In addition, we believe the price differentials between the Mid-Continent and Gulf Coast market centers will narrow over the long-term as new fractionators and pipelines, including ONEOK Partners' MB-2 fractionator and Sterling III pipeline, begin to alleviate constraints impacting NGL prices and the location price differential between the two market centers.

Sterling III Pipeline - ONEOK Partners plans to build a 570-plus-mile natural gas liquids pipeline, the Sterling III Pipeline, which will have the flexibility to transport either unfractionated NGLs or NGL products from the Mid-Continent to the Texas Gulf Coast. The Sterling III Pipeline will traverse the NGL-rich Woodford Shale that is currently under development, as well as provide transportation capacity for the growing NGL production from the Cana-Woodford Shale and Granite Wash areas, where the pipeline can gather unfractionated NGLs from the new natural gas processing plants that are being built as a result of increased drilling activity in these areas. The Sterling III Pipeline will have an initial capacity to transport up to 193 MBbl/d of production from ONEOK Partners' natural gas liquids infrastructure at Medford, Oklahoma, to its storage and fractionation facilities in Mont Belvieu, Texas. ONEOK Partners has multi-year supply commitments from producers and natural gas processors for approximately 75 percent of the pipeline's capacity. Additional pump stations could expand the capacity of the pipeline to 250 MBbl/d. Following the receipt of all necessary permits and the acquisition of rights-of-way, construction is scheduled to begin in 2013, with an expected completion late in the same year.

The investment also includes reconfiguring its existing Sterling I and II Pipelines, which currently distribute NGL products between the Mid-Continent and Gulf Coast NGL market centers, to transport either unfractionated NGLs or NGL products.

The project costs for the new pipeline and reconfiguring projects are estimated to be $610 million to $810 million, excluding AFUDC.

MB-2 fractionator - ONEOK Partners plans to construct a 75-MBbl/d fractionator, MB-2, near ONEOK Partners' storage facility in Mont Belvieu, Texas. The Texas Commission on Environmental Quality (TCEQ) has approved the permit application to build this fractionator. Construction of the MB-2 fractionator began in June 2011 and is expected to be completed in mid-2013. The cost of the MB-2 fractionator is estimated to be $300 million to $390 million, excluding AFUDC. ONEOK Partners has multi-year supply commitments from producers and natural gas processors for all of the fractionator's capacity. The fractionator can be expanded to 125 MBbl/d to accommodate additional NGL volumes from the Arbuckle Pipeline and the Sterling I, II and III pipelines.

Bakken Pipeline and related projects - ONEOK Partners plans to build a 525- to 615-mile natural gas liquids pipeline, the Bakken Pipeline, to transport unfractionated NGLs from the Williston Basin to the Overland Pass Pipeline. The Bakken Pipeline initially will have the capacity to transport up to 60 MBbl/d of unfractionated NGL production and can be expanded to 110 MBbl/d with additional pump stations. The unfractionated NGLs will then be delivered to ONEOK Partners' existing natural gas liquids fractionation and distribution infrastructure in the Mid-Continent. Project costs for the new pipeline are estimated to be $450 million to $550 million, excluding AFUDC.

NGL supply commitments for the Bakken Pipeline will be anchored by NGL production from ONEOK Partners' natural gas processing plants in the Williston Basin. Following receipt of all necessary permits, construction of the 12-inch diameter pipeline is expected to begin in the second quarter of 2012 and be in service during the first half of 2013.

The unfractionated NGLs from the Bakken Pipeline and other supply sources under development in the Rocky Mountain region will require installing additional pump stations and expanding existing pump stations on the Overland Pass Pipeline, in which ONEOK Partners owns a 50-percent equity interest. These additions and expansions will increase the capacity of Overland Pass Pipeline to 255 MBbl/d. ONEOK Partners' anticipated share of the costs for this project is estimated to be $35 million to $40 million, excluding AFUDC.

Bushton Fractionator Expansion - To accommodate the additional volume from the Bakken Pipeline, ONEOK Partners is investing $110 million to $140 million, excluding AFUDC, to expand and upgrade its existing fractionation capacity at Bushton, Kansas, increasing its capacity to 210 MBbl/d from 150 MBbl/d. This project is expected to be in service during the fourth quarter of 2012.

Cana-Woodford Shale and Granite Wash projects - ONEOK Partners plans to invest approximately $197 million to $257 million, excluding AFUDC, in its existing Mid-Continent infrastructure, primarily in the Cana-Woodford Shale and Granite Wash areas. These investments will expand ONEOK Partners' ability to transport unfractionated NGLs from these Mid-Continent supply areas to fractionation facilities in Oklahoma and Texas and distribute NGL products to the Mid-Continent, Gulf Coast and upper Midwest market centers.

These investments include constructing more than 230 miles of natural gas liquids pipelines that will expand its existing Mid-Continent natural gas liquids gathering system in the Cana-Woodford Shale and Granite Wash areas. The pipelines will connect to three new third-party natural gas processing facilities that are under construction and to three existing third-party natural gas processing facilities that are being expanded. Additionally, ONEOK Partners will install additional pump stations on the Arbuckle Pipeline to increase its capacity to 240 MBbl/d. When completed, these projects are expected to add, through multi-year supply contracts, approximately 75 to 80 MBbl/d of unfractionated NGL, to ONEOK Partners' existing natural gas liquids gathering systems. These projects are expected to be completed early in the second quarter of 2012 and cost approximately $180 million to $240 million, excluding AFUDC.

In 2010, ONEOK Partners invested approximately $17 million to increase the accessibility of new NGL supply to the Arbuckle Pipeline and Mont Belvieu fractionation facilities.

Sterling I Pipeline Expansion - In 2011, ONEOK Partners installed seven additional pump stations at a cost of approximately $30 million, excluding AFUDC, along its existing Sterling I natural gas liquids distribution pipeline, increasing its capacity by 15 MBbl/d, which is supplied by ONEOK Partners' Mid-Continent natural gas liquids infrastructure. The Sterling I pipeline transports NGL products from ONEOK Partners' fractionator in Medford, Oklahoma, to the Mont Belvieu, Texas, market center.

For a discussion of ONEOK Partners' capital expenditure financing, see "Capital Expenditures" in "Liquidity and Capital Resources" on page 58.

Selected Financial Results and Operating Information - ONEOK Partners' 2011 and 2010 operating results reflect increases in NGL volumes gathered, fractionated and sold in its natural gas liquids business and natural gas volumes processed in the Williston Basin in its natural gas gathering and processing business. ONEOK Partners expects continued development of the reserves in the Bakken Shale and Three Forks formations in the Williston Basin and in the Cana-Woodford Shale and Granite Wash areas in Oklahoma and Texas, as drilling activities increase in these areas.

The following table sets forth certain selected financial results for our ONEOK Partners segment for the periods indicated:

	Years Ended December 31,			Variances 2011 vs. 2010		Variances 2010 vs. 2009	
Financial Results	**2011**	**2010**	**2009**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
Revenues	**$11,322.6**	$ 8,675.9	$ 6,474.5	**$ 2,646.7**	**31%**	$ 2,201.4	34%
Cost of sales and fuel	**9,745.2**	7,531.0	5,355.2	**2,214.2**	**29%**	2,175.8	41%
Net margin	**1,577.4**	1,144.9	1,119.3	**432.5**	**38%**	25.6	2%
Operating costs	**459.4**	403.5	411.3	**55.9**	**14%**	(7.8)	(2%)
Depreciation and amortization	**177.5**	173.7	164.1	**3.8**	**2%**	9.6	6%
Gain (loss) on sale of assets	**(1.0)**	18.6	2.7	**(19.6)**	*****	15.9	*
Operating income	**$ 939.5**	$ 586.3	$ 546.6	**$ 353.2**	**60%**	$ 39.7	7%
Equity earnings from investments	**$ 127.2**	$ 101.9	$ 72.7	**$ 25.3**	**25%**	$ 29.2	40%
Interest expense	**$ (223.1)**	$ (204.3)	$ (206.0)	**$ 18.8**	**9%**	$ (1.7)	(1%)
Capital expenditures	**$ 1,063.4**	$ 352.7	$ 615.7	**$ 710.7**	*****	$ (263.0)	(43%)

* Percentage change is greater than 100 percent.

2011 vs. 2010 - Net margin increased due primarily to the following:

- an increase of $363.6 million in optimization and marketing margins in ONEOK Partners' natural gas liquids business due primarily to the following:
    - an increase of $335.2 million from more favorable NGL price differentials and additional fractionation and transportation capacity available for optimization activities between the Conway, Kansas, and Mont Belvieu, Texas, NGL market centers; and
    - an increase of $28.4 from higher marketing volumes and more favorable margins on NGL products marketed;
- an increase of $32.6 million due to higher net realized NGL and condensate prices in ONEOK Partners' natural gas gathering and processing business;
- an increase of $32.5 million from higher NGL volumes gathered and fractionated in Texas and the Mid-Continent and Rocky Mountain regions, excluding the impact of the September 2010 deconsolidation of Overland Pass Pipeline Company, and contract renegotiations for higher fees associated with ONEOK Partners' NGL exchange services activities, offset partially by higher costs associated with NGL volumes fractionated by third parties in its natural gas liquids business;
- an increase of $26.4 million related to higher isomerization margins resulting from wider price differentials between normal butane and iso-butane and higher isomerization volumes in ONEOK Partners' natural gas liquids business;
- an increase of $19.4 million due to higher natural gas volumes processed in the Williston Basin and western Oklahoma resulting from increased drilling activity, offsetting reduced drilling activity in certain parts of Kansas and weather-related outages during the first quarter in ONEOK Partners' natural gas gathering and processing business;
- an increase of $12.4 million due to higher storage margins as a result of contract renegotiations in ONEOK Partners' natural gas liquids business; and
- an increase of $8.8 million due to favorable changes in contract terms in ONEOK Partners' natural gas gathering and processing business; offset partially by
- a decrease of $42.8 million due to the deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method in ONEOK Partners' natural gas liquids business;
- a decrease of $12.5 million from lower natural gas transportation margins due to narrower natural gas price location differentials that decreased contracted transportation capacity on Midwestern Gas Transmission and interruptible transportation volumes across ONEOK Partners' pipelines in its natural gas pipelines business; and
- a decrease of $8.2 million due to lower natural gas volumes gathered as a result of continued production declines and reduced drilling activity by producers in the Powder River Basin in ONEOK Partners' natural gas gathering and processing business.

Operating costs increased due primarily to the following:

- an increase of $35.7 million in higher labor and employee-related costs associated with incentive and benefit plans, which includes higher share-based compensation costs resulting from common stock awarded to employees as part of ONEOK's stock award program and the appreciation in ONEOK's share price, affecting all of ONEOK Partners' businesses;
- an increase of $9.4 million from higher materials and outside services expenses associated primarily with scheduled maintenance at fractionation, pipeline and storage facilities in ONEOK Partners' natural gas liquids business; and
- an increase of $5.0 million due to higher ad valorem taxes associated with the completed capital projects in all of ONEOK Partners' businesses; offset partially by
- a decrease of $5.4 million due to the deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method of accounting in ONEOK Partners' natural gas liquids business.

Gain (loss) on sale of assets decreased due to the $16.3 million gain on the sale of a 49-percent interest of Overland Pass Pipeline Company recorded in 2010.

Equity earnings include Overland Pass Pipeline Company in ONEOK Partners' natural gas liquids business, which it began accounting for under the equity method of accounting in September 2010. Equity earnings from investments increased due primarily to increased contracted capacity on Northern Border Pipeline in ONEOK Partners' natural gas pipelines business. Northern Border Pipeline benefited from wider natural gas price location differentials between the markets it serves, which resulted in a significant increase in its capacity being sold in 2011. Substantially all of Northern Border Pipeline's long-haul capacity has been contracted through March 2013.

Capital expenditures increased due primarily to the growth projects in ONEOK Partners' natural gas gathering and processing and natural gas liquids businesses.

Previously, ONEOK Partners had a Processing and Services Agreement with us and OBPI, under which we contracted for all of OBPI's rights, including all of the capacity of the Bushton Plant, reimbursing OBPI for all costs associated with the operation and maintenance of the Bushton Plant and its obligations under equipment leases covering portions of the Bushton Plant. In April 2011, pursuant to its rights under the Processing and Services Agreement, ONEOK Partners directed OBPI to give notice of intent to exercise the purchase option for the leased equipment pursuant to the terms of the equipment leases. On June 30, 2011, through a series of transactions, we sold OBPI to ONEOK Partners, and OBPI closed the purchase option and terminated the equipment leases. The total amount paid by ONEOK Partners to complete the transactions was approximately $94.2 million, which included the reimbursement to us of obligations related to the Processing and Services Agreement.

2010 vs. 2009 - Net margin increased due primarily to the following:

- an increase of $51.4 million due to higher NGL volumes gathered, fractionated and transported, primarily associated with the completion of the Arbuckle Pipeline and Piceance and D-J Basin lateral pipelines, as well as new NGL supply connections in ONEOK Partners' natural gas liquids business;
- an increase of $14.4 million due to higher storage margins, primarily as a result of contract renegotiations in ONEOK Partners' natural gas pipelines and natural gas liquids businesses;
- an increase of $9.1 million due to increased Williston Basin volumes in ONEOK Partners' natural gas gathering and processing business; and
- an increase of $8.7 million from higher natural gas transportation margins from an increase in contracted capacity on Midwestern Gas Transmission, Viking Gas Transmission's Fargo lateral pipeline and the incremental margin from the Guardian Pipeline expansion and extension project in ONEOK Partners' natural gas pipelines business; offset partially by
- a decrease of $34.7 million related to lower optimization margins due to limited NGL fractionation and transportation capacity available for optimization activities between the Mid-Continent and Gulf Coast NGL market centers until September 2010 and less favorable NGL price differentials in ONEOK Partners' natural gas liquids business;
- a decrease of $7.8 million due to decreased volumes processed and sold in western Oklahoma and Kansas as a result of natural production declines, operational outages and a period of ethane rejection in ONEOK Partners' natural gas gathering and processing business;
- a decrease of $6.5 million from selling ONEOK Partners' Lehman Brothers bankruptcy claims in 2009; and
- a decrease of $6.3 million due to lower natural gas volumes gathered as a result of natural production declines and reduced drilling activity by its customers in the Powder River Basin in ONEOK Partners' natural gas gathering and processing business.

Operating costs decreased due primarily to a decrease of $8.2 million due to lower than estimated ad valorem taxes associated with ONEOK Partners' capital projects completed in 2009 in its natural gas liquids business.

Depreciation and amortization expense increased primarily as a result of ONEOK Partners' capital projects completed in 2009 in its natural gas liquids and natural gas pipelines businesses, offset partially by the deconsolidation of Overland Pass Pipeline Company in the third quarter of 2010 in ONEOK Partners' natural gas liquids business.

Gain (loss) on sale of assets increased due primarily to the gain on sale of a 49-percent ownership interest in Overland Pass Pipeline Company in ONEOK Partners' natural gas liquids business.

Equity earnings from investments increased due primarily to increased contracted capacity on Northern Border Pipeline due to wider natural gas price differentials in ONEOK Partners' natural gas pipelines business and equity earnings from ONEOK Partners' investment in Overland Pass Pipeline Company, which was deconsolidated in September 2010.

Selected Operating Information - The following table sets forth selected operating information for our ONEOK Partners segment for the periods indicated:

Operating Information	**2011**	**2010**	**2009**
Natural gas gathering and processing business (a)			
Natural gas gathered *(BBtu/d)*	**1,030**	1,067	1,123
Natural gas processed *(BBtu/d)* (b)	**713**	674	658
NGL sales *(MBbl/d)*	**48**	44	43
Residue gas sales *(BBtu/d)*	**317**	286	291
Realized composite NGL net sales price *($/gallon)* (c)	**$ 1.08**	$ 0.94	$ 0.90
Realized condensate net sales price *($/Bbl)* (c)	**$ 82.56**	$ 63.81	$ 78.35
Realized residue gas net sales price (*$/MMBtu*) (c)	**$ 5.47**	$ 5.58	$ 3.55
Realized gross processing spread *($/MMBtu)* (c)	**$ 8.17**	$ 6.41	$ 6.63
Natural gas pipelines business (a)			
Natural gas transportation capacity contracted *(MDth/d)*	**5,373**	5,616	5,507
Transportation capacity subscribed	**83%**	87%	86%
Average natural gas price			
Mid-Continent region *($/MMBtu)*	**$ 3.88**	$ 4.17	$ 3.28
Natural gas liquids business			
NGL sales *(MBbl/d)*	**497**	457	408
NGLs fractionated *(MBbl/d)* (d)	**537**	512	481
NGLs transported-gathering lines *(MBbl/d)* (a) (e)	**436**	440	372
NGLs transported-distribution lines *(MBbl/d)* (a)	**473**	468	459
Conway-to-Mont Belvieu OPIS average price differential			
Ethane *($/gallon)*	**$ 0.28**	$ 0.10	$ 0.11

(a) - For consolidated entities only.

(b) - Includes volumes processed at company-owned and third-party facilities.

(c) - Presented net of the impact of hedging activities and includes equity volumes only.

(d) - Includes volumes fractionated from company-owned and third-party facilities.

(e) - 2010 and 2009 volume information includes 62 and 69 MBbl/d, respectively, related to Overland Pass Pipeline Company, which was deconsolidated in September 2010.

2011 vs. 2010 - Natural gas gathered decreased in 2011, compared with 2010, due to continued production declines and reduced drilling activity, primarily in the Powder River Basin in Wyoming and certain parts of Kansas, and weather-related outages in the first quarter of 2011, offset partially by increased drilling activity in the Williston Basin and western Oklahoma.

Natural gas processed and residue gas sales increased in 2011, compared with 2010, due to an increase in drilling activity in the Williston Basin and western Oklahoma, offsetting reduced drilling activity and natural production declines in Kansas and weather-related outages in the first quarter of 2011.

Natural gas transportation capacity contracted decreased due primarily to lower contracted capacity on Midwestern Gas Transmission due to narrower natural gas price location differentials between the markets we serve.

NGLs gathered and fractionated, excluding the impact of the September 2010 deconsolidation of Overland Pass Pipeline Company, increased due primarily to increased throughput through existing connections in Texas and the Mid-Continent and Rocky Mountain regions, and new supply connections in the Mid-Continent and Rocky Mountain regions. In the second quarter 2011, additional Gulf Coast fractionation capacity became available through our 60 MBbl/d fractionation service agreement with Targa Resources Partners.

NGLs transported on distribution lines increased due primarily to increased volumes of NGL products transported on our North System pipeline to Midwest markets and our Sterling I pipeline expansion discussed above.

2010 vs. 2009 - Natural gas gathered decreased in 2010, compared with 2009, due to continued production declines and reduced drilling activity, primarily in the Powder River Basin in Wyoming and certain parts of western Oklahoma and Kansas, offset partially by increased drilling activity in the Williston Basin.

Natural gas processed increased during 2010, compared with 2009, due to an increase in drilling activity in the Williston Basin, offsetting reduced drilling activity and natural production declines in Kansas, and reduced drilling activity in certain parts of western Oklahoma.

Natural gas transportation capacity contracted increased due primarily to increased capacity on Midwestern Gas Transmission due to a new interconnection with the Rockies Express Pipeline, Viking Gas Transmission’s Fargo lateral and Guardian Pipeline expansion and extension projects completed in 2009.

NGLs gathered, fractionated and distributed increased primarily due to new connections and increased production associated with the completion of the Arbuckle Pipeline, Piceance Lateral and D-J Basin lateral pipelines.

ONEOK Partners’ natural gas pipelines business primarily serves end-users, such as natural gas distribution companies and electric-generation companies, that require natural gas to operate their businesses regardless of price or location price differentials. The development of shale gas and other resource plays has continued to increase available natural gas supply and has caused natural gas prices to decrease and locational and seasonal price differentials to narrow. As additional supply is developed, ONEOK Partners expects producers to demand incremental services in the future to transport their production to market. The abundance of shale gas supply and new regulations on emissions from coal-fired electric-generation plants also may increase the demand for our services from electric-generation companies if they were to convert to a natural gas fuel source. Conversely, demand from certain customers that are focused on capturing location or seasonal natural gas price differentials may decrease in the future due to narrowing price differentials. Overall, we expect our fee-based earnings to remain relatively stable in the future as the development of shale and other resource plays continue.

Natural Gas Distribution

In December 2011, we entered into a definitive agreement to sell ONEOK Energy Marketing Company to Constellation Energy Group, Inc. for $22.5 million plus working capital. The transaction closed on February 1, 2012. As a result, we expect to recognize a pre-tax gain of approximately $20 million to $23 million in the first quarter of 2012. The financial information of ONEOK Energy Marketing Company is reflected as discontinued operations in this Annual Report. All prior periods presented have been recast to reflect the discontinued operations.

Selected Financial Results - The following table sets forth certain selected financial results for the continuing operations of our Distribution segment for the periods indicated:

Financial Results	Years Ended December 31, 2011	2010	2009	Variances 2011 vs. 2010 Increase (Decrease)		Variances 2010 vs. 2009 Increase (Decrease)	
				(Millions of dollars)			
Gas sales	**$ 1,492.5**	$ 1,687.4	$ 1,708.8	**$ (194.9)**	**(12%)**	$ (21.4)	(1%)
Transportation revenues	**90.9**	91.5	87.6	**(0.6)**	**(1%)**	3.9	4%
Cost of gas	**869.5**	1,062.5	1,122.9	**(193.0)**	**(18%)**	(60.4)	(5%)
Net margin, excluding other revenues	**713.9**	716.4	673.5	**(2.5)**	**(0%)**	42.9	6%
Other revenues	**37.9**	38.5	42.5	**(0.6)**	**(2%)**	(4.0)	(9%)
Net margin	**751.8**	754.9	716.0	**(3.1)**	**(0%)**	38.9	5%
Operating costs	**422.0**	398.8	384.1	**23.2**	**6%**	14.7	4%
Depreciation and amortization	**132.2**	131.0	122.6	**1.2**	**1%**	8.4	7%
Gain (loss) on sale of assets	**-**	-	0.5	**-**	**0%**	(0.5)	(100%)
Operating income	**$ 197.6**	$ 225.1	$ 209.8	**$ (27.5)**	**(12%)**	$ 15.3	7%
Capital expenditures	**$ 242.6**	$ 215.6	$ 157.5	**$ 27.0**	**13%**	$ 58.1	37%

The following table sets forth our net margin, excluding other revenues, by type of customer, for the periods indicated:

Net Margin, Excluding Other Revenues	Years Ended December 31 2011	2010	2009	Variances 2011 vs. 2010 Increase (Decrease)		Variances 2010 vs. 2009 Increase (Decrease)	
Gas sales				(Millions of dollars)			
Regulated							
Residential	**$ 510.5**	$ 509.1	$ 473.8	**$ 1.4**	**0%**	$ 35.3	7%
Commercial	**105.5**	108.9	105.1	**(3.4)**	**(3%)**	3.8	4%
Industrial	**2.4**	2.2	2.5	**0.2**	**9%**	(0.3)	(12%)
Wholesale/public authority	**4.6**	4.7	4.5	**(0.1)**	**(2%)**	0.2	4%
Net margin on gas sales	**623.0**	624.9	585.9	**(1.9)**	**(0%)**	39.0	7%
Transportation margin	**90.9**	91.5	87.6	**(0.6)**	**(1%)**	3.9	4%
Net margin, excluding other revenues	**$ 713.9**	$ 716.4	$ 673.5	**$ (2.5)**	**(0%)**	$ 42.9	6%

2011 vs. 2010 - Net margin decreased due primarily to the following:

- a decrease of $5.9 million from lower sales in Kansas, due to lower consumption by residential and commercial customers due to warmer than normal weather in the first quarter;
- a decrease of $4.9 million due to expiration of the Integrity Management Program (IMP) rider, which allowed us to recover certain deferred pipeline-integrity costs in Oklahoma; offset partially by
- an increase of $3.3 million from new rates and rider recoveries in Texas;
- an increase of $2.1 million from customer growth, primarily in Texas; and
- an increase of $1.7 million from capital-recovery mechanisms in Kansas.

Operating costs increased due primarily to the following:

- an increase of $14.7 million in share-based compensation costs from common stock awarded to employees as part of ONEOK’s stock award program and the appreciation in ONEOK’s share price;
- an increase of $8.1 million of employee-related incentive and health benefit costs; and
- an increase of $3.2 million in pension costs as a result of the annual change in our estimated discount rate.

Depreciation and amortization expense increased due primarily to an increase of $6.4 million associated with additional capital expenditures, specifically investments in automated meter reading in Oklahoma, offset partially by a decrease of $4.9 million in regulatory amortization associated with the expiration of the IMP rider, which allowed us to defer recognition of certain pipeline-integrity costs in Oklahoma.

2010 vs. 2009 - Net margin increased due primarily to the following:

- an increase of $40.1 million from new rates in Oklahoma that increased fixed fees, which lowered our volumetric sensitivity and provides more consistent revenues each month;
- an increase of $6.5 million from rider recoveries in Oklahoma and ad valorem tax surcharge recoveries in Kansas;
- an increase of $3.7 million from higher natural gas sales volumes, primarily in the first quarter of 2010, due to colder weather;
- an increase of $3.4 million from capital-recovery mechanisms in Kansas; and
- an increase of $2.7 million from higher transportation volumes; offset partially by
- a decrease of $17.4 million from the expiration of the 2009 capital-recovery mechanism in Oklahoma, which as a result of our 2009 rate case in Oklahoma, the revenues related to capital recovery are now included in base rates.

Operating costs increased due primarily to an increase of $15.5 million related to the recognition of previously deferred IMP costs in Oklahoma that have been approved for recovery in our revenues.

Depreciation and amortization expense increased due primarily to an increase of $6.7 million in regulatory amortization associated with revenue rider recoveries.

Capital Expenditures - Our capital expenditures program includes expenditures for pipeline integrity, automated meter reading, extending service to new areas, modifications to customer-service lines, increasing system capabilities and replacements. It is our practice to maintain and upgrade facilities to ensure safe, reliable and efficient operations.

Capital expenditures increased for 2011, compared with 2010, primarily as a result of increased spending on pipeline replacements in Kansas and Texas, and replacements due to highway construction in Oklahoma, offset partially by decreased spending on automated meter reading in Oklahoma. Capital expenditures increased for 2010, compared with 2009, primarily as a result of expenditures related to an investment in automated meter reading in Oklahoma.

Selected Operating Information - The following tables set forth certain selected information for the regulated operations of our Distribution segment for the periods indicated:

	Years Ended December 31,		
Number of Customers	**2011**	**2010**	**2009**
Residential	**1,921,017**	1,912,205	1,901,782
Commercial	**153,227**	153,650	156,337
Industrial	**1,248**	1,271	1,343
Wholesale/Public Authority	**2,730**	2,701	2,767
Transportation	**11,708**	11,308	10,410
Total customers	**2,089,930**	2,081,135	2,072,639

	Years Ended December 31,		
Volumes *(MMcf)*	**2011**	**2010**	**2009**
Gas sales			
Residential	**117,969**	121,240	120,370
Commercial	**33,805**	35,223	35,414
Industrial	**1,367**	1,211	1,208
Wholesale/Public Authority	**3,287**	12,060	12,705
Total volumes sold	**156,428**	169,734	169,697
Transportation	**203,655**	205,692	201,952
Total volumes delivered	**360,083**	375,426	371,649

Residential and commercial volumes decreased for 2011, compared with 2010, due primarily to warmer temperatures in the first quarter of 2011. Wholesale sales represent contracted gas volumes that exceed the needs of our residential, commercial, and industrial customer base and are available for sale to other parties. Wholesale volumes decreased for 2011, compared with 2010; however, the impact to margins was minimal.

Regulatory Initiatives - Oklahoma - In February 2011, Oklahoma Natural Gas filed its first application related to its performance-based rate change mechanism. The application did not seek a modification of customer rates because Oklahoma Natural Gas' regulatory return on equity was within the range approved by the OCC. The OCC signed the final order on this filing in July 2011, with no modification to customer rates.

In September 2010, Oklahoma Natural Gas filed an application and supporting testimony with the OCC seeking approval of a demand portfolio of conservation and energy-efficiency programs and authorizing recovery of costs and performance incentives. A settlement agreement was reached among all the parties and filed at the OCC in February 2011. This agreement allows Oklahoma Natural Gas to pursue the key energy-efficiency programs requested in its filing and allows the company to earn up to $1.5 million annually beginning mid-2012 if program objectives are achieved. The filing and settlement agreement were approved by the OCC in May 2011, and billings to customers began in June 2011.

Kansas - The KCC approved the application from Kansas Gas Service to increase the Gas System Reliability Surcharge by an additional $2.9 million effective January 2012. This surcharge is a capital-recovery mechanism that allows for rate adjustment providing recovery and a return on incremental safety-related and government-mandated capital investments made between rate cases. We expect to file a general rate proceeding with the KCC in mid-2012.

Texas - In January 2012, the Texas Railroad Commission approved the settlement between Texas Gas Service and the City of El Paso that allows for recovery of 2010-2013 pipeline-integrity expenditures and partial recovery of rate-case expenses. We do not expect the settlement to have a material impact on our results of operations.

In addition, Texas Gas Service has made annual filings for interim rate relief under the Gas Reliability Infrastructure Program (GRIP) statute with the cities of Austin, Texas, and surrounding communities in February 2011 and El Paso, Texas, in May 2011 for approximately $1.6 million and $1.1 million, respectively. GRIP is a capital-recovery mechanism that allows for an interim rate adjustment providing recovery and a return on incremental capital investments made between rate cases. In May 2011, the city of Austin approved the filing in the amount of $1.5 million, effective in June 2011. In August 2011, the city of El Paso approved the filing in the amount of $1.0 million, effective in August 2011.

In the normal course of business, we have filed rate cases and for GRIP and cost-of-service adjustments in various other Texas jurisdictions to address investments in rate base and changes in expense.

General - Certain costs to be recovered through the ratemaking process have been capitalized as regulatory assets. Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria for recognition and accordingly, a write-off of regulatory assets and stranded costs may be required. There were no write-offs of regulatory assets resulting from the failure to meet the criteria for capitalization during 2011, 2010 or 2009.

Energy Services

Selected Financial Results - The following table sets forth certain selected financial results for our Energy Services segment for the periods indicated:

	Years Ended December 31,			Variances 2011 vs. 2010		Variances 2010 vs. 2009	
Financial Results	**2011**	**2010**	**2009**	**Increase (Decrease)**		**Increase (Decrease)**	
	(Millions of dollars)						
Revenues	**$ 2,777.2**	$ 3,301.2	$ 3,553.6	**$ (524.0)**	**(16%)**	$ (252.4)	(7%)
Cost of sales and fuel	**2,728.5**	3,141.5	3,394.0	**(413.0)**	**(13%)**	(252.5)	(7%)
Net margin	**48.7**	159.7	159.6	**(111.0)**	**(70%)**	0.1	0%
Operating costs	**24.5**	28.4	35.5	**(3.9)**	**(14%)**	(7.1)	(20%)
Depreciation and amortization	**0.4**	0.6	0.5	**(0.2)**	**(33%)**	0.1	20%
Operating income	**$ 23.8**	$ 130.7	$ 123.6	**$ (106.9)**	**(82%)**	$ 7.1	6%

The following table sets forth our margins by activity for the periods indicated:

	Years Ended December 31,			Variances 2011 vs. 2010		Variances 2010 vs. 2009	
	2011	2010	2009	Increase (Decrease)		Increase (Decrease)	
	(Millions of dollars)						
Marketing, storage and transportation revenues, gross	**$ 208.0**	$ 342.9	$ 367.7	**$ (134.9)**	**(39%)**	$ (24.8)	(7%)
Storage and transportation costs	**161.2**	189.4	211.2	**(28.2)**	**(15%)**	(21.8)	(10%)
Marketing, storage and transportation, net	**46.8**	153.5	156.5	**(106.7)**	**(70%)**	(3.0)	(2%)
Financial trading, net	**1.9**	6.2	3.1	**(4.3)**	**(69%)**	3.1	100%
Net margin	**$ 48.7**	$ 159.7	$ 159.6	**$ (111.0)**	**(70%)**	$ 0.1	0%

In accordance with our strategy to better align fixed costs with the current business environment, we reduced our leased transportation capacity in 2011. Our storage and transportation costs decreased 15 percent in 2011 compared with 2010, primarily due to this transportation capacity reduction. For additional information on transportation capacity refer to "Selected Operating Information" below.

Marketing, storage and transportation revenues, gross, primarily includes marketing, purchases and sales, premium services and the impact of cash flow and fair value hedges and other derivative instruments used to manage our risk associated with these activities. Storage and transportation costs primarily include the cost of leasing capacity, storage injection and withdrawal fees, fuel charges and gathering fees. Risk management and operational decisions have an impact on the net result of our marketing, premium services and storage activities. We evaluate our strategies on an ongoing basis to optimize the value of our contracted assets and to minimize the financial impact of market conditions on the services we provide.

Financial trading, net, includes activities that are executed generally using financially settled derivatives. These activities are normally short term in nature, with a focus on capturing short-term price volatility. Revenues in our Consolidated Statements of Income include financial trading margins, as well as certain physical natural gas transactions with our trading counterparties. Revenues and cost of sales and fuel from such physical transactions are reported on a net basis.

<u>2011 vs. 2010</u> - The factors discussed in Energy Services' "Narrative Description of the Business" included in Item I, Business, of this Annual Report have led to a significant decrease in net margin, including:

- a decrease of $65.3 million in transportation margins, net of hedging, due primarily to narrower price location differentials and lower hedge settlements in 2011;
- a decrease of $34.3 million in storage and marketing margins, net of hedging activities, due primarily to the following:
    - lower realized seasonal storage price differentials; offset partially by
    - favorable marketing activity and unrealized fair value changes on nonqualifying economic storage hedges;
- a decrease of $7.3 million in premium-services margins, associated primarily with the reduction in the value of the fees collected for these services as a result of low commodity prices and reduced natural gas price volatility in the first quarter of 2011 compared with the first quarter of 2010; and
- a decrease of $4.3 million in financial trading margins, as low natural gas prices and reduced natural gas price volatility limited our financial trading opportunities.

Additionally, our net margin includes $91.1 million in adjustments to natural gas inventory reflecting the lower of cost or market value. Because of the adjustments to our inventory value, we reclassified $91.1 million of deferred gains on associated cash flow hedges into earnings.

Operating costs decreased due primarily to a decrease in ad valorem taxes.

<u>2010 vs. 2009</u> - Net margin was relatively unchanged but reflects the following:

- an increase of $39.7 million in storage and marketing margins, net of hedging activities, due primarily to the following:
    - higher realized seasonal storage price differentials and a decrease in storage expense due to the reduction in storage capacity; offset partially by
    - a reduction in storage withdrawals due to decreased natural gas storage capacity under lease; and
    - unfavorable unrealized fair-value changes on nonqualifying economic hedge activity and marketing margins; and
- an increase of $3.1 million in financial trading margins; offset by
- a decrease of $21.4 million in transportation margins, net of hedging, due primarily to narrower realized Mid-Continent-to-Gulf Coast price differentials; and

- a decrease of $21.3 million in premium-services margins, associated primarily with lower demand fees as a result of lower volatility of natural gas prices, offset partially by the favorable management of customer-peaking requirements resulting from warmer weather in the fourth quarter of 2010, compared with the same period in 2009.

Additionally, our net margin includes $58.7 million in adjustments to natural gas inventory reflecting the lower of cost or market value. Because of the adjustments to our inventory value, we reclassified $58.7 million of deferred gains on associated cash flow hedges into earnings.

Operating costs decreased due primarily to a decrease in legal-related costs and ad valorem taxes.

Selected Operating Information - The following table sets forth certain selected operating information for our Energy Services segment for the periods indicated:

	Years Ended December 31,		
Operating Information	**2011**	**2010**	**2009**
Natural gas marketed *(Bcf)*	**845**	919	1,105
Natural gas gross margin *($/Mcf)*	**$ 0.06**	$ 0.18	$ 0.15
Physically settled volumes *(Bcf)*	**1,724**	1,874	2,217

Natural gas volumes marketed and physically settled volumes decreased in both 2011 and 2010 due primarily to reduced transportation capacity and lower transported volumes. Transportation capacity in certain markets was not utilized due to the economics of the location differentials as a result of increased supply of natural gas, primarily from shale production and increased pipeline capacity as a result of pipeline construction.

Our natural gas in storage at December 31, 2011, was 70.5 Bcf, compared with 63.0 Bcf at December 31, 2010. At December 31, 2011, our total natural gas storage capacity under lease was 75.6 Bcf, compared with 73.6 Bcf at December 31, 2010. At December 31, 2011, our natural gas storage capacity under lease had a maximum withdrawal capability of 2.4 Bcf/d and maximum injection capability of 1.3 Bcf/d. At December 31, 2011, our natural gas transportation capacity was 1.2 Bcf/d, of which 1.1 Bcf/d was contracted under long-term natural gas transportation contracts, compared with 1.4 Bcf/d of total capacity and 1.1 Bcf/d of long-term capacity at December 31, 2010.

Although our intent is to reduce our natural gas storage capacity, we had an increase in the capacity under lease at December 31, 2011, compared with December 31, 2010, as a result of new capacity that was committed to in prior years. Reducing both storage and transportation capacity will continue to be a focus as we continue to attempt to reduce fixed costs because of the current business environment. It is possible that we may recognize charges to our earnings as a result of certain of these actions.

CONTINGENCIES

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, and we are unable to estimate reasonably possible losses, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows. Additional information about our legal proceedings is included under Part I, Item 3, Legal Proceedings, in this Annual Report.

LIQUIDITY AND CAPITAL RESOURCES

General - ONEOK and ONEOK Partners have relied primarily on operating cash flow, commercial paper, bank credit facilities, debt issuances and/or the issuance of equity for their liquidity and capital resource requirements. ONEOK and ONEOK Partners fund operating expenses, debt service, dividends to shareholders and distributions to unitholders primarily with operating cash flow. Capital expenditures are funded by short- and long-term debt, issuances of equity and operating cash flow. We expect to continue to use these sources for our liquidity and capital resource needs. Neither ONEOK nor ONEOK Partners guarantees the debt or other similar commitments to unaffiliated parties, and ONEOK does not guarantee the debt or other similar commitments of ONEOK Partners.

In 2011, ONEOK and ONEOK Partners accessed the commercial paper markets to meet their short-term liquidity needs. Additionally, ONEOK Partners accessed the public debt markets in January 2011 for its long-term financing needs. See discussion below under “ONEOK Partners’ Debt Issuance and Maturities” for more information.

ONEOK's and ONEOK Partners' ability to continue to access capital markets for debt and equity financing under reasonable terms depends on market conditions and ONEOK's and ONEOK Partners' respective financial condition and credit ratings. We anticipate that our cash flow generated from operations, existing capital resources, including proceeds from the issuance of our $700 million 4.25-percent senior notes issued in January 2012, and distributions from ONEOK Partners will enable us to maintain our current and planned level of operations and fund the remainder of our three-year, $750-million stock repurchase program. ONEOK Partners anticipates that its cash flow generated from operations, existing capital resources and ability to obtain financing will enable it to maintain its current and planned level of operations. Additionally, ONEOK Partners expects to fund its future capital expenditures with short- and long-term debt, the issuance of equity and operating cash flows.

Capitalization Structure - The following table sets forth our consolidated capitalization structure for the periods indicated:

	December 31, 2011	**December 31, 2010**
Long-term debt	**56%**	52%
Total equity	**44%**	48%
Debt (including notes payable)	**60%**	55%
Total equity	**40%**	45%

For purposes of determining compliance with financial covenants in the ONEOK 2011 Credit Agreement, which are described below, the debt of ONEOK Partners is excluded. The following table sets forth ONEOK's capital structure, excluding the debt of ONEOK Partners, for the periods indicated:

	December 31, 2011	**December 31, 2010**
Long-term debt	**31%**	38%
ONEOK shareholders' equity	**69%**	62%
Debt (including notes payable)	**45%**	40%
ONEOK shareholders' equity	**55%**	60%

Stock Repurchase Program - In 2011, we repurchased approximately 4.3 million shares of our common stock for approximately $300 million pursuant to an accelerated stock repurchase agreement. The stock repurchase was part of our three-year stock repurchase program to buy up to $750 million of our common stock that was authorized by our Board of Directors in October 2010.

Cash Management - ONEOK and ONEOK Partners each use similar centralized cash management programs that concentrate the cash assets of their operating subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Both centralized cash management programs provide that funds in excess of the daily needs of the operating subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within the respective consolidated groups. ONEOK Partners' operating subsidiaries participate in these programs to the extent they are permitted pursuant to FERC regulations or their operating agreements. Under these cash management programs, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, ONEOK and ONEOK Partners provide cash to their respective subsidiaries or the subsidiaries provide cash to them.

Short-term Liquidity - ONEOK's principal sources of short-term liquidity consist of cash generated from operating activities, quarterly distributions from ONEOK Partners and the issuance of commercial paper. ONEOK Partners' principal sources of short-term liquidity consist of cash generated from operating activities, the issuance of its commercial paper program and distributions received from unconsolidated affiliates. To the extent commercial paper is unavailable, ONEOK's and ONEOK Partners' respective revolving credit agreements may be utilized.

<u>ONEOK 2011 Credit Agreement</u> - In April 2011, ONEOK entered into the five-year, $1.2 billion ONEOK 2011 Credit Agreement, which replaced the $1.2 billion ONEOK Credit Agreement that was scheduled to expire in July 2011. The ONEOK 2011 Credit Agreement, which is scheduled to expire in April 2016, contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONEOK's stand-alone debt-to-capital ratio of no more than 67.5 percent at the end of any calendar quarter, limitations on the ratio of indebtedness secured by liens and indebtedness of subsidiaries to consolidated net tangible assets, a requirement that ONEOK maintains the power to control the management and policies of ONEOK Partners, and a limit on new investments in master limited partnerships.

The ONEOK 2011 Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, investments, fundamental changes in the nature of ONEOK's businesses, transactions with affiliates, the use of proceeds and a covenant that limits ONEOK's ability to restrict its subsidiaries' ability to pay dividends. Under the terms of the ONEOK 2011 Credit Agreement, ONEOK may request an increase in the size of the facility to an aggregate of $1.7 billion from $1.2 billion by either commitments from new lenders or increased commitments from existing lenders.

The debt covenant calculations in the ONEOK 2011 Credit Agreement exclude the debt of ONEOK Partners. Upon breach of certain covenants by ONEOK, amounts outstanding under the ONEOK 2011 Credit Agreement may become due and payable immediately. At December 31, 2011, ONEOK's stand-alone debt-to-capital ratio, as defined by the ONEOK 2011 Credit Agreement, was 44.4 percent, and ONEOK was in compliance with all covenants under the ONEOK 2011 Credit Agreement.

The total amount of short-term borrowings authorized by ONEOK's Board of Directors is $2.8 billion. At December 31, 2011, ONEOK had $842.0 million of commercial paper outstanding, $2.0 million in letters of credit issued under the ONEOK 2011 Credit Agreement and approximately $30.9 million of cash and cash equivalents. ONEOK had approximately $356.0 million of credit available at December 31, 2011, under the ONEOK 2011 Credit Agreement. As of December 31, 2011, ONEOK could have issued $3.1 billion of additional short- and long-term debt under the most restrictive provisions contained in its various borrowing agreements.

The ONEOK 2011 Credit Agreement is available to repay our commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONEOK 2011 Credit Agreement. The ONEOK 2011 Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Borrowings, if any, will accrue at LIBOR plus 150 basis points, and the annual facility fee is 25 basis points based on our current credit rating.

ONEOK Partners 2011 Credit Agreement - In August 2011, ONEOK Partners entered into the five-year, $1.2 billion ONEOK Partners 2011 Credit Agreement, which replaced the $1.0 billion ONEOK Partners Credit Agreement that was due to expire in March 2012. The ONEOK Partners 2011 Credit Agreement, which is scheduled to expire in August 2016, contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in the ONEOK Partners 2011 Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1. If ONEOK Partners consummates one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will be increased to 5.5 to 1 for the three calendar quarters following the acquisition. Upon breach of certain covenants by ONEOK Partners in the ONEOK Partners 2011 Credit Agreement, amounts outstanding under the ONEOK Partners 2011 Credit Agreement, if any, may become due and payable immediately.

The ONEOK Partners 2011 Credit Agreement includes a $100-million sublimit for the issuance of standby letters of credit and also features an option to request an increase in the size of the facility to an aggregate of $1.7 billion from $1.2 billion by either commitments from new lenders or increased commitments from existing lenders.

The ONEOK Partners 2011 Credit Agreement is available to repay ONEOK Partners' commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONEOK Partners 2011 Credit Agreement. The ONEOK Partners 2011 Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in ONEOK Partners' credit rating. Borrowings, if any, will accrue at LIBOR plus 130 basis points, and the annual facility fee is 20 basis points based on ONEOK Partners' current credit rating. The ONEOK Partners 2011 Credit Agreement is guaranteed fully and unconditionally by ONEOK Partners' wholly owned subsidiary, ONEOK Partners Intermediate Limited Partnership. Borrowings under the ONEOK Partners 2011 Credit Agreement are nonrecourse to ONEOK.

The total amount of short-term borrowings authorized by the Board of Directors of ONEOK Partners GP, the general partner of ONEOK Partners, is $2.5 billion. At December 31, 2011, ONEOK Partners had no commercial paper outstanding, no letters of credit issued, no borrowings outstanding under the ONEOK Partners 2011 Credit Agreement, approximately $35.1 million of cash and $1.2 billion of credit available under the ONEOK Partners 2011 Credit Agreement. As of December 31, 2011, ONEOK Partners could have issued $3.5 billion of short- and long-term debt to meet its liquidity needs under the most restrictive provisions contained in its various borrowing agreements.

At December 31, 2011, ONEOK Partners' ratio of indebtedness to adjusted EBITDA was 2.9 to 1, and ONEOK Partners was in compliance with all covenants under the ONEOK Partners 2011 Credit Agreement.

At December 31, 2011, the weighted-average interest rate on ONEOK’s short-term debt outstanding was 0.50 percent. The weighted-average interest rates for the year ended December 31, 2011, on ONEOK’s and ONEOK Partners’ short-term borrowings were 0.29 percent and 0.37 percent, respectively. Based on the forward LIBOR curve, we expect the interest rates on ONEOK’s and ONEOK Partners’ short-term borrowings to increase in 2012, compared with interest rates on amounts outstanding at December 31, 2011.

Long-term Financing - In addition to the principal sources of short-term liquidity discussed above, ONEOK expects to fund its longer-term cash requirements by issuing equity or long-term notes. ONEOK Partners expects to fund its longer-term cash requirements by issuing common units or long-term notes. Other options to obtain financing include, but are not limited to, issuance of convertible debt securities, asset securitization and the sale and leaseback of facilities.

ONEOK and ONEOK Partners are subject to changes in the debt and equity markets, and there is no assurance they will be able or willing to access the public or private markets in the future. ONEOK and ONEOK Partners may choose to meet their cash requirements by utilizing some combination of cash flows from operations, borrowing under existing commercial paper or credit facilities, altering the timing of controllable expenditures, restricting future acquisitions and capital projects, or pursuing other debt or equity financing alternatives. Some of these alternatives could involve higher costs or negatively affect their respective credit ratings, among other factors. Based on ONEOK’s and ONEOK Partners’ investment-grade credit ratings, general financial condition and market expectations regarding their future earnings and projected cash flows, ONEOK and ONEOK Partners believe that they will be able to meet their respective cash requirements and maintain their investment-grade credit ratings.

ONEOK Debt Issuance - In January 2012, we completed an underwritten public offering of $700 million of 4.25-percent senior notes due 2022. The net proceeds from the offering, after deducting underwriting discounts and offering expenses, of approximately $693.9 million were used to repay amounts outstanding under our commercial paper program. We will pay interest on the senior notes due 2022 on February 1 and August 1 of each year, beginning August 1, 2012.

ONEOK Debt Repayments - In 2011, ONEOK repaid $400 million of maturing senior notes and redeemed $90.5 million of 6.4-percent senior notes with available cash and short-term borrowings.

ONEOK Debt Covenants - The indentures governing ONEOK’s senior notes due 2028 (6.5 percent and 6.875 percent) include an event of default upon acceleration of other indebtedness of $15 million or more, and the indentures governing the senior notes due 2015, 2022 and 2035 include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2015, 2022, 2028 and 2035 to declare those senior notes immediately due and payable in full.

ONEOK may redeem the senior notes due 2015, 2028 (6.875 percent) and 2035, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. ONEOK may redeem the senior notes due 2028 (6.5 percent), in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest. ONEOK may redeem its 4.25-percent senior notes due 2022 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting three month before the maturity date. Prior to this date, ONEOK may redeem these senior notes on the same basis as its other senior notes due 2015, 2028 (6.875 percent) and 2035. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. ONEOK’s senior notes due 2015, 2022, 2028 and 2035 are senior unsecured obligations, ranking equally in right of payment with all of ONEOK’s existing and future unsecured senior indebtedness.

ONEOK Partners’ Debt Issuance and Maturities - In January 2011, ONEOK Partners completed an underwritten public offering of $1.3 billion of senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering of approximately $1.28 billion were used to repay amounts outstanding under ONEOK Partners’ commercial paper program, to repay $225 million of ONEOK Partners’ senior notes that matured in March 2011 and for general partnership purposes, including capital expenditures.

ONEOK Partners intends to repay its $350 million of 5.9-percent senior notes that mature in April 2012 with a combination of cash on hand and short-term borrowings.

ONEOK Partners’ Debt Covenants - The indentures governing ONEOK Partners’ senior notes include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of ONEOK Partners’ outstanding senior notes to declare those senior notes immediately due and payable in full.

ONEOK Partners may redeem the senior notes due 2012, 2016 (6.15 percent), 2019, 2036 and 2037, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. ONEOK Partners may redeem its senior notes due 2016 (3.25 percent) and senior notes due 2041 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting one month and six months, respectively, before their maturity dates. Prior to these dates, ONEOK Partners may redeem these senior notes on the same terms as its other senior notes. ONEOK Partners' senior notes are senior unsecured obligations, ranking equally in right of payment with all of ONEOK Partners' existing and future unsecured senior indebtedness, and structurally subordinate to all of the existing and future debt and other liabilities of any nonguarantor subsidiaries. ONEOK Partners' senior notes are nonrecourse to ONEOK.

Interest-rate Swaps - At December 31, 2011, ONEOK and ONEOK Partners had forward-starting interest-rate swaps with notional amounts of $500 million and $750 million, respectively. The purpose of the swaps is to hedge the variability of interest payments on a portion of forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued. In January 2012, ONEOK entered into an additional interest-rate swap that was designated as a cash flow hedge with a notional amount of $200 million. Upon issuance in January 2012 of our $700 million of 4.25-percent senior notes due 2022, ONEOK settled its swaps and realized a loss of $44.1 million that will be amortized to interest expense over the term of the debt.

Capital Expenditures - ONEOK's and ONEOK Partners' capital expenditures are financed typically through operating cash flows, short- and long-term debt and the issuance of equity. Capital expenditures were $1,336.1 million, $582.7 million and $791.2 million for 2011, 2010 and 2009, respectively, exclusive of acquisitions. Of these amounts, ONEOK Partners' capital expenditures were $1,063.4 million, $352.7 million and $615.7 million for 2011, 2010 and 2009, respectively, exclusive of acquisitions. Capital expenditures for 2011 increased, compared with 2010, due primarily to the growth projects in ONEOK Partners' natural gas gathering and processing and natural gas liquids businesses.

The following table sets forth our 2012 projected capital expenditures, excluding AFUDC:

2012 Projected Capital Expenditures

	(Millions of dollars)	
ONEOK Partners	$	1,969
Natural Gas Distribution		270
Other		32
Total projected capital expenditures	$	2,271

Unconsolidated Affiliates - The Overland Pass Pipeline Company limited liability company agreement provides that distributions to Overland Pass Pipeline Company's members are to be made on a pro-rata basis according to each member's ownership interest. The Overland Pass Pipeline Company Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, cash distributions from Overland Pass Pipeline Company requires the unanimous approval of the Overland Pass Pipeline Management Committee. Cash distributions are equal to 100 percent of available cash as defined in the limited liability company agreement.

The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro-rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon EBITDA, less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement. The Northern Border Pipeline Management Committee has adopted a cash distribution policy related to financial ratio targets and capital contributions. The cash distribution policy defines minimum equity-to-total-capitalization ratios to be used by the Northern Border Pipeline Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions.

Credit Ratings - Our credit ratings as of December 31, 2011, are shown in the table below:

	ONEOK		ONEOK Partners	
Rating Agency	**Rating**	**Outlook**	**Rating**	**Outlook**
Moody's	Baa2	Stable	Baa2	Stable
S&P	BBB	Stable	BBB	Stable

ONEOK's and ONEOK Partners' commercial paper programs are each rated Prime-2 by Moody's and A2 by S&P. ONEOK's and ONEOK Partners' credit ratings, which currently are investment grade, may be affected by a material change in financial ratios or a material event affecting the business. The most common criteria for assessment of credit ratings are the debt-to-capital ratio, business risk profile, pretax and after-tax interest coverage, and liquidity. ONEOK and ONEOK Partners currently do not anticipate their respective credit ratings to be downgraded. However, if ONEOK's or ONEOK Partners' credit ratings were downgraded, the cost to borrow funds under their respective commercial paper programs and credit agreements would increase, and ONEOK or ONEOK Partners potentially could lose access to the commercial paper market. In the event that ONEOK is unable to borrow funds under its commercial paper program and there has not been a material adverse change in its business, ONEOK would continue to have access to the ONEOK 2011 Credit Agreement, which expires in April 2016. In the event that ONEOK Partners is unable to borrow funds under its commercial paper program and there has not been a material adverse change in its business, ONEOK Partners would continue to have access to the ONEOK Partners 2011 Credit Agreement, which expires in August 2016. An adverse rating change alone is not a default under the ONEOK 2011 Credit Agreement or the ONEOK Partners 2011 Credit Agreement.

Our Energy Services segment relies upon the investment-grade rating of ONEOK's senior unsecured long-term debt to reduce its collateral requirements. If ONEOK's credit ratings were to decline below investment grade, our ability to participate in energy marketing and trading activities could be significantly limited. Without an investment-grade rating, we may be required to fund margin requirements with our counterparties with cash, letters of credit or other negotiable instruments. At December 31, 2011, ONEOK could have been required to fund approximately $5.9 million in margin requirements related to financial contracts upon such a downgrade. A decline in ONEOK's credit rating below investment grade also may impact significantly other business segments.

In the normal course of business, ONEOK's and ONEOK Partners' counterparties provide secured and unsecured credit. In the event of a downgrade in ONEOK's or ONEOK Partners' credit ratings or a significant change in ONEOK's or ONEOK Partners' counterparties' evaluation of our creditworthiness, ONEOK or ONEOK Partners could be required to provide additional collateral in the form of cash, letters of credit or other negotiable instruments as a condition of continuing to conduct business with such counterparties.

Commodity Prices - We are subject to commodity price volatility. Significant fluctuations in commodity prices will impact our overall liquidity due to the impact commodity price changes have on our cash flows from operating activities, including the impact on working capital for NGLs and natural gas held in storage, margin requirements and certain energy-related receivables. We believe that ONEOK's and ONEOK Partners' available credit and cash and cash equivalents are adequate to meet liquidity requirements associated with commodity price volatility. See discussion beginning on page 68 under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for information on our hedging activities.

Pension and Postretirement Benefit Plans - Information about our pension and postretirement benefits plans, including anticipated contributions, is included under Note M of the Notes to Consolidated Financial Statements in this Annual Report.

During 2011, we made contributions of $62.6 million and $11.5 million to our defined benefit pension plans and postretirement benefit plans, respectively. Our 2011 contributions to our defined benefit pension plans are attributable to the 2012 plan year. During the first quarter of 2012, we made a contribution of $60.0 million to our defined benefit pension plan attributable to the 2013 plan year. We do not anticipate that we will be required to make additional material defined benefit pension plan contributions in 2012. We anticipate our 2012 contributions for our postretirement benefit plans will be approximately $10.7 million. The expected 2012 benefit payments for our postretirement benefit plans are estimated to be $16.4 million.

CASH FLOW ANALYSIS

We use the indirect method to prepare our Consolidated Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, allowance for equity funds used during construction, gain or loss on sale of assets, equity earnings from investments, distributions received from unconsolidated affiliates, deferred income taxes, share-based compensation expense, other amounts, and changes in our assets and liabilities not classified as investing or financing activities.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	**$ 1,360.0**	$ 834.0	$ 1,452.7
Investing activities	**(1,371.6)**	(134.3)	(787.8)
Financing activities	**55.4**	(698.1)	(1,145.6)
Change in cash and cash equivalents	**43.8**	1.6	(480.7)
Change in cash and cash equivalents included in discontinued operations	**(8.2)**	(2.2)	15.6
Change in cash and cash equivalents from continuing operations	**35.6**	(0.6)	(465.1)
Cash and cash equivalents at beginning of period	**30.4**	30.9	496.0
Cash and cash equivalents at end of period	**$ 66.0**	$ 30.3	$ 30.9

Operating Cash Flows - Operating cash flows are affected by earnings from our business activities. Changes in commodity prices and demand for our services or products, whether because of general economic conditions, changes in supply, changes in demand for the end products that are made with our products or increased competition from other service providers, could affect our earnings and operating cash flows.

2011 vs. 2010 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1,397.7 million for 2011, compared with $994.9 million for 2010. The increase was due primarily to changes in net margin and operating expenses discussed in Financial Results and Operating Information on page 42.

The changes in operating assets and liabilities decreased operating cash flows $37.7 million for 2011, compared with a decrease of $160.9 million for 2010. The change was due primarily to the collection and payment of trade receivables and payables, resulting from the timing of invoices collected from customers and paid to vendors and suppliers, which vary from period to period; and a decrease in volumes of NGLs in storage in our ONEOK Partners segment in the current period, compared with an increase in volumes in storage in our ONEOK Partners segment in the same period last year.

2010 vs. 2009 - Cash flows from operating activities, before changes in operating assets and liabilities, were $994.9 million for 2010, compared with $974.3 million for 2009. The increase was due primarily to changes in net margin and operating expenses discussed in Financial Results and Operating Information on page 42.

The changes in operating assets and liabilities decreased operating cash flows $160.9 million for 2010, compared with an increase of $478.4 million for 2009, primarily as a result of the impact of commodity prices on our operating assets and liabilities and an increase in volumes of commodities in storage primarily in our Natural Gas Distribution segment and ONEOK Partners' natural gas liquids business.

Investing Cash Flows - Cash used in investing activities increased for 2011, compared with cash used in investing activities for the same period in 2010, due primarily to ONEOK Partners' growth projects in its natural gas gathering and processing and natural gas liquids businesses and the $423.7 million in proceeds ONEOK Partners received from the Overland Pass Pipeline transaction in September 2010.

Financing Cash Flows - Cash provided by financing activities increased for 2011 compared with 2010. The change is a result of ONEOK Partners' January 2011 debt issuance, a portion of the proceeds from which were used to repay ONEOK Partners' short-term borrowings and the March 2011 maturity of a portion of ONEOK Partners' long-term debt. The net cash flows provided by these financing activities were offset partially by the repayment of a scheduled maturity of ONEOK's long-term debt, ONEOK's $300 million share repurchase in May 2011, increased distributions to noncontrolling interests and increased dividends.

Cash used in financing activities decreased for 2010, compared with the 2009, due primarily to decreased borrowings resulting from the completion of ONEOK Partners' capital projects in 2009, ONEOK Partners' repayment of $250 million of maturing senior notes in 2010, an increase of approximately 12.0 percent in dividends paid during 2010, an increase of approximately 3.0 percent in cash distributions per unit paid to noncontrolling interests and additional ONEOK Partners common units, offset partially by increased net proceeds generated from ONEOK Partners' common unit offering in 2010.

REGULATORY AND ENVIRONMENTAL MATTERS

Environmental Matters - We are subject to multiple historical and wildlife preservation laws and environmental regulations affecting many aspects of our present and future operations. Regulated activities include those involving air emissions; storm water and wastewater discharges; handling and disposal of solid and hazardous wastes; hazardous materials transportation; and pipeline and facility construction. These laws and regulations require us to obtain and comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If a leak or spill of hazardous substances or petroleum products occurs from pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and cleanup costs, which could affect materially our results of operations and cash flows. In addition, emission controls required under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In May 2010, the EPA finalized the "Tailoring Rule" that will regulate greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities will be required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011 and, at current emission threshold levels, will have a minimal impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In addition, the EPA issued a proposed rule on air-quality standards, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, with a compliance date in 2013. The rule will require capital expenditures over the next three years for the purchase and installation of new emissions-control equipment. We do not expect these expenditures to have a material impact on our results of operations, financial position or cash flows.

Additional information about our environmental matters is included in "Environmental and Safety Matters" of Item 1, Business and Note Q of the Notes to Consolidated Financial Statements in this Annual Report. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters did not have a material impact on earnings or cash flows during 2011, 2010 and 2009.

Financial Markets Legislation - The Dodd-Frank Act represents a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the CFTC has issued final regulations for certain provisions of the Dodd-Frank Act, many remain outstanding. In November 2011, the CFTC published final rules on speculative position limits, which we do not expect to impact directly our current risk-management practices. In December 2011, the CFTC issued an order that further defers the effective date of the provisions of the Dodd-Frank Act that require a rulemaking, such as definitions of certain terms, until the earlier of the effective date of the final rule defining the reference terms or July 16, 2012. Until the remaining final regulations are established, we are unable to ascertain how we may be affected by them. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We also may incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations; however, we do not believe the costs will be material. These requirements could affect adversely market liquidity and pricing of derivative contracts making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

Other - Several regulatory initiatives impacted the earnings and future earnings potential for our Natural Gas Distribution segment. See discussion of our Natural Gas Distribution segment's regulatory initiatives beginning on page 52.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note A of the Notes to Consolidated Financial Statements in this Annual Report.

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates.

The following is a summary of our most critical accounting policies, which are defined as those estimates and policies most important to the portrayal of our financial condition and results of operations and requiring management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our estimates and critical accounting policies with the Audit Committee of our Board of Directors.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use the market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. While many of the contracts in our portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist, but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. Inputs into our fair value estimates include commodity exchange prices, over-the-counter quotes, volatility, historical correlations of pricing data and LIBOR and other liquid money-market instrument rates. We also utilize internally developed basis curves that incorporate observable and unobservable market data. We validate our valuation inputs with third-party information and settlement prices from other sources, where available. In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value using interest-rate yields to calculate present-value discount factors derived from LIBOR, Eurodollar futures and interest-rate swaps. We also take into consideration the potential impact on market prices of liquidating positions in an orderly manner and over a reasonable period of time using current market conditions. We consider current market data in evaluating counterparties', as well as our own, nonperformance risk, net of collateral, by using specific and sector bond yields and also monitoring the credit default swap markets. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be material.

The fair value of our forward-starting interest-rate swaps is determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest-rate swap settlements.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are, either directly or indirectly, observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and
- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. Transfers in and out of Level 3 typically result from derivatives for which fair value is determined based on multiple inputs. If prices change for a particular input from the previous measurement date to the current measurement date, the impact could result in the derivative being moved between Level 2 and Level 3, depending upon management's judgment of the significance of the price change of that particular input to the total fair value of the derivative.

For more information on our fair value measurements, fair value sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note C of the Notes to Consolidated Financial Statements in this Annual Report.

Derivatives, Accounting for Financially Settled Transactions and Risk-Management Activities - We engage in wholesale energy marketing, trading and risk-management activities. We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery.

Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the nature of the risk being hedged and how effective the hedging instrument is. When possible, we implement effective hedging strategies using derivative instruments that qualify as hedges for accounting purposes. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, then we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain or loss in any given period.

To reduce our exposure to fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, forwards, options or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs and condensate and fuel requirements. Interest-rate swaps are also used to manage interest-rate risk. Under certain conditions, we designate these derivative instruments as a hedge against our exposure to changes in fair values or cash flow. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss) and is subsequently recorded to earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings during the period the ineffectiveness occurs. However, if a derivative instrument is ineligible for hedge accounting or if the cash flow hedge is not properly designated, changes in fair value of the derivative instrument would be recorded currently in earnings. Additionally, if a cash flow hedge ceases to qualify for hedge accounting treatment because it is no longer probable that the forecasted transaction will occur, the change in fair value of the derivative instrument would be recognized in earnings.

For hedges against our exposure in changes in fair value, the gain or loss on the derivative instrument is recognized in earnings during the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. We do not believe that changes in our fair value estimates of our derivative instruments have a material impact on our results of operations as the majority of our derivatives are accounted for as hedges for which ineffectiveness is not material. We assess the effectiveness of hedging relationships quarterly by performing an effectiveness test on our hedging relationships to determine whether they are highly effective on a retrospective and prospective basis.

Upon election, many of our purchase and sale agreements that result in physical delivery and that otherwise would be required to follow the accounting for derivative instruments qualify as normal purchases and normal sales exceptions and are therefore exempt from fair value accounting treatment.

For more information on our derivatives and risk management activities, fair value sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note D of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion.

Impairment of Goodwill and Long-Lived Assets, Including Intangible Assets - We assess our goodwill and indefinite-lived intangible assets for impairment at least annually as of July 1. There were no impairment charges resulting from our 2011, 2010 or 2009 impairment tests. As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply multiples to forecasted cash flows. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

As part of our indefinite-lived intangible asset impairment test, we compare the estimated fair value of our indefinite-lived intangible assets with their book values. The fair value of our indefinite-lived intangible assets is estimated using the market approach. Under the market approach, we apply multiples to forecasted cash flows of the assets associated with our indefinite-lived intangible assets. The multiples used are consistent with historical asset transactions. We determined that there were no impairments to our indefinite-lived intangible asset in 2011, 2010 or 2009.

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no asset impairments in 2011, 2010 or 2009.

For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry our equity method investments to determine whether current events or circumstances warrant adjustments to our carrying value. We determined that there were no impairments to our investments in unconsolidated affiliates in 2011, 2010 or 2009.

Our impairment tests require the use of assumptions and estimates such as industry economic factors and the profitability of future business strategies. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future impairment charges.

See Notes E and F for our goodwill and long-lived assets disclosures.

Pension and Postretirement Employee Benefits - We have defined benefit retirement plans covering certain full-time employees. We sponsor welfare plans that provide postretirement medical and life insurance benefits to certain employees who retire with at least five years of service. Our actuarial consultant calculates the expense and liability related to these plans and uses statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize. See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional information.

Assumed health care cost-trend rates have a significant effect on the amounts reported for our health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects.

	One Percentage Point Increase	One Percentage Point Decrease
	(Thousands of dollars)	
Effect on total of service and interest cost	**$ 1,833**	**$ (1,559)**
Effect on postretirement benefit obligation	**$ 17,562**	**$ (16,079)**

During 2011, we recorded net periodic benefit costs of $40.0 million related to our defined benefit pension plans and $19.1 million related to postretirement benefits. We estimate that in 2012, we will record net periodic benefit costs of $47.2 million related to our defined benefit pension plans and $16.0 million related to postretirement benefits. In determining our estimated expenses for 2012, we assumed an 8.25-percent expected return on plan assets and a discount rate of 5.0 percent. A decrease in our expected return on plan assets to 8.0 percent would increase our 2012 estimated net periodic benefit costs by approximately $2.5 million for our defined benefit pension plans and would not have a significant impact on our postretirement benefit plans. A decrease in our assumed discount rate to 4.75 percent would increase our 2012 estimated net periodic benefit costs by approximately $3.6 million for our defined benefit pension plans and would not have a significant impact on our postretirement benefit plans. During 2011, we made contributions of $62.6 million and $11.5 million to our defined benefit pension plans and postretirement benefit plans, respectively. In 2011, all contributions to our defined benefit pension plans were attributable to the 2012 plan year. During the first quarter of 2012, we made a contribution of $60.0 million to our defined benefit pension plan attributable to the 2013 plan year; we do not anticipate that we will be required to make additional material defined benefit pension plan contributions in 2012. We anticipate our 2012 contributions for our postretirement benefit plans will be approximately $10.7 million.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We base our estimates on currently available facts and our assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows during 2011, 2010 and 2009. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note Q of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table sets forth our contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2011. For additional discussion of the debt and operating lease agreements, see Notes H and Q, respectively, of the Notes to the Consolidated Financial Statements in this Annual Report:

	Payments Due by Period						
Contractual Obligations	**Total**	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**
ONEOK	*(Thousands of dollars)*						
Commercial paper	$ 841,982	$ 841,982	$ -	$ -	$ -	$ -	$ -
Long-term debt	989,593	3,329	3,205	3,006	403,006	3,007	574,040
Interest payments on debt	821,000	57,400	57,200	57,000	45,500	35,800	568,100
Operating leases	3,014	1,209	906	638	252	9	-
Firm transportation and storage contracts	370,586	122,355	87,491	68,209	42,851	26,417	23,263
Financial and physical derivatives	1,031,022	1,017,617	12,565	840	-	-	-
Employee benefit plans	75,385	75,385	-	-	-	-	-
	$ 4,132,582	$ 2,119,277	$ 161,367	$ 129,693	$ 491,609	$ 65,233	$ 1,165,403
ONEOK Partners							
Long-term debt	$ 3,885,919	$ 361,062	$ 7,650	$ 7,650	$ 7,650	$ 1,107,650	$ 2,394,257
Interest payments on debt	3,768,100	224,300	218,400	216,600	215,300	189,000	2,704,500
Operating leases	17,706	3,414	2,840	2,770	1,292	1,009	6,381
Firm transportation and storage contracts	38,242	8,997	6,521	6,232	6,081	4,725	5,686
Financial and physical derivatives	149,899	149,899	-	-	-	-	-
Purchase commitments, rights of way and other	406,989	179,850	43,877	25,877	25,602	25,578	106,205
	$ 8,266,855	$ 927,522	$ 279,288	$ 259,129	$ 255,925	$ 1,327,962	$ 5,217,029
Total	$ 12,399,437	$ 3,046,799	$ 440,655	$ 388,822	$ 747,534	$ 1,393,195	$ 6,382,432

Long-term debt - Long-term debt as reported in our Consolidated Balance Sheets includes unamortized debt discount and the unamortized settlement values of interest-rate swaps.

Interest payments on debt - Interest expense is calculated by multiplying long-term debt by the respective coupon rates, adjusted for active swaps.

Operating leases - Our operating leases include leases for office space, pipeline equipment and vehicles.

Firm transportation and storage contracts - We are party to fixed-price contracts for firm transportation and storage capacity. However, the costs associated with our Natural Gas Distribution segment's contracts that are recovered through rates as allowed by the applicable regulatory agency are excluded from the table above.

Financial and physical derivatives - These are obligations arising from our fixed- and variable-price purchase commitments for financial and physical commodity derivatives and interest-rate swaps. However, the commitments associated with our Distribution segment's contracts are recovered through rates as allowed by the applicable regulatory agency and are excluded from the table above. Estimated future variable-price purchase commitments are based on market information at December 31, 2011. Actual future variable-price purchase commitments may vary depending on market prices at the time of delivery. Not included in these amounts are offsetting cash inflows from our ONEOK Partners and Energy Services segments' product sales and net positive settlements. As market information changes daily and is potentially volatile, these values may change significantly. Additionally, product sales may require additional purchase obligations to fulfill sales obligations that are not reflected in these amounts.

Employee benefit plans - Employee benefit plans include our anticipated contribution to maintain the minimum required funding level to our pension and postretirement benefit plans for 2012. See Note M of the Notes to Consolidated Financial Statements in this Annual Report for discussion of our employee benefit plans.

Purchase commitments, rights of way and other - Purchase commitments include commitments related to ONEOK Partners' growth capital expenditures and other rights-of-way and contractual commitments. Purchase commitments exclude commodity purchase contracts, which are included in the "Financial and physical derivatives" amounts.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management's plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled," and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Annual Report. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- the effects of weather and other natural phenomena, including climate change, on our operations, including energy sales and demand for our services and energy prices;
- competition from other United States and foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels such as ethanol and biodiesel;
- the status of deregulation of retail natural gas distribution;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, pipeline safety, environmental compliance, climate change initiatives and authorized rates of recovery of natural gas and natural gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers' desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- changes in demand for the use of natural gas because of market conditions caused by concerns about global warming;
- the impact of unforeseen changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension and postretirement expense and funding resulting from changes in stock and bond market returns;
- our indebtedness could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantages compared with our competitors that have less debt, or have other adverse consequences;
- actions by rating agencies concerning the credit ratings of ONEOK and ONEOK Partners;

- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC, the National Transportation Safety Board, the Pipeline and Hazardous Materials Safety Administration, the EPA and CFTC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
    - future demand for and prices of natural gas and NGLs;
    - competitive conditions in the overall energy market;
    - availability of supplies of Canadian and United States natural gas; and
    - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary permits, consents or other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- adverse labor relations;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the possible loss of natural gas distribution franchises or other adverse effects caused by the actions of municipalities;
- the impact of uncontracted capacity in our assets being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Item 1A, Risk Factors, in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Policy and Oversight - We control the scope of risk management, marketing and trading operations through a comprehensive set of policies and procedures involving senior levels of management. The Audit Committee of our Board of Directors has oversight responsibilities for our risk-management limits and policies. Our risk oversight committee, comprised of corporate and business-segment officers, oversees all activities related to commodity price and credit risk management, and marketing and trading activities. The committee also monitors risk metrics including value-at-risk (VAR) and mark-to-market losses. We have a risk control group that is assigned responsibility for establishing and enforcing the policies and procedures and monitoring certain risk metrics. Key risk control activities include risk measurement and monitoring, validation of transactions, portfolio valuation, VAR and other risk metrics.

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that would occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

COMMODITY PRICE RISK

We are exposed to commodity price risk and the impact of market price fluctuations of natural gas, NGLs and crude oil. Commodity price risk refers to the risk of loss in cash flows and future earnings arising from adverse changes in energy prices. To minimize the risk from market price fluctuations of natural gas, NGLs and crude oil, we use commodity derivative instruments such as futures, physical forward contracts, swaps and options to manage commodity price risk associated with existing or anticipated purchase and sale agreements, existing physical natural gas in storage and basis risk.

ONEOK Partners

ONEOK Partners is exposed to commodity price risk as a result of receiving commodities in exchange for its natural gas gathering and processing services. To a lesser extent, ONEOK Partners is exposed to the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to its keep-whole contracts. ONEOK Partners is also exposed to the risk of location price differentials and the cost of third-party transportation to various market locations. As part of ONEOK Partners' hedging strategy, ONEOK Partners uses commodity fixed-price physical forwards and derivative contracts, including NYMEX-based futures and over-the-counter swaps, to minimize earnings volatility in its natural gas gathering and processing business related to natural gas, NGL and condensate price fluctuations.

ONEOK Partners reduces its gross processing spread exposure through a combination of physical and financial hedges. ONEOK Partners utilizes a portion of its percent-of-proceeds equity natural gas as an offset, or natural hedge, to an equivalent portion of its keep-whole shrink requirements. This has the effect of converting ONEOK Partners' gross processing spread risk to NGL commodity price risk, and ONEOK Partners then uses financial instruments to hedge the sale of NGLs.

As of December 31, 2011, ONEOK Partners had $33.7 million of commodity-related derivative assets and $3.8 million of commodity-related derivative liabilities, excluding the impact of netting. The following tables set forth ONEOK Partners' hedging information for the periods indicated, as of February 20, 2012:

	Year Ending December 31, 2012		
	Volumes Hedged (a)	**Average Price**	**Percentage Hedged**
NGLs *(Bbl/d)*	8,544	$1.24 / gallon	72%
Condensate *(Bbl/d)*	1,818	$2.43 / gallon	73%
Total *(Bbl/d)*	10,362	$1.45 / gallon	72%
Natural gas *(MMBtu/d)*	44,344	$4.13 / MMBtu	73%

(a) - Hedged with fixed-price swaps.

	Year Ending December 31, 2013		
	Volumes Hedged (a)	**Average Price**	**Percentage Hedged**
NGLs *(Bbl/d)*	367	$2.55 / gallon	2%
Condensate *(Bbl/d)*	649	$2.55 / gallon	23%
Total *(Bbl/d)*	1,016	$2.55 / gallon	4%
Natural gas *(MMBtu/d)*	50,137	$3.85 / MMBtu	75%

(a) - Hedged with fixed-price swaps.

ONEOK Partners expects its commodity price risk in its gathering and processing business to increase in the future as volumes increase under POP contracts with our customers. ONEOK Partners' commodity price risk is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas, excluding the effects of hedging, and assuming normal operating conditions. ONEOK Partners' condensate sales are based on the price of crude oil. ONEOK Partners estimates the following:

- a $0.01 per gallon change in the composite price of NGLs would change annual net margin by approximately $1.7 million;
- a $1.00 per barrel change in the price of crude oil would change annual net margin by approximately $1.3 million; and
- a $0.10 per MMBtu change in the price of natural gas would change annual net margin by approximately $2.2 million.

ONEOK Partners is also exposed to location price differential risk primarily as a result of NGLs in storage, the relative values of the various NGL products to each other, the relative value of NGLs to natural gas and the relative value of NGL purchases at one location and sales at another location. ONEOK Partners utilizes fixed-price physical forward contracts to reduce earnings volatility related to NGL price fluctuations in the storage and optimization activities of its natural gas liquids business. ONEOK Partners has not entered into any financial instruments with respect to its natural gas liquids business's marketing activities.

In addition, ONEOK Partners is exposed to commodity price risk as its natural gas interstate and intrastate pipelines retain natural gas from its customers for operations or as part of its fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by its customers, the pipelines must buy or sell natural gas, or store or use natural gas from inventory, which exposes ONEOK Partners to commodity price risk. At December 31, 2011, there were no hedges in place with respect to natural gas price risk from ONEOK Partners' natural gas pipeline business.

Natural Gas Distribution

Our Natural Gas Distribution segment uses derivative instruments to hedge the cost of anticipated natural gas purchases during the winter heating months to protect its customers from upward volatility in the market price of natural gas. Gains or losses associated with these derivative instruments are included in, and recoverable through, the monthly purchased-gas cost-adjustment mechanism.

Energy Services

Our Energy Services segment is exposed to commodity price risk, location risk and price volatility arising from natural gas in storage, peaking natural gas load requirement contracts, asset management contracts and index-based purchases and sales of natural gas at various market locations. We attempt to mitigate our exposure to commodity price risk through the use of derivative instruments, which, under certain circumstances, are designated as cash flow or fair value hedges. We are also exposed to commodity price risk from fixed-price purchases and sales of natural gas, which we hedge with derivative instruments. Both the fixed-price purchases and sales and related derivatives are recorded at fair value.

Fair Value Component of the Energy Marketing and Risk Management Assets and Liabilities - The following table sets forth the fair value component of the energy marketing and risk management assets and liabilities, excluding $80.7 million and $101.1 million of net assets at December 31, 2011 and 2010, respectively, from derivative instruments declared as either fair value or cash flow hedges for the periods indicated:

Fair Value Component of Energy Marketing and Risk Management Assets and Liabilities

		(Thousands of dollars)
Net fair value of derivatives outstanding at January 1, 2010	$	2,725
Derivatives reclassified or otherwise settled during the period		(7,494)
Fair value of new derivatives entered into during the period		31,817
Other changes in fair value		(18,607)
Net fair value of derivatives outstanding at December 31, 2010		8,441
Derivatives reclassified or otherwise settled during the period		**(11,378)**
Fair value of new derivatives entered into during the period		**70,141**
Other changes in fair value		**(54,595)**
Net fair value of derivatives outstanding at December 31, 2011 (a)	**$**	**12,609**

(a) - The maturities of derivatives are based on injection and withdrawal periods from April through March, which is consistent with our business strategy. The maturities are as follows: $0.8 million matures through March 2012 and $11.8 million matures through March 2015.

The change in the net fair value of derivatives outstanding includes the effect of settled energy contracts and current period changes resulting primarily from newly originated transactions and the impact of market movements on the fair value of energy marketing and risk management assets and liabilities.

For further discussion of fair value measurements and trading activities and assumptions used in our trading activities, see the "Estimates and Critical Accounting Policies" section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation. Also, see Notes C and D of the Notes to Consolidated Financial Statements in this Annual Report.

VAR Disclosure of Commodity Price Risk - We measure commodity price risk in our Energy Services segment using a VAR methodology, which estimates the expected maximum loss of our portfolio over a specified time horizon within a given confidence interval. Our VAR calculations are based on the Monte Carlo approach. The quantification of commodity price risk using VAR provides a consistent measure of risk across diverse energy markets and products with different risk factors in order to set overall risk tolerance and to determine risk thresholds. The use of this methodology requires a number of key assumptions, including the selection of a confidence level and the holding period to liquidation. Historical data is used to estimate our VAR with more weight given to recent data, which is considered a more relevant predictor of immediate future commodity market movements. Other assumptions include a distribution of prices and historical data to calculate volatility and price correlations. We rely on VAR to determine the potential reduction in the portfolio values arising from changes in market conditions over a defined period. While management believes that the referenced assumptions and approximations are reasonable, no uniform industry methodology exists for estimating VAR. Different assumptions and approximations could produce materially different VAR estimates.

Our VAR exposure represents an estimate of potential losses that would be recognized due to adverse commodity price movements in our Energy Services segment's portfolio of derivative financial instruments, physical commodity contracts, leased transport, storage capacity contracts and natural gas in storage. A one-day time horizon and a 95-percent confidence level are used in our VAR data. Actual future gains and losses will differ from those estimated by the VAR calculation based on actual fluctuations in commodity prices, operating exposures and timing thereof, and the changes in our derivative financial instruments, physical contracts and natural gas in storage. VAR information should be evaluated in light of these assumptions and the methodology's other limitations.

The potential impact on our future earnings, as measured by VAR, was $2.7 million and $2.9 million at December 31, 2011 and 2010, respectively. The following table sets forth the average, high and low VAR calculations for the periods indicated:

	Years Ended December 31,	
Value-at-Risk	**2011**	**2010**
	(Millions of dollars)	
Average	**$ 3.0**	$ 5.5
High	**$ 6.6**	$ 9.6
Low	**$ 1.2**	$ 2.3

Our VAR calculation includes derivatives, executory storage and transportation agreements and their related hedges. The variations in the VAR data are reflective of market volatility and changes in our portfolio during the year. The decrease in average VAR for 2011, compared with 2010, was due primarily to lower average commodity prices and decreased price volatility in 2011.

To the extent open commodity positions exist, fluctuating commodity prices can impact our financial results and financial position either favorably or unfavorably. As a result, we cannot predict with precision the impact risk-management decisions may have on our business, operating results or financial position.

INTEREST-RATE RISK

General - We are subject to the risk of interest-rate fluctuation in the normal course of business. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates. At December 31, 2011, the interest rate on all of ONEOK's and ONEOK Partners' long-term debt was fixed, and ONEOK and ONEOK Partners had forward-starting interest-rate swaps that have been designated as cash flow hedges of the variability of interest payments on a portion of a forecasted debt issuance that may result from changes in the benchmark interest rate before the debt is issued.

COUNTERPARTY CREDIT RISK

ONEOK and ONEOK Partners assess the creditworthiness of their counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
ONEOK, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, shareholders' equity, comprehensive income and cash flows present fairly, in all material respects, the financial position of ONEOK, Inc. and its subsidiaries (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A in the Company's Form 10-K for the year ended December 31, 2011. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 21, 2012

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars, except per share amounts)		
Revenues	**$ 14,805,794**	$ 12,678,791	$ 10,805,753
Cost of sales and fuel	**12,425,435**	10,616,621	8,807,802
Net margin	**2,380,359**	2,062,170	1,997,951
Operating expenses			
Operations and maintenance	**813,666**	740,881	729,986
Depreciation and amortization	**312,160**	307,224	288,923
General taxes	**94,657**	90,032	100,974
Total operating expenses	**1,220,483**	1,138,137	1,119,883
Gain (loss) on sale of assets	**(963)**	18,619	4,806
Operating income	**1,158,913**	942,652	882,874
Equity earnings from investments (Note O)	**127,246**	101,880	72,722
Allowance for equity funds used during construction	**2,335**	1,018	26,868
Other income	**1,410**	11,527	19,730
Other expense	**(9,336)**	(11,067)	(14,709)
Interest expense	**(297,006)**	(292,232)	(300,820)
Income before income taxes	**983,562**	753,778	686,665
Income taxes (Note N)	**(226,048)**	(213,720)	(203,008)
Income from continuing operations	**757,514**	540,058	483,657
Income from discontinued operations, net of tax (Note B)	**2,230**	1,272	7,547
Net income	**759,744**	541,330	491,204
Less: Net income attributable to noncontrolling interests	**399,150**	206,698	185,753
Net income attributable to ONEOK	**$ 360,594**	$ 334,632	$ 305,451
Amounts attributable to ONEOK:			
Income from continuing operations	**$ 358,364**	$ 333,360	$ 297,904
Income from discontinued operations	**2,230**	1,272	7,547
Net Income	**$ 360,594**	$ 334,632	$ 305,451
Basic earnings per share (Note K):			
Income from continuing operations	**$ 3.42**	$ 3.14	$ 2.83
Income from discontinued operations	**0.02**	0.01	0.07
Net Income	**$ 3.44**	$ 3.15	$ 2.90
Diluted earnings per share (Note K):			
Income from continuing operations	**$ 3.34**	$ 3.09	$ 2.80
Income from discontinued operations	**0.02**	0.01	0.07
Net Income	**$ 3.36**	$ 3.10	$ 2.87
Average shares (*thousands*)			
Basic	**104,672**	106,368	105,362
Diluted	**107,249**	107,785	106,320
Dividends declared per share of common stock	**$ 2.16**	$ 1.82	$ 1.64

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Net income	**$ 759,744**	$ 541,330	$ 491,204
Other comprehensive income (loss), net of tax			
Unrealized gain (losses) on energy marketing and risk management assets/liabilities, net of tax of $(8,670), $(43,039) and $(26,488), respectively	**(19,828)**	85,623	24,455
Realized gains in net income, net of tax of $53,714, $29,278 and $48,059, respectively	**(84,025)**	(48,117)	(104,549)
Unrealized holding gains (losses) on available-for-sale securities, net of tax of $242, $44 and $(396), respectively	**(384)**	(70)	627
Change in pension and postretirement benefit plan liability, net of tax of $16,298, $7,570 and $9,186, respectively	**(25,837)**	(12,001)	(14,560)
Other, net of tax of $50, $(45) and $(84), respectively	**(79)**	71	244
Total other comprehensive income (loss), net of tax	**(130,153)**	25,506	(93,783)
Comprehensive income	**629,591**	566,836	397,421
Less: Comprehensive income attributable to noncontrolling interests	**366,316**	222,393	139,967
Comprehensive income attributable to ONEOK	**$ 263,275**	$ 344,443	$ 257,454

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

		December 31, 2011		December 31, 2010
Assets		*(Thousands of dollars)*		
Current assets				
Cash and cash equivalents	**$**	**65,953**	$	30,341
Accounts receivable, net		**1,339,933**		1,283,891
Gas and natural gas liquids in storage		**549,915**		706,912
Commodity imbalances		**63,452**		94,854
Energy marketing and risk management assets (Notes C and D)		**40,280**		54,691
Other current assets		**185,143**		149,521
Assets of discontinued operations (Note B)		**74,136**		59,525
Total current assets		**2,318,812**		2,379,735
Property, plant and equipment				
Property, plant and equipment		**11,177,934**		9,853,821
Accumulated depreciation and amortization		**2,733,601**		2,540,873
Net property, plant and equipment (Note E)		**8,444,333**		7,312,948
Investments and other assets				
Goodwill and intangible assets (Note F)		**1,014,127**		1,022,894
Investments in unconsolidated affiliates (Note O)		**1,223,398**		1,188,124
Other assets		**695,965**		595,474
Total investments and other assets		**2,933,490**		2,806,492
Total assets	**$**	**13,696,635**	$	12,499,175

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

		December 31, 2011		December 31, 2010
Liabilities and equity		*(Thousands of dollars)*		
Current liabilities				
Current maturities of long-term debt (Note H)	**$**	**364,391**	$	643,236
Notes payable (Note G)		**841,982**		556,855
Accounts payable		**1,341,718**		1,212,323
Commodity imbalances		**202,206**		288,494
Energy marketing and risk management liabilities (Notes C and D)		**137,680**		22,066
Other current liabilities		**345,383**		416,248
Liabilities of discontinued operations (Note B)		**12,815**		12,209
Total current liabilities		**3,246,175**		3,151,431
Long-term debt, excluding current maturities (Note H)		**4,529,551**		3,686,542
Deferred credits and other liabilities				
Deferred income taxes		**1,446,591**		1,171,997
Other deferred credits		**674,586**		568,364
Total deferred credits and other liabilities		**2,121,177**		1,740,361
Commitments and contingencies (Note Q)				
Equity (Note I)				
ONEOK shareholders' equity:				
Common stock, $0.01 par value:				
authorized 300,000,000 shares; issued 122,904,924 shares and outstanding 103,254,980 shares at December 31, 2011; issued 122,815,636 shares and outstanding 106,815,582 shares at December 31, 2010		**1,229**		1,228
Paid-in capital		**1,418,414**		1,392,671
Accumulated other comprehensive loss (Note J)		**(206,121)**		(108,802)
Retained earnings		**1,960,374**		1,826,800
Treasury stock, at cost: 19,649,944 shares at December 31, 2011 and 16,000,054 shares at December 31, 2010		**(935,323)**		(663,274)
Total ONEOK shareholders' equity		**2,238,573**		2,448,623
Noncontrolling interests in consolidated subsidiaries		**1,561,159**		1,472,218
Total equity		**3,799,732**		3,920,841
Total liabilities and equity	**$**	**13,696,635**	$	12,499,175

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Operating Activities			
Net income	**$ 759,744**	$ 541,330	$ 491,204
Depreciation and amortization	**312,288**	307,317	288,991
Allowance for equity funds used during construction	**(2,335)**	(1,018)	(26,868)
Loss (gain) on sale of assets	**963**	(18,619)	(4,806)
Equity earnings from investments	**(127,246)**	(101,880)	(72,722)
Distributions received from unconsolidated affiliates	**132,741**	96,958	75,377
Deferred income taxes	**256,688**	142,303	198,713
Share-based compensation expense	**66,371**	24,372	23,148
Other	**(1,471)**	4,153	1,216
Changes in assets and liabilities:			
Accounts receivable	**(55,861)**	92,469	(181,426)
Gas and natural gas liquids in storage	**65,845**	(164,722)	266,674
Accounts payable	**102,621**	(43,883)	154,039
Commodity imbalances, net	**(54,886)**	(15,316)	77,174
Energy marketing and risk management assets and liabilities	**(31,999)**	112,827	113,540
Fair value of firm commitments	**(22,252)**	(105,084)	176,799
Pension and postretirement benefits	**(29,863)**	(68,719)	(42,040)
Other assets and liabilities	**(11,376)**	31,554	(86,319)
Cash provided by operating activities	**1,359,972**	834,042	1,452,694
Investing Activities			
Capital expenditures (less allowance for equity funds used during construction)	**(1,336,067)**	(582,748)	(791,245)
Contributions to unconsolidated affiliates	**(64,491)**	(1,331)	(46,461)
Distributions received from unconsolidated affiliates	**23,644**	17,847	34,430
Proceeds from sale of assets	**1,288**	428,908	10,982
Other	**4,000**	2,968	4,500
Cash used in investing activities	**(1,371,626)**	(134,356)	(787,794)
Financing Activities			
Borrowing (repayment) of notes payable, net	**285,127**	(325,015)	(518,130)
Repayment of notes payable with maturities over 90 days	**-**	-	(870,000)
Issuance of debt, net of discounts	**1,295,450**	-	498,325
Long-term debt financing costs	**(10,986)**	-	(4,000)
Payment of debt	**(727,562)**	(262,715)	(114,975)
Repurchase of common stock	**(300,108)**	(7)	(254)
Issuance of common stock	**17,906**	20,912	17,317
Issuance of common units, net of discounts	**-**	322,701	241,642
Dividends paid	**(227,020)**	(193,542)	(172,774)
Distributions to noncontrolling interests	**(277,375)**	(260,385)	(222,710)
Cash provided by (used in) financing activities	**55,432**	(698,051)	(1,145,559)
Change in cash and cash equivalents	**43,778**	1,635	(480,659)
Change in cash and cash equivalents included in discontinued operations	**(8,166)**	(2,211)	15,558
Change in cash and cash equivalents from continuing operations	**35,612**	(576)	(465,101)
Cash and cash equivalents at beginning of period	**30,341**	30,917	496,018
Cash and cash equivalents at end of period	**$ 65,953**	$ 30,341	$ 30,917
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 278,162**	$ 298,354	$ 314,509
Cash paid (refunds received) for income taxes	**$ (68,696)**	$ 16,841	$ 30,560

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	ONEOK Shareholders' Equity			
	Common Stock Issued	**Common Stock**	**Paid-in Capital**	**Accumulated Other Comprehensive Income (Loss)**
	(Shares)	*(Thousands of dollars)*		
January 1, 2009	121,647,007	$ 1,216	$ 1,301,153	$ (70,616)
Net income	-	-	-	-
Other comprehensive loss	-	-	-	(47,997)
Repurchase of common stock	-	-	-	-
Common stock issued	747,008	8	21,187	-
Common stock dividends - $1.64 per share	-	-	-	-
Issuance of common units of ONEOK Partners	-	-	-	-
Distributions to noncontrolling interests	-	-	-	-
December 31, 2009	122,394,015	1,224	1,322,340	(118,613)
Net income	-	-	-	-
Other comprehensive income	-	-	-	9,811
Repurchase of common stock	-	-	-	-
Common stock issued	421,621	4	19,600	-
Common stock dividends - $1.82 per share	-	-	-	-
Issuance of common units of ONEOK Partners	-	-	50,731	-
Distributions to noncontrolling interests	-	-	-	-
Other	-	-	-	-
December 31, 2010	122,815,636	1,228	1,392,671	(108,802)
Net income	-	-	-	-
Other comprehensive income	-	-	-	**(97,319)**
Repurchase of common stock	-	-	-	-
Common stock issued	**89,288**	**1**	**25,743**	-
Common stock dividends - $2.16 per share	-	-	-	-
Distributions to noncontrolling interests	-	-	-	-
December 31, 2011	**122,904,924**	**$ 1,229**	**$ 1,418,414**	**$ (206,121)**

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Continued)

	ONEOK Shareholders' Equity			
	Retained Earnings	**Treasury Stock**	**Noncontrolling Interests in Consolidated Subsidiaries**	**Total Equity**
		(Thousands of dollars)		
January 1, 2009	$ 1,553,033	$ (696,616)	$ 1,079,369	$ 3,167,539
Net income	305,451	-	185,753	491,204
Other comprehensive income	-	-	(45,786)	(93,783)
Repurchase of common stock	-	(254)	-	(254)
Common stock issued	-	13,403	-	34,598
Common stock dividends -				
$1.64 per share	(172,774)	-	-	(172,774)
Issuance of common units of ONEOK Partners	-	-	241,642	241,642
Distributions to noncontrolling interests	-	-	(222,710)	(222,710)
December 31, 2009	1,685,710	(683,467)	1,238,268	3,445,462
Net income	334,632	-	206,698	541,330
Other comprehensive income	-	-	15,695	25,506
Repurchase of common stock	-	(7)	-	(7)
Common stock issued	-	20,200	-	39,804
Common stock dividends -				
$1.82 per share	(193,542)	-	-	(193,542)
Issuance of common units of ONEOK Partners	-	-	271,970	322,701
Distributions to noncontrolling interests	-	-	(260,385)	(260,385)
Other	-	-	(28)	(28)
December 31, 2010	1,826,800	(663,274)	1,472,218	3,920,841
Net income	**360,594**	**-**	**399,150**	**759,744**
Other comprehensive income	**-**	**-**	**(32,834)**	**(130,153)**
Repurchase of common stock	**-**	**(300,108)**	**-**	**(300,108)**
Common stock issued	**-**	**28,059**	**-**	**53,803**
Common stock dividends -				
$2.16 per share	**(227,020)**	**-**	**-**	**(227,020)**
Distributions to noncontrolling interests	**-**	**-**	**(277,375)**	**(277,375)**
December 31, 2011	**$ 1,960,374**	**$ (935,323)**	**$ 1,561,159**	**$ 3,799,732**

ONEOK, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - We are a diversified energy company and successor to the company founded in 1906 known as Oklahoma Natural Gas Company. We are a corporation incorporated under the laws of the state of Oklahoma, and our common stock is listed on the NYSE under the trading symbol "OKE." We are the sole general partner and own 42.8 percent of ONEOK Partners, L.P. (NYSE: OKS), one of the largest publicly traded master limited partnerships.

We have divided our operations into three reportable business segments as follows:

- ONEOK Partners;
- Natural Gas Distribution; and
- Energy Services.

ONEOK Partners is a diversified master limited partnership involved in the gathering, processing, storage and transportation of natural gas in the United States. In addition, ONEOK Partners owns one of the nation's premier natural gas liquids systems, connecting NGL supply in the Mid-Continent and Rocky Mountain regions with key market centers. To aid in understanding the important business and financial characteristics of our ONEOK Partners segment, the following describes its business with reference to its underlying activities.

ONEOK Partners' natural gas gathering and processing business is engaged in the gathering and processing of natural gas produced from crude oil and natural gas wells, primarily in the Mid-Continent and Rocky Mountain regions. These regions include the NGL-rich Cana-Woodford Shale and Granite Wash formations; the Mississippian Lime formation of Oklahoma and Kansas; Hugoton and Central Kansas Uplift Basins of Kansas; the Williston Basin of Montana and North Dakota that includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations; and the Powder River Basin of Wyoming. In the Powder River Basin, the natural gas that ONEOK Partners gathers is coal-bed methane, or dry, natural gas that does not require processing or NGL extraction in order to be marketable. Dry natural gas is gathered, compressed and delivered into a downstream pipeline or marketed for a fee.

ONEOK Partners' natural gas pipeline business operates interstate and intrastate natural gas transmission pipelines, natural gas storage facilities and nonprocessable natural gas gathering facilities. ONEOK Partners' FERC-regulated interstate assets transport natural gas through pipelines that access supply from Canada and from the Mid-Continent, Rocky Mountain and Gulf Coast regions. ONEOK Partners' intrastate natural gas pipeline assets are located in Oklahoma, Texas and Kansas, and have access to major natural gas producing areas in those states, including the Cana-Woodford, Granite Wash and Mississippian Lime formations. ONEOK Partners owns underground natural gas storage facilities in Oklahoma, Kansas and Texas, which are connected to its intrastate natural gas pipeline assets.

ONEOK Partners' natural gas liquids business consists of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas and Texas. Its natural gas liquids business owns or has an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, Wyoming and Colorado and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. It also owns FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa and Illinois that connect its Mid-Continent assets with Midwest markets, including Chicago, Illinois. ONEOK Partners' natural gas liquids business also owns and operates truck and rail-loading and unloading facilities that interconnect with its fractionation and pipeline assets.

Our Natural Gas Distribution segment provides natural gas distribution services to more than 2 million customers in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service. We serve residential, commercial, industrial and transportation customers in all three states. In addition, our natural gas distribution companies serve wholesale and public authority customers.

Our Energy Services segment is a provider of nonuniform natural gas supply and risk-management services for natural gas and electric utilities and commercial and industrial customers with natural gas needs. We use a network of leased storage and transportation capacity to supply natural gas to our customers. This network connects the major supply and demand centers throughout the United States and into Canada and, coupled with our industry knowledge and market intelligence, allows us to provide our customers with customized services in a more efficient and reliable manner than they can achieve independently. Our customers are primarily LDCs, electric utilities and commercial and industrial end-users. Our customers' natural gas needs vary with seasonal changes in weather and are therefore somewhat unpredictable.

Consolidation - Our consolidated financial statements include the accounts of ONEOK and our subsidiaries over which we have control. We have recorded noncontrolling interests in consolidated subsidiaries on our Consolidated Balance Sheets to recognize the percent of ONEOK Partners that we do not own. We reflected our ownership interest in ONEOK Partners' accumulated other comprehensive income (loss) in our consolidated accumulated other comprehensive income (loss). The remaining portion is reflected as an adjustment to noncontrolling interests in consolidated subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Investments in unconsolidated affiliates are accounted for using the equity method if we have the ability to exercise significant influence over operating and financial policies of our investee; conversely, if we do not have the ability to exercise significant influence, then we use the cost method. Impairment of equity and cost method investments is recorded when the impairments are other than temporary. Distributions paid to us from our unconsolidated affiliates are classified as operating activities on our Consolidated Statements of Cash Flows until the cumulative distributions exceed our proportionate share of income from the unconsolidated affiliate since the date of our initial investment. The amount of cumulative distributions paid to us that exceeds our cumulative proportionate share of income in each period represents a return of investment and is classified as an investing activity on our Consolidated Statements of Cash Flows.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, obligations under employee benefit plans, provisions for uncollectible accounts receivable, unbilled revenues for natural gas delivered but for which meters have not been read, gas purchased expense for natural gas purchased but for which no invoice has been received, provision for income taxes, including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience, consultation with experts and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use the market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. While many of the contracts in our portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist, but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. Inputs into our fair value estimates include commodity exchange prices, over-the-counter quotes, volatility, historical correlations of pricing data and LIBOR and other liquid money market instrument rates. We also utilize internally developed basis curves that incorporate observable and unobservable market data. We validate our valuation inputs with third-party information and settlement prices from other sources, where available. In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value using interest-rate yields to calculate present-value discount factors derived from LIBOR, Eurodollar futures and interest-rate swaps. We also take into consideration the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. We consider current market data in evaluating counterparties', as well as our own, nonperformance risk, net of collateral, by using specific and sector bond yields and also monitor the credit default swap markets. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be material.

The fair value of our forward-starting interest-rate swaps is determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest-rate swap settlements.

<u>Fair Value Hierarchy</u> - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are, either directly or indirectly, observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and

- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

We recognize transfers into and out of Level 3 as of the end of each reporting period. Transfers into Level 3 represent existing assets or liabilities that were categorized previously at a higher level for which the unobservable inputs became a more significant portion of the fair value estimates. Transfers out of Level 3 represent existing assets and liabilities that were classified previously as Level 3 for which the observable inputs became a more significant portion of the fair value estimates.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety. See Note C for additional disclosures of our fair value measurements.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Revenue Recognition - Our operating segments recognize revenue when services are rendered or product is delivered. ONEOK Partners' natural gas gathering and processing operations record revenue when gas is processed in or transported through its facilities. ONEOK Partners' natural gas liquids operations record revenues based upon contracted services and actual volumes exchanged or stored under service agreements in the period services are provided. Revenue for ONEOK Partners' natural gas pipelines and a portion of its natural gas liquids operations is recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided.

Our Natural Gas Distribution segment's major industrial and commercial natural gas distribution customers are invoiced at the end of each month. All natural gas distribution residential customers, all retail customers and some distribution commercial customers are invoiced on a cyclical basis throughout the month, and we accrue unbilled revenues at the end of each month.

Our Energy Services segment's wholesale customers are invoiced at the end of each month based on physical sales. Demand payments received for requirements contracts are recognized in the period in which the service is provided. Our fixed-price physical sales are accounted for as derivatives and are recorded at fair value. See discussion below in "Derivative and Risk Management Activities" for additional information.

Accounts Receivable - Accounts receivable represent valid claims against nonaffiliated customers for products sold or services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Outstanding customer receivables are reviewed regularly for possible nonpayment indicators and allowances for doubtful accounts are recorded based upon management's estimate of collectability at each balance sheet date. At December 31, 2011 and 2010, our allowance for doubtful accounts was not material.

Inventories - The values of current natural gas and NGLs in storage are determined using the lower of weighted-average cost or market method. Noncurrent natural gas and NGLs are classified as property and valued at cost. Materials and supplies are valued at average cost.

Commodity Imbalances - Commodity imbalances represent amounts payable or receivable for NGL exchange contracts and natural gas pipeline imbalances and are valued at fair value. Under the majority of our NGL exchange agreements, we physically receive volumes of unfractionated NGLs, including the risk of loss and legal title to such volumes, from the exchange counterparty. In turn, we deliver NGL products back to the customer and charge them gathering and fractionation fees. To the extent that the volumes we receive under such agreements differ from those we deliver, we record a net exchange receivable or payable position with the counterparties. These net exchange receivables and payables are settled with movements of NGL products rather than with cash. Natural gas pipeline imbalances are settled in cash or in-kind, subject to the terms of the pipelines' tariffs or by agreement.

Derivatives and Risk Management Activities - We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it.

If certain conditions are met, we may elect to designate a derivative instrument as a hedge of exposure to changes in fair values, cash flows or foreign currency. Certain nontrading derivative transactions, which are economic hedges of our accrual transactions such as our storage and transportation contracts, do not qualify for hedge accounting treatment.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in earnings
Cash flow hedge	- Recorded at fair value	- Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings
	- Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss)	- Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated other comprehensive income (loss) into earnings when the forecasted transaction affects earnings
Fair value hedge	- Recorded at fair value	- The gain or loss on the derivative instrument is recognized in earnings
	- Change in fair value of the hedged item is recorded as an adjustment to book value	- Change in fair value of the hedged item is recognized in earnings

Gains or losses associated with the fair value of derivative instruments entered into by our Natural Gas Distribution segment are included in, and recoverable through, the monthly purchased-gas cost mechanism.

We formally document all relationships between hedging instruments and hedged items, as well as risk-management objectives, strategies for undertaking various hedge transactions and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the asset, liability, firm commitment or forecasted transaction that has been designated as the hedged item. We assess the effectiveness of hedging relationships quarterly by performing an effectiveness analysis on our cash flow and fair value hedging relationships to determine whether the hedge relationships are highly effective on a retrospective and prospective basis. We also document our normal purchases and normal sales transactions that we expect to result in physical delivery and that we elect to exempt from derivative accounting treatment.

The presentation of settled derivative instruments on either a gross or net basis in our Consolidated Statements of Income is dependent on the relevant facts and circumstances of our different types of activities rather than based solely on the terms of the individual contracts. All financially settled derivative instruments, as well as derivative instruments considered held for trading purposes that result in physical delivery, are reported on a net basis in revenues in our Consolidated Statements of Income. The realized revenues and purchase costs of derivative instruments that are not considered held for trading purposes and nonderivative contracts are reported on a gross basis. Derivatives that qualify as normal purchases or normal sales that are expected to result in physical delivery are also reported on a gross basis.

Revenues in our Consolidated Statements of Income include financial trading margins, as well as certain physical natural gas transactions with our trading counterparties. Revenues and cost of sales and fuel from such physical transactions are reported on a net basis.

Cash flows from futures, forwards, options and swaps that are accounted for as hedges are included in the same category as the cash flows from the related hedged items in our Consolidated Statements of Cash Flows.

See Notes C and D for more discussion of our fair value measurements and risk management and hedging activities using derivatives.

Property, Plant and Equipment - Our properties are stated at cost, including AFUDC. Generally, the cost of regulated property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or retirement of nonregulated properties or an entire operating unit or system of our regulated properties are recognized in income. Maintenance and repairs are charged directly to expense.

The interest portion of AFUDC represents the cost of borrowed funds used to finance construction activities. We capitalize interest costs during the construction or upgrade of qualifying assets. Interest costs capitalized in 2011, 2010 and 2009 were $24.0 million, $4.9 million and $17.0 million, respectively. Capitalized interest is recorded as a reduction to interest expense.

The equity portion of AFUDC represents the capitalization of the estimated average cost of equity used during the construction of major projects and is recorded in the cost of our regulated properties and as a credit to the allowance for equity funds used during construction.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. For our regulated assets, these depreciation studies are completed as a part of our rate proceedings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are billed. For our nonregulated assets, if it is determined that the estimated economic life changes, the changes are made prospectively. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position or results of operations.

Property, plant and equipment on our Consolidated Balance Sheets includes construction work in progress for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in progress when they are substantially complete and ready for their intended use.

See Note E for disclosures of our property, plant and equipment.

Impairment of Goodwill and Long-Lived Assets, Including Intangible Assets - We assess our goodwill and indefinite-lived intangible assets for impairment at least annually as of July 1. As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge. There were no impairment charges resulting from our 2011, 2010 or 2009 impairment tests.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply multiples to forecasted cash flows. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

As part of our indefinite-lived intangible asset impairment test, we compare the estimated fair value of our indefinite-lived intangible assets with their book values. The fair value of our indefinite-lived intangible assets is estimated using the market approach. Under the market approach, we apply multiples to forecasted cash flows of the assets associated with our indefinite-lived intangible assets. The multiples used are consistent with historical asset transactions. We determined that there were no impairments to our indefinite-lived intangible asset in 2011, 2010 or 2009.

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no asset impairments in 2011, 2010 or 2009.

For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry our equity method investments to determine whether current events or circumstances warrant adjustments to our carrying value. We determined that there were no impairments to our investments in unconsolidated affiliates in 2011, 2010 or 2009.

Our impairment tests require the use of assumptions and estimates such as industry economic factors and the profitability of future business strategies. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future impairment charges.

See Notes E and F for our goodwill and long-lived assets disclosures.

Regulation - Our natural gas distribution operations and ONEOK Partners' intrastate natural gas transmission pipelines are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. ONEOK Partners' interstate natural gas and natural gas liquids pipelines are subject to regulation by the FERC. In Kansas and Texas, natural gas storage may be regulated by the state and the FERC for certain types of services. Oklahoma Natural Gas, Kansas Gas Service, Texas Gas Service and portions of our ONEOK Partners segment follow the accounting and reporting guidance for regulated operations. During the rate-making process, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time, as opposed to expensing such costs as incurred. Examples include costs for fuel and fuel losses, acquisition costs and contributions in aid of construction. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent, third-party regulators;
- designed to recover the specific entity's costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

At December 31, 2011 and 2010, we recorded regulatory assets of approximately $539.7 million and $463.9 million, respectively, which are being recovered as a result of various approved rate proceedings or are expected to be recovered. Of these amounts, approximately $466.6 million and $375.1 million relate to our pension and postretirement benefit plans at December 31, 2011 and 2010, respectively, which are discussed on page 107. Regulatory assets are being recovered as a result of approved rate proceedings over varying time periods up to 40 years. These assets are reflected in other assets on our Consolidated Balance Sheets.

Pension and Postretirement Employee Benefits - We have defined benefit retirement plans covering certain full-time employees. We sponsor welfare plans that provide postretirement medical and life insurance benefits to certain employees who retire with at least five years of service. Our actuarial consultant calculates the expense and liability related to these plans and uses statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize. See Note M for more discussion of pension and postretirement employee benefits.

Income Taxes - Deferred income taxes are recorded for the difference between the financial statement and income tax basis of assets and liabilities and carry-forward items, based on income tax laws and rates existing at the time the temporary differences are expected to reverse. The effect on deferred taxes of a change in tax rates is deferred and amortized for operations regulated by the OCC, KCC, RRC and various municipalities in Texas if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates. For all other operations, the effect is recognized in income in the period that includes the enactment date. We continue to amortize previously deferred investment tax credits for ratemaking purposes over the period prescribed by the OCC, KCC, RRC and various municipalities in Texas.

We utilize a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. During 2011, 2010 and 2009, our tax positions did not require an establishment of a material reserve.

We file numerous consolidated and separate income tax returns with federal tax authorities of the United States and Canada, along with the tax authorities of several states. There are no United States federal audits or statute waivers at this time. We have been notified by the state of Texas of its intent to audit tax years 2008-2011. See Note N for additional discussion of income taxes.

Asset Retirement Obligations - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. We recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. We are not able to estimate reasonably the fair value of the asset retirement obligations for portions of our assets because the settlement dates are indeterminable. For our assets that we are able to make an estimate, the fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement. The depreciation and amortization expense are immaterial to our consolidated financial statements.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs are nonlegal obligations; however, the amounts collected that are in excess of these nonlegal asset-removal costs incurred are accounted for as a regulatory liability. Historically, the regulatory authorities that have jurisdiction over our regulated operations have not required us to quantify this amount; rather, these costs are addressed prospectively in depreciation rates and are set in each general rate order. We have made an estimate of our regulatory liability using current rates since the last general rate order in each of our jurisdictions; however, significant uncertainty exists regarding the ultimate determination of this liability, pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory authorities, and the liability may be adjusted as more information is obtained. We record the estimated nonlegal asset removal obligation in noncurrent liabilities in other deferred credits on our Consolidated Balance Sheets. To the extent this estimated liability is adjusted, such amounts will be reclassified between accumulated depreciation and amortization and other deferred credits and therefore will not have an impact on earnings.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be estimated reasonably. We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note Q for additional discussion of contingencies.

Share-Based Payments - We expense the fair value of share-based payments net of estimated forfeitures. We estimate forfeiture rates based on historical forfeitures under our share-based payment plans.

Earnings per Common Share - Basic EPS is calculated based on the daily weighted-average number of shares of common stock outstanding during the period. Diluted EPS is calculated based on the daily weighted-average number of shares of common stock outstanding during the period plus potentially dilutive components. The dilutive components are calculated based on the dilutive effect for each quarter. For fiscal year periods, the dilutive components for each quarter are averaged to arrive at the fiscal year-to-date dilutive component.

Recently Issued Accounting Standards Update - In January 2010, the FASB issued ASU 2010-06, "Improving Disclosures about Fair Value Measurements," which requires separate disclosures of purchases, sales, issuances and settlements in the reconciliation of our Level 3 fair value measurements. We adopted this guidance with our March 31, 2011, Quarterly Report, and the impact was not material. Other provisions of ASU 2010-06 were adopted in 2010.

In May 2011, the FASB issued ASU 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS)," which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and IFRS. This new guidance changes some fair value measurement principles and disclosure requirements. We expect the impact of this guidance to be immaterial when we adopt it beginning with our March 31, 2012, Quarterly Report.

In June 2011, the FASB issued ASU 2011-05, "Presentation of Comprehensive Income," which provides two options for presenting items of net income, comprehensive income and total comprehensive income by creating either one continuous statement of comprehensive income or two separate consecutive statements, and requires certain other disclosures. In December 2011, the FASB issued ASU 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05," which deferred certain presentation requirements in ASU 2011-05 for items reclassified out of accumulated other comprehensive income. We expect the impact of this guidance to be immaterial when we adopt it beginning with our March 31, 2012, Quarterly Report.

In September 2011, the FASB issued ASU 2011-08, "Testing Goodwill for Impairment," which permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Under the amendments in this update, an entity is not required to calculate the fair value of a reporting unit unless the entity determines that it is more likely than not that its fair value is less than its carrying amount. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may also resume performing the qualitative assessment in any subsequent period. We will adopt this guidance beginning with our July 1, 2012, goodwill impairment test.

B. DISCONTINUED OPERATIONS

In December 2011, we entered into a definitive agreement to sell ONEOK Energy Marketing Company to Constellation Energy Group, Inc. for $22.5 million plus working capital. The transaction closed on February 1, 2012. The financial information of ONEOK Energy Marketing Company is reflected as discontinued operations in this Annual Report. All prior periods presented have been recast to reflect the discontinued operations.

The amounts of revenue, costs and income taxes reported in discontinued operations are set forth in the table below for the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Operating revenues	**$ 313,371**	$ 351,260	$ 305,897
Cost of sales and fuel	**302,561**	340,888	287,902
Net margin	**10,810**	10,372	17,995
Operating costs	**7,147**	8,914	6,162
Depreciation, depletion and amortization	**128**	93	68
Operating income	**3,535**	1,365	11,765
Other income (expense), net	**(50)**	21	95
Income taxes	**(1,255)**	(114)	(4,313)
Income from discontinued operations, net	**$ 2,230**	$ 1,272	$ 7,547

The following table discloses the major classes of discontinued assets and liabilities included on our Consolidated Balance Sheets for the periods indicated:

	December 31,	
	2011	**2010**
Assets	*(Thousands of dollars)*	
Cash and cash equivalents	**$ 8,859**	$ 693
Accounts receivable, net	**47,967**	48,834
Gas in storage	**2,101**	2,020
Energy marketing and risk management assets	**15,016**	7,703
Property, plant and equipment, net	**145**	235
Other assets	**48**	40
Assets of discontinued operations	**$ 74,136**	$ 59,525
Liabilities		
Accounts payable	**$ 11,435**	$ 3,147
Energy marketing and risk management liabilities	**629**	1,053
Other liabilities	**751**	8,009
Liabilities of discontinued operations	**$ 12,815**	$ 12,209

At December 31, 2011 and 2010, the liabilities of our discontinued operations exclude $45.7 million and $40.2 million, respectively, of intercompany payables due to its parent or other affiliates.

C. FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements - The following tables set forth our recurring fair value measurements for our continuing and discontinued operations for the periods indicated:

	December 31, 2011				
	Level 1	**Level 2**	**Level 3**	**Netting**	**Total**
	(Thousands of dollars)				
Assets					
Derivatives (a)					
Commodity contracts					
Financial contracts	$ 545,247	$ 13,874	$ 32,931	$ -	$ 592,052
Physical contracts	-	23,879	14,916	-	38,795
Netting	-	-	-	(569,243)	(569,243)
Total derivatives	545,247	37,753	47,847	(569,243)	61,604
Trading securities (b)	5,749	-	-	-	5,749
Available-for-sale investment securities (c)	1,949	-	-	-	1,949
Total assets	$ 552,945	$ 37,753	$ 47,847	$ (569,243)	$ 69,302
Liabilities					
Derivatives (a)					
Commodity contracts					
Financial contracts	$ (479,073)	$ (6,498)	$ (20,995)	$ -	$ (506,566)
Physical contracts	-	(261)	(1,748)	-	(2,009)
Netting	-	-	-	497,608	497,608
Interest-rate contracts	-	(128,666)	-	-	(128,666)
Total derivatives	(479,073)	(135,425)	(22,743)	497,608	(139,633)
Fair value of firm commitments (d)	-	-	(7,283)	-	(7,283)
Total liabilities	$ (479,073)	$ (135,425)	$ (30,026)	$ 497,608	$ (146,916)

(a) - Our derivative assets and liabilities are presented in our Consolidated Balance Sheets as energy marketing and risk-management assets and liabilities, other assets and other deferred credits on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2011, we held $73.3 million of cash collateral and had posted $1.7 million of cash collateral with various counterparties.

(b) - Included in our Consolidated Balance Sheets as other current assets.

(c) - Included in our Consolidated Balance Sheets as other assets.

(d) - Included in our Consolidated Balance Sheets as other current liabilities and other deferred assets.

	December 31, 2010				
	Level 1	Level 2	Level 3	Netting	Total
	(Thousands of dollars)				
Assets					
Derivatives (a)					
Commodity contracts					
Financial contracts	$ 127,789	$ 1,755	$ 152,639	$ -	$ 282,183
Physical contracts	-	13,185	20,391	-	33,576
Netting	-	-	-	(251,898)	(251,898)
Total derivatives	127,789	14,940	173,030	(251,898)	63,861
Trading securities (b)	7,591	-	-	-	7,591
Available-for-sale investment securities (c)	2,574	-	-	-	2,574
Total assets	$ 137,954	$ 14,940	$ 173,030	$ (251,898)	$ 74,026
Liabilities					
Derivatives (a)					
Commodity contracts					
Financial contracts	$ (64,768)	$ (3,241)	$ (119,430)	$ -	$ (187,439)
Physical contracts	-	(3,763)	(4,334)	-	(8,097)
Netting	-	-	-	170,515	170,515
Total derivatives	(64,768)	(7,004)	(123,764)	170,515	(25,021)
Fair value of firm commitments (d)	-	-	(29,536)	-	(29,536)
Total liabilities	$ (64,768)	$ (7,004)	$ (153,300)	$ 170,515	$ (54,557)

(a) - Our derivative assets and liabilities are presented in our Consolidated Balance Sheets as energy marketing and risk-management assets and liabilities, other assets and other deferred credits on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2010, we held $82.5 million of cash collateral and had posted $1.1 million of cash collateral with various counterparties.

(b) - Included in our Consolidated Balance Sheets as other current assets.

(c) - Included in our Consolidated Balance Sheets as other assets.

(d) - Included in our Consolidated Balance Sheets as other current liabilities and other deferred credits.

The tables above include balances for ONEOK Energy Marketing Company that have been reflected as a discontinued component in our Consolidated Balance Sheets. At December 31, 2011, we had $15.0 million in derivative assets and $0.6 million in derivative liabilities related to this discontinued operation. At December 31, 2010, we had $7.7 million in derivative assets and $1.1 million in derivative liabilities related to this discontinued operation.

Our Level 1 fair value measurements are based on NYMEX-settled prices and actively quoted prices for equity securities. These balances are comprised predominantly of exchange-traded derivative contracts, including futures and certain options for natural gas and crude oil, which are valued based on unadjusted quoted prices in active markets. Also included in Level 1 are equity securities.

Our Level 2 fair value inputs are based on NYMEX-settled prices for natural gas and crude oil that are utilized to determine the fair value of certain nonexchange-traded financial instruments, including natural gas and crude oil swaps, as well as physical forwards. Also, included in Level 2 are interest-rate swaps that are valued using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest swap settlements.

Our Level 3 inputs include internally developed basis curves incorporating observable and unobservable market data, NGL price curves from broker quotes, market volatilities derived from the most recent NYMEX close spot prices and forward LIBOR curves, and adjustments for the credit risk of our counterparties. We corroborate the data on which our fair value estimates are based using our market knowledge of recent transactions, analysis of historical correlations and validation with independent broker quotes. The derivatives categorized as Level 3 include natural gas basis swaps, swing swaps, options, other commodity swaps and physical forward contracts. Also included in Level 3 are the fair values of firm commitments. We do not believe that our Level 3 fair value estimates have a material impact on our results of operations, as the majority of our derivatives are accounted for as hedges for which ineffectiveness is not material.

The following tables set forth the reconciliation of our Level 3 fair value measurements for the periods indicated:

	Derivative Assets (Liabilities)	Fair Value of Firm Commitments	Total
		(Thousands of dollars)	
January 1, 2011	$ 49,266	$ (29,536)	$ 19,730
Total realized/unrealized gains (losses):			
Included in earnings (a)	**(28,425)**	**22,253**	**(6,172)**
Included in other comprehensive income (loss)	**5,443**	**-**	**5,443**
Transfers into Level 3	**1,428**	**-**	**1,428**
Transfers out of Level 3	**(2,608)**	**-**	**(2,608)**
December 31, 2011	**$ 25,104**	**$ (7,283)**	**$ 17,821**
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities still held as of December 31, 2011 (a)	**$ 21,349**	**$ (6,581)**	**$ 14,768**

(a) - Reported in revenues and cost of sales and fuel in our Consolidated Statements of Income.

	Derivative Assets (Liabilities)	Fair Value of Firm Commitments	Total
		(Thousands of dollars)	
January 1, 2010	$ 136,694	$ (134,620)	$ 2,074
Total realized/unrealized gains (losses):			
Included in earnings (a)	(91,662)	105,084	13,422
Included in other comprehensive income (loss)	11,122	-	11,122
Transfers into Level 3	765	-	765
Transfers out of Level 3	(7,653)	-	(7,653)
December 31, 2010	$ 49,266	$ (29,536)	$ 19,730
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities still held as of December 31, 2010 (a)	$ 22,101	$ (4,551)	$ 17,550

(a) - Reported in revenues and cost of sales and fuel in our Consolidated Statements of Income.

Realized/unrealized gains (losses) include the realization of our derivative contracts through maturity and changes in fair value of our hedged firm commitments.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and notes payable is equal to book value, due to the short-term nature of these items.

The estimated fair value of our consolidated long-term debt, including current maturities, was $5.6 billion and $4.7 billion at December 31, 2011 and 2010, respectively. The book value of long-term debt, including current maturities, was $4.9 billion and $4.3 billion at December 31, 2011 and 2010, respectively. The estimated fair value of long-term debt has been determined using quoted market prices of ONEOK's and ONEOK Partners' senior notes or similar issues with similar terms and maturities.

D. RISK MANAGEMENT AND HEDGING ACTIVITIES USING DERIVATIVES

Our Energy Services and ONEOK Partners segments are exposed to various risks that we manage by periodically entering into derivative instruments. These risks include the following:

- Commodity price risk - We are exposed to the risk of loss in cash flows and future earnings arising from adverse changes in the price of natural gas, NGLs and crude oil. We use commodity derivative instruments such as futures, physical forward contracts, swaps and options to reduce the commodity price risk associated with a portion of the forecasted purchases and sales of commodities and natural gas and natural gas liquids in storage. Commodity price volatility may have a significant impact on the fair value of our derivative instruments as of a given date;
- Basis risk - We are exposed to the risk of loss in cash flows and future earnings arising from adverse changes in the price differentials between pipeline receipt and delivery locations. Our firm transportation capacity allows us to purchase natural gas at a pipeline receipt point and sell natural gas at a pipeline delivery point. As market conditions permit, our Energy Services segment periodically enters into basis swaps between the transportation receipt and delivery points in order to protect the fair value of these location price differentials related to our firm commitments;
- Currency exchange rate risk - As a result of our Energy Services segment's activities in Canada, we are exposed to the risk of loss in cash flows and future earnings from adverse changes in currency exchange rates on our commodity purchases and sales, primarily related to our firm transportation and storage contracts that are transacted in a currency other than our functional currency, the United States dollar. To reduce our exposure to exchange-rate fluctuations, we use physical forward transactions, which result in an actual two-way flow of currency on the settlement date in which we exchange United States dollars for Canadian dollars with another party; and
- Interest-rate risk - We are also subject to fluctuations in interest rates. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps.

The following derivative instruments are used to manage our exposure to these risks:

- Futures contracts - Standardized exchange-traded contracts to purchase or sell natural gas and crude oil at a specified price, requiring delivery on or settlement through the sale or purchase of an offsetting contract by a specified future date under the provisions of exchange regulations;
- Forward contracts - Commitments to purchase or sell natural gas, crude oil or NGLs for physical delivery at some specified time in the future. We also use currency forward contracts to manage our currency exchange rate risk. Forward contracts are different from futures in that forwards are customized and nonexchange traded;
- Swaps - Financial trades involving the exchange of payments based on two different pricing structures for a commodity or other instrument. In a typical commodity swap, parties exchange payments based on changes in the price of a commodity or a market index, while fixing the price they effectively pay or receive for the physical commodity. As a result, one party assumes the risks and benefits of movements in market prices, while the other party assumes the risks and benefits of a fixed price for the commodity. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts; and
- Options - Contractual agreements that give the holder the right, but not the obligation, to buy or sell a fixed quantity of a commodity, at a fixed price, within a specified period of time. Options may either be standardized and exchange traded or customized and nonexchange traded.

Our objectives for entering into such contracts include but are not limited to:

- reducing the variability of cash flows by locking in the price for all or a portion of anticipated index-based physical purchases and sales, transportation fuel requirements, asset management transactions and customer-related business activities;
- locking in a price differential to protect the fair value between transportation receipt and delivery points and to protect the fair value of natural gas or NGLs that are purchased in one month and sold in a later month;
- reducing our exposure to fluctuations in interest and foreign currency exchange rates; and
- reducing variability in cash flows from changes in interest rates associated with forecasted debt issuances.

Our Energy Services segment also enters into derivative contracts for financial trading purposes primarily to capitalize on opportunities created by market volatility, weather-related events, supply-demand imbalances and market liquidity inefficiencies, which allow us to capture additional margin. Financial trading activities are executed generally using financially settled derivatives and are normally short term in nature.

With respect to the net open positions that exist within our marketing and financial trading operations, fluctuating commodity prices can impact our financial position and results of operations. The net open positions are actively managed, and the impact of the changing prices on our financial condition at a point in time is not necessarily indicative of the impact of price movements throughout the year.

Our Natural Gas Distribution segment also uses derivative instruments to hedge the cost of a portion of anticipated natural gas purchases during the winter heating months to protect our customers from upward volatility in the market price of natural gas. The use of these derivative instruments and the associated recovery of these costs have been approved by the OCC, KCC and regulatory authorities in certain of our Texas jurisdictions.

At December 31, 2011, ONEOK and ONEOK Partners had forward-starting interest-rate swaps with notional amounts of $500 million and $750 million, respectively, that have been designated as cash flow hedges of the variability of interest payments on a portion of forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued. In January 2012, ONEOK entered into an additional interest-rate swap that was designated as a cash flow hedge with a notional amount of $200 million. Upon issuance in January 2012 of our $700 million of 4.25-percent senior notes due 2022, ONEOK settled its swaps and realized a loss of $44.1 million that will be amortized to interest expense over the term of the debt. At December 30, 2010, ONEOK and ONEOK Partners did not have any interest-rate swap agreements.

Fair Values of Derivative Instruments - The following table sets forth the fair values of our derivative instruments for our continuing and discontinued operations for the periods indicated:

	December 31, 2011		December 31, 2010	
	Fair Values of Derivatives (a)		Fair Values of Derivatives (a)	
	Assets	(Liabilities)	Assets	(Liabilities)
	(Thousands of dollars)			
Derivatives designated as hedging instruments				
Commodity contracts				
Financial contracts	**$ 184,184** (b)	**$ (73,346)**	$ 136,040 (c)	$ (23,843)
Physical contracts	**62**	**(344)**	-	(883)
Interest-rate contracts	**-**	**(128,666)**	-	-
Total derivatives designated as hedging instruments	**184,246**	**(202,356)**	136,040	(24,726)
Derivatives not designated as hedging instruments				
Commodity contracts				
Nontrading instruments				
Financial contracts	**295,948**	**(323,170)**	125,503	(144,940)
Physical contracts	**38,733**	**(1,665)**	33,576	(7,214)
Trading instruments				
Financial contracts	**111,920**	**(110,050)**	20,640	(18,656)
Total derivatives not designated as hedging instruments	**446,601**	**(434,885)**	179,719	(170,810)
Total derivatives	**$ 630,847**	**$ (637,241)**	$ 315,759	$ (195,536)

(a) - Included on a net basis in energy marketing and risk-management assets and liabilities on our Consolidated Balance Sheets.

(b) - Includes $88.9 million of derivative assets associated with cash flow hedges of inventory that were adjusted to reflect the lower of cost or market value. The deferred gains associated with these assets have been reclassified from accumulated other comprehensive loss.

(c) - Includes $44.9 million of derivative assets associated with cash flow hedges of inventory that were adjusted to reflect the lower of cost or market value. The deferred gains associated with these assets have been reclassified from accumulated other comprehensive loss.

Notional Quantities for Derivative Instruments - The following table sets forth the notional quantities for derivative instruments held for our continuing and discontinued operations for the periods indicated:

	Contract Type	December 31, 2011 Purchased/ Payor	December 31, 2011 Sold/ Receiver	December 31, 2010 Purchased/ Payor	December 31, 2010 Sold/ Receiver
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
- Natural gas *(Bcf)*	Exchange futures	**21.2**	**(23.4)**	0.4	(7.6)
	Swaps	**19.5**	**(111.9)**	3.0	(69.9)
- Crude oil and NGLs *(MMBbl)*	Swaps	**-**	**(2.9)**	-	(1.5)
Basis					
- Natural gas *(Bcf)*	Forwards and swaps	**3.2**	**(82.8)**	2.8	(64.9)
Interest-rate contracts *(Millions of dollars)*	Forward-starting swaps	**$ 1,250.0**	**-**	-	-
Fair value hedges					
Basis					
- Natural gas *(Bcf)*	Forwards and swaps	**76.5**	**(77.0)**	141.1	(141.1)
Derivatives not designated as hedging instruments:					
Fixed price					
- Natural gas *(Bcf)*	Exchange futures	**76.9**	**(59.6)**	34.6	(20.6)
	Forwards and swaps	**235.8**	**(253.4)**	73.6	(100.3)
	Options	**33.6**	**(14.3)**	81.0	(74.3)
- Crude and NGLs *(MMBbl)*	Forwards and swaps	**-**	**-**	0.6	(0.6)
Basis					
- Natural gas *(Bcf)*	Forwards and swaps	**216.9**	**(219.3)**	411.5	(419.7)
Index					
- Natural gas *(Bcf)*	Forwards and swaps	**29.3**	**(22.1)**	33.6	(6.1)

These notional amounts are used to summarize the volume of financial instruments; however, they do not reflect the extent to which the positions offset one another and consequently do not reflect our actual exposure to market or credit risk.

Cash Flow Hedges - Our Energy Services and ONEOK Partners segments use derivative instruments to hedge the cash flows associated with anticipated purchases and sales of natural gas, NGLs and condensate and cost of fuel used in the transportation of natural gas. Accumulated other comprehensive income (loss) at December 31, 2011, includes net losses of approximately $1.8 million, net of tax, related to these hedges that will be recognized within the next 24 months as the forecasted transactions affect earnings. If prices remain at current levels, we will recognize $12.8 million in net losses over the next 12 months, and we will recognize net gains of $11.0 million thereafter. The amounts deferred in accumulated comprehensive income (loss) attributable to our interest-rate swaps will be amortized to interest expense over the life of long-term, fixed-rate debt upon issuance of the debt.

In 2011 and 2010, cost of sales and fuel in our Consolidated Statements of Income includes $91.1 million and $58.7 million in each period, respectively, reflecting an adjustment to natural gas inventory at the lower of cost or market value. In each period, we reclassified $91.1 million and $58.7 million, respectively, of deferred gains, before income taxes, on associated cash flow hedges from accumulated other comprehensive income (loss) into earnings.

The following table sets forth the effect of cash flow hedges recognized in other comprehensive income (loss) for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Years Ended December 31, **2011**	**2010**	**2009**
	(Thousands of dollars)		
Commodity contracts	**$ 117,508**	$ 128,662	$ 49,344
Interest rate contracts	**(128,666)**	-	1,599
Total gain (loss) recognized in other comprehensive income (loss) on derivatives (effective portion)	**$ (11,158)**	$ 128,662	$ 50,943

The following tables set forth the effect of cash flow hedges on our Consolidated Statements of Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)	Years Ended December 31, 2011	2010	2009
		(Thousands of dollars)		
Commodity contracts	Revenues	**$ 48,601**	$ 68,209	$ 188,144
Commodity contracts	Cost of sales and fuel	**89,618**	9,158	(36,776)
Interest rate contracts	Interest expense	**(480)**	28	1,240
Total gain (loss) reclassified from accumulated other comprehensive income (loss) into net income on derivatives (effective portion)		**$ 137,739**	$ 77,395	$ 152,608

Ineffectiveness related to our cash flow hedges was not material for the years ended December 31, 2011, 2010 and 2009. In the event that it becomes probable that a forecasted transaction will not occur, we will discontinue cash flow hedge treatment, which will affect earnings. For the years ended December 31, 2011, 2010 and 2009, there were no gains or losses due to the discontinuance of cash flow hedge treatment as a result of the underlying transactions being no longer probable.

Other Derivative Instruments - The following table sets forth the effect of our derivative instruments that are not part of a hedging relationship on our Consolidated Statements of Income for our continuing and discontinued operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss)	Years Ended December 31, 2011	2010	2009
		(Thousands of dollars)		
Commodity contracts - trading	Revenues	**$ 1,796**	$ 5,710	$ 3,210
Commodity contracts - non-trading (a)	Cost of sales and fuel	**16,178**	5,371	10,085
Foreign exchange contracts	Revenues	**-**	18	886
Total gain recognized in income on derivatives		**$ 17,974**	$ 11,099	$ 14,181

(a) - Amounts are presented net of deferred losses associated with derivatives entered into by our Natural Gas Distribution segment.

Our Natural Gas Distribution segment held natural gas call options with premiums totaling $10.0 million and $16.7 million at December 31, 2011 and 2010, respectively. The premiums are recorded in other current assets as these contracts are included in, and recoverable through, the monthly purchased-gas cost mechanism. We recorded losses associated with the decline in the value and expiration of option contracts totaling approximately $14.5 million, $25.5 million and $22.6 million for the years ended December 31, 2011, 2010 and 2009, respectively, which were deferred as part of our unrecovered purchased-gas costs.

Fair Value Hedges - In prior years, we terminated various interest-rate swap agreements that had been designated as fair value hedges. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Interest expense savings from the amortization of terminated swaps for 2011, 2010 and 2009, were $4.3 million, $10.2 million and $10.3 million, respectively.

Our Energy Services segment uses basis swaps to hedge the fair value of price location differentials related to certain firm transportation commitments. Cost of sales and fuel in our Consolidated Statements of Income includes gains of $14.6 million, $2.4 million and $253.2 million for 2011, 2010 and 2009, respectively, related to the change in fair value of derivatives designated as fair value hedges. Revenues include losses of $13.8 million, $2.7 million and $250.5 million for 2011, 2010 and 2009, respectively, to recognize the change in fair value of the related hedged firm commitments. Ineffectiveness included in cost of sales and fuel related to these hedges was immaterial for the years ended December 31, 2011, 2010 and 2009.

Credit Risk - We monitor the creditworthiness of our counterparties and compliance with policies and limits established by our Risk Oversight and Strategy Committee. We maintain credit policies with regard to our counterparties that we believe minimize overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings, bond yields and credit default swap rates), collateral requirements under certain circumstances and the use of standardized master-netting agreements that allow us to net the positive and negative exposures associated with a single counterparty. We have counterparties whose credit is not rated, and for those customers we use internally developed credit ratings.

Some of our derivative instruments contain provisions that require us to maintain an investment-grade credit rating from S&P and/or Moody's. If our credit ratings on senior unsecured long-term debt were to decline below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request collateralization on derivative instruments in net liability positions. The aggregate fair value of all financial derivative instruments with contingent features related to credit risk that were in a net liability position as of December 31, 2011, was $5.9 million. If the contingent features underlying these agreements were triggered on December 31, 2011, we would have been required to post an additional $5.9 million of collateral to our counterparties.

The counterparties to our derivative contracts consist primarily of major energy companies, LDCs, electric utilities, financial institutions and commercial and industrial end-users. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, we do not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

The following tables set forth the net credit exposure from our derivative assets for the period indicated:

	December 31, 2011			
	Investment Grade	**Non-investment Grade**	**Not Rated**	**Total**
Counterparty sector	*(Thousands of dollars)*			
Gas and electric utilities	**$ 22,335**	**$ -**	**$ 564**	**$ 22,899**
Oil and gas	**9,986**	**5**	**80**	**10,071**
Industrial	**7**	**-**	**14,955**	**14,962**
Financial	**13,566**	**-**	**-**	**13,566**
Other	**100**	**6**	**-**	**106**
Total	**$ 45,994**	**$ 11**	**$ 15,599**	**$ 61,604**

	December 31, 2010			
	Investment Grade	**Non-investment Grade**	**Not Rated**	**Total**
Counterparty sector	*(Thousands of dollars)*			
Gas and electric utilities	$ 33,847	$ 1,240	$ 678	$ 35,765
Oil and gas	8,995	35	2,091	11,121
Industrial	18	-	7,682	7,700
Financial	9,254	-	-	9,254
Other	-	-	21	21
Total	$ 52,114	$ 1,275	$ 10,472	$ 63,861

E. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	Estimated Useful Lives (Years)	December 31, 2011	December 31, 2010
		(Thousands of dollars)	
Non-Regulated			
Gathering pipelines and related equipment	5 to 46	**$ 1,350,227**	$ 1,144,753
Processing and fractionation and related equipment	5 to 42	**1,294,586**	993,100
Storage and related equipment	5 to 54	**299,610**	263,125
Transmission pipelines and related equipment	15 to 54	**182,863**	198,373
General plant and other	2 to 42	**288,445**	297,407
Construction work in process	-	**725,944**	228,862
Regulated			
Natural gas distribution pipelines and related equipment	15 to 80	**3,309,876**	3,160,197
Storage and related equipment	5 to 54	**136,971**	133,314
Natural gas transmission pipelines and related equipment	5 to 77	**1,771,752**	1,717,276
Natural gas liquids transmission pipelines and related equipment	5 to 80	**1,436,500**	1,351,245
General plant and other	2 to 85	**291,642**	261,783
Construction work in process	-	**89,518**	104,386
Property, plant and equipment		**11,177,934**	9,853,821
Accumulated depreciation and amortization - non-regulated		**(811,644)**	(707,535)
Accumulated depreciation and amortization - regulated		**(1,921,957)**	(1,833,338)
Net property, plant and equipment		**$ 8,444,333**	$ 7,312,948

The average depreciation rates for our regulated property are set forth, by segment, in the following table for the periods indicated:

	Years Ended December 31,		
Regulated Property	**2011**	**2010**	**2009**
ONEOK Partners	**1.9% - 2.2%**	1.9% - 2.2%	1.8% - 2.2%
Natural Gas Distribution	**2.0% - 2.9%**	2.1% - 2.8%	2.6% - 2.7%

F. GOODWILL AND INTANGIBLE ASSETS

Goodwill - The following table sets forth our goodwill, by segment, at both December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(Thousands of dollars)	
ONEOK Partners	**$ 433,535**	$ 433,537
Natural Gas Distribution	**157,953**	157,953
Energy Services	**10,255**	10,255
Other	**-**	1,099
Total goodwill	**$ 601,743**	$ 602,844

Intangible Assets - The following table sets forth the gross carrying amount and accumulated amortization of intangible assets for the periods indicated:

	December 31, 2011	December 31, 2010
	(Thousands of dollars)	
Gross intangible assets	**$ 462,214**	$ 462,214
Accumulated amortization	**(49,830)**	(42,164)
Net intangible assets	**$ 412,384**	$ 420,050

At December 31, 2011 and 2010, our ONEOK Partners segment has $256.8 million and $264.5 million, respectively, of intangible assets related primarily to contracts acquired through acquisition, which are being amortized over an aggregate weighted-average period of 40 years. The remaining intangible asset balance has an indefinite life. Amortization expense for intangible assets for 2011, 2010 and 2009 was $7.7 million each year, and the aggregate amortization expense for each of the next five years is estimated to be approximately $7.7 million.

G. CREDIT FACILITIES AND SHORT-TERM NOTES PAYABLE

ONEOK 2011 Credit Agreement - In April 2011, ONEOK entered into the five-year, $1.2 billion ONEOK 2011 Credit Agreement, which replaced the $1.2 billion ONEOK Credit Agreement that was scheduled to expire in July 2011. The ONEOK 2011 Credit Agreement, which is scheduled to expire in April 2016, contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONEOK's stand-alone debt-to-capital ratio of no more than 67.5 percent at the end of any calendar quarter, limitations on the ratio of indebtedness secured by liens and indebtedness of subsidiaries to consolidated net tangible assets, a requirement that ONEOK maintains the power to control the management and policies of ONEOK Partners, and a limit on new investments in master limited partnerships.

The ONEOK 2011 Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, investments, fundamental changes in the nature of ONEOK's businesses, transactions with affiliates, the use of proceeds and a covenant that limits ONEOK's ability to restrict its subsidiaries' ability to pay dividends. Under the terms of the ONEOK 2011 Credit Agreement, ONEOK may request an increase in the size of the facility to an aggregate of $1.7 billion from $1.2 billion by either commitments from new lenders or increased commitments from existing lenders.

The debt covenant calculations in the ONEOK 2011 Credit Agreement exclude the debt of ONEOK Partners. Upon breach of certain covenants by ONEOK, amounts outstanding under the ONEOK 2011 Credit Agreement may become due and payable immediately. At December 31, 2011, ONEOK's stand-alone debt-to-capital ratio, as defined by the ONEOK 2011 Credit Agreement, was 44.4 percent, and ONEOK was in compliance with all covenants under the ONEOK 2011 Credit Agreement. At December 31, 2011, ONEOK had $842.0 million of commercial paper outstanding and $2.0 million in letters of credit issued, leaving approximately $356.0 million of credit available under the ONEOK 2011 Credit Agreement.

The ONEOK 2011 Credit Agreement is available to repay our commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONEOK 2011 Credit Agreement. The ONEOK 2011 Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Borrowings, if any, will accrue at LIBOR plus 150 basis points, and the annual facility fee is 25 basis points based on our current credit rating.

The weighted-average interest rate on ONEOK's short-term debt outstanding was 0.50 percent and 0.38 percent at December 31, 2011 and 2010, respectively.

ONEOK Partners 2011 Credit Agreement - In August 2011, ONEOK Partners entered into the five-year, $1.2 billion ONEOK Partners 2011 Credit Agreement, which replaced the $1.0 billion ONEOK Partners Credit Agreement that was due to expire in March 2012. The ONEOK Partners 2011 Credit Agreement, which is scheduled to expire in August 2016, contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in the ONEOK Partners 2011 Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1. If ONEOK Partners consummates one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the three calendar quarters following the acquisitions. Upon breach of certain covenants by ONEOK Partners in the ONEOK Partners 2011 Credit Agreement, amounts outstanding under the ONEOK Partners 2011 Credit Agreement, if any, may become due and payable immediately.

The ONEOK Partners 2011 Credit Agreement includes a $100-million sublimit for the issuance of standby letters of credit and also features an option to request an increase in the size of the facility to an aggregate of $1.7 billion from $1.2 billion by either commitments from new lenders or increased commitments from existing lenders.

The ONEOK Partners 2011 Credit Agreement is available to repay ONEOK Partners' commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONEOK Partners 2011 Credit Agreement. The ONEOK Partners 2011 Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in ONEOK Partners' credit rating. Borrowings, if any, will accrue at LIBOR plus 130 basis points, and the annual facility fee is 20 basis points based on ONEOK Partners' current credit rating. The ONEOK Partners 2011 Credit Agreement is guaranteed fully and unconditionally by ONEOK Partners' wholly owned subsidiary, ONEOK Partners Intermediate Limited Partnership. Borrowings under the ONEOK Partners 2011 Credit Agreement are nonrecourse to ONEOK.

At December 31, 2011, ONEOK Partners' ratio of indebtedness to adjusted EBITDA was 2.9 to 1, and ONEOK Partners was in compliance with all covenants under the ONEOK Partners 2011 Credit Agreement. At December 31, 2011, ONEOK Partners had no commercial paper outstanding, no letters of credit issued and no borrowings under the ONEOK Partners 2011 Credit Agreement. The weighted-average interest rate on ONEOK Partners' short-term debt outstanding was 0.38 percent at December 31, 2010.

Neither ONEOK nor ONEOK Partners guarantees the debt or other similar commitments to unaffiliated parties, and ONEOK does not guarantee the debt or other similar commitments of ONEOK Partners.

H. LONG-TERM DEBT

All notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness. The following table sets forth our long-term debt for the periods indicated:

	December 31, 2011	December 31, 2010
	(Thousands of dollars)	
ONEOK		
$400,000 at 7.125% due 2011	**$ -**	$ 400,000
$400,000 at 5.2% due 2015	**400,000**	400,000
$100,000 at 6.4% due 2019	**-**	90,091
$100,000 at 6.5% due 2028	**87,735**	87,971
$100,000 at 6.875% due 2028	**100,000**	100,000
$400,000 at 6.0% due 2035	**400,000**	400,000
Other	**1,858**	2,163
Total ONEOK senior notes payable	**989,593**	1,480,225
ONEOK Partners		
$225,000 at 7.10% due 2011	**-**	225,000
$350,000 at 5.90% due 2012	**350,000**	350,000
$650,000 at 3.25% due 2016	**650,000**	-
$450,000 at 6.15% due 2016	**450,000**	450,000
$500,000 at 8.625% due 2019	**500,000**	500,000
$600,000 at 6.65% due 2036	**600,000**	600,000
$600,000 at 6.85% due 2037	**600,000**	600,000
$650,000 at 6.125% due 2041	**650,000**	-
Guardian Pipeline		
Average 7.85%, due 2022	**85,919**	97,850
Total ONEOK Partners senior notes payable	**3,885,919**	2,822,850
Total long-term notes payable	**4,875,512**	4,303,075
Unamortized portion of terminated swaps	**28,776**	33,113
Unamortized debt discount	**(10,346)**	(6,410)
Current maturities	**(364,391)**	(643,236)
Long-term debt	**$ 4,529,551**	$ 3,686,542

The aggregate maturities of long-term debt outstanding for the years 2012 through 2016 are shown below:

	ONEOK	ONEOK Partners	Guardian Pipeline	Total
		(Millions of dollars)		
2012	$ 3.3	$ 350.0	$ 11.1	$ 364.4
2013	$ 3.2	$ -	$ 7.7	$ 10.9
2014	$ 3.0	$ -	$ 7.7	$ 10.7
2015	$ 403.0	$ -	$ 7.7	$ 410.7
2016	$ 3.0	$1,100.0	$ 7.7	$1,110.7

Additionally, our senior notes due 2028 (6.5 percent) are callable at par at our option from now until maturity.

ONEOK Debt Repayments - In 2011, ONEOK repaid $400 million of maturing senior notes and redeemed $90.5 million of 6.4-percent senior notes with available cash and short-term borrowings.

ONEOK Debt Issuance - In January 2012, we completed an underwritten public offering of $700 million of 4.25-percent senior notes due 2022. The net proceeds from the offering, after deducting underwriting discounts and offering expenses, of approximately $693.9 million were used to repay amounts outstanding under our $1.2 billion commercial paper program and general corporate purposes, which may include one or more of the following: the repurchase of our common stock, the purchase of additional common units of ONEOK Partners and the payment of dividends. We will pay interest on the senior notes due 2022 on February 1 and August 1 of each year, beginning August 1, 2012.

ONEOK Debt Covenants - The indentures governing ONEOK's senior notes due 2028 (6.5 percent and 6.875 percent) include an event of default upon acceleration of other indebtedness of $15 million or more, and the indentures governing the senior notes due 2015, 2022 and 2035 include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2015, 2022, 2028 and 2035 to declare those senior notes immediately due and payable in full.

ONEOK may redeem the senior notes due 2015, 2028 (6.875 percent) and 2035, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. ONEOK may redeem the senior notes due 2028 (6.5 percent), in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest. ONEOK may redeem its 4.25-percent senior notes due 2022 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting three month before the maturity date. Prior to this date, ONEOK may redeem these senior notes on the same basis as its other senior notes due 2015, 2028 (6.875 percent) and 2035. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. ONEOK's senior notes due 2015, 2022, 2028 and 2035 are senior unsecured obligations, ranking equally in right of payment with all of ONEOK's existing and future unsecured senior indebtedness.

ONEOK Partners' Debt Issuance and Maturities - In January 2011, ONEOK Partners completed an underwritten public offering of $1.3 billion of senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering of approximately $1.28 billion were used to repay amounts outstanding under ONEOK Partners' commercial paper program, to repay the $225 million of ONEOK Partners' senior notes that matured in March 2011 and for general partnership purposes, including capital expenditures.

ONEOK Partners intends to repay its $350 million 5.9-percent senior notes that mature in April 2012 with a combination of cash on hand and short-term borrowings.

ONEOK Partners' Debt Covenants - The indentures governing ONEOK Partners' senior notes include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of ONEOK Partners' outstanding senior notes to declare those senior notes immediately due and payable in full.

ONEOK Partners may redeem the senior notes due 2012, 2016 (6.15 percent), 2019, 2036 and 2037, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. ONEOK Partners may redeem its senior notes due 2016 (3.25 percent) and 2041 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting one month and six months, respectively, before their maturity dates. Prior to these dates, ONEOK Partners may redeem these senior notes on the same terms as its other senior notes. ONEOK Partners' senior notes are senior unsecured obligations, ranking equally in right of payment with all of ONEOK Partners' existing and future unsecured senior indebtedness, and structurally subordinate to all of the existing and future debt and other liabilities of any nonguarantor subsidiaries. ONEOK Partners' senior notes are nonrecourse to ONEOK.

ONEOK Partners' Debt Guarantee - ONEOK Partners' senior notes are guaranteed on a senior unsecured basis by the Intermediate Partnership. The Intermediate Partnership's guarantee is full and unconditional, subject to certain customary automatic release provisions. The guarantee ranks equally in right of payment to all of the Intermediate Partnership's existing and future unsecured senior indebtedness. ONEOK Partners has no significant assets or operations other than its investment in the Intermediate Partnership, which is also consolidated. At December 31, 2011, the Intermediate Partnership held the equity of ONEOK Partners' subsidiaries, as well as a 50-percent interest in Northern Border Pipeline. ONEOK Partners' long-term debt is nonrecourse to ONEOK.

Guardian Pipeline Senior Notes - These senior notes were issued under a master shelf agreement dated November 8, 2001, with certain financial institutions. Principal payments are due quarterly through 2022. Interest rates on the $85.9 million in senior notes outstanding at December 31, 2011, range from 7.61 percent to 8.27 percent, with an average rate of 7.85 percent. Guardian Pipeline's senior notes contain financial covenants that require the maintenance of a ratio of (i) EBITDAR, as defined in the master shelf agreement to fixed charges (interest expense plus operating lease expense) of not less than 1.5 to 1; and (ii) total indebtedness to EBITDAR of not greater than 4.75 to 1. Upon any breach of these covenants, all amounts outstanding under the master shelf agreement may become due and payable immediately. At December 31, 2011, Guardian Pipeline's EBITDAR-to-fixed-charges ratio was 6.5 to 1, the ratio of total indebtedness to EBITDAR was 1.8 to 1, and Guardian Pipeline was in compliance with its financial covenants.

Interest-rate Swaps - See Note D for a discussion of our interest-rate swaps.

Other - We amortize premiums, discounts and expenses incurred in connection with the issuance of long-term debt consistent with the terms of the respective debt instrument.

I. EQUITY

Series A and B Convertible Preferred Stock - There are no shares of Series A or Series B Preferred Stock currently issued or outstanding.

Series C Preferred Stock - Series C Preferred Stock (Series C) is designed to protect our shareholders from coercive or unfair takeover tactics. If issued, holders of shares of Series C are entitled to receive, in preference to the holders of ONEOK Common Stock, quarterly dividends in an amount per share equal to the greater of $0.50 or, subject to adjustment, 100 times the aggregate per share amount of all cash dividends, and 100 times the aggregate per share amount (payable in kind) of all noncash dividends. No shares of Series C have been issued.

Common Stock - At December 31, 2011, we had approximately 179.8 million shares of authorized and unreserved common stock available for issuance.

Stock Split - On February 15, 2012, our Board of Directors authorized a two-for-one split of our common stock, subject to shareholder approval of a proposal to increase the number of authorized shares of our common stock to 600 million from 300 million. The proposal will be voted on at our 2012 annual meeting of shareholders on May 23, 2012.

Dividends - Dividends paid totaled $227.0 million, $193.5 million and $172.8 million for 2011, 2010 and 2009, respectively. The following table sets forth the quarterly dividends per share declared and paid on our common stock for the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
First Quarter	**$ 0.52**	$ 0.44	$ 0.40
Second Quarter	**$ 0.52**	$ 0.44	$ 0.40
Third Quarter	**$ 0.56**	$ 0.46	$ 0.42
Fourth Quarter	**$ 0.56**	$ 0.48	$ 0.42
Total	**$ 2.16**	$ 1.82	$ 1.64

Additionally, a quarterly dividend of $0.61 per share was declared in January 2012, payable in the first quarter of 2012.

Stock Repurchase Plan - In 2011, we repurchased approximately 4.3 million shares of our common stock for approximately $300 million pursuant to an accelerated stock repurchase agreement. The 2011 stock repurchase was part of our three-year stock repurchase program to buy up to $750 million of our common stock that was authorized by our Board of Directors in October 2010.

J. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table sets forth the balance in accumulated other comprehensive income (loss) for the periods indicated:

	Unrealized Gains (Losses) on Energy Marketing and Risk Management Assets/Liabilities	Unrealized Holding Gains (Losses) on Investment Securities	Pension and Postretirement Benefit Plan Obligations	Accumulated Other Comprehensive Income (Loss)
	(Thousands of dollars)			
January 1, 2010	$ (6,151)	$ 1,441	$ (113,903)	$ (118,613)
Other comprehensive income (loss) attributable to ONEOK	21,882	(70)	(12,001)	9,811
December 31, 2010	15,731	1,371	(125,904)	(108,802)
Other comprehensive income (loss) attributable to ONEOK	**(71,098)**	**(384)**	**(25,837)**	**(97,319)**
December 31, 2011	**$ (55,367)**	**$ 987**	**$ (151,741)**	**$ (206,121)**

K. EARNINGS PER SHARE

The following tables set forth the computation of basic and diluted EPS from continuing operations for the periods indicated:

	Year Ended December 31, 2011		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	**$ 358,364**	**104,672**	**$ 3.42**
Diluted EPS from continuing operations			
Effect of options and other dilutive securities	**-**	**2,577**	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	**$ 358,364**	**107,249**	**$ 3.34**

	Year Ended December 31, 2010		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$ 333,360	106,368	$ 3.14
Diluted EPS from continuing operations			
Effect of options and other dilutive securities	-	1,417	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$ 333,360	107,785	$ 3.09

	Year Ended December 31, 2009		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$ 297,904	105,362	$ 2.83
Diluted EPS from continuing operations			
Effect of options and other dilutive securities	-	958	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$ 297,904	106,320	$ 2.80

There were no option shares excluded from the calculation of diluted EPS for 2011 and 2010. There were 192,952 option shares excluded from the calculation of diluted EPS for 2009 since their inclusion would be antidilutive.

L. SHARE-BASED PAYMENTS

Equity Compensation Plan

The ONEOK, Inc. Equity Compensation Plan provides for the granting of stock-based compensation, including incentive stock options, nonstatutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards, performance stock awards and performance unit awards to eligible employees and the granting of stock awards to nonemployee directors. We have reserved a total of 5.0 million shares of common stock for issuance under the plan, and at December 31, 2011, we had 2.2 million shares available for issuance under the plan. The Equity Compensation Plan allows for the deferral of awards granted in stock or cash, in accordance with Internal Revenue Code section 409A requirements.

Restricted Stock Units - Restricted stock units may be granted to key employees with ownership of the common stock underlying the unit vesting over a period determined by the Executive Compensation Committee of our Board of Directors (the Executive Compensation Committee). Awards outstanding vest over a three-year period and entitle the grantee to receive shares of our common stock. Restricted stock unit awards are measured at fair value as if they were vested and issued on the grant date, reduced by expected dividend payments and adjusted for estimated forfeitures. No dividends are paid on the restricted stock units. Compensation expense is recognized on a straight-line basis over the vesting period of the award.

Performance Unit Awards - Performance unit awards may be granted to key employees. The shares of our common stock underlying the performance units vest at the expiration of a period determined by the Executive Compensation Committee if certain performance criteria are met by us. Outstanding performance units vest at the expiration of a three-year period. Upon vesting, a holder of performance units is entitled to receive a number of shares of our common stock equal to a percentage (0 percent to 200 percent) of the performance units granted based on our total shareholder return over the vesting period, compared with the total shareholder return of a peer group of other energy companies over the same period. Compensation expense is recognized on a straight-line basis over the period of the award.

If paid, the outstanding performance unit awards entitle the grantee to receive the grant in shares of our common stock. Our outstanding performance unit awards are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market condition is satisfied. The fair value of these performance units was estimated on the grant date based on a Monte Carlo model. The compensation expense on these awards will only be adjusted for changes in forfeitures.

Long-Term Incentive Plan

The ONEOK, Inc. Long-Term Incentive Plan (the LTIP) provides for the granting of stock awards similar to those described above with respect to the Equity Compensation Plan. We have reserved a total of approximately 7.8 million shares of common stock for issuance under the plan. The maximum number of shares for which options or other awards may be granted to any employee during any year is 300,000.

Options - Stock options may be granted that are not exercisable until a fixed future date or in installments. All outstanding options issued to date have vested and must be exercised no later than 10 years after grant date. Options issued to date become void upon involuntary termination of employment for just cause or voluntary termination of employment other than retirement. In the event of retirement or involuntary termination other than for just cause, the optionee may exercise the option within a period determined by the Executive Compensation Committee and stated in the option. In the event of death, the option may be exercised by the personal representative of the optionee within a period to be determined by the Committee and stated in the option. No stock options have been granted since 2003.

Stock Compensation Plan for Non-Employee Directors

The ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (the DSCP) provides for the granting of stock options, stock bonus awards, including performance unit awards, restricted stock awards and restricted stock unit awards. Under the DSCP, these awards may be granted by the Executive Compensation Committee at any time, until grants have been made for all shares authorized under the DSCP. We have reserved a total of 700,000 shares of common stock for issuance under the DSCP. The maximum number of shares of common stock which can be issued to a participant under the DSCP during any year is 20,000. No performance unit awards or restricted stock awards have been made to nonemployee directors under the DSCP.

General

For all awards outstanding, we used a forfeiture rate ranging from zero percent to 12 percent based on historical forfeitures under our share-based payment plans. We primarily use issuances from treasury stock to satisfy our share-based payment obligations.

Compensation cost expensed for our share-based payment plans described below was $40.7 million, $15.9 million and $15.1 million during 2011, 2010 and 2009, respectively, which is net of $25.7 million, $10.0 million and $9.5 million of tax benefits, respectively. Share-based compensation cost capitalized was not material for 2011 and we had no share-based compensation cost capitalized for 2010 and 2009.

Cash received from the exercise of awards under all share-based payment arrangements was $0.9 million, $6.0 million and $3.3 million for 2011, 2010 and 2009, respectively. The tax benefit realized for the anticipated tax deductions of the exercise of share-based payment arrangements totaled $1.8 million, $3.4 million and $0.9 million for 2011, 2010 and 2009, respectively.

Stock Option Activity

The following table sets forth the stock option activity for employees and nonemployee directors for the periods indicated:

	Number of Shares	Weighted Average Price
Outstanding December 31, 2010	135,190	$ 21.52
Exercised	(105,540)	$ 22.78
Outstanding December 31, 2011	29,650	$ 17.03
Exercisable December 31, 2011	29,650	$ 17.03

The aggregate intrinsic value in the table below represents the total pre-tax intrinsic value, based on our year-end closing stock price of $86.69, that would have been received by the option holders had all option holders exercised their options as of December 31, 2011:

	Stock Options Outstanding and Exercisable			
Range of Exercise Prices	Number of Awards	Weighted Average Remaining Life (yrs)	Weighted Average Exercise Price	Aggregate Intrinsic Value (in 000's)
$16.88 to $25.32	29,650	1.02	$ 17.03	$ 2,065

As of December 31, 2011, all stock options were fully vested and expensed. The following table sets forth statistics relating to our stock option activity:

	December 31, 2011	December 31, 2010	December 31, 2009
		(Thousands of dollars)	
Intrinsic value of options exercised	**$ 4,756**	$ 8,953	$ 2,453

Restricted Stock Unit Activity

As of December 31, 2011, there was $10.5 million of total unrecognized compensation cost related to our nonvested restricted stock unit awards, which is expected to be recognized over a weighted-average period of 1.13 years. The following tables set forth activity and various statistics for our restricted stock unit awards:

	Number of Shares	Weighted Average Price
Nonvested December 31, 2010	**488,786**	**$ 35.07**
Granted	**205,750**	**$ 57.00**
Released to participants	**(1,271)**	**$ 29.26**
Forfeited	**(8,928)**	**$ 42.96**
Nonvested December 31, 2011	**684,337**	**$ 41.57**

	2011	2010	2009
Weighted-average grant date fair value (per share)	**$ 57.00**	$ 37.33	$ 23.47
Fair value of shares granted (thousands of dollars)	**$ 11,728**	$ 8,206	$ 2,251

Performance Unit Activity

As of December 31, 2011, there was $7.4 million of total unrecognized compensation cost related to the nonvested performance unit awards, which is expected to be recognized over a weighted-average period of 1.09 years. The following tables set forth activity and various statistics related to the performance unit awards and the assumptions used in the valuations of the 2011, 2010 and 2009 grants at the grant date:

	Number of Units	Weighted Average Price
Nonvested December 31, 2010	**1,314,587**	**$ 40.30**
Granted	**420,850**	**$ 69.35**
Forfeited	**(19,276)**	**$ 46.12**
Nonvested December 31, 2011	**1,716,161**	**$ 47.36**

	2011	2010	2009
Volatility (a)	**39.91%**	40.60%	43.58%
Dividend Yield	**3.30%**	4.12%	5.70%
Risk-free Interest Rate	**1.33%**	1.47%	1.01%

(a) - Volatility was based on historical volatility over three years using daily stock price observations.

	2011	2010	2009
Weighted-average grant date fair value (per share)	**$ 69.35**	$ 48.09	$ 29.34
Fair value of shares granted (thousands of dollars)	**$ 29,186**	$ 20,738	$ 17,232

Employee Stock Purchase Plan

We have reserved a total of 4.8 million shares of common stock for issuance under our ONEOK, Inc. Employee Stock Purchase Plan (the ESPP). Subject to certain exclusions, all full-time employees are eligible to participate in the ESPP. Employees can choose to have up to 10 percent of their annual base pay withheld to purchase our common stock, subject to terms and limitations of the plan. The Executive Compensation Committee may allow contributions to be made by other means, provided that in no event will contributions from all means exceed 10 percent of the employee's annual base pay. The purchase price of the stock is 85 percent of the lower of its grant date or exercise date market price. Approximately 56 percent, 53 percent and 53 percent of employees participated in the plan in 2011, 2010 and 2009, respectively. Compensation expense for the ESPP was $7.2 million, $3.9 million and $6.5 million in 2011, 2010 and 2009, respectively. Under the plan, we sold 182,558 shares at $47.39 in 2011, 216,897 shares at $37.95 per share in 2010 and 321,888 shares at $24.41 per share in 2009.

Employee Stock Award Program

Under our Employee Stock Award Program, we issued, for no monetary consideration, to all eligible employees one share of our common stock when the per-share closing price of our common stock on the NYSE was for the first time at or above $26 per share. Shares issued to employees under this program during 2011 totaled 147,847, and compensation expense related to the Employee Stock Award Plan was $16.0 million. For 2010, the number of shares issued under this program was immaterial, and there were no shares issued in 2009.

The total number of shares of our common stock available for issuance under this program was 300,000. During 2011, the number of shares of our common stock available for distribution for issuance under this program was met. Shareholder approval is required for further stock awards to be issued under the program.

Deferred Compensation Plan for Non-Employee Directors

The ONEOK, Inc. Nonqualified Deferred Compensation Plan for Non-Employee Directors provides our directors, who are not our employees, the option to defer all or a portion of their compensation for their service on our Board of Directors. Under the plan, directors may elect either a cash deferral option or a phantom stock option. Under the cash deferral option, directors may defer the receipt of all or a portion of their annual retainer fees, plus accrued interest. Under the phantom stock option, directors may defer all or a portion of their annual retainer fees and receive such fees on a deferred basis in the form of shares of common stock under our Long-Term Incentive Plan or Equity Compensation Plan. Shares are distributed to nonemployee directors at the fair market value of our common stock at the date of distribution.

M. EMPLOYEE BENEFIT PLANS

Retirement and Postretirement Benefit Plans

Retirement Plans - We have a defined benefit pension plan covering nonbargaining unit employees hired prior to January 1, 2005, and certain bargaining unit employees. Nonbargaining unit employees hired after December 31, 2004, employees represented by Local No. 304 of the IBEW hired on or after July 1, 2010, employees represented by the United Steelworkers hired on or after December 15, 2011, and employees who accepted a one-time opportunity to opt out of our pension plan, are covered by a profit-sharing plan. In addition, we have a supplemental executive retirement plan for the benefit of certain officers. No new participants in our supplemental executive retirement plan have been approved since 2005. We fund our pension costs at a level needed to maintain or exceed the minimum funding levels required by the Employee Retirement Income Security Act of 1974, as amended, and the Pension Protection Act of 2006.

Postretirement Benefit Plans - We sponsor welfare plans that provide postretirement medical and life insurance benefits to certain employees who retire with at least five years of service. The postretirement medical plan is contributory based on hire date, age and years of service, with retiree contributions adjusted periodically, and contains other cost-sharing features such as deductibles and coinsurance.

In December 2011, we announced to participants a change from a self-insured postretirement medical plan to a fully insured solution for plan participants who have reached the age of 65 that coordinates with Medicare. This announcement resulted in a $44.6 million reduction in our accumulated postretirement benefit obligation that was recognized in other comprehensive income and will be amortized to net periodic benefit cost over the expected remaining years of service for plan participants.

Regulatory Treatment - The OCC, KCC and regulatory authorities in Texas have approved the recovery of pension costs and postretirement benefits costs through rates for Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. The costs recovered through rates are based on current funding requirements and the net periodic benefit cost for pension and postretirement costs. Differences, if any, between the expense and the amount recovered through rates are reflected in earnings, net of authorized deferrals.

Our regulated entities historically have recovered pension and postretirement benefit costs through rates. We believe it is probable that regulators will continue to include the net periodic pension and postretirement benefit costs in our regulated entities' cost of service. Accordingly, we have recorded a regulatory asset for the minimum liability associated with our regulated entities' pension and postretirement benefit obligations that otherwise would have been recorded in accumulated other comprehensive income.

Obligations and Funded Status - The following tables set forth our pension and postretirement benefit plans benefit obligations and fair value of plan assets for the periods indicated.

	Pension Benefits December 31,		Postretirement Benefits December 31,	
	2011	**2010**	**2011**	**2010**
Change in Benefit Obligation		*(Thousands of dollars)*		
Benefit obligation, beginning of period	**$ 1,098,232**	$ 997,003	**$ 295,483**	$ 267,666
Service cost	**20,013**	19,277	**4,987**	4,926
Interest cost	**58,757**	58,143	**15,632**	15,643
Plan participants' contributions	**-**	-	**6,751**	3,048
Actuarial (gain) loss	**92,609**	75,704	**25,617**	20,761
Benefits paid	**(53,679)**	(51,895)	**(17,864)**	(16,561)
Plan amendment	**-**	-	**(44,562)**	-
Benefit obligation, end of period	**1,215,932**	1,098,232	**286,044**	295,483
Change in Plan Assets				
Fair value of plan assets, beginning of period	**904,089**	748,686	**117,585**	92,360
Actual return on plan assets	**(10,750)**	110,473	**(4,876)**	12,677
Employer contributions	**62,575** (a)	96,825 (b)	**11,454**	12,548
Benefits paid	**(53,679)**	(51,895)	**-**	-
Fair value of assets, end of period	**902,235**	904,089	**124,163**	117,585
Balance at December 31	**$ (313,697)**	$ (194,143)	**$ (161,881)**	$ (177,898)
Current liabilities	**$ (4,545)**	$ (4,203)	**$ -**	$ -
Non-current liabilities	**(309,152)**	(189,940)	**(161,881)**	(177,898)
Balance at December 31	**$ (313,697)**	$ (194,143)	**$ (161,881)**	$ (177,898)

(a) - Includes $62.6 million contributed for the 2012 plan year.

(b) - Includes $57.0 million contributed for the 2011 plan year.

The accumulated benefit obligation for our pension plans was $1,152.4 million and $1,041.5 million at December 31, 2011 and 2010, respectively.

There are no plan assets expected to be withdrawn and returned to us in 2012.

Components of Net Periodic Benefit Cost - The following tables set forth the components of net periodic benefit cost for our pension and postretirement benefit plans for the periods indicated:

	Pension Benefits		
	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Components of net periodic benefit cost			
Service cost	**$ 20,013**	$ 19,277	$ 20,762
Interest cost	**58,757**	58,143	58,052
Expected return on assets	**(75,500)**	(73,651)	(66,034)
Amortization of unrecognized prior service cost	**1,018**	1,278	1,565
Amortization of net loss	**35,708**	27,555	17,322
Net periodic benefit cost	**$ 39,996**	$ 32,602	$ 31,667

	Postretirement Benefits		
	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Components of net periodic benefit cost			
Service cost	**$ 4,987**	$ 4,926	$ 5,173
Interest cost	**15,632**	15,643	16,918
Expected return on assets	**(10,272)**	(7,896)	(6,809)
Amortization of unrecognized net asset at adoption	**3,189**	3,189	3,189
Amortization of unrecognized prior service cost	**(2,518)**	(2,003)	(2,003)
Amortization of net loss	**8,123**	7,009	9,660
Net periodic benefit cost	**$ 19,141**	$ 20,868	$ 26,128

Other Comprehensive Income (Loss) - The following tables set forth the amounts recognized in other comprehensive income (loss) related to our pension benefits and postretirement benefits for the periods indicated:

	Pension Benefits		
	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Regulatory asset gain (loss)	**$ 114,625**	$ 19,146	$ (4,674)
Net loss arising during the period	**(182,987)**	(43,055)	(30,340)
Amortization of regulatory asset	**(23,265)**	(18,359)	(11,465)
Amortization of prior service credit	**1,018**	1,278	1,565
Amortization of loss	**35,708**	27,555	17,322
Deferred income taxes	**21,236**	5,197	10,674
Total recognized in other comprehensive income (loss)	**$ (33,665)**	$ (8,238)	$ (16,918)

	Postretirement Benefits		
	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands of dollars)		
Regulatory asset gain (loss)	**$ 7,389**	$ 8,408	$ (19,292)
Net gain (loss) arising during the period	**(40,765)**	(15,980)	21,692
Amortization of regulatory asset	**(7,214)**	(6,759)	(9,400)
Amortization of transition obligation	**3,189**	3,189	3,189
Amortization of prior service cost	**(2,518)**	(2,003)	(2,003)
Amortization of loss	**8,123**	7,009	9,660
Plan amendment	**44,562**	-	-
Deferred income taxes	**(4,938)**	2,373	(1,488)
Total recognized in other comprehensive income (loss)	**$ 7,828**	$ (3,763)	$ 2,358

The table below sets forth the amounts in accumulated other comprehensive income (loss) that had not yet been recognized as components of net periodic benefit expense for the periods indicated:

	Pension Benefits December 31,		Postretirement Benefits December 31,	
	2011	**2010**	**2011**	**2010**
	(Thousands of dollars)			
Transition obligation	**$ -**	$ -	**$ (3,157)**	$ (6,346)
Prior service credit (cost)	**(2,991)**	(4,009)	**46,426**	4,377
Accumulated gain (loss)	**(630,886)**	(483,607)	**(123,489)**	(90,846)
Accumulated other comprehensive income (loss) before regulatory assets	**(633,877)**	(487,616)	**(80,220)**	(92,815)
Regulatory asset for regulated entities	**407,886**	316,527	**58,752**	58,577
Accumulated other comprehensive income (loss) after regulatory assets	**(225,991)**	(171,089)	**(21,468)**	(34,238)
Deferred income taxes	**87,413**	66,180	**8,305**	13,243
Accumulated other comprehensive income (loss), net of tax	**$ (138,578)**	$ (104,909)	**$ (13,163)**	$ (20,995)

The following table sets forth the amounts recognized in either accumulated comprehensive income (loss) or regulatory assets expected to be recognized as components of net periodic benefit expense in the next fiscal year:

	Pension Benefits	Postretirement Benefits
Amounts to be recognized in 2012	*(Thousands of dollars)*	
Transition obligation	$ -	$ 2,874
Prior service credit (cost)	$ 969	$ (8,252)
Net loss	$ 48,439	$ 13,184

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations for pension and postretirement benefits for the periods indicated:

	Years Ended December 31,	
	2011	**2010**
Discount rate	**5.00%**	5.50%
Compensation increase rate	**3.2% - 3.8%**	3.3% - 3.9%

The following table sets forth the weighted-average assumptions used to determine net periodic benefit costs for the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
Discount rate	**5.50%**	6.00%	6.25%
Expected long-term return on plan assets	**8.25%**	8.50%	8.50%
Compensation increase rate	**3.30% - 3.90%**	3.1% - 4.0%	4.3% - 4.8%

We determine our overall expected long-term rate of return on plan assets, based on our review of historical returns and economic growth models.

We determine our discount rates annually. We estimate our discount rate based upon a comparison of the expected cash flows associated with our future payments under our pension and postretirement obligations to a hypothetical bond portfolio created using high-quality bonds that closely match expected cash flows. Bond portfolios are developed by selecting a bond for each of the next 60 years based on the maturity dates of the bonds. Bonds selected to be included in the portfolios are only those rated by Moody's as AA- or better and exclude callable bonds, bonds with less than a minimum issue size, yield outliers and other filtering criteria to remove unsuitable bonds.

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost trend rates for the periods indicated:

	2011	2010
Health care cost-trend rate assumed for next year	**4.0% - 9.0%**	6.0% - 9.0%
Rate to which the cost-trend rate is assumed to decline (the ultimate trend rate)	**4.0% - 5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2021**	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for our health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	**One Percentage Point Decrease**
	(Thousands of dollars)	
Effect on total of service and interest cost	**$ 1,833**	**$ (1,559)**
Effect on postretirement benefit obligation	**$ 17,562**	**$ (16,079)**

Plan Assets - Our investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. The plan's investments include a diverse blend of various domestic and international equities, investments in various classes of debt securities, insurance contracts and venture capital. The target allocation for the assets of our pension plan is as follows:

U.S. large-cap equities	37%
Aggregate bonds	24%
Developed foreign large-cap equities	10%
Alternative investments	8%
Mid-cap equities	6%
Emerging markets equities	5%
Small-cap equities	4%
High yield bonds	3%
Developed foreign bonds	2%
Emerging market bonds	1%
Total	100%

As part of our risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning our stock.

The following tables set forth our pension benefits and postretirement benefits plan assets by category as of the measurement date:

	Pension Benefits December 31, 2011			
Asset Category	**Level 1**	**Level 2**	**Level 3**	**Total**
	(Thousands of dollars)			
Investments:				
Equity securities (a)	**$ 481,971**	**$ 32,475**	**$ -**	**$ 514,446**
Government obligations	**-**	**96,341**	**-**	**96,341**
Corporate obligations (b)	**18,835**	**58,977**	**-**	**77,812**
Cash and money market funds (c)	**76,575**	**-**	**-**	**76,575**
Insurance contracts and group annuity contracts	**-**	**-**	**70,818**	**70,818**
Other investments (d)	**-**	**-**	**66,243**	**66,243**
Total assets	**$ 577,381**	**$ 187,793**	**$ 137,061**	**$ 902,235**

(a) - This category represents securities of the respective market sector from diverse industries.

(b) - This category represents bonds from diverse industries.

(c) - This category is primarily money market funds.

(d) - This category represents alternative investments.

	Pension Benefits December 31, 2010							
Asset Category	**Level 1**		**Level 2**		**Level 3**		**Total**	
	(Thousands of dollars)							
Investments:								
Equity securities (a)	$	588,224	$	-	$	-	$	588,224
Government obligations		-		80,233		-		80,233
Corporate obligations (b)		26,439		49,199		-		75,638
Cash and money market funds (c)		86,734		-		-		86,734
Insurance contracts and group annuity contracts		-		-		72,198		72,198
Other investments (d)		-		-		1,062		1,062
Total assets	$	701,397	$	129,432	$	73,260	$	904,089

(a) - This category represents securities of the respective market sector from diverse industries.

(b) - This category represents bonds from diverse industries.

(c) - This category is primarily money market funds.

(d) - This category represents alternative investments.

	Postretirement Benefits December 31, 2011							
Asset Category	**Level 1**		**Level 2**		**Level 3**		**Total**	
	(Thousands of dollars)							
Investments:								
Equity securities (a)	**$**	**21,915**	**$**	**113**	**$**	**-**	**$**	**22,028**
Government obligations		**-**		**334**		**-**		**334**
Corporate obligations (b)		**12,156**		**205**		**-**		**12,361**
Cash and money market funds (c)		**12,477**		**-**		**-**		**12,477**
Insurance contracts and group annuity contracts		**-**		**76,733**		**-**		**76,733**
Other investments (d)		**-**		**-**		**230**		**230**
Total assets	**$**	**46,548**	**$**	**77,385**	**$**	**230**	**$**	**124,163**

(a) - This category represents securities of the respective market sector from diverse industries.

(b) - This category represents bonds from diverse industries.

(c) - This category is primarily money market funds.

(d) - This category represents alternative investments.

	Postretirement Benefits December 31, 2010							
Asset Category	**Level 1**		**Level 2**		**Level 3**		**Total**	
	(Thousands of dollars)							
Investments:								
Equity securities (a)	$	17,261	$	-	$	-	$	17,261
Corporate obligations (b)		12,149		-		-		12,149
Cash and money market funds (c)		12,614		-		-		12,614
Insurance contracts and group annuity contracts		-		75,561		-		75,561
Total assets	$	42,024	$	75,561	$	-	$	117,585

(a) - This category represents securities of the respective market sector from diverse industries.

(b) - This category represents mutual funds that invest in bonds from diverse industries.

(c) - This category represents an insurance contract with underlying investments that are primarily directed by us which include equity securities and bonds from diverse inidustries.

The following tables set forth the reconciliation of Level 3 fair value measurements of our pension plan for the periods indicated:

	Pension Benefits December 31, 2011		
	Insurance Contracts	Other Investments	Total
	(Thousands of dollars)		
January 1, 2011	$ 72,198	$ 1,062	$ 73,260
Purchases	-	**65,000**	**65,000**
Actual return on plan assets held at the reporting date	**(1,380)**	**181**	**(1,199)**
December 31, 2011	**$ 70,818**	**$ 66,243**	**$ 137,061**

	Pension Benefits December 31, 2010		
	Insurance Contracts	Other Investments	Total
	(Thousands of dollars)		
January 1, 2010	$ 76,079	$ 1,098	$ 77,177
Actual return on plan assets held at the reporting date	(3,881)	(36)	(3,917)
December 31, 2010	$ 72,198	$ 1,062	$ 73,260

Contributions - During 2011, we made contributions of $62.6 million and $11.5 million to our defined benefit pension plans and postretirement benefit plans, respectively. The contributions to our defined benefit pension plan were attributable to the 2012 plan year. During the first quarter of 2012, we made a contribution of $60.0 million to our defined benefit pension plan; we do not anticipate that we will be required to make additional material defined benefit pension plan contributions attributable to the 2013 plan year in 2012. We anticipate our additional 2012 contributions will include $10.7 million for our postretirement benefit plans.

Pension and Postretirement Benefit Payments - Benefit payments for our pension and postretirement benefit plans for the period ending December 31, 2011, were $53.7 million and $17.9 million, respectively. The following table sets forth the pension benefits and postretirement benefit payments expected to be paid in 2012-2021:

	Pension Benefits	Postretirement Benefits
Benefits to be paid in:	(Thousands of dollars)	
2012	$ 62,378	$ 16,376
2013	$ 64,672	$ 17,023
2014	$ 66,383	$ 17,696
2015	$ 68,726	$ 18,006
2016	$ 70,722	$ 19,203
2017 through 2021	$ 391,808	$ 114,039

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligation at December 31, 2011, and include estimated future employee service.

Other Employee Benefit Plans

Thrift Plan - We have a Thrift Plan covering all full-time employees, and employee contributions are discretionary. We match 100 percent of employee contributions up to 6 percent of each participant's eligible compensation, subject to certain limits. Our contributions made to the plan were $15.9 million, $15.4 million and $14.7 million in 2011, 2010 and 2009, respectively.

Profit-Sharing Plan - We have a profit-sharing plan for all nonbargaining unit employees hired after December 31, 2004, and employees covered by the IBEW collective bargaining agreement hired after June 30, 2010. Nonbargaining unit employees who were employed prior to January 1, 2005, and employees covered by the IBEW collective bargaining agreement employed prior to July 1, 2010, were given a one-time opportunity to make an irrevocable election to participate in the profit-sharing plan and not accrue any additional benefits under our defined-benefit pension plan after December 31, 2004 and June 30, 2010, respectively. Employees covered by the United Steelworker collective bargaining agreement employed prior to December 16, 2011, were given a one-time opportunity to make an irrevocable election to participate in the profit-sharing plan. We plan to make a contribution to the profit-sharing plan each quarter equal to 1 percent of each participant's eligible compensation during the quarter. Additional discretionary employer contributions may be made at the end of each year. Employee contributions are not allowed under the plan. Our contributions made to the plan were $6.7 million, $4.7 million and $4.7 million in 2011, 2010 and 2009, respectively.

Employee Deferred Compensation Plan - The ONEOK, Inc. 2005 Nonqualified Deferred Compensation Plan provides select employees, as approved by our Board of Directors, with the option to defer portions of their compensation and provides nonqualified deferred compensation benefits that are not available due to limitations on employer and employee contributions to qualified defined contribution plans under the federal tax laws. Our contributions made to the plan were not material in 2011, 2010 and 2009.

N. INCOME TAXES

The following table sets forth our provisions for income taxes for the periods indicated:

	Years Ended December 31,			
	2011		2010	2009
Current income taxes			*(Thousands of dollars)*	
Federal	**$ (32,291)**		$ 58,844	$ 2,664
State	**1,707**		12,629	1,604
Total current income taxes from continuing operations	**(30,584)**	**(a)**	71,473	4,268
Deferred income taxes				
Federal	**228,257**		124,126	170,100
State	**28,375**		18,121	28,640
Total deferred income taxes from continuing operations	**256,632**	**(a)**	142,247	198,740
Total provision for income taxes from continuing operations	**226,048**		213,720	203,008
Discontinued operations	**1,255**		114	4,313
Total provision for income taxes	**$ 227,303**		$ 213,834	$ 207,321

(a) Includes a $37.7 million reclassification from current income taxes to deferred related to revisions of estimated depreciation in our filed tax returns compared with our 2010 tax provision.

The following table is a reconciliation of our income tax provision from continuing operations for the periods indicated:

	Years Ended December 31,		
	2011	2010	2009
		(Thousands of dollars)	
Income from continuing operations before income taxes	**$ 983,562**	$ 753,778	$ 686,665
Less: Net income attributable to noncontrolling interest	**399,150**	206,698	185,753
Income from continuing operations attributable to ONEOK before income taxes	**584,412**	547,080	500,912
Federal statutory income tax rate	**35%**	35%	35%
Provision for federal income taxes	**204,543**	191,478	175,319
State income taxes, net of federal tax benefit	**20,334**	19,946	19,625
Other, net	**1,171**	2,296	8,064
Income tax provision from continuing operations	**$ 226,048**	$ 213,720	$ 203,008

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	December 31, 2011	December 31, 2010
Deferred tax assets	*(Thousands of dollars)*	
Employee benefits and other accrued liabilities	**$ 136,997**	$ 89,480
Other comprehensive income	**134,037**	73,515
Other	**31,544**	25,694
Total deferred tax assets	**302,578**	188,689
Deferred tax liabilities		
Excess of tax over book depreciation and depletion	**664,415**	519,627
Investment in partnerships	**851,408**	729,682
Regulatory assets	**200,010**	157,756
Total deferred tax liabilities	**1,715,833**	1,407,065
Net deferred tax liabilities before discontinued operations	**1,413,255**	1,218,376
Discontinued operations	**82**	26
Net deferred tax liabilities	**$ 1,413,337**	$ 1,218,402

We had income taxes receivable of approximately $10.7 million and $45.7 million at December 31, 2011 and 2010, respectively.

O. UNCONSOLIDATED AFFILIATES

Northern Border Pipeline - The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon EBITDA less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement. The Northern Border Pipeline Management Committee has adopted a cash distribution policy related to financial ratio targets and capital contributions. The cash distribution policy defines minimum equity-to- total-capitalization ratios to be used by the Northern Border Pipeline Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions.

During 2011, ONEOK Partners made equity contributions to Northern Border Pipeline Company totaling approximately $54.8 million.

Overland Pass Pipeline Company - In September 2010, ONEOK Partners completed a transaction to sell a 49-percent ownership interest in Overland Pass Pipeline Company to a subsidiary of Williams Partners, resulting in each joint-venture member now owning 50 percent of Overland Pass Pipeline Company. In accordance with the joint-venture agreement, ONEOK Partners received approximately $423.7 million in cash at closing. As a result of the transaction, ONEOK Partners no longer controls Overland Pass Pipeline Company and began accounting for the investment under the equity method of accounting in September 2010. In connection with the deconsolidation of Overland Pass Pipeline Company, ONEOK Partners recognized approximately $16.3 million in gain on sale of assets, primarily attributable to the remeasurement of its retained investment in Overland Pass Pipeline Company to its fair value, and has recorded its retained investment of approximately $438 million in investments in unconsolidated affiliates. The estimate of the fair value of ONEOK Partners' retained interest in Overland Pass Pipeline Company was based upon the income and market valuation approaches.

The Overland Pass Pipeline Company limited liability company agreement provides that distributions to Overland Pass Pipeline Company's members are to be made on a pro rata basis according to each member's percentage interest. The Overland Pass Pipeline Company Management Committee determines the amount and timing of such distributions. Any changes to, or suspensions of, cash distributions from Overland Pass Pipeline Company requires the unanimous approval of the Overland Pass Pipeline Management Committee. Cash distributions are equal to 100 percent of available cash as defined in the limited liability company agreement.

Investments in Unconsolidated Affiliates - The following table sets forth our investments in unconsolidated affiliates for the periods indicated:

	Net Ownership Interest	December 31, 2011	December 31, 2010
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 416,206**	$ 384,011
Overland Pass Pipeline Company	50%	**447,449**	443,392
Fort Union Gas Gathering, L.L.C.	37%	**117,353**	115,148
Bighorn Gas Gathering, L.L.C.	49%	**91,748**	92,659
Other	Various	**150,642**	152,914
Investments in unconsolidated affiliates (a)		**$ 1,223,398**	$ 1,188,124

(a) - Equity method goodwill (Note A) was $185.6 million at December 31, 2011 and 2010.

Equity Earnings from Investments - The following table sets forth our equity earnings from investments for the periods indicated. All amounts in the table below are equity earnings from investments in our ONEOK Partners segment:

	Years Ended December 31, 2011	2010	2009
		(Thousands of dollars)	
Northern Border Pipeline	**$ 76,365**	$ 68,124	$ 41,300
Overland Pass Pipeline Company (a)	**19,535**	5,421	-
Fort Union Gas Gathering, L.L.C.	**15,280**	14,367	14,533
Bighorn Gas Gathering, L.L.C.	**5,990**	5,495	7,807
Other	**10,076**	8,473	9,082
Equity earnings from investments	**$ 127,246**	$ 101,880	$ 72,722

(a) - Beginning in September 2010, following the sale of a 49-percent interest, Overland Pass Pipeline Company was deconsolidated and prospectively accounted for under the equity method.

Unconsolidated Affiliates Financial Information - The following tables set forth summarized combined financial information of our unconsolidated affiliates for the periods indicated:

	December 31, 2011	December 31, 2010
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 133,579**	$ 93,698
Property, plant and equipment, net	**$ 2,451,798**	$ 2,500,708
Other noncurrent assets	**$ 35,548**	$ 28,222
Current liabilities	**$ 76,355**	$ 74,969
Long-term debt	**$ 534,485**	$ 616,210
Other noncurrent liabilities	**$ 15,510**	$ 13,773
Accumulated other comprehensive income (loss)	**$ (2,700)**	$ (2,883)
Owners' equity	**$ 1,997,275**	$ 1,920,559

	Years Ended December 31, 2011	2010	2009
		(Thousands of dollars)	
Income Statement (a)			
Operating revenues	**$ 496,158**	$ 440,826	$ 383,625
Operating expenses	**$ 221,261**	$ 189,437	$ 178,194
Net income	**$ 249,559**	$ 223,715	$ 164,002
Distributions paid to us	**$ 156,385**	$ 114,805	$ 109,807

(a) - Financial information for 2011 is not directly comparable with 2010 and 2009 due to the deconsolidation of Overland Pass Pipeline Company in September 2010.

P. ONEOK PARTNERS

Unit Split - In July 2011, ONEOK Partners completed a two-for-one split of its common and Class B units, and its Partnership Agreement was amended to adjust the formula for distributing available cash among its general partner and limited partners to reflect the unit split. As a result, all unit and per-unit amounts contained herein have been adjusted to be presented on a post-split basis.

Ownership Interest in ONEOK Partners - Our ownership interest in ONEOK Partners is shown in the table below as of December 31, 2011 and 2010:

General partner interest	**2.0%**
Limited partner interest (a)	**40.8%**
Total ownership interest	**42.8%**

(a) - Represents 11.8 million common units and approximately 73.0 million Class B units, which are convertible, at our option, into common units.

In February 2010, ONEOK Partners completed an underwritten public offering of 11,001,800 common units, including the partial exercise by the underwriters of their over-allotment option, at a public offering price of $30.38 per common unit, generating net proceeds of approximately $322.7 million. In conjunction with the offering, ONEOK Partners GP contributed $6.8 million in order to maintain its 2-percent general partner interest. ONEOK Partners used the proceeds from the sale of common units and the general partner contribution to repay borrowings under the ONEOK Partners Credit Agreement and for general partnership purposes.

We account for the difference between the carrying amount of our investment in ONEOK Partners and the underlying book value arising from issuance of common units by ONEOK Partners as an equity transaction. If ONEOK Partners issues common units at a price different than our carrying value per unit, we account for the premium or deficiency as an adjustment to paid-in capital. As a result of ONEOK Partners' issuance of common units at a premium to our carrying value per unit, we recognized an increase to paid-in capital of $50.7 million for the year ended December 31, 2010.

Cash Distributions - We receive distributions from ONEOK Partners on our common and Class B units and our 2-percent general partner interest, which includes our incentive distribution rights. Under ONEOK Partners' partnership agreement, as amended, distributions are made to the partners with respect to each calendar quarter in an amount equal to 100 percent of available cash as defined in ONEOK Partners' partnership agreement, as amended. Available cash generally will be distributed 98 percent to limited partners and 2 percent to the general partner. The general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met during the quarter. In July 2011, the partnership agreement was amended to adjust the formula for distributing available cash among the general partner and limited partners to reflect the two-for-one unit split. Under the incentive distribution provisions, as set forth in ONEOK Partners' partnership agreement, as amended, the general partner receives:

- 15 percent of amounts distributed in excess of $0.3025 per unit;
- 25 percent of amounts distributed in excess of $0.3575 per unit; and
- 50 percent of amounts distributed in excess of $0.4675 per unit.

The following table shows ONEOK Partners' distributions paid in the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
	(Thousands, except per unit amounts)		
Distribution per unit	**$ 2.325**	$ 2.230	$ 2.165
General partner distributions	**$ 12,189**	$ 11,264	$ 10,005
Incentive distributions	**123,386**	103,463	84,657
Distributions to general partner	**135,575**	114,727	94,662
Limited partner distributions to ONEOK	**197,133**	189,078	183,567
Limited partner distributions to noncontrolling interest	**276,738**	259,380	222,024
Total distributions paid	**$ 609,446**	$ 563,185	$ 500,253

The following table shows ONEOK Partners' distributions declared for the periods indicated and paid within 45 days of the end of the period:

	Years Ended December 31,		
	2011	2010	2009
	(Thousands, except per unit amounts)		
Distribution per unit	**$ 2.365**	$ 2.250	$ 2.175
General partner distributions	**$ 12,515**	$ 11,578	$ 10,228
Incentive distributions	**131,213**	108,711	87,734
Distributions to general partner	**143,728**	120,289	97,962
Limited partner distributions to ONEOK	**200,524**	190,774	184,415
Limited partner distributions to noncontrolling interest	**281,499**	267,811	229,030
Total distributions declared	**$ 625,751**	$ 578,874	$ 511,407

Relationship - We consolidate ONEOK Partners in our consolidated financial statements; however, we are restricted from the assets and cash flows of ONEOK Partners except for the distributions we receive. Distributions are declared quarterly by ONEOK Partners' general partner based on the terms of the ONEOK Partners partnership agreement. See Note R for more information on ONEOK Partners' results.

Affiliate Transactions - We have certain transactions with ONEOK Partners and its subsidiaries, which comprise our ONEOK Partners segment.

ONEOK Partners sells natural gas from its natural gas gathering and processing operations to our Energy Services segment. In addition, a portion of ONEOK Partners' revenues from its natural gas pipelines business is from our Energy Services and Natural Gas Distribution segments, which contract with ONEOK Partners for natural gas transportation and storage services. ONEOK Partners also purchases natural gas from our Energy Services segment for its natural gas liquids and its natural gas gathering and processing operations.

Previously, ONEOK Partners had a Processing and Services Agreement with us and OBPI, under which it contracted for all of OBPI's rights, including all of the capacity of the Bushton Plant, reimbursing OBPI for all costs associated with the operation and maintenance of the Bushton Plant and its obligations under equipment leases covering portions of the Bushton Plant. In April 2011, pursuant to its rights under the Processing and Services Agreement, ONEOK Partners directed OBPI to give notice of intent to exercise the purchase option for the leased equipment pursuant to the terms of the equipment leases. On June 30, 2011, through a series of transactions, we sold OBPI to ONEOK Partners and OBPI closed the purchase option and terminated the equipment leases. The total amount paid by ONEOK Partners to complete the transactions was approximately $94.2 million, which included the reimbursement to us of obligations related to the Processing and Services Agreement.

We provide a variety of services to our affiliates, including cash management and financial services, legal and administrative services by our employees and management, insurance and office space leased in our headquarters building and other field locations. Where costs are incurred specifically on behalf of an affiliate, the costs are billed directly to the affiliate by us. In other situations, the costs may be allocated to the affiliates through a variety of methods, depending upon the nature of the expenses and the activities of the affiliates. For example, a service that applies equally to all employees is allocated based upon the number of employees in each affiliate. However, an expense benefiting the consolidated company but having no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, operating income and payroll expense. It is not practicable to determine what these general overhead costs would be on a stand-alone basis.

The following table shows ONEOK Partners' transactions with us for the periods indicated:

	Years Ended December 31,		
	2011	2010	2009
	(Thousands of dollars)		
Revenues	**$ 403,603**	$ 457,740	$ 475,765
Expenses			
Cost of sales and fuel	**$ 48,163**	$ 53,107	$ 46,824
Administrative and general expenses	**251,239**	207,282	200,002
Total expenses	**$ 299,402**	$ 260,389	$ 246,826

Q. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under noncancelable equipment leases covering office space, pipeline equipment, rights of way and vehicles. Firm transportation and storage contracts are fixed-price contracts that provide us with firm transportation and storage capacity. Rental expense in 2011, 2010 and 2009 was not material. The following table sets forth our operating lease and firm transportation and storage contract payments for the periods indicated:

ONEOK	Operating Leases	Firm Transportation and Storage Contracts	Total
		(Millions of dollars)	
2012	$ 1.2	$ 122.4	$ 123.6
2013	0.9	87.5	88.4
2014	0.6	68.2	68.8
2015	0.3	42.9	43.2
2016	-	26.4	26.4
Thereafter	-	23.2	23.2
Total	$ 3.0	$ 370.6	$ 373.6

ONEOK Partners	Operating Leases	Firm Transportation and Storage Contracts	Total
		(Millions of dollars)	
2012	$ 3.4	$ 9.0	$ 12.4
2013	2.8	6.5	9.3
2014	2.8	6.2	9.0
2015	1.3	6.1	7.4
2016	1.0	4.7	5.7
Thereafter	6.4	5.7	12.1
Total	$ 17.7	$ 38.2	$ 55.9

Environmental Liabilities - We are subject to multiple historical and wildlife preservation laws and environmental regulations affecting many aspects of our present and future operations. Regulated activities include those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If a leak or spill of hazardous substances or petroleum products occurs from pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and cleanup costs, which could affect materially our results of operations and cash flows. In addition, emission controls required under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured natural gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE presently governs all work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater.

Of the 12 sites, we have begun soil remediation on 11 sites. Regulatory closure has been achieved at three locations, and we have completed or are near completion of soil remediation at eight sites. We have begun site assessment at the remaining site where no active remediation has occurred.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2011, 2010 or 2009.

In May 2010, the EPA finalized the "Tailoring Rule" that will regulate greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities will be required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011, and at current emission threshold levels, we believe it will have a minimal impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In addition, the EPA has issued a rule on air-quality standards, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, with a compliance date in 2013. The rule will require capital expenditures over the next two years for the purchase and installation of new emissions-control equipment. We do not expect these expenditures to have a material impact on our results of operations, financial position or cash flows.

On July 28, 2011, the EPA issued a proposed rule package that would change the air emission New Source Performance Standards and Maximum Achievable Control Technology requirements applicable to natural gas production, processing, transmission and underground storage. The proposed rules would impact emission limits for specific equipment through the use of controls; however, potential costs associated with the proposed rules are currently unknown.

Pipeline Safety - We are subject to Pipeline and Hazardous Materials Safety Administration regulations, including integrity-management regulations. The Pipeline Safety Improvement Act of 2002 requires pipeline companies operating high-pressure pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. The new law increased the maximum penalties for violating federal pipeline safety regulations and directs the Department of Transportation and Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include but are not limited to:

- an evaluation of whether natural gas liquid and natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a review of all natural gas and hazardous natural gas liquid gathering pipeline exemptions;
- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test pipelines previously untested in high-consequence areas operating above 30 percent yield strength.

The potential capital and operating expenditures related to this legislation, the associated regulations or other new pipeline safety regulations are unknown.

Financial Markets Legislation - The Dodd-Frank Act represents a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the CFTC has issued final regulations for certain provisions of the Dodd-Frank Act, many remain outstanding. In November 2011, the CFTC published final rules on speculative position limits, which we do not expect to impact directly our current risk-management practices. In December 2011, the CFTC issued an order that further defers the effective date of the provisions of the Dodd-Frank Act that require a rulemaking, such as definitions of certain terms, until the earlier of the effective date of the final rule defining the reference terms or July 16, 2012. Until the remaining final regulations are established, we are unable to ascertain how we may be affected by them. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We also may incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations; however, we do not believe the costs will be material. These requirements could affect adversely market liquidity and pricing of derivative contracts making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, and we are unable to estimate reasonably possible losses, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

R. SEGMENTS

Segment Descriptions - Our operations are divided into three reportable business segments as follows: (i) our ONEOK Partners segment reflects the consolidated operations of ONEOK Partners. We own a 42.8-percent ownership interest and control ONEOK Partners through our ownership of its general partner interest. ONEOK Partners gathers, processes, treats, transports, stores and sells natural gas and gathers, treats, fractionates, stores, distributes and markets NGLs. We and ONEOK Partners maintain significant financial and corporate governance separations. We seek to receive increasing cash distributions as a result of our investment in ONEOK Partners, and our investment decisions are made based on the anticipated returns from ONEOK Partners in total, not specific to any of its businesses individually; (ii) our Natural Gas Distribution segment is comprised of our regulated public utilities that deliver natural gas to residential, commercial and industrial customers, and transport natural gas; and (iii) our Energy Services segment markets natural gas to wholesale customers. Other and eliminations consist of the operating and leasing operations of our headquarters building and related parking facility and other amounts needed to reconcile our reportable segments to our consolidated financial statements.

Accounting Policies - The accounting policies of the segments are the same as those described in Note A. Intersegment sales are recorded on the same basis as sales to unaffiliated customers and are discussed in further detail in Note P. Net margin is comprised of total revenues less cost of sales and fuel. Cost of sales and fuel includes commodity purchases, fuel, and storage and transportation costs.

Customers - In 2011, 2010 and 2009, we had no single external customer from which we received 10 percent or more of our consolidated gross revenues.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated:

Year Ended December 31, 2011	ONEOK Partners (a)	Natural Gas Distribution	Energy Services	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 10,919,004	$ 1,609,628	$ 2,274,799	$ 2,363	$ 14,805,794
Intersegment revenues	403,603	11,706	502,418	(917,727)	-
Total revenues	$ 11,322,607	$ 1,621,334	$ 2,777,217	$ (915,364)	$ 14,805,794
Net margin	$ 1,577,380	$ 751,835	$ 48,740	$ 2,404	$ 2,380,359
Operating costs	459,364	422,073	24,527	2,359	908,323
Depreciation and amortization	177,549	132,212	445	1,954	312,160
Gain (loss) on sale of assets	(963)	-	-	-	(963)
Operating income	$ 939,504	$ 197,550	$ 23,768	$ (1,909)	$ 1,158,913
Equity earnings from investments	$ 127,246	$ -	$ -	$ -	$ 127,246
Investments in unconsolidated affiliates	$ 1,223,398	$ -	$ -	$ -	$ 1,223,398
Total assets	$ 8,946,676	$ 3,392,475	$ 562,728	$ 794,756	$ 13,696,635
Noncontrolling interests in consolidated subsidiaries	$ 5,112	$ -	$ -	$ 1,556,047	$ 1,561,159
Capital expenditures	$ 1,063,383	$ 242,590	$ 41	$ 30,053	$ 1,336,067

(a) - Our ONEOK Partners segment has regulated and nonregulated operations. Our ONEOK Partners segment's regulated operations had revenues of $658.5 million, net margin of $469.0 million and operating income of $232.8 million.

Year Ended December 31, 2010	ONEOK Partners (a)	Natural Gas Distribution	Energy Services	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 8,218,160	$ 1,810,502	$ 2,647,460	$ 2,669	$ 12,678,791
Intersegment revenues	457,740	6,900	653,717	(1,118,357)	-
Total revenues	$ 8,675,900	$ 1,817,402	$ 3,301,177	$ (1,115,688)	$ 12,678,791
Net margin	$ 1,144,853	$ 754,917	$ 159,739	$ 2,661	$ 2,062,170
Operating costs	403,476	398,861	28,384	192	830,913
Depreciation and amortization	173,708	130,968	694	1,854	307,224
Gain (loss) on sale of assets	18,632	(13)	-	-	18,619
Operating income	$ 586,301	$ 225,075	$ 130,661	$ 615	$ 942,652
Equity earnings from investments	$ 101,880	$ -	$ -	$ -	$ 101,880
Investments in unconsolidated affiliates	$ 1,188,124	$ -	$ -	$ -	$ 1,188,124
Total assets	$ 7,920,100	$ 3,237,890	$ 651,960	$ 689,225	$ 12,499,175
Noncontrolling interests in consolidated subsidiaries	$ 5,176	$ -	$ -	$ 1,467,042	$ 1,472,218
Capital expenditures	$ 352,714	$ 215,608	$ 488	$ 13,938	$ 582,748

(a) - Our ONEOK Partners segment has regulated and non-regulated operations. Our ONEOK Partners segment's regulated operations had revenues of $612.2 million, net margin of $479.1 million and operating income of $250.9 million.

Year Ended December 31, 2009	ONEOK Partners (a)	Natural Gas Distribution	Energy Services	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 5,998,726	$ 1,832,146	$ 2,971,902	$ 2,979	$ 10,805,753
Intersegment revenues	475,765	6,745	581,740	(1,064,250)	-
Total revenues	$ 6,474,491	$ 1,838,891	$ 3,553,642	$ (1,061,271)	$ 10,805,753
Net margin	$ 1,119,297	$ 716,028	$ 159,647	$ 2,979	$ 1,997,951
Operating costs	411,227	384,126	35,542	65	830,960
Depreciation and amortization	164,136	122,594	540	1,653	288,923
Gain (loss) on sale of assets	2,668	486	-	1,652	4,806
Operating income	$ 546,602	$ 209,794	$ 123,565	$ 2,913	$ 882,874
Equity earnings from investments	$ 72,722	$ -	$ -	$ -	$ 72,722
Investments in unconsolidated affiliates	$ 765,163	$ -	$ -	$ -	$ 765,163
Total assets	$ 7,953,259	$ 3,120,704	$ 930,086	$ 823,634	$ 12,827,683
Noncontrolling interests in consolidated subsidiaries	$ 5,603	$ -	$ -	$ 1,232,665	$ 1,238,268
Capital expenditures	$ 615,691	$ 157,508	$ 105	$ 17,941	$ 791,245

(a) - Our ONEOK Partners segment has regulated and non-regulated operations. Our ONEOK Partners segment's regulated operations had revenues of $555.9 million, net margin of $451.0 million and operating income of $200.3 million.

S. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2011	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars except per share amounts)			
Total revenues (a)	**$ 3,760,600**	**$ 3,444,798**	**$ 3,529,359**	**$ 4,071,037**
Net margin (a)	**$ 629,877**	**$ 518,833**	**$ 532,624**	**$ 699,025**
Income from continuing operations (a)	**$ 198,285**	**$ 134,330**	**$ 161,158**	**$ 263,741**
Income (loss) from operations of discontinued operations, net of tax (a)	**$ 1,061**	**$ 437**	**$ (278)**	**$ 1,010**
Net income	**$ 199,346**	**$ 134,767**	**$ 160,880**	**$ 264,751**
Net income attributable to ONEOK	**$ 130,130**	**$ 55,142**	**$ 60,321**	**$ 115,001**
Earnings per share total				
Basic	**$ 1.22**	**$ 0.52**	**$ 0.58**	**$ 1.12**
Diluted	**$ 1.19**	**$ 0.51**	**$ 0.57**	**$ 1.09**

Year Ended December 31, 2010	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars except per share amounts)			
Total revenues (a)	$ 3,780,203	$ 2,740,689	$ 2,877,849	$ 3,280,050
Net margin (a)	$ 615,099	$ 455,558	$ 449,504	$ 542,009
Income from continuing operations (a)	$ 185,232	$ 86,146	$ 120,005	$ 148,675
Income (loss) from operations of discontinued operations, net of tax (a)	$ 1,488	$ 228	$ 296	$ (740)
Net income	$ 186,720	$ 86,374	$ 120,301	$ 147,935
Net income attributable to ONEOK	$ 154,539	$ 41,724	$ 55,295	$ 83,074
Earnings per share total				
Basic	$ 1.46	$ 0.39	$ 0.52	$ 0.78
Diluted	$ 1.44	$ 0.39	$ 0.51	$ 0.76

(a) These amounts vary from the amounts previously filed due to the sale of ONEOK Energy Marketing Company in February 2012. See Note B for additional information on our discontinued operations.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

Our internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein (Item 8).

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended December 31, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of the Registrant

Information concerning our directors is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Executive Officers of the Registrant

Information concerning our executive officers is included in Part I, Item 1, Business, of this Annual Report.

Compliance with Section 16(a) of the Exchange Act

Information on compliance with Section 16(a) of the Exchange Act is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Code of Ethics

Information concerning the code of ethics, or code of business conduct, is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Committee Procedures

Information concerning the Nominating Committee procedures is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Audit Committee

Information concerning the Audit Committee is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Audit Committee Financial Experts

Information concerning the Audit Committee Financial Experts is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners

Information concerning the ownership of certain beneficial owners is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Security Ownership of Management

Information on security ownership of directors and officers is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

Equity Compensation Plan Information

The following table sets forth certain information concerning our equity compensation plans as of December 31, 2011:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities in Column (a)) (c)
Equity compensation plans approved by security holders (1)	2,487,877	$44.24	3,393,142
Equity compensation plans not approved by security holders (2)	233,502	$83.14 (3)	503,602
Total	2,721,379	$47.57	3,896,744

(1) - Includes shares granted under our Employee Stock Purchase Plan, and Employee Stock Award Program, and stock options, restricted stock incentive units and performance unit awards granted under our Long-Term Incentive Plan and Equity Compensation Plan. For a brief description of the material features of these plans, see Note K of the Notes to Consolidated Financial Statements in this Annual Report. Column (c) includes 389,237, 2,978, 840,691 and 2,160,236 shares available for future issuance under our Employee Stock Purchase Plan, Employee Stock Award Program, Long-Term Incentive Plan and Equity Compensation Plan, respectively.

(2) - Includes our Employee Non-Qualified Deferred Compensation Plan, Deferred Compensation Plan for Non-Employee Directors and Stock Compensation Plan for Non-Employee Directors. For a brief description of the material features of these plans, see Note L of the Notes to Consolidated Financial Statements in this Annual Report.

(3) - Compensation deferred into our common stock under our Employee Non-Qualified Deferred Compensation Plan and Deferred Compensation Plan for Non-Employee Directors is distributed to participants at fair market value on the date of distribution. The price used for these plans to calculate the weighted-average exercise price in the table is $86.09, which represents the year-end closing price of our common stock on the NYSE.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions and director independence is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information concerning the principal accountant’s fees and services is set forth in our 2012 definitive Proxy Statement and is incorporated herein by this reference.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(2) Financial Statement Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

3	Not used.
3.1	Not used.
3.2	Not used.
3.3	Not used.
3.4	Amended and Restated Bylaws of ONEOK, Inc. (incorporated by reference from Exhibit 99.1 to Form 8-K filed January 20, 2009).
3.5	Amended and Restated Certificate of Incorporation of ONEOK, Inc. dated May 15, 2008 (incorporated by reference from Exhibit 3.1 to Form 8-K filed May 19, 2008).
3.6	Certificate of Correction form dated November 5, 2008 (incorporated by reference from Exhibit 4.2 to Registration Statement on Form S-3 filed November 21, 2008).
4	Certificate of Designation for Convertible Preferred Stock of WAI, Inc. (now ONEOK, Inc.) filed November 21, 2008 (incorporated by reference from Exhibit 4.2 to Registration Statement on Form S-3 filed November 21, 2008, Commission File No. 333-155593).
4.1	Certificate of Designation for Series C Participating Preferred Stock of ONEOK, Inc. filed November 21, 2008 (incorporated by reference from Exhibit No. 4.2 to Registration Statement on Form S-3 filed November 21, 2008).
4.2	Form of Common Stock Certificate (incorporated by reference from Exhibit 1 to Registration Statement on Form 8-A filed November 21, 1997).

4.3	Indenture, dated September 24, 1998, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4.1 to Registration Statement on Form S-3 filed August 26, 1998, Commission File No. 333-62279).
4.4	Indenture dated December 28, 2001, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.1 to Amendment No. 1 to Registration Statement on Form S-3 filed December 28, 2001, Commission File No. 333-65392).
4.5	First Supplemental Indenture dated September 24, 1998, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 5(a) to Form 8-K/A filed October 2, 1998).
4.6	Second Supplemental Indenture dated September 25, 1998, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 5(b) to Form 8-K/A filed October 2, 1998).
4.7	Second Amended and Restated Rights Agreement, dated as of March 31, 2011, between ONEOK, Inc. and Wells Fargo Bank, N.A. as Rights Agent (incorporated by reference from Exhibit 4.1 to the Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011).
4.8	Fourth Supplemental Indenture dated February 17, 1999, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4.5 to Registration Statement on Form S-3 filed April 15, 1999, Commission File No. 333-76375).
4.9	Not used.
4.10	Not used.
4.11	Not used.
4.12	Eighth Supplemental Indenture dated April 6, 2001, between ONEOK, Inc. and The Chase Manhattan Bank (incorporated by reference from Exhibit 4.9 to Registration Statement on Form S-3 filed July 19, 2001, Commission File No. 333-65392).
4.13	Not used.
4.14	Second Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.1 to Form 8-K filed June 17, 2005).
4.15	Third Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.3 to Form 8-K filed June 17, 2005).
4.16	Not used.
4.17	Not used.
4.18	Indenture, dated as of March 21, 2001, between Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.3 to Northern Border Partners, L.P.'s Form 10-K for the year ended December 31, 2001, filed on March 29, 2002 (File No. 1-12202)).
4.19	Indenture, dated as of September 25, 2006, between ONEOK Partners, L.P. and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.20	First Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 5.90 percent Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).

4.21	Second Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.15 percent Senior Notes due 2016 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.22	Third Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.65 percent Senior Notes due 2036 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.23	Fourth Supplemental Indenture, dated as of September 28, 2007, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.85 percent Senior Notes due 2037 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 28, 2007 (File No. 1-12202)).
4.24	Fifth Supplemental Indenture, dated as of March 3, 2009, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 8.625 percent Senior Notes due 2019 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed by ONEOK Partners, L.P. on March 3, 2009 (File No. 1-12202)).
4.25	Not used.
4.26	Form of Class B unit certificate of ONEOK Partners, L.P. (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Form 8-K filed on April 12, 2006 (File No. 1-12202)).
4.27	Sixth Supplemental Indenture, dated January 26, 2011, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.250 percent Senior Notes due 2016 (incorporated by reference from Exhibit 4.2 to Form 8-K for the filed January 26, 2011 (File No. 1-12202)).
4.28	Seventh Supplemental Indenture, dated January 26, 2011, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.125 percent Senior Notes due 2041 (incorporated by reference from Exhibit 4.3 to Form 8-K for the filed January 26, 2011 (File No. 1-12202)).
4.29	Indenture, dated as of January 26, 2012, among ONEOK, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 26, 2012).
4.30	First Supplemental Indenture, dated January 26, 2012, among ONEOK, Inc. and U.S. Bank National Association, as trustee, with respect to the 4.25 percent Senior Notes due 2022 (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 26, 2012).
10	ONEOK, Inc. Long-Term Incentive Plan (incorporated by reference from Exhibit 10(a) to Form 10-K for the fiscal year ended December 31, 2001, filed March 14, 2002).
10.1	ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (incorporated by reference from Exhibit 99 to Form S-8 filed January 25, 2001).
10.2	ONEOK, Inc. Supplemental Executive Retirement Plan terminated and frozen December 31, 2004 (incorporated by reference from Exhibit 10.1 to Form 8-K filed on December 20, 2004).
10.3	ONEOK, Inc. 2005 Supplemental Executive Retirement Plan, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.3 to Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009).
10.4	Not used.

10.5	Form of Indemnification Agreement between ONEOK, Inc. and ONEOK, Inc. officers and directors, as amended, dated January 1, 2003 (incorporated by reference from Exhibit 10.4 to Form 10-K for the fiscal year ended December 31, 2002, filed March 10, 2003).
10.6	Amended and Restated ONEOK, Inc. Annual Officer Incentive Plan (incorporated by reference from Exhibit 10.1 to Form 8-K filed May 27, 2009).
10.7	ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, as amended and restated December 16, 2004 (incorporated by reference from Exhibit 10.3 to Form 8-K filed December 20, 2004).
10.8	ONEOK, Inc. 2005 Nonqualified Deferred Compensation Plan, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.8 to Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009).
10.9	ONEOK, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.9 to Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009).
10.10	Not used.
10.11	Not used.
10.12	Credit Agreement, dated as of April 5, 2011, among ONEOK, Inc., as borrower, the lenders party thereto, Bank of America, N.A., as administrative agent, swing line lender, and a letter of credit issuer, and JPMorgan Chase Bank, N.A. and The Royal Bank of Scotland plc, as letter of credit issuers (incorporated by reference from Exhibit 10.1 to ONEOK Inc.'s Current Report on Form 8-K filed on April 7, 2011 (File No. 001-13643)).
10.13	Amended and Restated Limited Liability Company Agreement of Overland Pass Pipeline Company LLC entered into between ONEOK Overland Pass Holdings, L.L.C. and Williams Field Services Company, LLC dated May 31, 2006 (incorporated by reference to Exhibit 10.6 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).
10.14	Form of ONEOK, Inc. Officer Change in Control Severance Plan (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed July 22, 2011 (File No. 001-13643)).
10.15	Not used.
10.16	Not used.
10.17	Not used.
10.18	Not used.
10.19	Form of Restricted Unit Stock Bonus Award Agreement dated February 15, 2012.
10.20	Form of Performance Unit Award Agreement dated February 15, 2012.
10.21	Not used.
10.22	Commercial Paper Dealer Agreement between ONEOK Partners, L.P. and Citigroup Global Markets Inc. dated as of June 16, 2010 (incorporated by reference to Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed on June 22, 2010).
10.23	Commercial Paper Dealer Agreement between ONEOK Partners, L.P. and Banc of America Securities LLC dated as of June 16, 2010 (incorporated by reference to Exhibit 10.2 to ONEOK, Inc.'s Current Report on Form 8-K filed on June 22, 2010).

10.24	Commercial Paper Dealer Agreement between ONEOK Partners, L.P. and SunTrust Robinson Humphrey, Inc. dated as of June 16, 2010 (incorporated by reference to Exhibit 10.3 to ONEOK, Inc.'s Current Report on Form 8-K filed on June 22, 2010).
10.25	Purchase Agreement dated May 17, 2011, by and between ONEOK, Inc., and Barclays Bank PLC acting through Barclays Capital Inc. as agent (incorporated by reference to Exhibit 10.2 to ONEOK, Inc.'s Quarterly Report on Form 10-Q filed on August 3, 2011 (File No. 001-13643)).
10.26	Credit Agreement, dated as of August 1, 2011, among ONEOK Partners, L.P., as borrower, the lenders party thereto, Citibank, N.A., as administrative agent, swing line lender and a letter-of-credit issuer, and Barclays Bank and Wells Fargo Bank, N.A., as letter-of-credit issuers (incorporated by reference from Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed August 2, 2011 (File No. 001-12202)).
10.27	Guaranty Agreement, dated as of August 1, 2011, by ONEOK Partners Intermediate Limited Partnership in favor of the Citibank, N.A., as administrative agent, under the above-referenced Credit Agreement (incorporated by reference from Exhibit 10.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed August 2, 2011 (File No. 001-12202)).
10.28	Underwriting Agreement dated January 23, 2012, among ONEOK, Inc. and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 26, 2012).
10.29	Underwriting Agreement dated January 21, 2011, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership and Citigroup Global Markets Inc., RBS Securities Inc. and UBS Securities LLC, therein (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed by ONEOK Partners, L.P. on January 26, 2011 (File No. 001-12202)).
10.30	Not used.
10.31	Not used.
10.32	Services Agreement among ONEOK, Inc., Northern Plains Natural Gas Company, LLC, NBP Services, LLC, Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership executed April 6, 2006, but effective as of April 1, 2006 (incorporated by reference from Exhibit 10.1 to our Form 8-K filed April 12, 2006).
10.33	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated as of September 15, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).
10.34	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on February 17, 2012 (File No. 1-12202)).
10.35	Not used.
10.36	Not used.
10.37	ONEOK, Inc. Profit Sharing Plan dated January 1, 2005 (incorporated by reference from Exhibit 99 to Registration Statement on Form S-8 filed December 30, 2004).
10.38	ONEOK, Inc. Employee Stock Purchase Plan as amended and restated effective as of December 20, 2007 (incorporated by reference from Exhibit 4.2 to Registration Statement on Form S-8 filed August 4, 2008).

10.39	Form of Non-Statutory Stock Option Agreement (incorporated by reference from Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2004, filed November 3, 2004).
10.40	Not used.
10.41	Not used.
10.42	Not used.
10.43	Not used.
10.44	ONEOK, Inc. Equity Compensation Plan, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.44 to Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009).
10.45	Form of Restricted Unit Award Agreement (incorporated by reference from Exhibit 10.45 to Form 10-K filed February 28, 2007).
10.46	Form of Performance Unit Award Agreement (incorporated by reference from Exhibit 10.46 to Form 10-K filed February 28, 2007).
10.47	Not used.
10.48	Not used.
10.49	Not used.
10.50	Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries as amended and restated effective as of January 1, 2008 (incorporated by reference from Exhibit 4.3 to Registration Statement on Form S-8 filed August 4, 2008).
10.51	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 20, 2007 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 10-Q filed on August 3, 2007 (File No. 001-12202)).
10.52	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 12, 2011 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on July 12, 2011 (File No. 001-12202)).
10.53	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Form 8-K filed on February 17, 2012 (File No. 1-12202)).
10.54	Form of Performance Unit Award Agreement dated January 15, 2009 (incorporated by reference from Exhibit 10.54 to Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009).
10.55	Form of Restricted Unit Stock Bonus Award Agreement dated January 15, 2009 (incorporated by reference from Exhibit 10.55 to Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009).
10.56	First Amended and Restated Limited Liability Company Agreement of ONEOK ILP GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.2 to ONEOK Partners, L.P.'s report on Form 8-K filed on July 17, 2009).
10.57	Form of Restricted Unit Stock Bonus Award Agreement dated February 18, 2010 (incorporated by reference from Exhibit 10.57 to Form 10-K/A for the fiscal year ended December 31, 2009, filed October 12, 2010).

10.58	Form of Performance Unit Award Agreement dated February 18, 2010 (incorporated by reference from Exhibit 10.58 to Form 10-K/A for the fiscal year ended December 31, 2009, filed October 12, 2010).
10.59	Form of Restricted Unit Stock Bonus Award Agreement (incorporated by reference from Exhibit 10.59 to Form 10-K for the fiscal year ended December 31, 2010, filed February 22, 2011).
10.60	Form of Performance Unit Award Agreement (incorporated by reference from Exhibit 10.60 to Form 10-K for the fiscal year ended December 31, 2010, filed February 22, 2011).
12	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2011, 2010, 2009, 2008 and 2007.
16	Not used.
21	Required information concerning the registrant's subsidiaries.
23	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
23.1	Not used.
31.1	Certification of John W. Gibson pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Robert F. Martinovich pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of John W. Gibson pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Robert F. Martinovich pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definitions Document
101.LAB	XBRL Taxonomy Label Linkbase Document
101.PRE	XBRL Taxonomy Presentation Linkbase Document

Attached as Exhibit 101 to this Annual Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009; (iii) Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010 and 2009; (iv) Consolidated Balance Sheets at December 31, 2011 and 2010; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; (vi) Consolidated Statements of Shareholders' Equity for the years ended December 31, 2011, 2010 and 2009; and (vii) Notes to Consolidated Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ONEOK, Inc.
Registrant

Date: February 21, 2012

By: /s/ Robert F. Martinovich
Robert F. Martinovich
Executive Vice President,
Chief Financial Officer and Treasurer

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 21st day of February 2012.

/s/ John W. Gibson John W. Gibson Chairman and Chief Executive Officer	/s/ Robert F. Martinovich Robert F. Martinovich Executive Vice President, Chief Financial Officer and Treasurer
/s/ Derek S. Reiners Derek S. Reiners Senior Vice President and Chief Accounting Officer	/s/ James C. Day James C. Day Director
/s/ Julie H. Edwards Julie H. Edwards Director	/s/ William L. Ford William L. Ford Director
Bert H. Mackie Director	/s/ Steven J. Malcolm Steven J. Malcolm Director
/s/ Jim W. Mogg Jim W. Mogg Director	/s/ Pattye L. Moore Pattye L. Moore Director
/s/ Gary D. Parker Gary D. Parker Director	/s/ Eduardo A. Rodriguez Eduardo A. Rodriguez Director
/s/ Gerald B. Smith Gerald B. Smith Director	/s/ David J. Tippeconnic David J. Tippeconnic Director

GLOSSARY

Hedge, Hedging: The use of derivative commodity and interest-rate instruments to reduce financial exposure to commodity-price and interest-rate volatility.

Master Limited Partnership (MLP): A limited partnership business that is publicly traded on an exchange, such as the New York Stock Exchange. MLPs have one or more general partners who manage the business and assume its legal debts and obligations.

Natural Gas Liquids (NGL): Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, ethane/propane mix, propane, iso-butane, butane and natural gasoline.

Partnership Units: The ownership interests owned by partners – the investors – in a partnership; similar to owning shares of stock in a corporation.

Risk: Exposure to commodity-price, interest-rate and throughput volatility, as well as disruptions in the operations of the company's assets.

Units of Measure:
Mcf = Thousand cubic feet
Bbls = Barrels (42 U.S. gallons)
MMcf = Million cubic feet
MBbls = Thousand barrels
Bcf = Billion cubic feet
MGal = Thousand gallons
MMBtu = Million British thermal units
BBtu = Billion British thermal units
bpd = Barrels per day

CORPORATE INFORMATION

ONEOK is a diversified energy company.

ONEOK is listed on the New York Stock Exchange under the symbol OKE.

A ONEOK subsidiary is sole general partner of ONEOK Partners, L.P.

The company was founded in 1906 as an intrastate natural gas pipeline business in Oklahoma.

Its businesses consist of its interest in ONEOK Partners, which is engaged in the midstream natural gas and natural gas liquids business; its natural gas distribution business that serves more than 2 million customers in Oklahoma, Kansas and Texas; and its energy services business that markets natural gas and related services.

Annual Meeting
The 2012 annual meeting of shareholders will be held Wednesday, May 23, 2012, at 9 a.m. Central Daylight Time at ONEOK Plaza, 100 West Fifth Street, Tulsa, Oklahoma.

Auditors
PricewaterhouseCoopers LLP
Two Warren Place
6120 South Yale Avenue, Suite 1850
Tulsa, OK 74136

Direct Stock Purchase and Dividend Reinvestment Plan
The company's Direct Stock Purchase and Dividend Reinvestment Plan provides investors the opportunity to purchase shares of common stock without payment of any brokerage fees or service charges and to reinvest dividends automatically.

Transfer Agent, Registrar and Dividend Paying Agent
Wells Fargo Shareowner Services
P.O. Box 64854
St. Paul, MN 65164-0854
Phone toll free: 866-235-0232
Website: www.shareowneronline.com

Credit Rating

Standard & Poor's	BBB
Moody's Investors Service	Baa2

Master Limited Partnership Units
Common units for ONEOK Partners, L.P. trade on the New York Stock Exchange under the symbol OKS.

Investor Relations
Dan Harrison, vice president – investor relations and public affairs, by phone at 918-588-7950 or by email at dan.harrison@oneok.com.

Andrew Ziola, manager – investor relations, by phone at 918-588-7163 or by email at andrew.ziola@oneok.com.

Corporate Website
ONEOK business and financial information is available at www.oneok.com.

NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) FINANCIAL MEASURES

We have disclosed in this annual report earnings before interest, taxes, depreciation and amortization (EBITDA) and distributable cash flow (DCF) amounts of ONEOK Partners that are non-GAAP financial measures. EBITDA and DCF are used as measures of the financial performance of ONEOK Partners. EBITDA is defined as ONEOK Partners' net income adjusted for interest expense, depreciation and amortization, income taxes and allowance for equity funds used during construction attributable to ONEOK Partners. DCF is defined as EBITDA, computed as described above, less interest expense, maintenance capital expenditures and equity earnings from investments attributable to ONEOK Partners, adjusted for distributions received and certain other items attributable to ONEOK Partners. We believe the non-GAAP financial measures described above are useful to investors because these measurements are used by many companies in its industry as a measurement of financial performance of ONEOK Partners and are commonly employed by financial analysts and others to evaluate the financial performance of the partnership and to compare the financial performance of the partnership with the performance of other publicly traded partnerships within its industry. ONEOK Partners' EBITDA and DCF should not be considered alternatives to net income, earnings per unit or any other measure of financial performance presented in accordance with GAAP. These non-GAAP financial measures exclude some, but not all, items that affect net income. Additionally, these calculations may not be comparable with similarly titled measures of other companies. Furthermore, these non-GAAP measures should not be viewed as indicative of the actual amount of cash that is available for distributions or that is planned to be distributed for a given period nor do they equate to available cash as defined in ONEOK Partners' partnership agreement.

FORWARD-LOOKING STATEMENT

The statements in this annual report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation and "Forward-Looking Statements" in the ONEOK, Inc. Annual Report on Form 10-K for the year ended December 31, 2011, included in this annual report.

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From responsible sources
FSC® C103375
www.fsc.org

ONEOK

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Tulsa, OK 74103-4298

Post Office Box 871
Tulsa, OK 74102-0871

www.oneok.com

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FINANCIAL STATEMENTS ARE PROVIDED IN SECTION 13

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.
Summary of Revenue by General Customer Classification
Test Year Ended December 31, 2011

Line No.	Description	Pro Forma Revenue Existing Tariffs	Revenue Increase	Pro Forma Revenue Proposed Tariffs
	Col. 1	Col. 2	Col. 3	Col. 4
	Operating Revenues			
	Sales service revenue			
1	Residential sales service	$176,749,315	$50,707,853	$227,457,168
2	General sales service	36,101,473	0	36,101,473
3	Small generator sales service	345,629	0	345,629
4	Gas irrigation service	391,940	0	391,940
5	Kansas Gas Supply sales service D	46,852	0	46,852
6	Sales service for resale	25,980	0	25,980
7	Total sales revenue	$213,661,189	$50,707,853	$264,369,042
	Transportation service revenue			
8	Small transportation service	$2,337,926	$0	$2,337,926
9	General transportation service	10,271,501	0	10,271,501
10	Compressed natural gas transportation service	10,047	0	10,047
11	Gas irrigation transportation service	1,887,239	0	1,887,239
12	Large volume transportation service	15,987,787	0	15,987,787
13	Wholesale transportation service	1,394,971	0	1,394,971
14	Total transportation revenue	$31,889,471	$0	$31,889,471
15	Other operating revenue	$13,245,906	$0	13,245,906
16	Total operating revenues	$258,796,566	$50,707,853	$309,504,419
17	Proposed target revenue			309,504,417
18	Rate design difference			$2

Line No.	Description	Reference	Residential Sales Service Tariff Schedule - RS: Sales	Residential Sales Service Tariff Schedule - RS: Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	576,318	0
2	Pro forma adjustments		(477)	0
3	Pro forma average number of customers		575,841	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	44,398,690	0
5	Pro forma adjustments		(1,033,492)	0
6	Pro forma deliveries (Mcf)		43,365,197	0
	Revenue			
7	Base revenue		$183,255,186	$0
8	Cost of Gas		249,527,507	0
9	Total revenue per books	8-F	$432,782,693	$0
10	Pro forma revenue adjustments		(256,033,378)	0
11	Pro forma revenue		$176,749,315	$0
12	Revenue per unit (line 11 / line 6)		$4.0758	$0.0000

Line No.	Description	Reference	General Sales Service Tariff Schedule - GS: Sales	General Sales Service Tariff Schedule - GS: Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	49,486	0
2	Pro forma adjustments		(120)	0
3	Pro forma average number of customers		49,366	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	11,562,065	0
5	Pro forma adjustments		(291,107)	0
6	Pro forma deliveries (Mcf)		11,270,958	0
	Revenue			
7	Base revenue		$37,530,495	$0
8	Cost of Gas		64,945,174	0
9	Total revenue per books	8-F	$102,475,669	$0
10	Pro forma revenue adjustments		(66,374,196)	0
11	Pro forma revenue		$36,101,473	$0
12	Revenue per unit (line 11 / line 6)		$3.2031	$0.0000

Line No.	Description	Reference	Small Generator Sales Service Tariff Schedule - SGS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	553	0
2	Pro forma adjustments		14	0
3	Pro forma average number of customers		567	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	5,661	0
5	Pro forma adjustments		53	0
6	Pro forma deliveries (Mcf)		5,715	0
	Revenue			
7	Base revenue		$348,387	$0
8	Cost of Gas		31,847	0
9	Total revenue per books	8-F	$380,235	$0
10	Pro forma revenue adjustments		(34,606)	0
11	Pro forma revenue		$345,629	$0
12	Revenue per unit (line 11 / line 6)		$60.4775	$0.0000

Line No.	Description	Reference	Gas Irrigation Service Tariff Schedule - GIS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	231	0
2	Pro forma adjustments		(4)	0
3	Pro forma average number of customers		228	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	228,224	0
5	Pro forma adjustments		(3,478)	0
6	Pro forma deliveries (Mcf)		224,746	0
	Revenue			
7	Base revenue		$418,592	$0
8	Cost of Gas		1,367,550	0
9	Total revenue per books	8-F	$1,786,142	$0
10	Pro forma revenue adjustments		(1,394,203)	0
11	Pro forma revenue		$391,940	$0
12	Revenue per unit (line 11 / line 6)		$1.7439	$0.0000

Line No.	Description	Reference	Kansas Gas Supply Sales Service D Tariff Schedule - KGSSD Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	<u>Customers</u>			
1	Average number of customers per books	8-F	1	0
2	Pro forma adjustments		(0)	0
3	Pro forma average number of customers		1	0
	<u>Deliveries</u>			
4	Deliveries (Mcf) per books	8-F	66,687	0
5	Pro forma adjustments		(9,699)	0
6	Pro forma deliveries (Mcf)		56,988	0
	<u>Revenue</u>			
7	Base revenue		$60,670	$0
8	Cost of Gas		372,363	0
9	Total revenue per books	8-F	$433,033	$0
10	Pro forma revenue adjustments		(386,181)	0
11	Pro forma revenue		$46,852	$0
12	Revenue per unit (line 11 / line 6)		$0.8221	$0.0000

Line No.	Description	Reference	Sales Service for Resale Tariff Schedule - SSR Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	17	0
2	Pro forma adjustments		(13)	0
3	Pro forma average number of customers		4	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	41,643	0
5	Pro forma adjustments		(23,547)	0
6	Pro forma deliveries (Mcf)		18,096	0
	Revenue			
7	Base revenue		$53,185	$0
8	Cost of Gas		232,625	0
9	Total revenue per books	8-F	$285,810	$0
10	Pro forma revenue adjustments		(259,830)	0
11	Pro forma revenue		$25,980	$0
12	Revenue per unit (line 11 / line 6)		$1.4357	$0.0000

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STk Sales	Small Transportation Service Tariff Schedule - STk Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	544
2	Pro forma adjustments		0	45
3	Pro forma average number of customers		0	589
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	852,080
5	Pro forma adjustments		0	76,237
6	Pro forma deliveries (Mcf)		0	928,317
	Revenue			
7	Base revenue		$0	$1,793,897
8	Cost of Gas		0	(21,160)
9	Total revenue per books	8-F	$0	$1,772,737
10	Pro forma revenue adjustments		0	67,271
11	Pro forma revenue		$0	$1,840,008
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.9821

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	156
2	Pro forma adjustments		0	9
3	Pro forma average number of customers		0	165
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	231,742
5	Pro forma adjustments		0	8,516
6	Pro forma deliveries (Mcf)		0	240,258
	Revenue			
7	Base revenue		$0	$509,011
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$509,011
10	Pro forma revenue adjustments		0	(11,092)
11	Pro forma revenue		$0	$497,918
12	Revenue per unit (line 11 / line 6)		$0.0000	$2.0724

Line No.	Description	Reference	General Transportation Service Tariff Schedule - GTk Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books		0	2,703
2	Pro forma adjustments		0	16
3	Pro forma average number of customers	8-F	0	2,719
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	4,569,134
5	Pro forma adjustments		0	(83,262)
6	Pro forma deliveries (Mcf)		0	4,485,872
	Revenue			
7	Base revenue		$0	$8,152,708
8	Cost of Gas		0	(105,252)
9	Total revenue per books	8-F	$0	$8,047,456
10	Pro forma revenue adjustments		0	(864,213)
11	Pro forma revenue		$0	$7,183,242
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.6013

Line No.	Description	Reference	General Transportation Service Tariff Schedule - GTt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	870
2	Pro forma adjustments		0	(1)
3	Pro forma average number of customers		0	869
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	1,538,017
5	Pro forma adjustments		0	(50,828)
6	Pro forma deliveries (Mcf)		0	1,487,189
	Revenue			
7	Base revenue		$0	$3,403,257
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$3,403,257
10	Pro forma revenue adjustments		0	(314,998)
11	Pro forma revenue		$0	$3,088,259
12	Revenue per unit (line 11 / line 6)		$0.0000	$2.0766

Line No.	Description	Reference	Compressed Natural Gas General Transportation Service Tariff Schedule - CNGt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	1
2	Pro forma adjustments		0	(0)
3	Pro forma average number of customers		0	1
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	13,036
5	Pro forma adjustments		0	0
6	Pro forma deliveries (Mcf)		0	13,036
	Revenue			
7	Base revenue		$0	$11,029
8	Cost of Gas		0	(169)
9	Total revenue per books	8-F	$0	$10,861
10	Pro forma revenue adjustments		0	(814)
11	Pro forma revenue		$0	$10,047
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.2975

Line No.	Description	Reference	Gas Irrigation Transportation Service Tariff Schedule - GITt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	456
2	Pro forma adjustments		0	2
3	Pro forma average number of customers		0	459
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	1,131,898
5	Pro forma adjustments		0	272
6	Pro forma deliveries (Mcf)		0	1,132,170
	Revenue			
7	Base revenue		$0	$1,976,601
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,976,601
10	Pro forma revenue adjustments		0	(89,362)
11	Pro forma revenue		$0	$1,887,239
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.6669

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	485
2	Pro forma adjustments		0	(49)
3	Pro forma average number of customers		0	436
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	18,117,524
5	Pro forma adjustments		0	(7,901,909)
6	Pro forma deliveries (Mcf)		0	10,215,615
	Revenue			
7	Base revenue		$0	$12,114,684
8	Cost of Gas		0	(105,856)
9	Total revenue per books	8-F	$0	$12,008,828
10	Pro forma revenue adjustments		0	(3,053,416)
11	Pro forma revenue		$0	$8,955,413
12	Revenue per unit (line 11 / line 6)		$0.0000	$0.8766

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	153
2	Pro forma adjustments		0	(27)
3	Pro forma average number of customers		0	126
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	25,698,201
5	Pro forma adjustments		0	(20,376,644)
6	Pro forma deliveries (Mcf)		0	5,321,557
	Revenue			
7	Base revenue		$0	$13,056,145
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$13,056,145
10	Pro forma revenue adjustments		0	(6,023,770)
11	Pro forma revenue		$0	$7,032,374
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.3215

Line No.	Description	Reference	Wholesale Transportation Service Tariff Schedule - WTt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	27
2	Pro forma adjustments		0	(0)
3	Pro forma average number of customers		0	27
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	2,790,112
5	Pro forma adjustments		0	(1,597,291)
6	Pro forma deliveries (Mcf)		0	1,192,821
	Revenue			
7	Base revenue		$0	$1,703,000
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,703,000
10	Pro forma revenue adjustments		0	(308,029)
11	Pro forma revenue		$0	$1,394,971
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.1695

Line No.	Description	Reference	Residential Sales Service Tariff Schedule - RS Sales	Residential Sales Service Tariff Schedule - RS Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	575,841	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	43,365,197	0
	Revenue			
3	Proposed revenue		$227,457,168	$0
4	Pro forma revenue - existing tariffs	17-B	176,749,315	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$50,707,853	$0
6	COGR revenue		$243,940,609	$0
7	Percent increase (line 5 / (line 4+6))		12.05%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$5.2452	$0.0000

Line No.	Description	Reference	General Sales Service Tariff Schedule - GS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	49,366	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	11,270,958	0
	Revenue			
3	Proposed revenue		$36,101,473	$0
4	Pro forma revenue - existing tariffs	17-B	36,101,473	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		($0)	$0
6	COGR revenue		$63,402,096	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$3.2031	$0.0000

Line No.	Description	Reference	Small Generator Sales Service Tariff Schedule - SGS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	567	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	5,715	0
	Revenue			
3	Proposed revenue		$345,629	$0
4	Pro forma revenue - existing tariffs	17-B	345,629	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		($0)	$0
6	COGR revenue		$32,148	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$60.4775	$0.0000

Line No.	Description	Reference	Gas Irrigation Service Tariff Schedule - GIS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	228	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	224,746	0
	Revenue			
3	Proposed revenue		$391,940	$0
4	Pro forma revenue - existing tariffs	17-B	391,940	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		($0)	$0
6	COGR revenue		$1,264,255	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$1.7439	$0.0000

Line No.	Description	Reference	Kansas Gas Supply Sales Service D Tariff Schedule - KGSSD Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	1	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	56,988	0
	Revenue			
3	Proposed revenue		$46,852	$0
4	Pro forma revenue - existing tariffs	17-B	46,852	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		($0)	$0
6	COGR revenue (b)		$320,572	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.8221	$0.0000

Line No.	Description	Reference	Sales Service for Resale Tariff Schedule - SSR Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	4	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	18,096	0
	Revenue			
3	Proposed revenue		$25,980	$0
4	Pro forma revenue - existing tariffs	17-B	25,980	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$101,795	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$1.4357	$0.0000

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STk Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	589
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	928,317
	Revenue			
3	Proposed revenue		$0	$1,840,008
4	Pro forma revenue - existing tariffs	17-B	0	1,840,008
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	($0)
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.9821

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STt Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	165
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	240,258
	Revenue			
3	Proposed revenue		$0	$497,918
4	Pro forma revenue - existing tariffs	17-B	0	497,918
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$2.0724

Line No.	Description	Reference	General Transportation Service Tariff Schedule - GTk Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	2,719
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	4,485,872
	Revenue			
3	Proposed revenue		$0	$7,183,242
4	Pro forma revenue - existing tariffs	17-B	0	7,183,242
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.6013

Line No.	Description	Reference	General Transportation Service Tariff Schedule - GTt Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	869
	Deliveries			
2	Pro forma deliveries (MCF)	17-B	0	1,487,189
	Revenue			
3	Proposed revenue		$0	$3,088,259
4	Pro forma revenue - existing tariffs	17-B	0	3,088,259
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$2.0766

Line No.	Description	Reference	Compressed Natural Gas General Transportation Service Tariff Schedule - CNGt	
			Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	1
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	13,036
	Revenue			
3	Proposed revenue		$0	$10,047
4	Pro forma revenue - existing tariffs	17-B	0	10,047
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue (b)		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$0.7707

Line No.	Description	Reference	Gas Irrigation Transportation Service Tariff Schedule - GITt	
			Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	459
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	1,132,170
	Revenue			
3	Proposed revenue		$0	$1,887,239
4	Pro forma revenue - existing tariffs	17-B	0	1,887,239
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	($0)
6	COGR revenue (b)		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.6669

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	436
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	10,215,615
	Revenue			
3	Proposed revenue		$0	$8,955,413
4	Pro forma revenue - existing tariffs	17-B	0	8,955,413
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	($0)
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$0.8766

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	126
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	5,321,557
	Revenue			
3	Proposed revenue		$0	$7,032,374
4	Pro forma revenue - existing tariffs	17-B	0	7,032,374
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.3215

Line No.	Description	Reference	Wholesale Transportation Service Tariff Schedule - WTt Sales	Wholesale Transportation Service Tariff Schedule - WTt Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	27
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	1,192,821
	Revenue			
3	Proposed revenue		$0	$1,394,971
4	Pro forma revenue - existing tariffs	17-B	0	1,394,971
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	($0)
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.1695