BOARD OF PUBLIC WORKS
DEPARTMENT OF UTILITIES

January 4, 2017
4:15 P.M.
Fremont Municipal Building, 2nd Floor Conference Room,
400 East Military, Fremont Nebraska

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1. Roll call.

2. Approve minutes of December 21, 2016.

3. Consider Accounts Payable – 1st half of January 2017.

4. Consider open season bid with Northern Natural Gas for additional Firm Deferred Delivery Service Storage (staff report).

5. Consider Clawback Provisions and Indemnification Agreement with Costco Wholesale Corp. (staff report).

6. Investments (staff report).

7. General Manager Update (no board action is requested).
    a. Annual report – Keith Kontor
    b. Public Power in Nebraska – Newton

8. Adjournment

The agenda was posted at the Municipal Building on December 28, 2016. The agenda and enclosures are distributed to Board and posted on the City of Fremont's website. The official current copy of the agenda is available at Municipal Building, 400 East Military, office of the General Manager. A copy of the Open Meeting Law is posted in the 2nd floor conference room for review by the public. The Board of Public Works reserves the right to adjust the order of items on this agenda.

***items referred to City Council (if any)**

CITY OF FREMONT BOARD OF PUBLIC WORKS
DECEMBER 21, 2016 - 4:15 P.M.

A meeting of the Board of Public Works was held on December 21, 2016 at 4:15 p.m. in the 2nd floor meeting room at 400 East Military, Fremont, Nebraska. The meeting was preceded by publicized notice in the Fremont Tribune and the agenda displayed in the Municipal Building. The meeting was open to the public. A continually current copy of the agenda was available for public inspection at the office of the General Manger, Department of Utilities, 400 East Military. The agenda was distributed to the Board of Public Works on December 19, 2016, and posted, along with the supporting documents, on the City's website. A copy of the open meeting law is posted continually for public inspection.

ROLL CALL.
Roll call showed Board Members Sawtelle, Shelso, Vering, Behrens and Hoegemeyer present; 5 present, 0 absent. Others in attendance included City Councilman Steve Landholm, City Councilwoman Susan Jacobus; Troy Schaben, Asst. GM; Jan Rise, Admin. Services Dir.; Jeff Shanahan, LDW Supt.; Dan Goebel, Accountant; Larry Andreasen, Water Supt.; Al Kasper, Dir. of Engineering; John Hemschemeyer, Dir. HR; Keith Kontor, WWTP Supt.; Mike Royuk, Electric Superintendent; and Dean Kavan, Stores Supervisor.

APPROVE MINUTES.
Moved by Member Vering and seconded by Member Behrens to approve the minutes of the December 7, 2016 meeting. Motion carried 5-0.

CONSIDER ACCOUNTS PAYABLE – 2nd HALF OF DECEMBER 2016.
Moved by Member Shelso and seconded by Member Hoegemeyer to approve the accounts payable in the amount of $2,411,634.21. Motion carried 5-0.

REVIEW COLLECTION REPORT FOR NOVEMBER 2016.
Chairman Sawtelle noted the board reviewed and received the November 2016 collections report.

CONSIDER PURCHASE OF 2018 FREIGHTLINER/2017 VACTOR 2100 FROM NEBRASKA ENVIRONMENTAL PRODUCTS.
Moved by Member Behrens and seconded by Member Shelso to approve the purchase of a 2018 Freightliner and 2017 Vactor 2100 jet pump for $453,256 from Nebraska Environmental Products using the National Joint Powers Alliance (NJPA) contract; and recommend approval by the City Council. Andreasen reviewed some of the reasons the Vactor jet pump was preferred and the advantages of using the NJPA. Motion carried 5-0.

CONSIDER EXTENSION OF POWER MARKETING AGENT/METERING/COMMUNICATIONS AGREEMENT WITH OPPD.
Moved by Member Vering and seconded by Member Hoegemeyer to renew the power marketing agent/metering/communications agreement with OPPD for another year at the cost of $11,508.15 per month (a 2% increase over the prior year). Shanahan explained the purpose of the agreement and why staff recommended renewing the agreement. Motion carried 5-0.

INVESTMENTS.
Goebel reviewed the investments staff had made since the last board meeting. Member Vering moved to accept and receive the report, seconded by Member Behrens. Motion carried 5-0.

GENERAL MANAGER UPDATE.
Kasper and Royuk presented the annual electric engineering and distribution system report and reviewed the information with the board. Newton reviewed a draft letter from OPPD detailing what it

would cost to reroute and bury a portion of the proposed Elkhorn River Valley Transmission line to avoid the aesthetics of the line along Ritz Lake. The Board noted its acceptance to underground construction as long as all additional costs are to be paid by the developer. Newton explained the Northern Natural Gas (NNG) open season for additional Firm Deferred Delivery (FDD) storage. Currently FDU has 305,000 MMBtu of storage or approximately 13% of average annual gas sales. With the possibility of the Costco load, Newton asked the Board to consider authorizing staff to bid for additional storage, noting that if the bid was successful, the allocation could always be turned back into NNG without penalty. The item will be placed on next month's agenda. Kontor updated the board on the progress of updating the wastewater treatment plant and Hormel's commitment to install pretreatment.

ADJOURNMENT

Member Behrens moved and Member Shelso seconded the motion to adjourn the meeting at 5:30 p.m. Motion carried 5-0.

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Allen Sawtelle, Chairman

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Toni Vering, Secretary

Approved by:

____
Dennis Behrens

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David Shelso

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Erik Hoegemeyer

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EAL DESCRIPTION:  EAL: 12282016 ANDERSEND
PAYMENT TYPES
   Checks . . . . . . . . . . . . . . . . . . . . . .  Y
   EFTs . . . . . . . . . . . . . . . . . . . . . . .  Y
   ePayables  . . . . . . . . . . . . . . . . . . . .  Y
VOUCHER SELECTION CRITERIA
   Voucher/discount due date  . . . . . . . . . . . .  12/29/2016
   All banks  . . . . . . . . . . . . . . . . . . . .  A
REPORT SEQUENCE OPTIONS:
   Vendor . . . . . . . . . . . . . . . . . . . . . .  X      One vendor per page? (Y,N)  . . . . . . . . . .  N
   Bank/Vendor  . . . . . . . . . . . . . . . . . . .         One vendor per page? (Y,N)  . . . . . . . . . .  N
   Fund/Dept/Div  . . . . . . . . . . . . . . . . . .         Validate cash on hand? (Y,N)  . . . . . . . . .  N
   Fund/Dept/Div/Element/Obj  . . . . . . . . . . . .         Validate cash on hand? (Y,N)  . . . . . . . . .  N
   Proj/Fund/Dept/Div/Elm/Obj . . . . . . . . . . . .
 This report is by:  Vendor
   Process by bank code? (Y,N)  . . . . . . . . . . .  Y
   Print reports in vendor name sequence? (Y,N) . . .  Y
   Calendar year for 1099 withholding . . . . . . . .  2016
   Disbursement year/per  . . . . . . . . . . . . . .  2017/03
   Payment date . . . . . . . . . . . . . . . . . . .  12/28/2016
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Electric Fund – 051

Water Fund – 053

Sewer Fund – 055

Gas Fund – 057

VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
9999999	00	BOYER, JORDON G						
000072221		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	107.75	
						VENDOR TOTAL *	107.75	
0000584	00	CEI						
20161229		PR1229		00 12/29/2016	051-0000-241.00-00	PAYROLL SUMMARY	EFT:	4,144.44
						VENDOR TOTAL *	.00	4,144.44
9999999	00	FERGUSON, STEFANIE L						
000072125		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	165.62	
						VENDOR TOTAL *	165.62	
0001964	00	IBEW LOCAL UNION 1536						
20161201		PR1201		00 12/29/2016	051-0000-241.00-00	PAYROLL SUMMARY	1,785.01	
20161215		PR1215		00 12/29/2016	051-0000-241.00-00	PAYROLL SUMMARY	1,785.01	
						VENDOR TOTAL *	3,570.02	
0002999	00	LAUGHLIN TRUSTEE, KATHLEEN A						
20161229		PR1229		00 12/29/2016	051-0000-241.00-00	PAYROLL SUMMARY	162.00	
						VENDOR TOTAL *	162.00	
0005002	00	NATIONAL ACCOUNT SYSTEMS OF OMAHA						
20161229		PR1229		00 12/29/2016	051-0000-241.00-00	PAYROLL SUMMARY	239.29	
						VENDOR TOTAL *	239.29	
0004192	00	PAYROLL EFT DEDUCTIONS						
20161229		PR1229		00 12/29/2016	051-0000-241.00-00	PAYROLL SUMMARY	182,707.79	
						VENDOR TOTAL *	182,707.79	
9999999	00	RAY, RUSSELL & ABBIE						
000030097		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	125.67	
						VENDOR TOTAL *	125.67	
9999999	00	SCHWARTZ, CODY L						
000072893		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	20.76	
						VENDOR TOTAL *	20.76	
9999999	00	SIBBALD, TOM						
000071969		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	16.09	
						VENDOR TOTAL *	16.09	
9999999	00	TOWN & COUNTRY PROPERTIES, LLC						
000069021		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	96.82	
						VENDOR TOTAL *	96.82	
9999999	00	VANEK, CARLIE A						
000071017		UT		00 12/22/2016	051-0000-143.00-00	FINAL BILL REFUND	228.99	
						VENDOR TOTAL *	228.99	
						EFT/EPAY TOTAL ***		4,144.44

VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK	CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
9999999	00								
							TOTAL EXPENDITURES ****	187,440.80	4,144.44
						GRAND TOTAL	********************		191,585.24

Account Number	Employee Name	Social Security	Deposit Amount		
		Final Total	281,671.99	Count	172

DEPARTMENT OF UTILITIES

ELECTRONIC WITHDRAWAL LIST

FOR BOARD OF PUBLIC WORKS MEETING: 1/4/17

AJ GROUP NO	VENDOR NAME	WITHDRAWAL DATE	ACCOUNT NO	ITEM DESCRIPTION	WITHDRAWAL AMOUNT
5606	VANTIV	12/20/16	051-5001-903-60-77	KIOSK CREDIT CARD FEES	13.20
				TOTAL EXPENDITURES	13.20

M:\Accounts Payable\DU\DU Electronic Withdrawals\12-20-16

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EAL DESCRIPTION:  EAL: 12292016 ANDERSEND
PAYMENT TYPES
   Checks . . . . . . . . . . . . . . . . . . . . . .  Y
   EFTs . . . . . . . . . . . . . . . . . . . . . . .  Y
   ePayables  . . . . . . . . . . . . . . . . . . . .  Y
VOUCHER SELECTION CRITERIA
   Voucher/discount due date  . . . . . . . . . . . .  01/05/2017
   All banks  . . . . . . . . . . . . . . . . . . . .  A
REPORT SEQUENCE OPTIONS:
   Vendor . . . . . . . . . . . . . . . . . . . . . .  X      One vendor per page? (Y,N)  . . . . . . . . . . .  N
   Bank/Vendor  . . . . . . . . . . . . . . . . . . .         One vendor per page? (Y,N)  . . . . . . . . . . .  N
   Fund/Dept/Div  . . . . . . . . . . . . . . . . . .         Validate cash on hand? (Y,N)  . . . . . . . . . .  N
   Fund/Dept/Div/Element/Obj  . . . . . . . . . . . .         Validate cash on hand? (Y,N)  . . . . . . . . . .  N
   Proj/Fund/Dept/Div/Elm/Obj . . . . . . . . . . . .
 This report is by:  Vendor
   Process by bank code? (Y,N)  . . . . . . . . . . .  Y
   Print reports in vendor name sequence? (Y,N) . . .  Y
   Calendar year for 1099 withholding . . . . . . . .  2017
   Disbursement year/per  . . . . . . . . . . . . . .  2017/04
   Payment date . . . . . . . . . . . . . . . . . . .  01/05/2017
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VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK	CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0000957	00	AAA GARAGE DOOR INC							
16-2960		PI1482		00	01/05/2017	051-5001-940.50-35	PO NUM 043515	9.64	
16-2960		PI1483		00	01/05/2017	051-5001-940.60-61	PO NUM 043515	128.99	
16-2972		PI1584		00	01/05/2017	051-5001-940.50-35	PO NUM 044728	65.28	
16-2972		PI1585		00	01/05/2017	051-5001-940.60-61	PO NUM 044728	109.00	
16-3023		PI1625		00	01/05/2017	051-5001-940.50-35	PO NUM 044783	10.05	
16-3023		PI1626		00	01/05/2017	051-5001-940.60-61	PO NUM 044783	119.65	
							VENDOR TOTAL *	442.61	
0000959	00	ACE HARDWARE							
98669/3		PI1484		00	01/05/2017	051-5001-940.50-35	PO NUM 043953	101.61	
98730/3		PI1485		00	01/05/2017	051-5001-940.50-35	PO NUM 043953	156.54	
98737/3		PI1487		00	01/05/2017	051-5001-940.50-35	PO NUM 043953	28.86	
98772/3		PI1598		00	01/05/2017	051-5001-940.50-35	PO NUM 043953	91.87	
98731/3		PI1486		00	01/05/2017	051-5105-502.50-35	PO NUM 043953	2.45	
98741/3		PI1523		00	01/05/2017	055-7105-512.50-35	PO NUM 044742	69.99	
							VENDOR TOTAL *	451.32	
0004995	00	ACME CONTROLS							
983143		PI1612		00	01/05/2017	055-7105-512.50-35	PO NUM 044650	275.00	
							VENDOR TOTAL *	275.00	
0000960	00	ADAMS OIL INC							
16594		PI1623		00	01/05/2017	055-7105-502.50-30	PO NUM 044768	EFT:	3,202.10
							VENDOR TOTAL *	.00	3,202.10
0004920	00	ADVANCED ELECTRICAL AND MOTOR							
AEM-16-3262		PI1512		00	01/05/2017	051-5105-502.60-61	PO NUM 044673	EFT:	5,119.84
AEM-16-3262		PI1513		00	01/05/2017	051-5105-502.60-79	PO NUM 044673	EFT:	152.38
							VENDOR TOTAL *	.00	5,272.22
0004276	00	AIRGAS USA LLC							
9058250553		PI1597		00	01/05/2017	051-5105-502.50-35	PO NUM 036774	EFT:	228.96
9058477045		PI1606		00	01/05/2017	051-5105-502.50-35	PO NUM 044169	EFT:	1,399.50
9058477045		PI1607		00	01/05/2017	051-5105-502.50-35	PO NUM 044169	EFT:	739.12
							VENDOR TOTAL *	.00	2,367.58
0000967	00	ALLIED APPLIANCE INC							
57287		PI1515		00	01/05/2017	055-7105-512.50-35	PO NUM 044682	549.00	
57287		PI1516		00	01/05/2017	055-7105-512.60-61	PO NUM 044682	80.00	
							VENDOR TOTAL *	629.00	
0003124	00	ALLIED ELECTRONICS INC							
9007055470		PI1596		00	01/05/2017	055-0000-154.00-00	PO NUM 044741	EFT:	468.92
							VENDOR TOTAL *	.00	468.92
0002612	00	ALTEC INDUSTRIES INC							
10670882		PI1514		00	01/05/2017	051-5205-580.50-35	PO NUM 044675	1,424.13	
							VENDOR TOTAL *	1,424.13	
0002228	00	AMERICAN WATER WORKS ASSOCIATION							

VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0002228	00	AMERICAN WATER WORKS ASSOCIATION						
7001267194		PI1624		00 01/05/2017	053-6001-905.60-67	PO NUM 044769	3,361.00	
						VENDOR TOTAL *	3,361.00	
0000583	00	ANCHOR SCIENTIFIC INC						
225180		PI1479		00 01/05/2017	051-0000-155.00-00	PO NUM 044725	402.00	
225180		PI1522		00 01/05/2017	051-5105-502.60-79	PO NUM 044725	19.49	
						VENDOR TOTAL *	421.49	
0002531	00	BABCOCK & WILCOX						
BA60333056		PI1595		00 01/05/2017	051-0000-153.00-00	PO NUM 044698	EFT:	8,078.50
						VENDOR TOTAL *	.00	8,078.50
0001662	00	BARR-THORP ELECTRIC CO INC						
S1433694-001		PI1557		00 01/05/2017	051-5105-502.60-65	PO NUM 044428	2,949.99	
						VENDOR TOTAL *	2,949.99	
0003660	00	BAUER BUILT INC						
880049540		PI1613		00 01/05/2017	055-7105-502.50-48	PO NUM 044676	422.00	
880049540		PI1614		00 01/05/2017	055-7105-502.60-61	PO NUM 044676	50.00	
880048884		PI1615		00 01/05/2017	057-8205-870.50-48	PO NUM 044690	256.53	
880048884		PI1616		00 01/05/2017	057-8205-870.60-61	PO NUM 044690	27.70	
880049553		PI1618		00 01/05/2017	057-8205-870.50-48	PO NUM 044729	278.26	
880049553		PI1619		00 01/05/2017	057-8205-870.60-61	PO NUM 044729	28.37	
						VENDOR TOTAL *	1,062.86	
0005009	00	BDO USA LLP						
000742633				00 01/05/2017	051-0000-173.00-00	Nov/Turbine Damage Claim	7,625.00	
						VENDOR TOTAL *	7,625.00	
0004558	00	BLT PLUMBING HEATING & A/C INC						
13206		PI1605		00 01/05/2017	055-7105-512.50-35	PO NUM 044004	62.07	
						VENDOR TOTAL *	62.07	
0003545	00	BOMGAARS SUPPLY INC						
16196652		PI1488		00 01/05/2017	051-5001-940.50-35	PO NUM 043954	37.44	
16197382		PI1489		00 01/05/2017	051-5105-502.50-35	PO NUM 043954	114.46	
16198557		PI1490		00 01/05/2017	055-7105-512.50-35	PO NUM 043954	44.95	
						VENDOR TOTAL *	196.85	
0004996	00	BRIGGS AND MORGAN PA						
591184		PI1617		00 01/05/2017	051-5001-919.60-61	PO NUM 044713	6,772.50	
						VENDOR TOTAL *	6,772.50	
0004518	00	CAPPEL AUTO SUPPLY INC						
204325		PI1602		00 01/05/2017	051-5001-940.50-35	PO NUM 043990	212.93	
204414		PI1603		00 01/05/2017	051-5001-940.50-48	PO NUM 043990	161.51	
203240		PI1611		00 01/05/2017	051-5001-940.50-48	PO NUM 044606	376.43	
204201		PI1600		00 01/05/2017	051-5105-502.50-48	PO NUM 043990	230.62	
204294		PI1601		00 01/05/2017	051-5205-580.50-48	PO NUM 043990	156.40	

VEND NO / INVOICE NO	SEQ# / VOUCHER NO	VENDOR NAME / P.O. NO	BNK CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0004518	00	CAPPEL AUTO SUPPLY INC					
204488	PI1604		00 01/05/2017	055-7205-583.50-48	PO NUM 043990	131.88	
					VENDOR TOTAL *	1,269.77	
0003817	00	CED AUTOMATION OMAHA					
5411-492840	PI1477		00 01/05/2017	051-0000-155.00-00	PO NUM 044686	57.87	
5411-492934	PI1594		00 01/05/2017	051-0000-155.00-00	PO NUM 044686	264.20	
5411-492915	PI1478		00 01/05/2017	055-0000-154.00-00	PO NUM 044691	167.04	
					VENDOR TOTAL *	489.11	
0002675	00	CENTURYLINK					
4027272600 1216	PI1549		00 01/05/2017	051-5001-922.50-53	PO NUM 043996	48.12	
4027272606 1216	PI1550		00 01/05/2017	051-5001-922.50-53	PO NUM 043996	408.72	
4027272654 1216	PI1551		00 01/05/2017	051-5001-922.50-53	PO NUM 043996	48.54	
					VENDOR TOTAL *	505.38	
0002915	00	CREDIT BUREAU SERVICES INC					
NOV 2016	PI1521		00 01/05/2017	055-7001-905.55-04	PO NUM 044721	125.00	
					VENDOR TOTAL *	125.00	
0004646	00	DATABANK IMX LLC					
MO41000652	PI1518		00 01/05/2017	051-5001-922.60-65	PO NUM 044695	9,719.20	
					VENDOR TOTAL *	9,719.20	
0003586	00	DHHS LICENSURE UNIT					
2017 N HRBEK	PI1588		00 01/05/2017	053-6205-583.60-67	PO NUM 044740	115.00	
					VENDOR TOTAL *	115.00	
0000313	00	DIAMOND POWER INTERNATIONAL INC					
489894	PI1593		00 01/05/2017	051-0000-153.00-00	PO NUM 044660	1,730.20	
					VENDOR TOTAL *	1,730.20	
0001313	00	DILLON CHEVROLET FREMONT INC, SID					
1TCS121142	PI1664		00 01/05/2017	051-5205-580.60-61	PO NUM 043959	79.95	
					VENDOR TOTAL *	79.95	
0001927	00	DOKTER TRUCKING CORP					
2155	PI1608		00 01/05/2017	051-5105-502.60-61	PO NUM 044588	850.00	
2302	PI1609		00 01/05/2017	051-5105-502.60-61	PO NUM 044588	1,000.00	
2326	PI1610		00 01/05/2017	051-5105-502.60-61	PO NUM 044588	925.00	
2177	PI1643		00 01/05/2017	051-5105-502.60-61	PO NUM 044588	650.00	
					VENDOR TOTAL *	3,425.00	
0003321	00	DOUGLAS COUNTY TREASURER/LANDFILL					
1171482	PI1586		00 01/05/2017	051-5001-940.60-61	PO NUM 044730	32.27	
					VENDOR TOTAL *	32.27	
0004605	00	DXP ENTERPRISES INC					
48331088	PI1524		00 01/05/2017	051-0000-154.00-00	PO NUM 044038	EFT:	409.15
					VENDOR TOTAL *	.00	409.15
0003087	00	EAKES OFFICE SOLUTIONS					

VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0003087	00	EAKES OFFICE SOLUTIONS						
S 136574		PI1558		00 01/05/2017	051-5001-932.60-65	PO NUM 044456	1,250.99	
						VENDOR TOTAL *	1,250.99	
0004551	00	ELEMETAL FABRICATION LLC						
21516		PI1599		00 01/05/2017	051-5001-940.50-35	PO NUM 043975	245.04	
21495		PI1494		00 01/05/2017	051-5105-502.50-35	PO NUM 043975	244.92	
						VENDOR TOTAL *	489.96	
0001091	00	EMANUEL PRINTING INC						
8142		PI1511		00 01/05/2017	051-5001-903.50-40	PO NUM 044640	144.99	
						VENDOR TOTAL *	144.99	
0004993	00	FIKES COMMERCIAL HYGIENE LLC						
573		PI1495		00 01/05/2017	051-5001-932.60-61	PO NUM 044106	EFT:	164.78
						VENDOR TOTAL *	.00	164.78
0002168	00	FORNEY CORPORATION						
403987		PI1591		00 01/05/2017	051-0000-155.00-00	PO NUM 044446	1,595.47	
						VENDOR TOTAL *	1,595.47	
0004833	00	FREMONT AREA UNITED WAY						
NOV'16 CARESHAR				00 01/05/2017	055-0000-242.02-00	Nov 2016 Care & Share	EFT:	281.51
						VENDOR TOTAL *	.00	281.51
0001124	00	FREMONT PRINTING CO						
15037		PI1499		00 01/05/2017	051-5001-903.50-31	PO NUM 044256	77.15	
15037		PI1500		00 01/05/2017	051-5001-917.50-31	PO# 044256	213.98	
15037		PI1501		00 01/05/2017	051-5001-919.50-31	PO# 044256	25.66	
15037		PI1502		00 01/05/2017	051-5001-920.50-31	PO# 044256	34.23	
15037		PI1503		00 01/05/2017	051-5001-922.50-31	PO# 044256	25.66	
15037		PI1504		00 01/05/2017	051-5001-926.50-31	PO# 044256	25.66	
15037		PI1505		00 01/05/2017	051-5001-940.50-31	PO# 044256	34.23	
15037		PI1506		00 01/05/2017	051-5205-580.50-31	PO# 044256	34.23	
						VENDOR TOTAL *	470.80	
0003377	00	GEA MECHANICAL EQUIPMENT US INC						
7586519608		PI1576		00 01/05/2017	055-7105-512.50-35	PO NUM 044696	7,273.74	
						VENDOR TOTAL *	7,273.74	
0003102	00	GEORG FISCHER CENTRAL PLASTICS LLC						
1790200		PI1592		00 01/05/2017	057-0000-154.00-00	PO NUM 044482	3,477.00	
						VENDOR TOTAL *	3,477.00	
0002804	00	GOVERNMENT FINANCE OFFICERS ASSN						
0166596		PI1507		00 01/05/2017	051-5001-920.60-67	PO NUM 044333	150.00	
						VENDOR TOTAL *	150.00	
0004932	00	GRACE CONSULTING INC						
6187		PI1481		00 01/05/2017	051-5105-502.60-61	PO NUM 043258	13,000.00	

VEND NO / INVOICE NO	SEQ# / VOUCHER NO	VENDOR NAME / P.O. NO	BNK	CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0004932	00	GRACE CONSULTING INC						
						VENDOR TOTAL *	13,000.00	
0001445	00	GRAYBAR						
988880380	PI1474		00	01/05/2017	051-0000-154.00-00	PO NUM 044296	601.70	
988047958	PI1525		00	01/05/2017	051-0000-154.00-00	PO NUM 044274	1,547.00	
988451322	PI1589		00	01/05/2017	051-0000-154.00-00	PO NUM 044314	1,120.70	
988985403	PI1590		00	01/05/2017	051-0000-154.00-00	PO NUM 044314	439.20-	
						VENDOR TOTAL *	2,830.20	
0004707	00	GREAT PLAINS COMMUNICATIONS INC						
4020010078 1216	PI1496		00	01/05/2017	051-5001-922.50-53	PO NUM 044192	149.00	
4020010078 1216	PI1497		00	01/05/2017	051-5001-922.60-65	PO NUM 044192	500.00	
4020010078 1216	PI1498		00	01/05/2017	055-7105-502.60-76	PO NUM 044192	229.00	
						VENDOR TOTAL *	878.00	
0003155	00	HACH COMPANY						
10241141	PI1620		00	01/05/2017	055-7105-502.50-52	PO NUM 044743	825.73	
10241141	PI1621		00	01/05/2017	055-7105-512.50-35	PO NUM 044743	50.12	
						VENDOR TOTAL *	875.85	
0004419	00	HANSEN TIRE LLC						
17392	PI1629		00	01/05/2017	051-5105-502.50-48	PO NUM 043963	106.24	
17392	PI1630		00	01/05/2017	051-5105-502.60-61	PO NUM 043963	10.00	
17403	PI1631		00	01/05/2017	051-5205-580.50-48	PO NUM 043963	219.75	
						VENDOR TOTAL *	335.99	
0002794	00	HDR ENGINEERING INC						
1200025586	PI1533		00	01/05/2017	053-6205-583.60-61	PO NUM 043936	9,468.48	
1200025586	PI1534		00	01/05/2017	055-7205-583.60-61	PO NUM 043936	9,468.48	
						VENDOR TOTAL *	18,936.96	
0004599	00	IBT INC						
6926434	PI1627		00	01/05/2017	051-0000-154.00-00	PO NUM 044441	EFT:	571.85
6926433	PI1652		00	01/05/2017	055-7105-512.50-35	PO NUM 044716	EFT:	23.00
6926433	PI1653		00	01/05/2017	055-7105-512.50-35	PO NUM 044716	EFT:	775.56
						VENDOR TOTAL *	.00	1,370.41
0004264	00	INDUSTRIAL PIPE & SUPPLY LLC						
60175-00	PI1509		00	01/05/2017	051-5105-502.50-35	PO NUM 044564	EFT:	563.09
60175-00	PI1510		00	01/05/2017	051-5105-502.60-79	PO NUM 044564	EFT:	107.00
						VENDOR TOTAL *	.00	670.09
0001833	00	INDUSTRIAL SALES CO INC						
D 965795-003	PI1475		00	01/05/2017	057-0000-154.00-00	PO NUM 044383	1,233.64	
969275-000	PI1645		00	01/05/2017	057-8205-870.50-35	PO NUM 044647	439.08	
969275-000	PI1646		00	01/05/2017	057-8205-870.60-61	PO NUM 044647	94.95	
969275-000	PI1647		00	01/05/2017	057-8205-870.60-79	PO NUM 044647	22.94	
						VENDOR TOTAL *	1,790.61	
0001687	00	INLAND TRUCK PARTS & SERVICE						

VEND NO / INVOICE NO	SEQ# / VOUCHER NO	VENDOR NAME / P.O. NO	BNK CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0001687	00	INLAND TRUCK PARTS & SERVICE					
6-26834	PI1519		00 01/05/2017	055-7105-512.50-35	PO NUM 044717	270.62	
					VENDOR TOTAL *	270.62	
0003483	00	INTERSTATE CHEMCIAL CO INC					
260362	PI1480		00 01/05/2017	051-5105-502.50-52	PO NUM 042699	3,206.15	
					VENDOR TOTAL *	3,206.15	
0003085	00	KELLY SUPPLY CO					
11117134-0	PI1648		00 01/05/2017	051-5105-502.50-35	PO NUM 044662	391.95	
11117134-0	PI1649		00 01/05/2017	051-5105-502.60-79	PO NUM 044662	30.25	
					VENDOR TOTAL *	422.20	
0004676	00	KIEWIT ENGINEERING & DESIGN CO					
9000071425	PI1508		00 01/05/2017	051-5105-502.60-61	PO NUM 044516	6,650.93	
					VENDOR TOTAL *	6,650.93	
9999999	00	KING, JEFF					
120816 KING			00 01/05/2017	055-7205-583.50-01	Jeff King Crop Damage	661.50	
					VENDOR TOTAL *	661.50	
0002902	00	KRIZ-DAVIS CO					
S101461592-006	PI1476		00 01/05/2017	051-0000-154.00-00	PO NUM 044612	EFT:	133.75
S101446595-001	PI1527		00 01/05/2017	051-0000-154.00-00	PO NUM 044558	EFT:	9,373.67
S101461806-001	PI1644		00 01/05/2017	051-5105-502.50-35	PO NUM 044627	EFT:	144.45
S101468658-001	PI1517		00 01/05/2017	051-5205-580.60-62	PO NUM 044688	EFT:	400.00
S101469710-001	PI1520		00 01/05/2017	051-5205-580.50-64	PO NUM 044718	EFT:	474.01
S101469728-001	PI1491		00 01/05/2017	053-6205-583.50-35	PO NUM 043965	EFT:	258.48
S101469905-001	PI1492		00 01/05/2017	055-7105-512.50-35	PO NUM 043965	EFT:	128.37
S101470229-001	PI1493		00 01/05/2017	055-7205-583.50-35	PO NUM 043965	EFT:	49.46
					VENDOR TOTAL *	.00	10,962.19
0002654	00	LEAGUE ASSN OF RISK MANAGEMENT					
10539	PI1690		00 01/05/2017	051-5001-919.60-63	PO NUM 044808	3,194.02	
10541	PI1691		00 01/05/2017	051-5001-919.60-63	PO NUM 044808	507.58-	
					VENDOR TOTAL *	2,686.44	
0004976	00	MARCO TECHNOLOGIES LLC					
INV3878140	PI1555		00 01/05/2017	051-5001-920.60-65	PO NUM 044364	119.28	
					VENDOR TOTAL *	119.28	
0002052	00	MATHESON LINWELD					
14583016	PI1642		00 01/05/2017	051-5001-950.80-50	PO NUM 044514	EFT:	9,405.30
					VENDOR TOTAL *	.00	9,405.30
0003289	00	MATT FRIEND TRUCK EQUIPMENT INC					
0082383-IN	PI1564		00 01/05/2017	051-5001-940.50-48	PO NUM 044643	550.67	
0082383-IN	PI1565		00 01/05/2017	051-5001-940.60-79	PO NUM 044643	24.28	
					VENDOR TOTAL *	574.95	
0002963	00	MCGILL ASBESTOS ABATEMENT CO INC					

VEND NO INVOICE NO	SEQ#	VENDOR NAME VOUCHER NO	P.O. NO	BNK CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0002963	00	MCGILL ASBESTOS ABATEMENT CO INC						
114653		PI1692		00 01/05/2017	051-5001-932.60-61	PO NUM 044817	550.00	
						VENDOR TOTAL *	550.00	
0001469	00	MCGRATH NORTH MULLIN & KRATZ PC LLO						
450749		PI1628		00 01/05/2017	051-5105-502.60-61	PO NUM 041300	9,413.06	
						VENDOR TOTAL *	9,413.06	
0000667	00	MCMASTER-CARR SUPPLY CO						
93777563		PI1654		00 01/05/2017	051-5001-940.50-35	PO NUM 044745	423.26	
93777563		PI1655		00 01/05/2017	051-5001-940.60-79	PO NUM 044745	33.25	
92712110		PI1573		00 01/05/2017	051-5105-502.50-35	PO NUM 044685	152.31	
92712110		PI1574		00 01/05/2017	051-5105-502.50-35	PO NUM 044685	29.90	
92712110		PI1575		00 01/05/2017	051-5105-502.60-79	PO NUM 044685	8.10	
						VENDOR TOTAL *	646.82	
0001229	00	MENARDS - FREMONT						
21398		PI1535		00 01/05/2017	051-5001-940.50-35	PO NUM 043970	23.55	
21482		PI1537		00 01/05/2017	051-5001-922.50-42	PO NUM 043970	154.08	
21663		PI1540		00 01/05/2017	051-5001-922.50-42	PO NUM 043970	12.66	
21706		PI1542		00 01/05/2017	051-5001-922.50-42	PO NUM 043970	.95-	
21708		PI1543		00 01/05/2017	051-5001-922.50-42	PO NUM 043970	3.79	
21776		PI1635		00 01/05/2017	051-5001-940.50-35	PO NUM 043970	141.05	
21539		PI1538		00 01/05/2017	051-5105-502.50-35	PO NUM 043970	93.25	
21637		PI1633		00 01/05/2017	051-5105-502.50-35	PO NUM 043970	85.56	
21709		PI1634		00 01/05/2017	051-5105-502.50-35	PO NUM 043970	156.35	
21481		PI1536		00 01/05/2017	051-5205-580.50-35	PO NUM 043970	38.39	
21558		PI1539		00 01/05/2017	053-6105-502.50-35	PO NUM 043970	106.84	
21683		PI1541		00 01/05/2017	053-6105-502.50-35	PO NUM 043970	23.40	
						VENDOR TOTAL *	837.97	
0002069	00	MIDWEST OUTDOOR POWER LLC						
31704		PI1580		00 01/05/2017	051-5205-580.50-35	PO NUM 044719	79.66	
31704		PI1581		00 01/05/2017	051-5205-580.60-61	PO NUM 044719	96.30	
						VENDOR TOTAL *	175.96	
0004883	00	MISSISSIPPI LIME COMPANY						
1294399				00 01/05/2017	051-0000-158.02-00	12/16/16 25.37 TN	EFT:	4,336.12
1295404				00 01/05/2017	051-0000-158.02-00	12/22/16 24.64 TN	EFT:	4,211.47
						VENDOR TOTAL *	.00	8,547.59
0002646	00	MONITORING SOLUTIONS INC						
23945		PI1529		00 01/05/2017	051-0000-153.00-00	PO NUM 044723	300.21	
						VENDOR TOTAL *	300.21	
0001486	00	MOTION INDUSTRIES INC						
NE01-457662		PI1660		00 01/05/2017	051-0000-153.00-00	PO NUM 044754	18.51	
NE01-457994		PI1661		00 01/05/2017	051-0000-153.00-00	PO NUM 044754	39.07	
NE01-457286		PI1577		00 01/05/2017	051-5105-502.50-35	PO NUM 044701	289.96	
NE01-457286		PI1578		00 01/05/2017	051-5105-502.60-79	PO NUM 044701	23.01	

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0001486	00	MOTION INDUSTRIES INC						
NE01-457662	PI1687		00	01/05/2017	051-5105-502.60-79	PO NUM 044754	9.42	
NE01-457354	PI1556		00	01/05/2017	055-7105-512.50-35	PO NUM 044413	1,237.96	
						VENDOR TOTAL *	1,617.93	
0002985	00	MSC INDUSTRIAL SUPPLY CO INC						
47806196	PI1528		00	01/05/2017	051-0000-154.00-00	PO NUM 044704	EFT:	343.28
50924100	PI1662		00	01/05/2017	051-0000-154.00-00	PO NUM 044779	EFT:	338.03
						VENDOR TOTAL *	.00	681.31
0001958	00	NEBR PUBLIC HEALTH ENVIRONMENTAL						
483488	PI1559		00	01/05/2017	053-6105-502.60-61	PO NUM 044530	EFT:	15.00
483489	PI1560		00	01/05/2017	053-6105-502.60-61	PO NUM 044530	EFT:	601.00
						VENDOR TOTAL *	.00	616.00
0003428	00	NEW PIG CORPORATION						
22093434-00	PI1656		00	01/05/2017	051-5001-940.50-35	PO NUM 044749	295.00	
22093434-00	PI1657		00	01/05/2017	051-5001-940.60-79	PO NUM 044749	14.99	
						VENDOR TOTAL *	309.99	
0001020	00	O'REILLY AUTOMOTIVE INC						
0397-423531	PI1638		00	01/05/2017	051-5001-940.50-35	PO NUM 043973	66.05	
0397-423801	PI1639		00	01/05/2017	051-5001-940.50-48	PO NUM 043973	12.81	
0397-417612	PI1636		00	01/05/2017	051-5105-502.50-48	PO NUM 043973	76.65-	
0397-424252	PI1640		00	01/05/2017	051-5105-502.50-35	PO NUM 043973	74.47	
0397-423803	PI1658		00	01/05/2017	051-5105-502.50-48	PO NUM 044760	465.16	
0397-417614	PI1637		00	01/05/2017	055-7105-502.50-48	PO NUM 043973	71.64	
						VENDOR TOTAL *	613.48	
0002888	00	OFFICENET						
856347-0	PI1566		00	01/05/2017	051-5001-940.50-40	PO NUM 044669	215.54	
857575-0	PI1650		00	01/05/2017	051-5205-580.50-40	PO NUM 044689	96.82	
857193-0	PI1651		00	01/05/2017	051-5205-580.50-40	PO NUM 044702	190.88	
						VENDOR TOTAL *	503.24	
0002971	00	OMAHA DOOR & WINDOW CO INC						
ORD0037274	PI1561		00	01/05/2017	051-5001-940.50-35	PO NUM 044573	320.57	
ORD0037274	PI1562		00	01/05/2017	051-5001-940.60-79	PO NUM 044573	26.78	
						VENDOR TOTAL *	347.35	
0001912	00	OMAHA PUBLIC POWER DISTRICT						
CSB000537	PI1530		00	01/05/2017	051-5305-560.60-61	PO NUM 040993	EFT:	83,583.13
CSB000540	PI1531		00	01/05/2017	051-5305-560.60-61	PO NUM 040993	EFT:	3,620,348.50
						VENDOR TOTAL *	.00	3,703,931.63
0002946	00	OMAHA PUBLIC POWER DISTRICT						
1115740525	1216		00	01/05/2017	051-5305-560.60-76	Dec 2016 Interconnection	EFT:	4,285.88
						VENDOR TOTAL *	.00	4,285.88
0001268	00	P & H ELECTRIC INC						

Project payment on transmission line

VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK	CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0001268	00	P & H ELECTRIC INC							
116149		PI1641		00	01/05/2017	055-7105-512.50-35	PO NUM 043974	29.75	
							VENDOR TOTAL *	29.75	
0004948	00	PCM SALES INC							
S99833900101		PI1568		00	01/05/2017	051-5105-502.50-42	PO NUM 044674	30.09	
S99833900101		PI1569		00	01/05/2017	051-5105-502.60-79	PO NUM 044674	16.05	
							VENDOR TOTAL *	46.14	
0003827	00	PEST PRO'S INC							
MNCP BLD 122016		PI1673		00	01/05/2017	051-5001-932.60-61	PO NUM 044194	42.80	
ASH PD 122016		PI1674		00	01/05/2017	051-5105-502.60-61	PO NUM 044208	48.15	
CMBT TUR 122016		PI1675		00	01/05/2017	051-5105-502.60-61	PO NUM 044208	53.50	
PWR PLT 122216		PI1676		00	01/05/2017	051-5105-502.60-61	PO NUM 044208	85.60	
SUB STA 122016		PI1677		00	01/05/2017	051-5205-580.60-61	PO NUM 044218	190.35	
WTR PLT 122016		PI1671		00	01/05/2017	053-6105-502.60-61	PO NUM 044137	69.55	
WWTP 122216		PI1672		00	01/05/2017	055-7105-502.60-61	PO NUM 044189	110.00	
							VENDOR TOTAL *	599.95	
0004800	00	PINNACLE BANK - VISA							
AQ0FE0915570		PI1689		00	01/05/2017	051-5105-502.60-67	PO NUM 044793	150.00	
							VENDOR TOTAL *	150.00	
0002622	00	PITNEY BOWES INC							
1002711980		PI1670		00	01/05/2017	051-5001-903.60-65	PO NUM 044127	150.00	
							VENDOR TOTAL *	150.00	
0002793	00	PLIBRICO COMPANY LLC							
96365		PI1579		00	01/05/2017	051-5001-932.60-61	PO NUM 044711	4,463.75	
							VENDOR TOTAL *	4,463.75	
0004968	00	POWER SCREENING LLC							
H612018432		PI1663		00	01/05/2017	055-7001-950.80-50	PO NUM 043773	402,750.00	Screener for WWTP
							VENDOR TOTAL *	402,750.00	
0003762	00	PR DIAMOND PRODUCTS INC							
0043678-IN		PI1582		00	01/05/2017	053-6205-583.50-35	PO NUM 044726	474.00	
0043678-IN		PI1583		00	01/05/2017	053-6205-583.60-79	PO NUM 044726	18.00	
							VENDOR TOTAL *	492.00	
0004740	00	PREMIER STAFFING INC							
8917		PI1546		00	01/05/2017	051-5001-940.60-61	PO NUM 043988	30.00	
							VENDOR TOTAL *	30.00	
0004696	00	PRIME COMMUNICATIONS INC							
40447		PI1554		00	01/05/2017	051-5001-922.50-42	PO NUM 044348	5,236.23	
							VENDOR TOTAL *	5,236.23	
0004413	00	RADWELL INTERNATIONAL INC							
INV2678693		PI1680		00	01/05/2017	055-7105-512.50-35	PO NUM 044490	1,852.00	

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0004413	00	RADWELL INTERNATIONAL INC						
INV2680265		PI1681		00 01/05/2017	055-7105-512.60-61	PO NUM 044490	1,733.00	
						VENDOR TOTAL *	3,585.00	
0002876	00	RAWHIDE CHEMOIL INC						
57775		PI1570		00 01/05/2017	051-5001-940.50-35	PO NUM 044680	41.73	
16441		PI1587		00 01/05/2017	051-5001-917.50-30	PO NUM 044737	16,763.64	
57793		PI1683		00 01/05/2017	051-5001-940.50-35	PO NUM 044680	13.91	
56376		PI1688		00 01/05/2017	055-7105-502.50-30	PO NUM 044767	633.15	
						VENDOR TOTAL *	17,452.43	
0001514	00	SAFWAY SERVICES LLC						
D058567/CO58655		PI1682		00 01/05/2017	055-7105-512.60-61	PO NUM 044653	EFT:	748.00
						VENDOR TOTAL *	.00	748.00
0001308	00	SHERWIN-WILLIAMS CO						
1392-4		PI1544		00 01/05/2017	053-6105-502.50-35	PO NUM 043978	58.09	
						VENDOR TOTAL *	58.09	
0000429	00	SKARSHAUG TESTING LABORATORY INC						
214099		PI1547		00 01/05/2017	051-5205-580.60-61	PO NUM 043994	432.95	
214099		PI1548		00 01/05/2017	051-5205-580.60-79	PO NUM 043994	146.22	
						VENDOR TOTAL *	579.17	
0003415	00	SNAP-ON INDUSTRIAL						
ARV/31101631		PI1686		00 01/05/2017	051-5001-940.50-35	PO NUM 044748	220.21	
						VENDOR TOTAL *	220.21	
0002023	00	SOLUTIONONE						
462621		PI1553		00 01/05/2017	051-5001-903.60-65	PO NUM 044126	158.98	
462979		PI1669		00 01/05/2017	051-5001-903.60-65	PO NUM 044126	49.22	
						VENDOR TOTAL *	208.20	
0003960	00	SPX TRANSFORMER SOLUTIONS INC						
041656		PI1567		00 01/05/2017	051-5205-580.50-35	PO NUM 044671	608.21	
						VENDOR TOTAL *	608.21	
0003923	00	STATE OF NEBRASKA - CELLULAR						
1042367				00 01/05/2017	051-5001-903.50-53	Cellular	EFT:	104.58
1042367				00 01/05/2017	051-5001-926.50-53	Safety Mgr Cellular	EFT:	57.59
1042367				00 01/05/2017	051-5105-502.50-53	Cellular	EFT:	137.64
1042367				00 01/05/2017	051-5205-580.50-53	Engineers Cellular	EFT:	230.36
1042367				00 01/05/2017	051-5205-580.50-53	Elect Distr Cellular	EFT:	359.51
1042367				00 01/05/2017	053-6105-502.50-53	Cellular	EFT:	57.59
1042367				00 01/05/2017	053-6205-583.50-53	Cellular	EFT:	164.57
1042367				00 01/05/2017	055-7105-502.50-53	Cellular	EFT:	23.22
1042367				00 01/05/2017	057-8205-870.50-53	Cellular	EFT:	188.82
						VENDOR TOTAL *	.00	1,323.88
0001137	00	STEFFY CHRYSLER CENTER INC, GENE						

VEND NO / INVOICE NO	SEQ#	VENDOR NAME / VOUCHER NO	P.O. NO	BNK	CHECK/DUE DATE	ACCOUNT NO	ITEM DESCRIPTION	CHECK AMOUNT	EFT, EPAY OR HAND-ISSUED AMOUNT
0001137	00	STEFFY CHRYSLER CENTER INC, GENE							
5053740		PI1622		00	01/05/2017	051-5105-502.50-48	PO NUM 044759	358.45	
							VENDOR TOTAL *	358.45	
0003891	00	SUNGARD PUBLIC SECTOR INC							
128242		PI1678		00	01/05/2017	051-5001-903.60-77	PO NUM 044387	EFT:	233.13
128242		PI1679		00	01/05/2017	051-5001-917.60-77	PO# 044387	EFT:	12.27
							VENDOR TOTAL *	.00	245.40
0004647	00	T SQUARE SUPPLY LLC							
15215		PI1665		00	01/05/2017	051-5001-940.50-35	PO NUM 043980	183.87	
15283		PI1667		00	01/05/2017	051-5001-940.50-35	PO NUM 043980	114.07	
15269		PI1666		00	01/05/2017	055-7105-512.50-35	PO NUM 043980	22.00	
							VENDOR TOTAL *	319.94	
0001339	00	TIMME WELDING & SUPPLY LLC							
32720		PI1668		00	01/05/2017	053-6205-583.50-35	PO NUM 043981	62.60	
							VENDOR TOTAL *	62.60	
0004754	00	TOTAL TOOL SUPPLY INC							
08556166		PI1532		00	01/05/2017	051-5105-502.60-61	PO NUM 043508	222.42	
							VENDOR TOTAL *	222.42	
0004515	00	TRACTOR SUPPLY CREDIT PLAN							
191520		PI1545		00	01/05/2017	051-5105-502.50-35	PO NUM 043982	56.67	
191347		PI1685		00	01/05/2017	057-8205-870.50-48	PO NUM 044693	353.09	
							VENDOR TOTAL *	409.76	
0002413	00	USI EDUCATION & GOVERNMENT SALES							
0381746901010		PI1684		00	01/05/2017	051-5205-580.50-40	PO NUM 044683	EFT:	70.10
							VENDOR TOTAL *	.00	70.10
0002568	00	WATER ENVIRONMENT FEDERATION							
9000414616		PI1571		00	01/05/2017	055-7105-502.60-67	PO NUM 044681	79.00	
2017 S SEELHOFF		PI1572		00	01/05/2017	055-7105-502.60-67	PO NUM 044681	79.00	
							VENDOR TOTAL *	158.00	
0000482	00	WESCO RECEIVABLES CORP							
784895		PI1526		00	01/05/2017	051-0000-154.00-00	PO NUM 044503	EFT:	353.10
796697		PI1659		00	01/05/2017	051-0000-154.00-00	PO NUM 044747	EFT:	192.60
							VENDOR TOTAL *	.00	545.70
0004135	00	WINDOW PRO INC							
30469		PI1552		00	01/05/2017	051-5001-932.60-61	PO NUM 044095	EFT:	10.70
							VENDOR TOTAL *	.00	10.70
							EFT/EPAY TOTAL ***		3,763,658.94
							TOTAL EXPENDITURES ****	564,763.64	3,763,658.94
							GRAND TOTAL *******************		4,328,422.58

STAFF REPORT

TO: Board of Public Works

FROM: Brian Newton, General Manager

DATE: January 4, 2017

SUBJECT: Open Season Bid for Northern Natural Gas Storage

Recommendation: Authorize the General Manager to submit an open season bid with Northern Natural Gas (NNG) for 72,000 MMBtu of additional storage at the NNG tariff rate.

Background: Northern Natural Gas (NNG) is soliciting binding bids for 6.1 Bcf of Firm Deferred Delivery (FDD) service (storage). The last time NNG held an open season for FDD storage was 2004, when FDU acquired 100,000 MMBtu. Currently FDU has 302,510 MMBtu of FDD storage with NNG, which represents approximately 13% of annual sales. With the possibly of the Costco poultry plant coming on line in 2018, submitting a bid for additional FDD storage would be a practical business decision. Also, should the additional FDD storage not be needed in the future, it can be returned to NNG without penalty.

Fiscal Impact: Approximately $53,000 per year.

From:	Rosman, Stacy
Subject:	Northern Natural Gas - Firm Deferred Delivery Service Open Season for Service Beginning June 1, 2017
Date:	Tuesday, December 06, 2016 4:51:46 PM
Attachments:	image002.png NNG_Email_Logo.bmp

Hello!

I wanted to make sure you all saw the Firm Deferred Delivery Service (FDD Storage) open season that was posted earlier today, so I've forwarded along a copy of the posting below…

Please feel free to contact me if you have any interest in purchasing additional storage and we can talk through the bid process.

Have a good evening!

Stacy

Stacy L Rosman
Account Director - Marketing

Northern Natural Gas
A BERKSHIRE HATHAWAY ENERGY COMPANY

Email: stacy.rosman@nngco.com | O: 402-398-7377 | C: 402-578-2525 | AIM: stacylrosman

From: notices@nngco.com [mailto:notices@nngco.com]
Sent: Tuesday, December 06, 2016 10:44 AM
Subject: Non-Critical, TSP Capacity Offering, 20161206, Northern, 784158214

Northern Natural Gas
A BERKSHIRE HATHAWAY ENERGY COMPANY

TSP Name: Northern Natural Gas Company	**Post Date/Time:** 12/06/2016 10:44 AM
TSP: 784158214	**Notice Effective Date/Time:** 12/06/2016 10:44 AM
Notice ID: **034607**	**Notice End Date/Time:** 01/13/2017 5:00 PM
Notice Type: TSP Capacity Offering	**For Gas Day(s):** 12/6/2016 - 1/13/2017
Subject: FIRM DEFERRED DELIVERY SERVICE OPEN SEASON FOR SERVICE BEGINNING JUNE 1, 2017	**Notice Status:** Initiate
Critical: N	**Required Response Indicator Description:** 5- No response required

Notice Text:

Northern Natural Gas Company is hereby soliciting binding bids for a total of 6.1 Bcf of Firm Deferred Delivery (FDD) service. This includes 5.8 Bcf of newly available capacity plus 0.3 Bcf of generally available capacity. Northern has identified that it can convert 5.8 Bcf of existing interruptible capacity to FDD. An increase in peak deliverability has been determined to be available at both the Redfield, Iowa and Cunningham, Kansas storage fields that will provide the maximum withdrawal rate to accommodate this conversion of service without significant facility requirements. Firm service made available pursuant to this Open Season is anticipated to be available for injections commencing on June 1, 2017, subject to FERC approval[1] FERC approval is anticipated prior to June 1, 2017, however, if FERC approval is received after June

1, 2017, but prior to August 1, 2017, service will begin upon receipt of FERC approval and shippers will pay all reservation and capacity fees as if the FDD service began June 1, 2017.[2] If FERC approval is received after August 1, 2017, the service will begin June 1 of the following year. Parameters for the firm service will be as described in Northern's FERC Gas Tariff (Tariff) under the FDD Rate Schedule.

Up to 0.3 Bcf of generally available capacity will be awarded without regard to the FERC approval of the proposed 5.8 Bcf of converted interruptible capacity to firm capacity.

Open Season

The open season commences Tuesday, December 6, 2016, and ends Friday, January 13, 2017, at 5:00 p.m. CCT. For a bid to be considered, it must be received by 5:00 p.m. CCT January 13, 2017. If you have any questions, please contact your account manager or Dave Stockdale at (402) 398-7643.

Bid Procedures

1. Submit your binding bid to Northern either via facsimile to (402) 398-7413 or e-mail to NNGOpenSea@nngco.com. The bid must contain a completed Open Season Bid Form or all the information required by such form. After submission, upon a determination by Northern that the bid is a best bid, the bid becomes a binding contract. If bidder is awarded capacity, bidder shall execute a service agreement upon tender by Northern. All bids must include the firm storage quantity (FSQ) bid, the minimum acceptable FSQ the bidder will accept and the term in years.
2. Bid quantities will only be accepted for service terms commencing on June 1, 2017, that are in full annual increments (June 1 through May 31).
3. Alternative Bid Methodology - The capacity will be awarded to the highest bidder(s) based on a determination of the best bid, or combination of bids that result in the highest net present value (NPV) of reservation revenue, on a per unit of capacity basis. Northern shall have the right to aggregate bids, or portions of bids, that generate the highest NPV to Northern. The NPV per unit will be determined by discounting the cash flow (using the FERC interest rate) generated from an annualized unit rate, based on the firm deferred delivery reservation fee and capacity fee, over the term bid and dividing by the FSQ requested. The annualized unit reservation rate equates to $0.7134 per Dth.
4. Northern will only be accepting maximum tariff rate bids. For purposes of bid evaluation, any bids exceeding twenty years will be economically evaluated as a bid for twenty years.
5. Northern agrees to a rollover charge per Dth equal to $0.00 for any quantity less than or equal to 5% of the contract FSQ on May 31 of each year for the term of the bid.
6. Northern and bidder(s) may agree to amend the service agreement, as allowed by Northern's FERC Gas Tariff, at any time after award of the capacity.
7. Northern will evaluate bids and award the capacity based on the terms of this open season.
8. Customer(s) must meet the creditworthiness provisions of Northern's Tariff. Upon request by Northern, customer shall provide appropriate credit assurance within ten (10) calendar days of Northern's request. If a non-creditworthy customer fails to provide the appropriate security, Northern may award the capacity to the next best bid(s) or proceed to remarket the capacity, and customer will be liable for any difference in value of the bids, in addition to any other remedies available by law.
9. The results will be posted on Northern's website and notification will be made to the winning bidder(s).
10. Northern may consider contingent bids.

[1] Changes to Northern's FERC Gas Tariff that increase the amount of FDD service that can be sold must be approved by the FERC.

[2] In the event the effective date of the FDD service is after June 1, 2017 but before August 1, 2017, the transportation service agreement will be filed as a non-conforming, negotiated rate service agreement.

Non-Critical notices are located on Northern's website at the following address - http://www.northernnaturalgas.com/InfoPostings/Notices/Pages/NonCritical.aspx

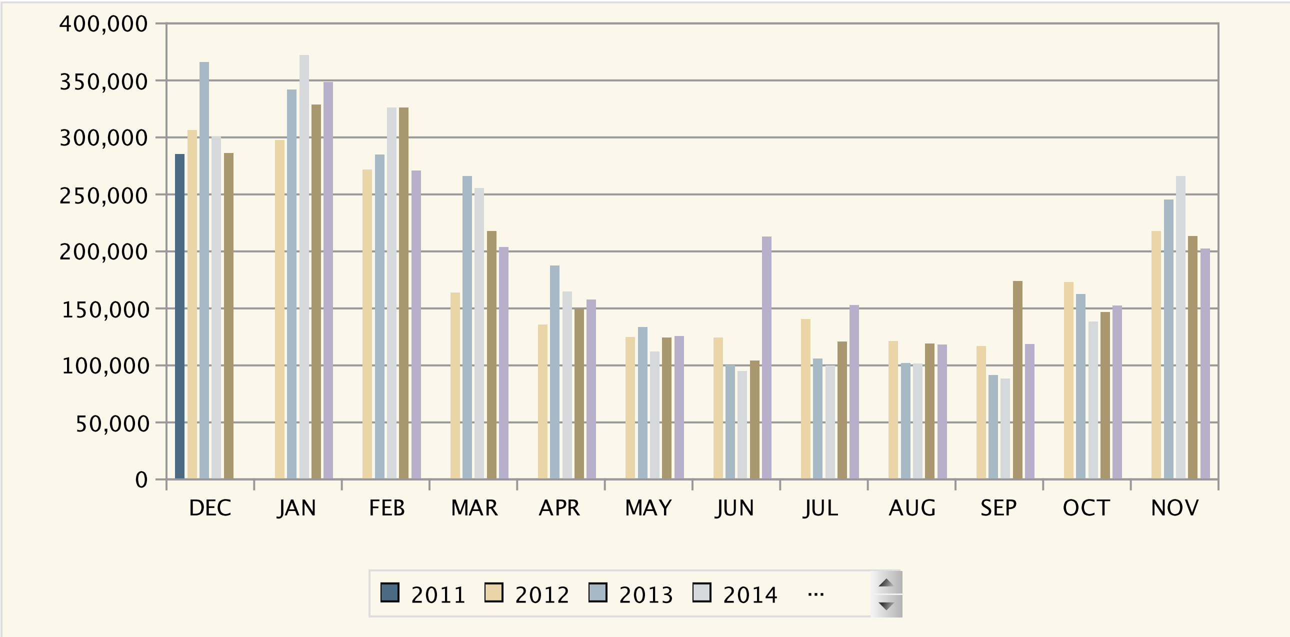
City of Fremont - Firm Storage Contract Information
10/11/16

Contract Type	Contract#	Initial Start Date	Current Start Date	End Date	ROFR or Rollover	FSQ	Max Bal on Aug 31st	Min Bal on Jan 31st	Max Bal on Mar 1st	Max Bal on May 31st	FDD Option Type	Rate Reservation Average	Rate Reservation Winter	Rate Reservation Summer	Rate Commodity	POI	Point Description	
FDD	22309	06/01/93	06/01/11	05/31/19	Rollover	202,510	134,669	81,004	50,628	10,126	4 Step	Max	Max	Max	Max	98	OGDEN DEF. DELIVERY	Max WD FDQ Max INJ FDQ INJ Period Max Bal - 8/31 WD Period Min Bal - 1/31 WD Period Max Bal - 3/1 Max Rollover Bal - 5/31
FDD	111012	06/01/04	06/01/11	05/31/21	ROFR	100,000	66,500	40,000	25,000	5,000	4 Step	Max	Max	Max	Max	98	OGDEN DEF. DELIVERY	Max WD FDQ Max INJ FDQ INJ Period Max Bal - 8/31 WD Period Min Bal - 1/31 WD Period Max Bal - 3/1 Max Rollover Bal - 5/31

Natural Gas Actual Usage - Monthly

City of Fremont Dept. of Utilities

Date Range : 12/01/2011 - 11/30/2016



(All Volumes in MMBtu)

Month	Actual (MMBtu)	MIN (MMBtu)	MAX (MMBtu)	AVG Usage	CO2e (Metric tons)
Dec - 11	285,246	6,771	12,804	9,201	15,532
Jan - 12	297,376	6,437	14,539	9,593	16,193
Feb - 12	271,886	7,059	13,503	9,375	14,805
Mar - 12	163,728	3,132	8,718	5,282	8,915
Apr - 12	135,602	3,180	5,957	4,520	7,384
May - 12	124,726	2,677	4,890	4,023	6,792
Jun - 12	124,333	2,576	8,289	4,144	6,770
Jul - 12	140,712	3,027	8,238	4,539	7,662
Aug - 12	121,327	2,599	4,529	3,914	6,606
Sep - 12	116,862	2,624	4,909	3,895	6,363
Oct - 12	172,862	3,372	8,590	5,576	9,413
Nov - 12	217,735	4,632	11,122	7,258	11,856
Dec - 12	306,320	5,492	13,835	9,881	16,680
Jan - 13	341,719	7,597	15,583	11,023	18,607
Feb - 13	284,656	7,064	13,533	10,166	15,500
Mar - 13	265,836	3,235	11,763	8,575	14,475
Apr - 13	187,618	2,489	9,718	6,254	10,216
May - 13	133,403	1,746	8,514	4,303	7,264
Jun - 13	100,387	1,859	4,235	3,346	5,466
Jul - 13	105,706	1,985	4,172	3,410	5,756
Aug - 13	102,045	1,810	4,244	3,292	5,557
Sep - 13	91,562	1,479	3,973	3,052	4,986
Oct - 13	162,554	3,178	7,711	5,244	8,851
Nov - 13	245,514	4,860	11,982	8,184	13,369
Dec - 13	366,153	6,905	15,501	11,811	19,938
Jan - 14	372,054	6,998	15,887	12,002	20,259
Feb - 14	326,040	8,154	15,674	11,644	17,754

Natural Gas Actual Usage - Monthly
City of Fremont Dept. of Utilities
Date Range : 12/01/2011 - 11/30/2016

(All Volumes in MMBtu)

Month	Actual (MMBtu)	MIN (MMBtu)	MAX (MMBtu)	AVG Usage	CO2e (Metric tons)
Mar - 14	255,399	3,787	13,065	8,239	13,907
Apr - 14	164,496	2,697	9,232	5,483	8,957
May - 14	111,919	1,761	6,366	3,610	6,094
Jun - 14	95,166	1,852	4,070	3,172	5,182
Jul - 14	99,806	2,231	3,960	3,220	5,435
Aug - 14	101,680	2,244	4,154	3,280	5,537
Sep - 14	88,539	1,644	3,981	2,951	4,821
Oct - 14	138,320	2,248	7,321	4,462	7,532
Nov - 14	265,968	4,118	13,598	8,866	14,482
Dec - 14	300,639	4,892	16,453	9,698	16,370
Jan - 15	328,808	7,156	16,147	10,607	17,904
Feb - 15	326,230	6,227	15,482	11,651	17,764
Mar - 15	217,956	3,882	12,934	7,031	11,868
Apr - 15	149,211	3,054	8,168	4,974	8,125
May - 15	124,205	2,632	5,928	4,007	6,763
Jun - 15	103,997	2,831	4,279	3,467	5,663
Jul - 15	121,026	2,388	7,452	3,904	6,590
Aug - 15	118,904	1,917	12,225	3,836	6,475
Sep - 15	173,796	2,920	13,327	5,793	9,464
Oct - 15	146,578	2,849	8,548	4,728	7,981
Nov - 15	213,292	3,755	11,462	7,110	11,614
Dec - 15	286,129	6,250	13,247	9,230	15,580
Jan - 16	348,347	7,096	15,256	11,237	18,968
Feb - 16	270,935	4,540	12,517	9,343	14,753
Mar - 16	203,618	3,827	11,572	6,568	11,087
Apr - 16	157,475	2,984	7,818	5,249	8,575
May - 16	125,573	2,404	5,330	4,051	6,838
Jun - 16	212,898	2,734	12,361	7,097	11,593
Jul - 16	152,977	2,643	14,676	4,935	8,330
Aug - 16	118,097	1,525	5,062	3,810	6,431
Sep - 16	118,868	2,898	4,740	3,962	6,473
Oct - 16	152,236	2,731	12,657	4,911	8,290
Nov - 16	202,373	4,022	10,069	6,746	11,020
Totals:	11,559,423	1,479	16,453	6,345	629,435

Input #	
72,000	MMBTU
Cycle Quantity	

FDD BILLING EXAMPLE

The storage rates shown in the table are the tariff rates starting November 1, 2006.

Ref Tariff Sheet Nos. 54 & 55

	FDD Season Jun-Oct	FDD Season Nov-May
Reservation Rate	1.714	1.7140
Capacity Rate	0.3567	0.3567
Injection/Withdrawal Rate	0.0149	0.0149
Overrun	0.0887	0.0887

COMPONENTS		Jun-Oct RATE	Nov-Apr RATE	BILLING QUANTITY	
RESERVATION FEE	* 1	$1.7140	$1.7140	MAXIMUM DAILY W/D QUANTITY 1,249	MMBTU
CAPACITY FEE	* 2	$0.3567	$0.3567	ANNUAL CYCLE QUANTITY 72,000	MMBTU
INJECTION and WITHDRAWAL FEES	* 3	SEE INFORMATION AT RIGHT		ACTUAL QUANTITIES	

	INJECTION PERIOD					WITHDRAWAL PERIOD							
	MONTHS					MONTHS						OVERRUN ONLY	
	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	JAN.	FEB.	MARCH	APRIL	MAY	TOTAL
RESERVATION FEE	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$2,140	$25,685
CAPACITY FEE	$5,136	$5,136	$5,136	$5,136	$5,136								$25,682

Injection Period	Withdrawal Period	Total
Inject. w/in Firm Reqrmts: $0.0149 per MMBTU	W/D w/in Firm Reqrmts: $0.0149 per MMBTU	$2,146
Inject. Overrun $0.0149 plus $0.0887 per MMBTU	W/D Overrun $0.0149 plus $0.0887 per MMBTU	Increm. Cost (if ar
W/D w/in Firm Reqrmts: $0.0887 per MMBTU	Inject. w/in Firm Reqrmts: $0.0887 per MMBTU	Increm. Cost (if ar
W/D Overrun $0.0887 per MMBTU	Inject. Overrun $0.0887 per MMBTU	Increm. Cost (if ar

FDD STORAGE FUEL see Tariff Sheet No. 54 for most current rate → ACTUAL SUMMER INJECTIONS

Note * 1: Rate x maximum daily w/d volume, billed monthly over 12 months

Note * 2: Rate x annual cycle volume, billed equally over the injection period, only

Note * 3: Rate x actual monthly injection or withdrawal volume equals each monthly bill

TOTAL FDD BILLING	$53,513
(w/o any increm. cost)	
FDD UNIT COST	$0.7432
(w/o any increm. VOL.)	PER MMBTU

FDU Gas Sales

	2014	2015	2016		Costco
Jan	372,054	328,808	348,347		45,000
Feb	326,040	326,230	270,935		45,000
Mar	255,399	217,956	203,618		45,000
Apr	164,496	149,211	157,475		45,000
May	111,919	124,205	125,573		45,000
Jun	95,166	103,997	212,898		45,000
Jul	99,806	121,026	152,977		45,000
Aug	101,680	118,904	118,097		45,000
Sept	88,539	173,796	118,868		45,000
Oct	138,320	146,578	152,236		45,000
Nov	265,968	213,292	202,373		45,000
Dec	300,639	286,129	300,000		45,000
Total Year	2,320,026	2,310,132	2,363,397		540,000
				Avg sales	2,331,185
Current storage	302510			New sales	2,871,185

	2014	2015	2016	New storage needs
% of storage to sales	13.04%	13.09%	12.80%	70744

STAFF REPORT

TO: Board of Public Works

FROM: Brian Newton, General Manager

DATE: January 4, 2017

SUBJECT: Clawback Agreement with Costco

Recommendation: Authorize the General Manager to execute the clawback agreement with Costco and recommend approval by the City Council.

Background: As part of the Amended and Restated Redevelopment Agreement with Costco the City agreed to provide Costco a $2,000,000 Economic Incentive for the installation and construction of utility infrastructure; subject to certain clawback provisions. Clawback provisions include a 15-year commitment by Costco to not discontinue use of its agricultural and industrial processing facilities and to meet yearly minimum utility consumption requirements. Failure to meet the provisions will require Costco to repay all or a portion of the Economic Incentive.

Fiscal Impact: None

CLAWBACK PROVISIONS AND INDEMNIFICATION AGREEMENT

This Clawback Provisions and Indemnification Agreement (the “Agreement”) is made and entered into on this ___ day of ________, _________, between the City of Fremont, a municipal political subdivision of the State of Nebraska (“City”), whose address for the purposes of this Agreement is 400 E Military Ave, Fremont NE 68025, and Costco Wholesale Corporation, a Washington corporation (“Costco”), whose address for the purposes of this Agreement is 999 Lake Drive, Issaquah, WA 98027.

PRELIMINARY STATEMENT

The City has agreed to provide Costco a $2,000,000 incentive (“Economic Development Incentive”) in the Amended and Restated Redevelopment Agreement dated ___________, ________ (“Redevelopment Agreement”) in connection with the installation and construction of utility infrastructure (electric, natural gas, water, and wastewater) the general locations as legally described on the attached Exhibit “A” (the “Costco Property”) to be owned by Costco and operated by Lincoln Premium Poultry as an agricultural and industrial processing facility so long as Costco or its lessee and/or operator consumes minimum volumes of utility services depicted in attached Exhibit “B” (the “Minimum Utility Requirements”) during the term of this agreement. Should Costco fail to meet the Minimum Utility Requirements during the term of this agreement, Costco has agreed to reimburse the City’s incentive, subject to the terms and conditions set forth herein.

TERMS AND CONDITIONS

Now, therefore, in consideration of the foregoing Preliminary Statement which is included herein by this reference and the mutual covenants of the parties hereto, it is agreed as follows:

1. Term: The term of this agreement shall be fifteen (15) years commencing (“Term”) one (1) year following the date of commercial operation.

2. Utility Consumption Reporting: Within ninety (90) days after receipt, Costco shall pay all utility consumption bills, and with such payment, Costco shall provide a summary of its utility consumption, which shall include a reasonable level of detail describing the utility service provided, the actual amount of utility services consumed by Costco, and the disparity between the actual utility services consumed on the Costco Property and the Minimum Utility Requirements.

3. Reimbursement: Costco shall reimburse the City the Economic Development Incentive upon the occurrence of the following events:

   a. If Costco elects to discontinue its use of the facilities at the Costco Property as contemplated in the Redevelopment Agreement during the Term of this Agreement, within thirty (30) days of such election Costco must: (1) notify the City in writing of such election, and (2) reimburse the Department of Utilities for the Economic Development Incentive in full; or

   b. If, at the end of the Term, Costco has not met the yearly Minimum Utility Requirements set forth on Exhibit “B”, within thirty (30) days following the expiration of the Term of this Agreement, Costco shall reimburse the Department of Utilities a portion of the two million dollar ($2,000,000.00)

Economic Development Incentive which corresponds to Costco's average overall deficiency percentage calculated as follows:

i. Every year during the Term of the Agreement for each of the four utilities listed on Exhibit "B", it shall be determined whether Costco met the Minimum Consumption Requirements for that utility outlined in Exhibit "B." If Costco did not meet the Minimum Consumption Requirements for some or all of the four utilities, the difference between the actual consumption and Minimum Consumption Requirements for each utility that did not meet the Minimum Consumption Requirements shall be used to calculate the percent Costco was deficient in meeting the Minimum Consumption Requirements for that utility as follows:

$$\frac{\text{Minimum Consumption Requirement } (-) \text{ Actual Consumption}}{\text{Minimum Consumption Requirement}} \;(X)\; \frac{X}{100} = \text{Deficiency \%}$$

ii. After the deficiency percentage is calculated for each utility as applicable, the deficiency percentage for each such utility shall be averaged by totaling said individual percentages and dividing the total by four (4) to produce an aggregate deficiency percentage for the year. No credit shall be given for consuming more than the Minimum Utility Requirements for any utility.

iii. After the aggregate yearly deficiency percentage is calculated for each year during the Term of the Agreement, the yearly deficiency percentage for each year shall be totaled, and the total shall be divided by the number of years in the Term to produce the average aggregate deficiency percentage for the Term, which aggregate percentage shall be multiplied by the amount of the Two Million Dollar Economic Development Incentive, the product of which is the amount which Costco must repay to the City pursuant to this Agreement.

4. Costco hereby agrees to indemnify and hold City harmless from and against any and all liabilities, expenses including reasonable attorneys' and engineers' fees, orders, lawsuits, causes of actions, claims, damages, costs, penalties, fines, interest and demands whatsoever suffered, threatened against, or paid, or incurred by City in connection with, or arising from, Costco's failure to reimburse the City.

5. This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the parties.

6. All notices or other communications required or permitted by this Agreement shall be in writing and in all cases addressed to the party at the location or address indicated above. Such notice shall be considered to be properly given by and received by a party (i) whenever delivered in person, or (ii) on the date a return receipt is signed by a party when sent by certified mail, regardless of when received or delivered. A party shall have the right to change its address for notice or other communication to any other person or location within the continental United States by giving prior written notice to the other party.

7. This Agreement may be executed in counterparts, each of which will be deemed an original and all of which together will constitute one agreement. Each counterpart may be delivered by facsimile or computer-scanned image transmission. The signature page of any counterpart may be detached therefrom without impairing the legal effect of the signature(s) thereon provided such signature page is attached to any other counterpart identical thereto.

8. No amendment of this Agreement shall be valid unless it is in writing and is signed by the parties or by their duly authorized representatives, and unless it specifies the nature and extent of the amendment.

9. The City and Costco each agree to abide by all federal, state, and local laws, statutes, ordinances and regulations governing the activities discussed herein. Costco shall comply with, and indemnify the City against any violations of applicable regulations promulgated by the Environmental Protection Agency or other government agencies regulating any activities engaged in by Costco.

10. This Agreement, and the rights and duties of the parties arising from or relating in any way to the terms, covenants, or conditions of this Agreement shall be governed by, construed and enforced in accordance with the laws of the State of Nebraska.

[Signature Page Follows]

IN WITNESS WHEREOF, this Agreement was executed on the date as first written hereinabove.

COSTCO WHOLESALE CORPORATION	**CITY OF FREMONT, NEBRASKA**,
a Washington corporation,	a municipal political subdivision of the State of Nebraska,
By:______________________________	By:______________________________ Scott Getzschman, Mayor
Name:__________________________	
Title:___________________________	
ATTEST	APPROVED AS TO FORM
______________________________ Tyler Ficken, City Clerk	______________________________ Paul Payne, City Attorney

[Signature Page to Clawback Provisions and Indemnification Agreement]

<u>Exhibit "A"</u>

("Costco Property")

A TRACT OF LAND TO BE ANNEXED INTO THE CITY OF FREMONT, LOCATED IN PART OF NORTHEAST AND NORTHWEST QUARTERS OF SECTION 26, TOWNSHIP 17 NORTH, RANGE 8 EAST OF THE 6TH P.M., DODGE COUNTY, NEBRASKA, MORE PARTICULARLY DESCRIBED AS FOLLOWS:

BEGINNING AT THE NORTHWEST CORNER OF THE SOUTHEAST QUARTER OF SECTION 26, TOWNSHIP 17 NORTH, RANGE 8 EAST, DODGE COUNTY, NEBRASKA, THENCE EASTERLY ON AN ASSUMED BEARING OF N87°43'50"E ON THE NORTH LINE OF THE SOUTHWEST QUARTER OF SECTION 26, 1130.95 FEET TO A POINT ON THE APROXIMATE WESTERLY RAILROAD RIGHT-OF-WAY LINE; THENCE S05°07'33"E ON SAID WESTERLY RAILROAD RIGHT-OF-WAY LINE, 1178.00 FEET TO A POINT INTERSECTING THE NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD; THENCE N59°05'58"W ON SAID NORTHERLY RIGHT-OF-WAY LINE; 697.41 FEET; THENCE CONTINUNING N86°26'21"W, ON SAID NORTHERLY RIGHT-OF-WAY LINE, 1931.80 FEET; THENCE N02°10'38"W, 1162.85 FEET TO THE NORTHWEST CORNER OF LOT 6, EAST INGLEWOOD SUBDIVISION, A PLATTED AND RECORDED SUBDIVISION IN DODGE COUNTY; THENCE N87°42'03"E ON THE NORTH LINE OF SAID LOT 6, 545.50 FEET TO THE NORTHEAST CORNER OF SAID LOT 6; THENCE N02°06'54"W ON THE EAST LINE OF LOT 5, SAID EAST INGLEWOOD SUBDIVISION, 283.94 FEET TO A POINT ON THE EAST LINE OF LOT 4, SAID EAST INGLEWOOD SUBDIVISION; THENCE N88°10'00"E, 772.03 FEET TO A POINT ON THE WEST LINE OF THE SOUTHWEST QUARTER OF THE NORTHEAST QUARTER; THENCE S01°58'55"E ON SAID WEST LINE OF THE NORTHEAST QUARTER, 842.47 FEET TO THE POINT OF BEGINNING.

SAID TRACT OF LAND CONTAINS A CALCULATED AREA OF 2,839,313.53 SQ. FT. OR 65.18 ACRES MORE OR LESS.

AND

A TRACT OF LAND TO BE ANNEXED INTO THE CITY OF FREMONT, LOCATED IN PART OF SOUTHEAST QUARTER OF THE NORTHEAST QUARTER, AND PART OF THE EAST HALF OF THE SOUTHWEST QUARTER OF SECTION 26, AND PART OF THE SOUTH HALF OF THE NORTHWEST QUARTER AND PART OF THE SOUTHWEST QUARTER AND PART OF THE WEST HALF OF THE SOUTHEAST QUARTER OF SECTION 25, AND PART OF THE NORTHWEST QUARTER OF THE NORTHEAST QUARTER OF SECTION 36, TOWNSHIP 17 NORTH, RANGE 8 EAST OF THE 6TH P.M., DODGE COUNTY, NEBRASKA, MORE PARTICULARLY DESCRIBED AS FOLLOWS:
COMMENCING AT THE SOUTHWEST CORNER OF THE NORTHEAST QUARTER OF THE NORTHEAST QUARTER OF SAID SECTION 26; THENCE NORTHEASTERLY ON THE NORTH LINE OF THE NORTHEAST QUARTER OF THE NORTHEAST QUARTER ON AN ASSUMED BEARING OF N87°52'30"E, 33.00 FEET TO THE POINT OF BEGINNING; THENCE S58°58'04"E, 191.84 FEET TO A POINT ON THE SOUTHERLY RIGHT-OF-WAY LINE OF EAST CLOVERLY ROAD; THENCE N88°05'46"E ON SAID SOUTHERLY RIGHT-OF-WAY LINE OF EAST CLOVERLY ROAD, 1425.78 FEET TO A POINT OF CURVATURE; THENCE ON A 1308.22 FOOT RADIUS CURVE TO THE RIGHT ON SAID SOUTHERLY RIGHT-OF-WAY LINE OF EAST CLOVERLY ROAD, AN ARC LENGTH OF 1030.78 FEET (LONG CHORD BEARS S69°21'38"E, 1004.32 FEET); THENCE S46°47'16"E ON SAID SOUTHERLY RIGHT-OF-WAY LINE OF EAST CLOVERLY ROAD, 1238.40 FEET TO A POINT OF CURVATURE; THENCE ON A 260.00 FOOT RADIUS CURVE TO THE LEFT ON SAID SOUTHERLY RIGHT-OF WAY LINE OF EAST CLOVERLY ROAD, AN ARC LENGTH OF 145.89 FEET (LONG CHORD BEARS S62°49'54"E, 143.98 FEET); THENCE

S43°15’’11”W, 507.62 FEET; THENCE S02°10’141”E, 149.93 FEET; THENCE S87°49’55”E, 729.97 FEET; THENCE N02°07’45”W, 189.94 FEET; THENCE N02°07’45”W, 256.01 FEET TO A POINT ON THE APPROXIMATE SOUTHWESTERLY RAILROAD RIGHT-OF-WAY LINE; THENCE S46°46’20”E ON SAID SOUTHWESTERLY RAILROAD RIGHT-OF-WAY LINE, 1911.83 FEET TO A POINT ON THE EAST LINE OF SAID WEST HALF OF THE SOUTHEAST QUARTER; THENCE S02°14’28”E ON SAID EAST LINE OF THE WEST HALF, 1107.05 FEET TO THE SOUTHEAST CORNER OF THE SOUTHWEST QUARTER OF THE SOUTHEAST QUARTER; THENCE S02°12’31”E ON THE EAST LINE OF SAID NORTHWEST QUARTER OF THE NORTHEAST QUARTER OF SECTION 36, 1356.15 FEET TO A POINT ON THE NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD; THENCE N70°35’17”W ON SAID NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD, 1410.04 FEET; THENCE N02°14’36”W, 711.27 FEET; THENCE N71°00’17”W, 375.56 FEET TO A POINT ON THE SOUTH LINE OF SAID SOUTHWEST QUARTER OF SECTION 25; THENCE CONTINUING N71°00’17”W, 825.89 FEET; THENCE N70°58’58”W, 290.07 FEET; THENCE N62°51’54”W, 488.40 FEET; THENCE S01°12’50”E, 631.29 FEET TO A POINT ON SAID SOUTH LINE OF THE SOUTHWEST QUARTER; THENCE N58°57’36”W ON THE NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD, 984.75 FEET TO A POINT INTERSECTING THE NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD AND THE WEST RIGHT-OF WAY LINE OF YAGER ROAD; THENCE N02°09’03”W ON SAID WEST RIGHT-OF-WAY LINE OF YAGER ROAD, 306.92 FEET TO THE NORTHEAST CORNER OF LOT 1R, REPLAT OF BLOCK 1 SOUTH FREMONT; THENCE S87°49’05”W ON THE NORTH LINE OF SAID LOT 1R, 226.99 FEET TO THE NORTHWEST CORNER OF SAID LOT 1R; THENCE S02°11’37”E ON THE WEST LINE OF SAID LOT 1R, 161.11 FEET TO A POINT ON SAID NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD; THENCE N59°08’09”W ON SAID NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD, 1231.92 FEET TO A POINT INTERSECTING SAID NORTHERLY RIGHT-OF-WAY LINE OF HILLS FARM ROAD AND THE EAST RIGHT-OF-WAY LINE OF SOUTH PLATTE AVENUE; THENCE N02°07’30”W ON SAID EAST RIGHT-OF-WAY LINE OF SOUTH PLATTE AVENUE, 2604.69 FEET TO THE POINT OF BEGINNING.

SAID TRACT OF LAND CONTAINS A CALCULATED AREA OF 15,119,539.82 SQ. FT. OR 347.10 ACRES MORE OR LESS.

Exhibit "B"

("Minimum Utility Requirements")

Utility:	**Minimum Yearly Requirements:**
Electric	10.15 MW
	62,380,800 kWh
Water	597,600,000 Gal
Wastewater	584,400,000 Gal
Natural gas	897,600 Dkt

WWTP ANNUAL REPORT 2015/2016

Agenda Item #7a

- WWTP 10 Employees
- Superintendent
- Lab Technician
- 5 Operators
- 3 Mechanics

Annual Budget 2015/2016			
Account	Budget	Actual	%
Wages	562000	531066	94.5
Benefits	290955	284031	97.6
Commodities	404000	425291	105.3
Contractual Services	438070	435184	99.4
Depreciation	819400	805774	98
Capital Projects	435000	338536	77.8
Total	**2,560,900**	**2,502,819.04**	**97.70**

Agenda Item #7a

CAPITAL EXPENDITURES

	Budget	Actual	
Roof Replacement	75,000.00	88,895.00	
Headwork's Heating System	110,000.00	98,450.00	
Dissolved Oxygen TSS meters	50,000.00	24,900.00	
Tractor	50,000.00	43,459.00	
Compost Screen	175,000.00	82,832.00	145,168.00 Grant (228,000)
Total	460,000.00	338,536.00	

WASTEWATER TREATED

- 1,661,112,000 Gallons/yr.
- 137,630,000 Gallons/month
- 4,614,200 Gallons/day
- 1.507 Cost/1000 gallons (1.021/1000 gallons)

Agenda Item #7a

BIOSOLIDS PROGRAM

- Biosolids Hauled/spread – 4730 tons
- Spread on 450 acres
- Hauling $31,984.00
- Spreading $22,920.00
- Scale $1348.00
- Total Expenses **$56,252.00**
- **Biosolids Income $48,735.00**
- **Net cost $7517.00**

Agenda Item #7a

WWTP UPGRADE

- HDR – Design and Specifications
- 30-35 Million estimated cost
- 25% complete
- Plans and Specs to DEQ (May 31, 2017)
- June/August 2017 bid????
- Completion by November 2019

Agenda Item #7a

Nebraska Public Power's Competitiveness in the Regional Energy Market

Produced for Wind is Water Foundation

December 12, 2016

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Table of Contents

Nebraska Public Power's Competitiveness In the Regional Energy Market

Preface

Nebraska Public Power's Competitiveness In the Regional Energy Market

The subsequent analysis was prepared for Wind is Water by Ernest Goss, Ph.D., Principal Investigator, and Jeff Milewski of Goss & Associates Economic Solutions. Findings remain the sole property of Wind is Water Foundation and may not be used without prior approval of this organization. Any errors or misstatements contained in this study are solely the responsibility of the authors.[1] The authors' biographies are provided in Appendix G. Please address all correspondence to:

Goss & Associates, Economic Solutions, LLC

Goss & Associates

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Goss & Associates thanks Wind is Water Foundation for their assistance in providing data for this study. However, any errors, omissions, or misstatements are solely the responsibility of Goss & Associates and the principal investigator.

Goals of the study

The goal of this study was to examine how Nebraska's power industry operates within the Southwest Power Pool, particularly the integrated marketplace, and to determine whether Nebraska's Public Power Model is adequately serving the ratepayer.

Specific goals of the study are to:

- Determine whether increased competition and choice in Nebraska's power industry leads to cheaper sources of electricity and better rates for consumers.
    - o If so, explore how increasing competition and choice affect Nebraska's generating utilities, consumer-utilities, and ratepayers.
- Examine how federal tax credits for renewables and environmental regulations, particularly the new Clean Power Plan, would affect Nebraska's public power utilities.
- Investigate how Nebraska's public power structure restricts choice. What disincentivizes private capital from investing in Nebraska's electricity sector?
- Determine whether legislative changes would help increase transparency and promote greater choice in the electric industry in Nebraska.

[1] This study was completed independent of Creighton University. As such, Creighton University bears no responsibility for findings or statements by Ernie Goss, or Goss & Associates, Economic Solutions.

Executive Summary

Nebraska Public Power's Competitiveness In the Regional Energy Market

- Since the implementation of the SPP Integrated Market (IM) in March 2014, electricity prices have trended downward due to the addition of wind generation and low natural gas prices. Because of the high cost of production at some plants in Nebraska, ratepayers have not fully benefited from the more than $1 billion saved by lower electricity prices from the SPP IM. Until Nebraska's generation costs are reduced, ratepayers will not benefit from the lower prices in the SPP IM.
- The cost effectiveness of Nebraska's public power generation is currently at risk in the SPP IM. There are two main reasons for this: (1) low natural gas prices; and (2) additional wind generation in the SPP footprint.
- The financial risk to ratepayers in owning generation is increasing, as seen with the decommissioning of the Fort Calhoun nuclear plant. Divesting from generating assets and embracing retail choice could reduce ratepayers' risk by eliminating the potential future costs of stranded assets.
- A more competitive energy landscape would allow consumers to choose among public and private power providers in the state. This arrangement is commonly referred to as "retail choice." In a competitive, retail choice environment, Nebraska public power could pursue a strategy to divest from owning generating assets, and instead, focus solely on the management and operation of transmission and distribution systems. This would incentivize competition to produce from the cheapest sources of generation and substantially reduce the ratepayer risk and uncertainly of owning generation in a changing energy market.

Section 1 - The Southwest Power Pool's Integrated Marketplace Challenges Nebraska's Public Power Model

Introduction

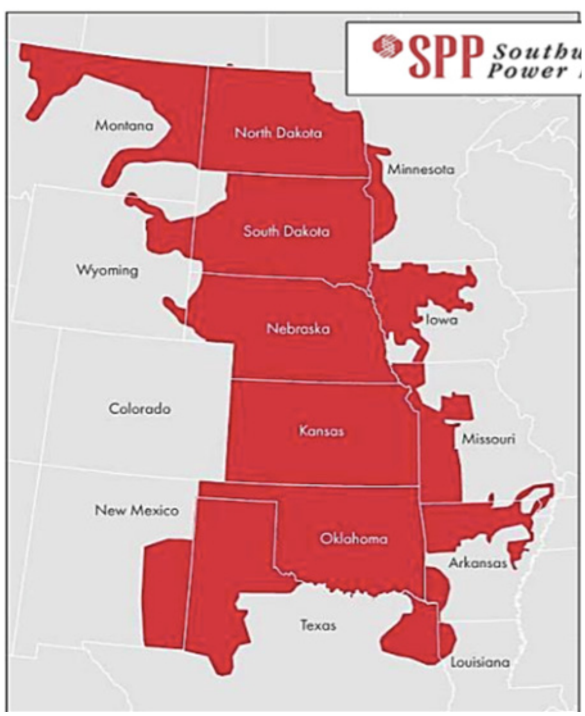
The Southwest Power Pool (SPP) is a regional transmission organization (RTO) based in Little Rock, Arkansas with approximately 600 employees. It covers all or parts of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

Figure 1.1 shows the SPP footprint. As of June 2016, the SPP had 94 members and 175 market participants (See Appendix A). Several Nebraska Public Power utilities own transmission, including the Nebraska Public Power District (NPPD) and the Omaha Public Power District (OPPD). NPPD and OPPD joined the SPP in 2009.

The SPP footprint recently expanded in October 2015 to include much of North Dakota and South Dakota, and parts of Montana.[2] This expansion added 5,000 megawatts of demand and 9,500 miles of transmission lines. The expansion added more wind production to the SPP footprint and integrated market.

In 2014, the SPP established a pooled marketplace, referred to as the Integrated Market (IM), for buying and selling electricity to its Market Participants (MP). Market Participants in the IM are members of the SPP, which consists of private and public utilities, independent power generators, and retail providers. The purpose of the IM is to optimize generation to meet the demand for the SPP footprint by determining which generation is dispatched for maximum cost-effectiveness.

Figure 1.1: SPP Footprint, 2016



Source: SPP

[2] http://www.spp.org/about-us/newsroom/southwest-power-pool-expands-electric-grid-management-to-14-states/.

When the IM became operational in 2014, the SPP consolidated 16 balancing authority areas into a single balancing authority. This meant that the SPP, instead of the individual SPP members, became responsible for balancing the supply and demand to ensure reliability over the entire SPP footprint. SPP does not own the transmission grid but independently operates it to ensure reliability, and manages long-term planning for future needs. The SPP members continue to own their transmission systems within the SPP footprint.

Essentially, electricity is a commodity that is traded like any other commodity. In the Integrated Marketplace, the SPP acts as the market operator, responsible for clearing transactions. As a market operator, the SPP determines which power is bought and sold based on current demand (load) and supply from electricity generators located throughout the power pool footprint.

The IM has a day-ahead market, where the market price changes hourly, and a real-time market, where the market price changes every 5 minutes. MPs can either submit load and generation into either the day-ahead or real-time market.

A total of 83,465 megawatts (MW) of generation capacity is available from 756 generating plants participating in the SPP integrated market. This currently provides a reserve capacity of 28% to ensure that the SPP can reliably meet demand for electricity during extreme peak times when loads are high.

To put this in perspective, all the current generation in Nebraska could be eliminated and the excess reserve capacity in the SPP integrated market would be enough to supply all customer demand in Nebraska.

The SPP IM does not select generation based on fuel type but on bid price and reliability. The market determines the winners and losers of generation based on the marginal production cost, which does not include any fixed costs.

Since the start of the SPP integrated marketplace, estimated electricity cost savings to MPs have totaled more than $1 billion.[3]

Since the start of the SPP integrated marketplace, estimated electricity cost savings to MPs have totaled more than $1 billion.

How is the SPP market price determined?

In the integrated market, each market participant bids in generation to supply their forecasted load for the following day as required by the SPP. The MP does not have to submit 100% of its forecasted load into the day-ahead market; a portion of the forecasted load can be submitted into the day-ahead market and the remaining portion of the load can be purchased from the real-time market.

Market participants bid generation into the IM based on their marginal cost of production, as allowed by SPP requirements. The generation bid amount does not include any fixed costs. The following terms used for the SPP IM are defined for the purposes of this report:

Generation. Generation is the ability of power plants to generate electricity that is bid into the SPP IM. Generation is also known as capacity, which is the amount of generation that a power plant is capable of producing at a given moment in time. For instance, if a 1,000 MW power plant is sitting idle and is capable of producing 1,000 MW of electricity if called upon (dispatched), then it would have 1,000 MW of capacity that could be bid into the SPP IM. If the same 1,000 MW power plant could only produce 800 MW of electricity, if called upon, due to being derated, then it would only have 800 MW of capacity available to bid into the SPP IM, not 1,000 MW.

There are three types of generation: baseload, intermediate, and renewable. Baseload generation is either fossil fuel or nuclear that are designed to operate at a constant output.

[3]https://www.spp.org/about-us/newsroom/total-savings-from-spp-s-markets-cross-the-1-billion-mark/.

Intermediate generation is designed to change output more quickly than baseload generation and is used when the demand for electricity changes.

Renewable generation output is based on the conditions (wind and sun) at any given time. Due to variable weather conditions, renewable generation cannot always generate at 100% of its rated output, SPP credits 10% of its rated output for capacity in the SPP IM.

Marginal Cost of Production (or Incremental Energy Cost). This is the incremental cost of a generator to produce electricity. This includes fuel and variable operations and maintenance (O&M) costs. Variable O&M costs are costs for items that are needed to produce electricity, but not needed when the plant is sitting idle. The marginal cost of production changes due to the plant's efficiency at different outputs. The plant does not incur the marginal cost of production when the plant is not producing electricity.

Fixed Cost. This is the generator's cost that does not change based on the output of the generation. This cost would be the same if the plant was sitting idle or operating at 100% of its capacity. Fixed costs include items like labor, debt service, routine maintenance, facilities, and corporate charges.

Cost of Production. This is the total cost of generation, which is sometimes referred to as busbar cost. Cost of production includes both the marginal cost of production and fixed cost.

SPP IM Market Price. This is the price established by SPP based on the generation and load submitted by the SPP Market Participants into the SPP IM. The Market Participants purchase electricity from the SPP IM at their purchase node. For Nebraska public power, the SPP North Hub is used for pricing the electricity that is purchased. Generation that is dispatched by SPP receives the market price for their electricity at the SPP pricing node for the generation's location. Each generation source in the SPP footprint has an SPP pricing node. Since cost data isn't available for Nebraska public power generation, the SPP North Hub market pricing will be used in this report.

Generation or Capacity Cost. This is the difference between the cost of production and the SPP market price at the generator's pricing node (Annual Cost of Production - Annual Revenue from the SPP IM). This is the cost to the Market Participant for owning the generation. If the cost of production is more than the SPP market price, the cost must be passed through to the ratepayers in the rates.

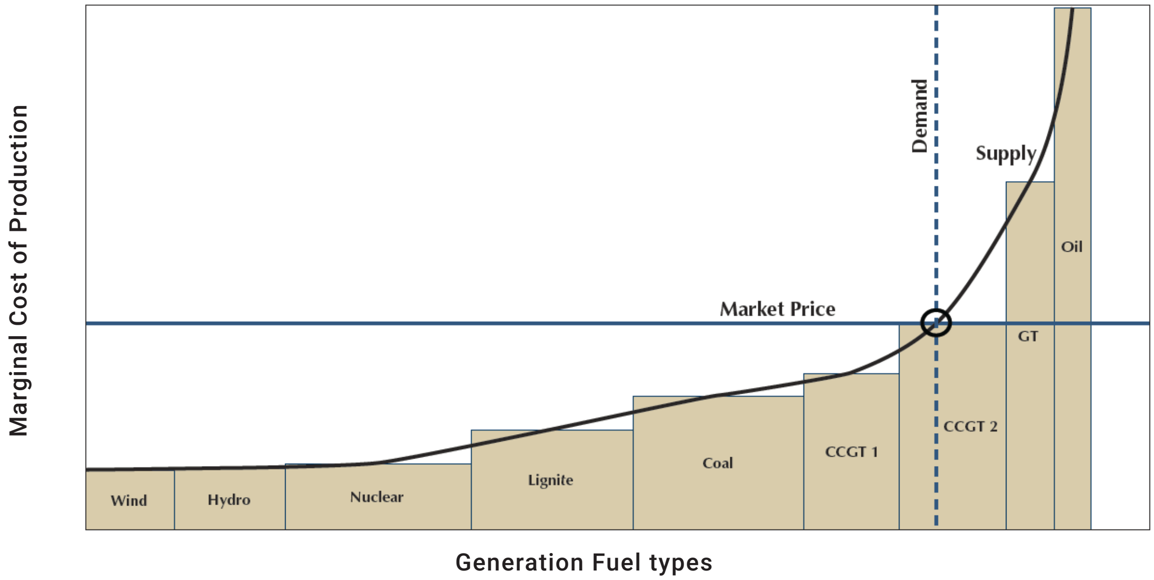
If a power plant that produces 6.8 million megawatt-hour (MWh) of electricity annually with a cost of production of $306 million, and the average annual SPP market price is $20/MWh, the generation cost for that year that must be passed on to the ratepayers is $170 million ($306 million - (6.8 million x $20)).

The SPP combines the forecasted load (demand) of all market participants to determine how much generation is needed to provide the most cost-effective and reliable combination of generation to be dispatched the following day.

For example, Figure 1.2 shows the forecasted load (demand line) and generation (supply curve) intersecting at the CCGT2 generator. The SPP will dispatch CCGT2 and all the generation units left of CCGT2 (i.e. the generators with the lowest marginal cost of production: CCGT1, Coal, Lignite, Nuclear, Hydro, and Wind). In the day-ahead market, the forecast load and generation are bid (offered) in hourly so the dispatch of generation and IM price changes hourly. If an MP's generation isn't selected to be dispatched for any hour in the day-ahead market, the MP can bid their generation into the real-time market using the same bid criteria as the day-ahead market. The MP is not required to submit their total forecasted load in the day-ahead market; load can be purchased from the real-time market at the real-time market price.

The market price in the integrated market is determined by the price of the next available generator that could be dispatched at the forecasted demand (see Figure 1.2). The graph shows the forecasted load (demand) and generation (supply) curve intersect at CCGT 2's marginal cost of production. At this intersection point, the market price is established at the bid price (i.e. marginal cost of production) of CCGT 2. If the market bid price for CCGT 2 was $23.74/MWh, then all

Figure 1.2: How the supply and demand of electricity signals price based on the dispatch order of different generation assets



Source: Goss & Associates

generation bids in the day-ahead market with lower marginal cost of production than CCGT 2 (left of the Demand line) would receive the same market price of $23.74/MWh for that hour.

Since the IM bid (offer) price for generation is based on fuel price, the dispatch order can change depending on fluctuations of fuel prices for different forms of generation. Due to the current generation mix and low gas prices in the SPP footprint, gas-fired generation is on the margin, meaning that gas generators are typically the last generation units dispatched during high demand (on-peak) periods.

During periods of very low demand (off-peak), it is possible that the SPP IM price can go negative because there is more supply than demand. Excess supply is created when large baseload plants (e.g. coal and nuclear) are unable to change output levels fast enough to react to changes in demand. Gas and renewable generators have the ability to rapidly adjust output, making them better able to capitalize on changing market conditions.

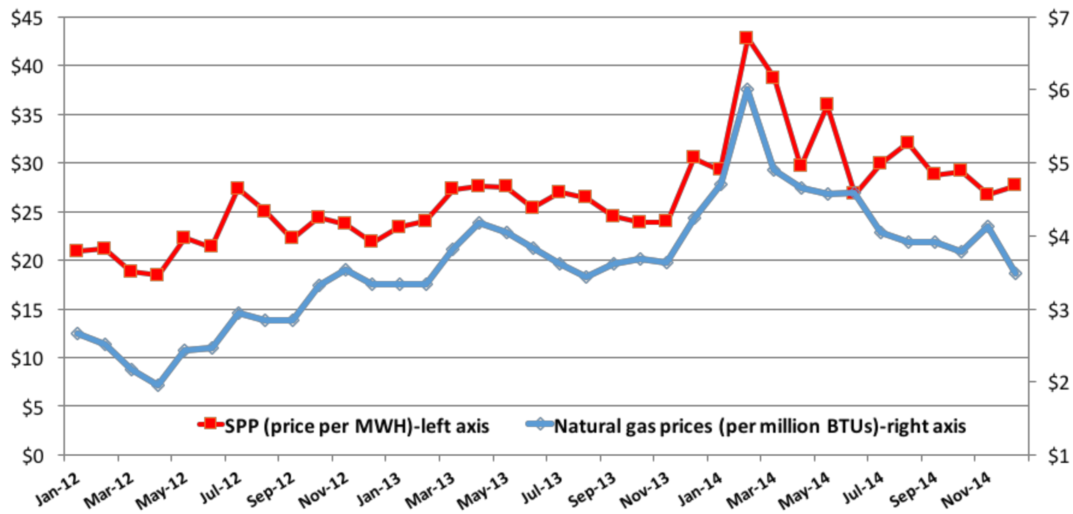
Natural gas prices have trended downward since the second half of 2008. Since electricity produced from gas-fired generators are dispatched as the marginal fuel supply, lower natural gas prices put downward pressure on the wholesale market price in the SPP's IM.

As explained above, it becomes increasingly important to own generation (capacity) with the lowest cost of production, not the lowest marginal cost of production, when participating in the SPP integrated market. The MP's customers must make up the difference between the cost of production and the market price.

Figure 1.3 profiles the relationship between the price of natural gas and SPP wholesale market prices. The data supports a strong positive association between the price of natural gas and SPP market prices. In fact, the correlation coefficient between natural gas prices and SPP market prices from January 2012 to December 2014 was 0.87 indicating that the two move in almost lockstep.[4]

[4]The linear correlation coefficient, measures the strength and the direction of a linear relationship between two variables, in this case natural gas prices and SPP prices. The value ranges between -1.0 and +1.0. A larger the value, the greater the association (e.g. +1.0 indicates two variables move in perfect lock step such as farenheit and centigrade temperature).

Figure 1.3: Natural gas prices and SPP day ahead locational market price, Jan. 2012- Nov. 2014



Source: Goss & Associates, SPP and Federal Reserve of St. Louis

Table 1.1 lists the electricity capacity and consumption by fuel type. As indicated, the consumption and capacity of coal generation has steadily declined, although coal consumption has declined more significantly than the capacity. This indicates that utilities in the region have not altered their generation mix capability as fast as market conditions dictate.

It also supports the hypothesis that electricity producers have reduced utilization (capacity factor) of electricity plants fueled by coal.[5] Likewise, the consumption of natural gas has risen more dramatically than capacity. On the other hand, wind generation has expanded steadily and significantly over that time period.

Table 1.1: SPP capacity (2013-2015) and consumption (2013-2016) by fuel type

Type		2013	2014	2015	2016 (rolling 365)
Coal	Capacity	34.1%	35.4%	33.3%	
Coal	Consumption	61.2%	58.8%	55.1%	47.9%
Natural gas	Capacity	42.0%	46.5%	42.6%	
Natural gas	Consumption	21.2%	18.9%	21.6%	23.4%
Nuclear	Capacity	3.3%	3.4%	3.2%	
Nuclear	Consumption	6.0%	7.9%	8.1%	8.0%
Wind	Capacity	10.0%	11.5%	14.9%	
Wind	Consumption	10.8%	11.8%	13.5%	16.7%
Hydro	Capacity	4.6%	1.1%	4.1%	
Hydro	Consumption	0.6%	2.5%	1.5%	3.7%
Other	Capacity	26.8%	20.8%	23.1%	
Other	Consumption	0.6%	2.5%	1.5%	0.3%

Source: SPP

[5]For example, a 1,000 MW coal plant operating at an 80% capacity factor would produce 7.0 million MWH of electricity in a year (1000*.80*8760). For a 70% capacity factor it would generate 6.1 million MWH of electricity in a year (1000*.70*8760).

There are currently more than 12,000 MW of wind generation in the SPP footprint. The addition of renewable generation and the retirement of coal and nuclear generation has impacted the market price. Since the fuel cost of wind energy is zero, and is dispatched first in the day-ahead market, wind generation lowers the market price by displacing generation with higher fuel cost. The retirement of nuclear generation, however, will increase market prices because nuclear has lower fuel costs than generation currently on the margin (gas-fired). The effect on market prices from the retirement of coal plants depends on whether the fuel cost is above or below the fuel cost on the margin. If it is above the fuel cost on the margin, then it will have no effect on market prices, but if it is below, one can expect the market price to increase.

Since the fuel cost of wind energy is zero, and is dispatched first in the day-ahead market, wind generation lowers the market price by displacing higher fuel-cost generation.

Effect of SPP Integrated Market on Nebraska's Public Power

Prior to the SPP Integrated Market becoming operational in March 2014, Nebraska public power was responsible for dispatching their own generation to match their load. They also acted as the balancing authority for Nebraska.

This meant that nearly all generation from power plants in Nebraska was used to serve the native load in Nebraska. Therefore, the cost of production (fuel, variable operations and maintenance, and fixed) for generation was passed along to customers through rates.

For an illustration of generation costs, see table 1.2. Note: the following information are approximations based on the best information available for various plant types. Nebraska public power has denied a request for information concerning generation costs so actual cost data is not being used.

Table 1.2: Breakdown of generation costs for specific types of power plants

Plant Type	Size (MW)	Marginal Cost of Production ($/MWh)*	Fixed Cost ($/MWh)	Cost of Production ($/MWh)
Large Coal	1,350	13.15	13.20	26.35
Small Coal	225	21.00	33.85	54.85
Nuclear	800	8.90	36.10	45.00
Combined Cycle	250	42.75	117.80	160.55
Wind	300	0.00	20.00**	20.00**

* This would be the generation bid price in the SPP Integrated Market
**This would be the Power Purchase Agreement (PPA) price

The cost for each type of generation ratepayers were paying prior to 2014, when the SPP IM went operational, is as follows:

Table 1.2a: Cost for each type of generation ratepayers were paying prior to 2014, when the SPP IM went operational

Plant Type	Annual Output (MWh)	Cost of Production ($/MWh)	Annual Energy and Demand Cost ($)
Large Coal	9,650,000	26.35	254,277,500
Small Coal	1,120,000	54.85	61,432,000
Nuclear	6,800,000	45.00	306,000,000
Combined Cycle	137,000	160.55	21,995,350
Wind	1,314,000	20.00	26,280,000

Prior to the SPP IM, and based on the costs in table 1.2a above, ratepayers would be charged $669,984,850 for their public power utility to provide them with electricity. If a utility sold 19,021,000 MWh, the generation cost (energy and demand) would have been $35.22/MWh.

After the SPP went operational in 2014, energy and demand costs are separate, as illustrated in Table 1.2b. Note: for simplicity and illustration purposes, the 2015 SPP North Hub average market price is being used; in reality, every generation in SPP has a market price node for their location.

Table 1.2b: Energy and demand costs

	Large Coal	Small Coal	Nuclear	Combined Cycle	Wind
Cost of Production ($/MWh)	$26.35	$54.85	$45.00	$160.55	$20.00
2015 Average Market Price[1] ($/MWh)	$20.28	$20.28	$20.28	$20.28	$20.28
Annual Output (MWh)	9,650,000	1,120,000	6,800,000	137,000	1,314,000
Demand Cost ($/MWh)	$6.07	$34.57	$24.72	$140.27	-$.08
Annual Demand Cost[2]	$58,575,500	$38,718,400	$168,096,000	$19,216,990	-$105,120
Annual Demand Cost[3]	$44,389/MW	$172,082/MW	$210,120/MW	$76,867/MW	-$350.40/MW

[1] Energy Cost

[2] Annual Cost to for generation that must be paid by the ratepayers as a demand cost

[3] Annual Demand Cost ($) divided by Generation Size

The Demand Cost ($/MWh) does not provide much value, the Annual Demand Cost is what is important since this amount must be included in the rates that the ratepayers must pay. The Annual Demand Cost expressed in $/MW is also important for determining the capacity cost relative to other types of generation . As shown in Table 1.2b, nuclear generation is the most expensive generation capacity.

Using the information from the Table 1.2b above, the SPP market price is the energy cost. The capacity or demand cost for the utility's total generation is $284,501,770/year or $14.94/MWh. The total energy and demand cost remains, as before the SPP IM went operational, at $35.22/MWh. As the energy price (SPP market price) decreases the demand cost for generation increases because the difference between the marginal cost of production and the market price isn't high enough to further offset fixed costs. If the generation's cost of production was lower than the market price, the generation would have negative demand cost and would have a positive cash flow.

Since the SPP IM went operational in March 2014, Nebraska public power no longer dispatches their own generation to supply electricity to their customers. Instead, they purchase power from the market, either day-ahead or real-time, which is supplied from generators within the SPP footprint with the lowest marginal cost of production (fuel and variable O&M). See Appendix B for an illustration on how the SPP Integrated Market works for generation and supplying electricity to market participants.

When the SPP market price is lower than Nebraska public power generation's marginal cost of production, the generation assets remain idle and Nebraska's public power utilities purchase electricity from the IM at a cost lower than their generation can produce it because they will not be incurring the marginal cost of production. Purchasing electricity from the SPP IM when the market price is lower than the MP's generators marginal cost of production saves the MP money and should ultimately save the ratepayer money because the MP is purchasing electricity cheaper than the cost of self-dispatching their generation to provide electricity to their customers, which they did prior to the SPP IM.

Table 1.3 shows the average SPP market prices since the IM went operational in March of 2014. As shown, the market price has been lower every year since becoming operational. This is due mostly to the increase of wind generation in the SPP footprint and low natural gas prices.

Table 1.3: Average SPP market price

	Average SPP market price (North hub)
2014 (As of March 1)	$28.06
2015	$20.28
2016 (thru June)	$17.34

Source: SPP

Section 2: Threats facing Nebraska's Public Power Generation

Introduction

The cost effectiveness of Nebraska's public power generation is currently at risk in the SPP IM. There are two main reasons for this: (1) low natural gas prices; and (2) additional wind generation in the SPP footprint.

Low natural gas prices keep the SPP IM market price low. Gas-fired generators are the marginal supply, so bids from those generators typically sets the market price. Lower fuel costs for natural gas generators lead to lower bids in the market since fuel is a major contributor to the generator's bid price.

Low market prices threaten the competitiveness and ultimately the value of coal and nuclear assets owned by Nebraska public power.

The second threat comes from additional wind generation in the SPP footprint.[6] Wind displaces higher cost fossil fuel generation when SPP dispatches generation. Significant increases in wind generation are expected in the SPP footprint.[7] The SPP will have nearly 17,000 MW of installed wind by the end of 2016, up from 12,397 MW in 2015. An additional 2,000 MW is expected to be installed in 2017. As more wind energy is produced, there is risk that Nebraska's coal plants will sit idle more often, less able to recover fixed costs, as electricity is dispatched from wind generation first, and mainly from other states within the SPP footprint.

Excess Coal and Nuclear Generation when Natural Gas is Cheap

Nebraska's generation portfolio has a higher coal and nuclear mix relative to the SPP generation mix. Table 2.1 shows the breakdown of NPPD's and OPPD's generation mix compared to the SPP generation mix. NPPD and OPPD combined have half the wind percentage and nearly 20 percent more coal capacity than the SPP generation mix.

Nebraska's generation portfolio has a higher coal and nuclear mix relative to the SPP generation mix.

Table 2.1: Generation Mix comparison between NPPD and OPPD and the total SPP mix, 2015

	NPPD and OPPD Generation Mix	SPP Generation Mix
Coal	52.2%	33.3%
Natural gas & oil	18.8%	42.6%
Nuclear	19.0%	3.2%
Wind	7.0%	14.9%
Other	3.1%	6.2%
Total	100.0%	100.0%

Source: SPP, NPPD, and OPPD Annual Reports

[6] Wind generation as a percentage of supply in the SPP continues to set records, with penetration now exceeding 40 percent on certain days: http://www.platts.com/latest-news/electric-power/houston/us-southwest-power-pool-sets-new-wind-peak-record-21139345.

[7] The SPP estimates that it can reliably handle up to 60 percent wind penetration: https://www.spp.org/documents/34200/2016%20wind%20integra¬tion%20study%20(wis)%20final.pdf.

Baseload capacity, like coal and nuclear, is expected to continue to decrease in value as wind generation capacity increases in the SPP.[8] For example, in September 2016, NPPD's Sheldon Station went offline because the SPP's wholesale market price was lower than its marginal cost of production. It doesn't make economic sense to burn the fuel to produce electricity which would have been sold below the fuel cost. Fixed costs, however, are still incurred while the plant sits idle.

Baseload capacity like coal and nuclear is expected to continue to decrease in value as wind generating capacity increases in the SPP.

OPPD recently took action to shut down Fort Calhoun Nuclear Station (FCS) because of its high cost of production and low SPP wholesale market prices. In 2015, OPPD's generation capability (capacity) was 3,080 MW and system peak load was 2,315 MW.[9] With SPP requirements to have generation capacity for 112% of peak load, OPPD had 487 MW of excess capacity with FCS. Shutting down FCS will decrease excess generation and reduce generation costs to OPPD ratepayers.

If additional generation is needed due to FCS being shutdown, OPPD can either replace the generation, by building new generation or contracting generation from another supplier, with a lower annual cost of production.

NPPD generates more than four million MWh of excess generation (more electricity is sold to the SPP market than purchased from the SPP market to serve their customers). In 2015, NPPD's generation capability (capacity) was 3,660 MW and system peak load was 2,695 MW.[10] Since SPP requires Market Participants have generation capacity for 112% of their peak load, NPPD had 642 MW of excess capacity. This excess generation would be at produced from NPPD's Cooper Nuclear Station since this is NPPD's generation with the highest annual cost of production.

Even when market prices are above the generation's marginal cost of production, low market prices result in less revenue to help offset the fixed cost of generation. OPPD's decision to shut down the Fort Calhoun station can be seen as an indication of low forecasted market prices in the SPP. OPPD determined that incurring decommissioning costs of over $1 billion today was more cost effective than shortfalls in covering fixed costs while keeping the station operating.[11]

The price of natural gas has reached near record lows in 2016. This has driven SPP IM wholesale market prices below $20/MWh for several months this year. Figure 2.1 shows this year's monthly gas price (right axis) compared to the average monthly wholesale market prices (left axis) in the SPP IM.

The price of natural gas has reached near record lows in 2016. This has driven SPP IM wholesale market prices below $20/MWh for several months

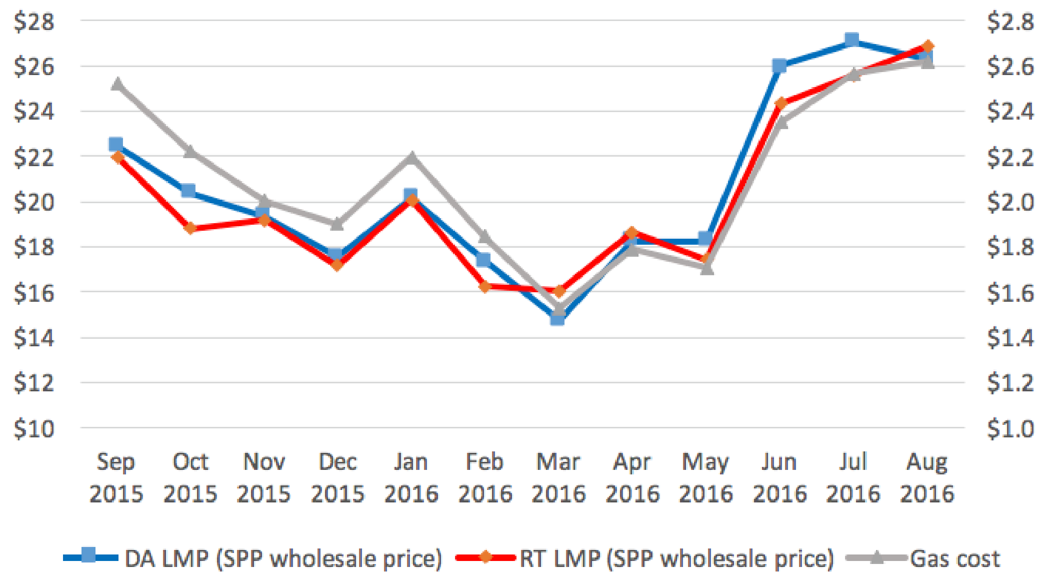
[8] Energy Information Administration (EIA), 'Higher wind generation in the Southwest Power Pool is reducing use of baseload capacity', http://www.eia.gov/today-inenergy/detail.php?id=12831.

[9] OPPD quick facts: http://www.oppd.com/media/216550/quick-facts.pdf.

[10] NPPD Financial and Sustainability Report, 2015 (http://www.nppd.com/assets/publications/2015FinancialSustainabilityReport/files/assets/basic-html/page-1.html#).

[11] http://www.oppd.com/news-resources/news-releases/2016/june/oppd-board-votes-to-decommission-fort-calhoun-station/.

Figure 2.1: SPP IM wholesale market prices versus the cost of natural gas



Source: SPP State of the Market Report, Summer 2016

The future price of natural gas is uncertain, but projections of supply growth versus demand growth in the United States indicate that excess supply from shale will remain. Projections by the U.S. Energy Information Administration (EIA) indicate that by 2020 domestic supply will substantially outpace domestic consumption, making the U.S. a net exporter.[12] Expect excess domestic supply to put downward pressure on the price of natural gas.

Although U.S. energy policy is uncertain going forward, the potential implementations of regulations from the Clean Power Plan could continue to increase the cost of production of fossil fuel generation. With Nebraska's heavy reliance on coal, there is a presence of regulatory risk.

Renewables Displace Baseload Generation

The growth in low-cost wind generation in the SPP footprint is putting downward pressure on the SPP IM wholesale market prices. As the amount of wind generation increases throughout the SPP footprint, expect this low-cost source of generation to drive down average wholesale market prices in the SPP IM as it displaces fossil-fueled baseload generation.

In October 2015, the SPP expanded its footprint to cover most of North Dakota and South Dakota, and parts of Montana. This added a substantial amount of wind generation to the SPP, raising wind generation as a percentage of total generation resources. As a result, more wind is now available to dispatch prior to other sources of generation.

In addition, wind generation in the SPP footprint is currently growing and is expected to continue to grow because of the recently renewed federal renewable electricity production tax credits (PTC). The PTC is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources. The electricity must be sold by the producer to an unrelated person or organization. Originally the duration of the credit was 10 years for all facilities placed into service after August 8, 2005.

In December 2015, Congress passed the Consolidated Appropriations Act, which extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction. For 2016, the inflation adjustment factor used by the IRS is 1.556, resulting in a 2016 calendar year tax credit amount of $0.023/kWh. The tax credits do, however, phase down with projects commencing construction after December 31, 2016.

[12]http://www.eia.gov/pressroom/presentations/siemin-ski_06282016.pdf..

The tax credit phase-down for wind facilities is a percentage reduction in the tax credit amount listed above: (a) for wind facilities commencing construction in 2017, the PTC amount is reduced by 20 percent, (b) for wind facilities commencing construction in 2018, the PTC amount is reduced by 40 percent, and (c) for wind facilities commencing construction in 2019, the PTC amount is reduced by 60 percent. The duration of the credit is 10 years after the date the facility is placed in service.[13]

These recently renewed tax credits are incentivizing wind generation investment throughout the SPP, putting downward pressure on the IM wholesale price. Nebraska's public utilities do not pay taxes and therefore are unable to directly benefit from tax credits. However, in most cases, wind generation is purchased from a private wind developer through a Power Purchase Agreement (PPA).

These recently renewed tax credits are incentivizing wind generation investment throughout the SPP, putting downward pressure on the IM wholesale price.

Nebraska's public power benefit from federal tax credits indirectly because they are factored into the PPA price along with any other capital or fixed costs incurred by wind generators. The PPA price for electricity can be thought of as the cost of production when comparing to other types of generation.

Since the private wind developer can receive tax credits, the price of PPAs incorporate those cost savings, allowing Nebraska Public Power to indirectly benefit from overall cheaper wholesale prices of electricity.

PPAs to purchase wind energy are currently averaging $20/MWh in the interior states, according to recent analysis by the Berkeley Lab and the U.S. Department of Energy.[14] PPAs at this price are significantly less than NPPD's and OPPD's average generation cost of production, and below the average 2015 SPP IM wholesale market price.

The growth of wind generation throughout the SPP will displace baseload generation in the dispatch order, raising the risk that baseload plants sit idle more often. This will raise the overall costs to own those types of plants, since revenue will not be generated to help offset fixed costs. This increases the risk that costlier generating assets will be forced to close as demand for baseload will not keep pace with this additional generation capacity.

The growth of wind generation throughout the SPP will displace baseload generation in the dispatch order, raising the risk that baseload plants sit idle more often.

[13] Renewable energy facilities placed in service after 2008 and commencing construction prior to 2015 (or 2020 for wind facilities) may elect to make an irrevocable election to claim the Investment Tax Credit (ITC) in lieu of the PTC. Wind facilities making such an election with have the ITC amount reduced by the same phase-down specified above for facilities commencing construction in 2017.

[14] PPAs for wind in the interior states have a significant cost advantage to the rest of the nation. In 2013, wind PPAs signed in the interior states averaged between $20-$25, whereas the Great Lakes region averaged above $40 and the West and Northeast region averaged above $50: http://energy.gov/sites/prod/files/2016/08/f33/2015-Wind-Technologies-Market-Report-Presentation.pdf.

Since wind generation is intermittent, it only receives capacity in the SPP integrated market for only 10 percent of its nameplate capacity (i.e. 10 MW for a 100 MW wind farm). This is unlike other types of generation, which receive credit for the full amount of nameplate capacity. Wind generation is bid into the SPP IM the same as other generation, but the credit counted toward market capacity requirements is different.

This is done to ensure that there is enough generation available when the wind does blow. Expect the SPP to consider larger capacity credit for wind in the future as energy storage technologies advance to alleviate intermittency concerns.[15] This will further decrease the value of baseload generation.

It is true that Federal Tax Credits are a key driver of the expected growth in wind generation throughout the SPP footprint. After the tax credits expire, expect investment in wind to lessen. However, cost of wind generation is falling rapidly and is expected to become competitive, even without tax credits, relative to new builds of other forms of energy.[16]

If new generation (capacity) is needed to supply demand growth in the future, expect wind and solar to compete with new builds of coal, natural gas, and nuclear.[17] The cost of solar has fallen rapidly in recent years due to increases in investment worldwide.[18]

[15] Although unproven in the market, industrial-sized batteries have seen some traction at the utility level. Tesla recently signed a deal to supply a California utility with industrial capacity lithium batteries to reduce intermittency concerns from renewables: http://www.bloomberg.com/news/articles/2016-09-15/tesla-wins-utility-contract-to-supply-grid-scale-battery-storage-after-porter-ranch-gas-leak.

[16] Lazard estimated that the unsubsidized levelized cost of energy for wind has decreased 61 percent from 2009 to 2015. The unsubsidized levelized cost of energy for solar has decreased 82 percent during that same period. New wind builds, unsubsidized, now average between $32-$52/MWh, compared to new coal at $61-$150/MWh and new natural gas at $52-$78/MWh.

[17] The EIA projects that in 2022 the LCOE for wind and solar will be $64.50/MWh and $84.70/MWh, respectively, compared new builds of coal to be $139.50/MWh and nuclear to be $102.80/MWh. New builds of natural gas LCOE is expected to range from $57-$84/MWh: https://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf .

[18] The learning curve (i.e. production cost decrease) for solar follows a trend called Swanson's Law. Swanson's Law is the observation that the cost of solar decreases 20 percent every time the cumulative shipped volume of photovoltaics doubles. Worldwide shipments of photovoltaics are growing fast, led by investment in Asia, with a compounded annual growth rate of 42 percent from 2000-2015: https://www.ise.fraunhofer.de/de/downloads/pdf-files/aktuelles/photovoltaics-report-in-englischer-sprache.pdf.

Section 3: A Case for Retail Choice in Nebraska: The effect on electric rates, reducing ratepayer risk, and the need for greater transparency using unbundled billing

A Case for Unbundling and Retail Choice in Nebraska

Nebraska public power has changed significantly since 1936 when public power was established to provide power to rural customers in Nebraska. More changes came when Nebraska public power joined the Southwest Power Pool in 2009 and began participating in the SPP Integrated Market in 2014, where they now buy and sell wholesale electricity.

Today with competitive wholesale energy markets, electricity is no longer a natural monopoly. Transmission and distribution systems, however, do remain for the most part natural monopolies because it is typically not economical to duplicate transmission and distributions systems in a given area. Providing electricity and being a transmission owner are two completely different business models, and as such it makes no sense for them to be bundled together.

Participating in a competitive wholesale market involves much risk and uncertainty, whereas being a transmission owner involves little risk (mainly weather events) since the same amount of electricity is transported through the transmission system regardless of who is providing the electricity. This is also holds true for the distribution system. The transmission and distribution system owner has the responsibility for maintaining their system to deliver electricity from the wholesale market to the end-use (retail) customer.

In 2009, when Nebraska public power joined the SPP, Nebraska was no longer an electricity island, but part of a much larger market-based RTO. The landscape changed even more dramatically in 2014 when the SPP IM became operational. In this environment, Nebraska public power no longer dispatches power plants or supplies electricity to their customers with their own generation. These functions were all turned over and are now the responsibility of the SPP.

As part of being members of the SPP, Nebraska public power no longer maintains the reliability of the transmission system in the state. Transmission owned by Nebraska public power is regulated by the Federal Energy Regulatory Commission (FERC). In 1996, FERC issued Order 888 to provide "open access" to transmission at non-discriminatory rates to third-party electricity providers to allow for a competitive wholesale electricity market.

What this means is that private electricity generators (e.g. wind farms) or power marketers are able to use transmission infrastructure owned by Nebraska public power for a regulated, set rate, which is non-discriminatory. This open-access infrastructure makes retail choice possible, where private power marketers with access to competitive generation and/or lower overhead costs can participate in the electricity market and potentially provide more competitive options to ratepayers in the state.

Furthermore, according to Nebraska legislative research, three conditions must be met for customer (retail) choice to be effective and beneficial to the citizens of Nebraska.[19] They are:

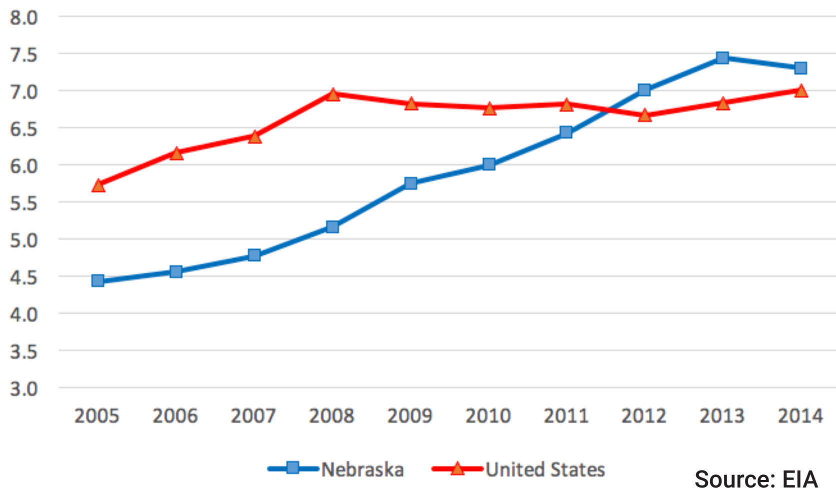
- A viable regional transmission organization and adequate transmission must exist in Nebraska or a region that includes Nebraska;
- A viable wholesale electricity market must exist in a region that includes Nebraska;
- Wholesale electricity prices in the region must be comparable or competitive to Nebraska prices.

[19] Annual report – Monitoring of "Conditions Certain" Issues 2010 Report in Neb. Rev. Stat. 70-1002 (6) to (8), dated 2010.

The report at the time stated that the first two conditions were satisfied and the last condition was not satisfied. However, since the report was last issued in 2010, Nebraska public power has significantly raised rates across the board and wholesale market prices have dropped significantly.

Figure 3.1 shows industrial rates in Nebraska compared to the United States from 2005 to 2014. Compared to US averages, the industrial rate in Nebraska became more expensive in 2012. Comparing Nebraska's rates to the U.S. understates how uncompetitive the state is to the surrounding region, as electricity rates on the East and West coast are usually significantly higher than the Midwest. Having uncompetitive industrial rates is a deterrent for bringing and keeping companies in Nebraska.

Figure 3.1: Nebraska's average industrial rate (cents per kWh) per year compared to the U.S. 2005-2014



Source: EIA

Wholesale market prices in the SPP IM are currently more competitive as well. Based on figures reported in NPPD's and OPPD's annual report, SPP IM wholesale market prices are substantially below the cost of production for NPPD's and OPPD's generation. As shown in Table 3.1, in 2015, NPPD had an average generation cost of production of $28.21/MWh and OPPD had an average generation cost of $32.11/MWh.[20] The 2015 average SPP IM day-ahead market price was $22.84/MWh and the real-time market price was $21.68/MWh.[21] The 2015 SPP average IM prices include both the North and South Hub. NPPD and OPPD had generation cost of production that were 23.5 percent and 40.6 percent, respectively, higher than the SPP IM day-ahead market price. Both the recent rise in rates for consumers and the decreasing market price of wholesale electricity satisfy the third criteria listed above. Retail choice in Nebraska would be effective and beneficial according to the guidelines of the legislative report discussed above.

As outlined in Section 2, lower wholesale market prices are the result of low natural gas prices and more renewable sources of generation in the SPP footprint. Natural gas prices in 2017 are expected to remain lower than the average price of the last five years.[22] Renewable generation is expected to expand significantly within the SPP footprint over the next few years due to the five-year extension of production tax credits. Expect wholesale market prices to remain low as the renewable market matures and natural gas extraction continues to provide plentiful supply.

This environment has resulted in wholesale market prices in the SPP IM dropping below the cost of production of coal and nuclear generation, creating additional losses for those types of plants.

[20] Reported average NPPD and OPPD generation costs presented here due not include capital costs or debt servicing costs, therefore these figures underestimate the true cost of generation, but still provide a conservative comparison for competitiveness to market prices.

[21] These prices were averaged from the SPP North and South Hubs. Source: SPP State of the Market Report, Winter 2016; https://www.spp.org/documents/37619/qsom_2016winter.pdf.

[22] https://www.eia.gov/forecasts/steo/report/natgas.cfm.

Table 3.1: Comparison of NPPD and OPPD average generation costs versus the SPP 2015 integrated market average prices

NPPD average generation cost	$28.21
OPPD average generation cost	$32.11
SPP IM day-ahead average price	$22.84
SPP IM real-time average price	$21.68
Source: SPP, OPPD and NPPD annual reports	

The decision to decommission OPPD's Fort Calhoun nuclear plant depended partially on the expectation that wholesale market prices in the SPP IM would remain low, making the plant expensive to operate relative to other generation resources. This controversial decision is a signal that OPPD's leadership does not expect wholesale market prices to return to levels where this nuclear station would be cost effective.

The financial risk to ratepayers in owning generation is increasing, as seen with the shutdown and decommissioning of the Fort Calhoun plant. Divesting from generating assets and embracing retail choice could reduce ratepayers' risk by eliminating the potential future costs of stranded assets. In this case, stranded assets are generating assets such as coal or nuclear plants that decrease in production value due to a change in the economics of the industry.

Stranded assets are generating assets such as coal or nuclear plants that decrease in production value due to a change in the economics of the industry.

Currently, inexpensive renewable generation, greater environmental regulations, and an excess supply of natural gas threaten the competitiveness of Nebraska's coal and nuclear plants, raising the risk that more plants will become more uneconomical in the future.

A more competitive energy landscape would allow consumers to choose among public and private power providers in the state.

This arrangement is commonly referred to as "retail choice." In a competitive, retail choice environment, Nebraska public power could pursue a strategy of competing in the energy market or divest from owning generating assets, and instead, focus solely on the management and operation of transmission and distribution systems.

Retail choice would incentivize competition by owning generation with the lowest production costs and maintaining low corporate overhead costs. This would substantially reduce the risk and uncertainly to the ratepayer in a changing energy market.

NPPD Wholesale Power Contact Renewal

In 2015, many rural public power districts and municipalities approved a new 20-year NPPD 2016 Wholesale Power Agreement.[23] This agreement requires that those who approved the contract to purchase the majority of their wholesale power requirement from NPPD who buys the power from the SPP IM. The agreement does not specify any price for the electricity but only a performance criteria that allows the customer to decrease the required amount of electricity that is purchased from NPPD if NPPD's rates go up drastically.

Several of NPPD's current wholesale customers did not sign the NPPD 2016 Wholesale Power Agreement, and decided instead to contract with other wholesale power providers.[24] This is possible due to the competitive wholesale markets and open access to transmission.

[23]NPPD 2016 wholesale power contract (http://info.cityoflex.com/ccdocs/meeting/2015/October27/5C102715.pdf).

[24]http://www.omaha.com/news/nebraska/rising-rate-hikes-prompt-some-nppd-customers-to-look-to/article_d99e15f9-e41d-58dc-8c3d-ac03c7cc36ec.html.

The Cost Composition of Electricity Rates

To understand how divesting from generation and embracing retail choice in Nebraska would affect ratepayers, it is important to know the composition of electric rates and how each cost component would be affected.

Electric rates are made up of various components that recover the electricity provider's costs to deliver their product to the customer. The two major types of electric rates are wholesale and retail.

Wholesale Rate: Wholesale power is the bulk electricity that is delivered by a wholesale power provider to the retail electricity providers for resale to its customers. Bulk electricity is bought and sold into an energy market similar to other commodity markets. The major cost components that go into a wholesale rate are: energy cost, demand cost, transmission cost and the wholesale power provider's overhead. For NPPD in 2014, the breakdown for wholesale energy costs is; 47% Energy, 39% Demand, 10% Transmission, and 4% other.

Retail Rate: The retail rate is what the end-use customer pays for electricity. There are typically three categories of retail rates that are based on electricity usage: industrial, commercial, and residential. Wholesale power is delivered to the retail customer by the local distribution entity after adding on the distribution charge. Local entities are often rural electric associations (REAs) or cities. The end rate paid by the retail customer is the retail rate. The retail rate includes the wholesale power cost and distribution cost to the customer. The breakdown of the cost components of the retail rate is generally: 60% wholesale electricity cost, 10% transmission, and 30% distribution.

Electricity Cost: This is the cost the wholesale power provider pays to purchase the electricity from the energy market. The energy market updates the electricity price every hour in the day-ahead market and every five minutes in the real-time market. The average 2015 market price for Nebraska public power was $20.28.

Transmission Cost: This is the cost the wholesale power provider pays to get the electricity from the energy market to the wholesale customer. Wholesale power is transported through transmission lines. The wholesale power provider may or may not own the transmission lines. The cost to use the transmission system is the same for all wholesale power providers that uses the transmission system.

Distribution Cost: This is the cost the local energy provider, usually a rural power district or city, pays to get the wholesale electricity from the transmission system to the retail customer.

Overhead: This is the cost that determines if the wholesale power provider's rate is competitive, because the costs for electricity and transmission are essentially the same for all wholesale power providers. Overhead costs include demand, debt service, administration, employee healthcare and pension plans.

One other major component of overhead is demand (capacity) costs. As mentioned above, capacity is the ability to generate electricity that can be supplied to the energy market at any given time when called upon to meet the market demand for electricity. The wholesale power provider must either own or purchase capacity to meet the energy market requirements for capacity (i.e. if a wholesale power provider is going to purchase 100 MW of electricity, then it must have at least 100 MW plus required SPP margin of capacity available).

It should be noted that just because a MP has 100 MW of capacity available, generation from another market participant might be used to produce the electricity needed to supply the MP's 100 MW load.

Generation or capacity cost is comprised of the total expenses (fuel, operation & maintenance, facilities, capital improvement, etc.) minus the revenue from selling the electricity generated to the energy market, such as an SPP integrated market. Capacity costs vary significantly depending on the type of generation (i.e. coal, nuclear, gas, renewable, hydro).

The Importance of Cost-Based Rates

The electricity rates on a ratepayer's most recent bill might not represent the true cost of power. It is possible that a utility could defer costs (i.e. pensions, retirement, decommissioning, debt, etc.) into the future in order to avoid raising rates in the present. These deferred costs, also known as unfunded liabilities, could expose customers to unexpected higher rates in the future.

An unfunded liability exists when a utility incurs an expense but defers payment. If current rates are based on deferred expense, the rate doesn't represent the true cost of electricity today. Therefore, once those unfunded liabilities come due, future customers will face higher rates, while customers today obtain the benefit.

An unfunded liability exists when a utility incurs an expense but defers payment. If current rates are based on deferred expense, the rate doesn't represent the true cost of electricity today.

When the ratepayer is locked into a monopolistic power provider and cannot choose from whom they purchase electricity, the rate should be cost-based to avoid receiving benefit from services they are not paying for. As described above, deferred costs by an electricity provider (public or private) are unacceptable for cost-based rates. If an electricity provider (public or private) makes bad business decisions, future ratepayers suffer the outcome because there is no other option for the customer to choose. The utility suffers no consequences in the form of lost customers as the result of its decisions.

Providing Cost Transparency through Unbundled Billing

With several cost components making up an electric rate, it is important that consumers understand what is driving any changes in their rates. Consumers can gain insight into costs of electricity production through unbundled billing.

Unbundled billing improves transparency and accountability by separating the cost components of the rate that the electric utilities charge. An example of an unbundled bill is illustrated in Appendix C, Example of an Unbundled Bill.

For example, an unbundled bill would show separate charges for energy, demand, transmission, and distribution, supplemental charges, which all contribute to the overall rate. Additional charges such as decommissioning costs and metering charges should also be included in a properly unbundled bill. This line-by-line billing information allows the ratepayer to scrutinize each component. When rates increase, an unbundled bill would indicate the factors that caused it.

Unbundled bills should be a staple in public power districts and cities in Nebraska. As a public power state, Nebraska's ratepayers vote for the board of directors of the public utilities that represent and serve them. A voter should be informed by seeing which costs drive any rate changes. Without this level of transparency, ratepayers lack the knowledge to make informed decisions when electing the board of directors who have the fiduciary responsibility to hold management accountable for decisions it has made.

The National Energy Marketers Association (NEM) says that "proper rate unbundling is a prerequisite to sending proper price signals, to assist in making educated consumption decisions, and to permit suppliers to invest risk capital to make competitive product and service offerings available to consumers."[25]

Increased transparency from unbundled billing is also important in today's changing energy landscape because of competition from renewable sources of generation. The preference for renewables is often overshadowed by the assumed higher costs rather than recent objective data. Unbundled bills would give Nebraska ratepayers insight into whether renewable sources of generation are cost effective compared to current sources such as coal and nuclear. Alternative sources of generation, such as wind or solar, could be offered by companies competing in a retail choice environment.

[25] https://www.energymarketers.com/Documents/nem_me_unbundling_ nal_cmts.pdf.

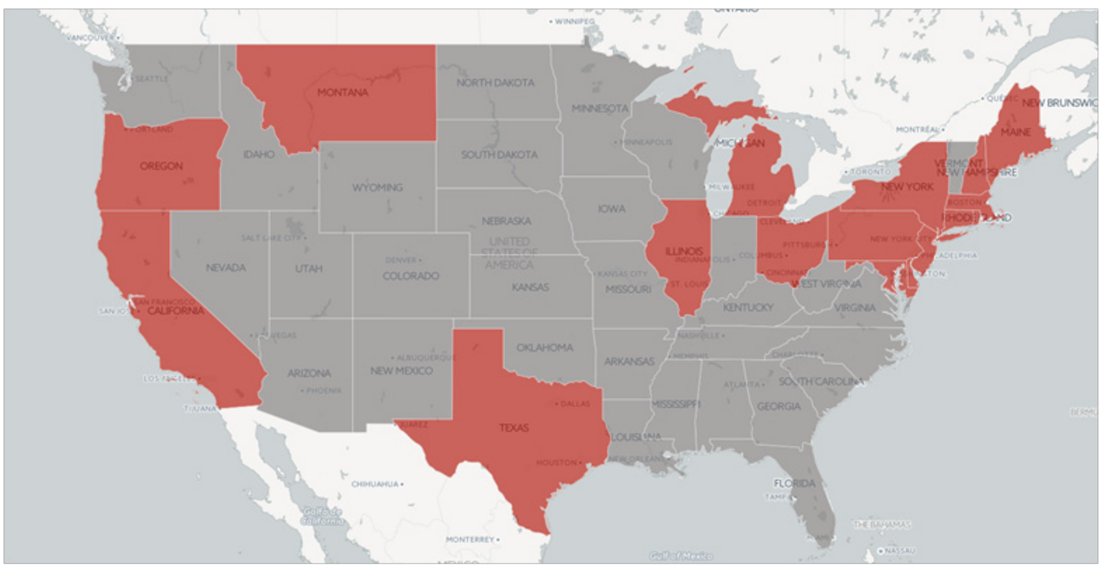
Having the costs separated, particularly distribution and transmission, would allow consumers to clearly compare prices of different energy providers. There is nothing physically (transmission or distribution) to prevent retail choice from being implemented in Nebraska. With retail choice, the only thing that would need to change would be a line item on the bill to show who the customer is purchasing electricity from. The transmission and distribution cost would remain the same as it is currently, with local entities delivering the electricity to the consumer. SPP is responsible for the planning and reliability of the transmission system. All repairs would still be handled the same as they are today, by the local distribution or transmission system owners.

Electricity is the competitive component of a customer's bill, whereas other charges are non-competitive; all retailers rely on the same transmission and distribution systems and incur the same charges. In a retail choice environment, electricity providers compete on how efficiently they can supply a commodity: electricity. Unbundled bills give clear information on who supplies electricity in the most cost-effective manner.

Retail Choice in Practice

Seventeen states have adopted retail choice. The level of adoption differs, with some states allowing full retail choice for all customers, and others providing it only to commercial and industrial customers. Retail choice becomes more important as competing sources of electricity production enter the market. Without retail choice, consumers are left with no other option than one with expensive rates if the monopoly utility makes poor business decisions such as choosing the wrong portfolio of generating assets. Figure 3.2 shows states that have implemented some form of retail choice.

Figure 3.2: States that have implemented retail choice



Source: EIA

Retail choice in Texas is administered by the Public Utility Commission through the website powertochoose.org (see Appendix D). This site provides a good example of how retail choice could work for residential, commercial, and industrial ratepayers in Nebraska. After entering a zip code, the ratepayer is shown multiple competitive offers from different electricity retail providers available in their area. Offers mainly differ in terms of price and contract length.

Some contracts last only three months while others last an entire year. This gives the ratepayer the option to lock in a current rate for an extended time, if that rate predictability is well-suited to their budget. Some retail providers offer rates based on the source of generation. This gives the ratepayer the option to buy electricity from a retailer that sources electricity entirely from renewables, if that's preferred.

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Electric retailers offer different rates because each company has its own strategy when it comes to sourcing the most cost effective sources of generation. Generation costs are based on many variables, most prominently fuel costs and technological advances. Since those variables are unknown in the future, strategic decisions should be made in an environment where market forces dictate the allocation of capital, which is not possible in a monopoly environment. The invested capital financed by ratepayers is at risk with publicly-owned generation, whereas, in retail choice, private investors bear the investment risk.

A retail choice environment promotes competition among suppliers and matches preferences to consumers. This ensures that the most cost-effective strategy to procure generation is available, which is passed on to consumers through lower rates. Ineffective generation investment strategies will be uncompetitive, ceasing to exist. On the demand side, consumer choice is especially important in being able to match production to consumer preferences, especially in regards to environmental concerns.

A retail choice environment promotes competition among suppliers and matches preferences to consumers.

If consumers prefer renewable sources of generation, a retail choice environment would be able to match that preference effectively. A competitive environment increases both productive and allocative efficiencies.[26]

Potential Cost Savings from Retail Choice

The price of a retail rate is comprised of approximately 60 percent generation cost, 30 percent distribution cost, and 10 percent transmission cost. The ability of retail choice to offer competitive rates is dependent on the costs of each retailer's owned generation mix and/or costs of wholesale purchases. The conditions that can affect wholesale energy costs can change rapidly, and are variable throughout the state. For example, the current market price for wholesale energy supplied through wind PPAs has recently dropped to levels that are very competitive to other sources of generation. Compared to the costs of owning and operating coal and nuclear plants, a retailer that is able to quickly adapt and execute wholesale purchases in favorable market conditions would be in a more competitive position. The combination of low-priced wholesale electric purchases and less overhead expense, should allow providers to put competitive downward pressure on rates in a retail choice environment.

To illustrate the variability in retail rates throughout the state, see Appendices E and F.

[26]Productive efficiency is the ability to produce at the lowest cost. Allocative efficiency is the ability to match production with consumer preferences. Market failures occur when the economy fails to allocate resources efficiently.

In the competitive wholesale environment, power districts, cities, and regional utilities are able to seek out the lowest cost wholesale supply, as did twelve cities and a regional utility in Nebraska.[27] For example, instead of NPPD, South Sioux City has signed a wholesale provider contract with a utility in Ohio and Northeast Nebraska Public Power District has signed with a provider in Kentucky.

This is because approximately 60 percent of the retail rate a city or regional utility offers to consumers is made up of the wholesale cost of electricity, so the cheaper they can procure this electricity supply, the more cost savings they can pass on to consumers.

In contracting with cheaper wholesale providers, entities like Northeast Nebraska Public Power and South Sioux City have less costs incurred with this wholesale supply component of the rate, which can then get passed on to end users in the form of cheaper rates.

This explains some of the rate variability possible throughout the state. Similar competitive forces, as seen in the wholesale competitive market, could lead to additional downward pressure on rates if applied to the retail environment.

According to the EIA, in 2015 Nebraska ratepayers paid more than $2.5 billion for electricity.[28] The ratepayer could save between $250-$400 million annually if retail choice was permitted in Nebraska as demonstrated by the public power districts and cities that chose to purchase their power from utilities outside of the Nebraska Public Power System. Since the SPP IM went operational, the competitive market price for electricity has dropped 38% but Nebraska public power electric rates have not decreased. In fact, many ratepayers are having to pay more for electricity because NPPD and OPPD are increasing the customer charges due to sustained revenue shortfall from external market factors and lower customer usage.

The Nebraska Public Power Model currently is not effective in the SPP wholesale power market due to past and current decisions to build and maintain generation resources. With a wholesale power market in place, the Nebraska Public Power Model should be changed to allow free market principles to work to lower electricity prices for the ratepayer. This would be consistent with the findings of the legislative study for retail choice in Nebraska.

[27]http://www.omaha.com/news/nebraska/cities-regional-utility-turn-down-new-nppd-contracts/article_205502e9-d68b-5cf5-8c5c-23eecf9aa5ec.html.

28http://www.eia.gov/electricity/sales_revenue_price/

Appendix A: SPP market participants

(source: https://www.spp.org/about-us/footprint/)

Alliant Energy Corporate Services, Inc.	Flat Ridge 2 Wind Energy	NSP Energy Trading
American Electric Power West	Franklin Power	Occidental Power Services
Appian Way Energy Partners Southwest, LLC	Freepoint Commodities, LLC	Oklahoma Gas & Electric Company
APX	Galt Power	Oklahoma Municipal Power Authority
Arkansas Electric Cooperative	Golden Spread Electric Cooperative	Omaha Public Power District
Associated Electric Cooperative, Inc. – Power Market	Goodwell Wind Project	Oneta Power
ATNV Energy, LP	Google Energy	Otter Tail Power Company
Automated Algorithums	Grand River Dam Authority	Peninsula Power, LLC
Basin Electric Power Cooperative	GRG Energy	Pharetram Energy Services, Ltd.
BioUrja Power, LLC	Guzman Energy	Powerex Corp.
BJ Energy	H.Q. Energy Services US	Public Service Co. of Colorado
Black Hills Power	Harlan Municipal Utilities	Public Service Co. of Colorado MISO MP
Black Oak Energy LLC	Hastings Utilities	Pure Energy
Blackout Power Trading	Heartland Consumers Power District	Rainbow Energy Marketing
Blue Canyon Windpower	Hexis Energy Trading	Resale Power Group of IOWA
Boston Energy Trading & Marketing	High Majestic Wind II	RPM Access LLC
BP Energy Company	Iberdola Renewables	Saracen Energy Midwest
Brookfield Energy Marketing LP	Inertia Power III	Seiling Wind LLC
Brookfield Renewable Energy Group	Intergrid Midwest Group	Sempra Generation
BTG Pactual Commodities (US)	Invenergy Energy Management	SESCO SPP Trading LLC
Buffalo Dunes Wind Project	J. Aron and Company	Shell Energy North America
Calicot Energy	Kansas City Board of Public Utilities	Smoky Hills Wind Project II
Calpine Energy Services	Kansas City Power and Light	Solea Energy, LLC
Canadian Woods Products	Kansas Municipal Energy Agency	Southern Company Services
Caney River	Kansas Power Pool	Southwestern Public Service
Canopus Power Trading, LLC	Kentucky Municipal Power Agency	Sunflower Electric Power
Cargill Power Markets	Lincoln Electric System	Sustaining Power Solutions
Carpe Diem Trading II	Little Elk Wind Project	SW Power Trading, LLC
Castleton Power Trading, LLC	LM Power	TEC Energy, Inc.
Chisholm View Wind Project	Macquarie Energy	Tenaska Power Services
Cimarron Wind Energy	MAG Energy Solutions	Tennessee Valley Authority
Citigroup Energy	Marshall Wind Energy	The Energy Authority
City of Chanute	Mercuria Energy America	Tios Capital, LLC
City of Fremont	Merrill Lynch Commodities	TPS1
City of Grand Island	MET Southwest Trading	TPS2
City of Independence, Mo.	MidAmerican Energy Company	TPS3
Conoco Phillips	Midwest Energy	TPS4
CP Bloom Wind	Midwest Energy Trading East	TPS5
Cumulus Master Fund	Minco Wind	TPS6
Darby Energy	Minnesota Muncipal Power Agency	TPS7
DC Energy Midwest	Minnkota Power Cooperative, Inc.	TPS8
DC Transco, LLC	Missouri Joint Municipal	Trailstone Power
Dempsey Ridge Wind Farm	Missouri River Energy Services	TransAlta Energy Marketing (U.S.) Inc.
Denver Energy	Montana-Dakota Utilities	Trumpet Trading LLC
Dogwood Power Management	Monterey SW	Tungsten Power LP
DTE Energy Trading	Monterey SWF	Twin Eagle Resource Management
Dufossat Capital VI	Morgan Stanley Capital Group	Uncia Energy LP - Series D
Dynasty Power	Morningstar Commodity Data, Inc	Utilities Plus
East Texas Electric Coop	Municipal Energy Agency of Nebraska	Velocity American
Ecesis	NextEra Energy Power Marketing	Vitol
EDF Trading North America	NJ Resources	Westar Energy
EDP Renewable North America	Noble Americas Gas & Power	Western Area Power Admininstration - Rocky Mountain Regio
eKapital Investments	Noble Great Plains Windpark	Western Area Power Administration - Upper Great Plains Mark
Emera Energy Services	Northern States Power	Western Area Power Administration
Empire District Electric	Northpoint Energy Solutions	Western Farmers Electric Cooperative
Endurance Energy Midwest LLC	Northstar Trading LTD	XO Energy SW
ETC Endure Energy	NorthWestern Corporation dba NorthWestern Energy	XO Energy SW2

Appendix B: Illustration of Southwest Power Pool Integrated Market

Market Participants submit bids for both their load and generation for each hour in the day-ahead market. Suppose an SPP Market Participant (MP) forecasts that their load (demand) for the following day at hour-12 will be 2,300 MWh. The MP submits a bid for their load into the day-ahead market for hour-12 the following day for 2,000 MWh (SPP does not require that 100% of the forecasted load be bid into the day-ahead market). The SPP will purchase the remaining 300 MWh forecasted load in the real-time market.

SPP requires the MP to submit generation bids into the day-ahead market with at least enough generation (capacity) to meet 112% of the load that was bid into the day-ahead market (2,240 MWh) for hour-12. The 112% requirement is to ensure that there is enough margin for reliability in case the demand is higher than expected. In the illustrative example below, the MP bids in the following generation into the day-ahead market for hour-12:

Table B1: Illustrative example of MP bids for generation into the day-ahead market for hour-12

	Amount	Marginal Cost of Production[2]	Cost of Production
Wind	200 MWh[1]	$0/MWh	$20.00[3]/MWh
Nuclear[4]	800 MWh	$8.90/MWh	$45.00/MWh
Large Coal	1,350 MWh	$13.15/MWh	$26.35/MWh
Small Coal	225 MWh	$21.00/MWh	$54.85/MWh
Combined Cycle	250 MWh	$42.75/MWh	$160.55/MWh

1 Wind generation is only credited 10% of rated nameplate or 20 MW toward the 2,240 MWh bid requirement
2 SPP generation bid price only includes fuel and variable operation & maintenance costs
3 This is recent Power Purchase Agreement cost for wind generation
4 Nuclear is considered “must-run” or a “price-taker” so it will dispatch regardless of market price

Based on the above table, the MP bid 2,645 MWh of generation into the day-ahead market. This is more than 2,240 MWh the SPP day-ahead required for supplying the MP load.

For example, if the day-ahead market price for hour-12 is determined to be $18.00/MWh based on the generation bids received from all the SPP Market Participants. SPP will dispatch the generation with marginal cost of production at or below $18.00/MWh. Based upon the information above, SPP will dispatch the MP wind, nuclear, and large coal. The MP will still purchase 2,000 MWh from the day-ahead market to serve the load they bid into the SPP day-ahead market. All the generation that is dispatched by SPP will receive $18.00/MWh for the output from their generation. Note that the cost of production for generation that was dispatched by SPP is, in this illustration, more than the market price of $18.00/MWh, except for wind generation. This means that the market price did not cover the cost of the MP to own the generation for other sources.

If the marginal cost of production for generation is greater than the day-ahead market price, the MP purchases electricity cheaper from the day-ahead market than it would cost them to produce the electricity themselves (for Small Coal, $21.00/MWh to produce vs. $18.00/MWh to purchase). The MP generation that SPP did not dispatch, Small Coal and Combined Cycle, did not receive any revenue from the day-ahead market and incurred fixed costs during this period.

Appendix C: Example of an Unbundled Bill

ComEd
An Exelon Company

www.comed.com
Customer Service / Power Outage
English
1-800-EDISON1 (1-800-334-7661)
Español
1-800-95-LUCES (1-800-955-8237)
Hearing/Speech Impaired
1-800-572-5789 (TTY)
For Electric Supply Choices visit
www.pluginillinois.org

Your Usage Profile
13-Month Usage (Total kWh)

Electric Usage

Month	kWh
Aug-12	565
Sep-12	505
Oct-12	270
Nov-12	305
Dec-12	425
Jan-13	850
Feb-13	800
Mar-13	830
Apr-13	545
May-13	510
Jun-13	375
Jul-13	565
Aug-13	**800**

Month Billed	Average Daily kWh	Temp
Last Year	19	75
Last Month	19	61
Current Month	27	83

Page 1 of 2

Account Number **9999999999**
Name
Service Location
Phone Number

Bill Summary	
Previous Balance	$72.16
Total Payments - Thank You	$72.16
Amount Due on August 22, 2013	**$81.62**

Issue Date August 1, 2013

Meter Information

Read Date	Meter Number	Load Type	Reading Type	Meter Reading Previous	Meter Reading Present	Difference	Multiplier X	Usage
8/1	999999999	General Service	Total kWh	69103	69903	800	1	800

Service from 07/02/2013 to 08/01/2013 - 30Days **Residential - Single**

Electricity Supply Services				**$44.09**
Electricity Supply Charge	800 kWh		0.04597	36.78
Transmission Services Charge	800 kWh	X	0.00914	7.31
Purchased Electricity Adjustment				0.00
Delivery Services - ComEd				**$32.09**
Customer Charge				12.78
Standard Metering Charge				2.86
Distribution Facilities Charge	800 kWh	X	0.01936	15.49
IL Electricity Distribution Charge	800 kWh	X	0.00120	0.96
Taxes and Other				**$5.44**
Environmental Cost Recovery Adj	800 kWh	X	0.00056	0.45
Energy Efficiency Programs	800 kWh	X	0.00186	1.49
Franchise Cost	$31.52	X	2.72100%	0.86
State Tax				2.64

Total Current Charges **$81.62**

(continued on next page)

Return only this portion with your check made payable to ComEd. Please write your account number on your check.

ComEd
An Exelon Company

99999 9999 90000 0000

John Doe
123 E. Main St
Anytown, IL 99999-0000

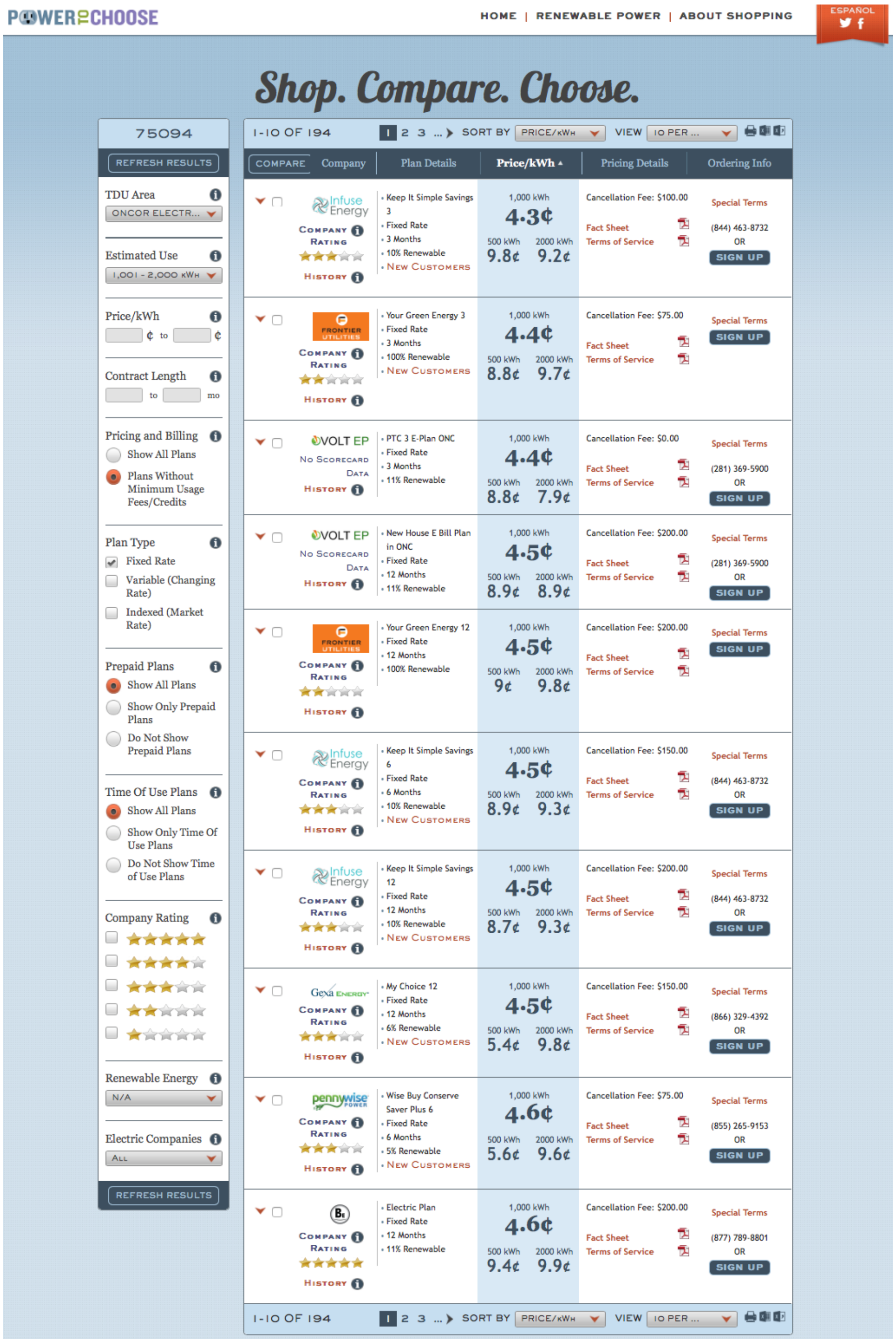
Account Number
9999999999

Payment Amount

Please pay this amount
by 08/22/2013 **$81.62**

ComEd
PO Box 6111
Carol Stream, IL 60197-6111

Appendix D: Screenshot of powertochoose.org showing suppliers' rate options



Appendix E: 2015 utility bundled retail sales - residential

2015 Utility Bundled Retail Sales- Residential

(Data from forms EIA-861- schedules 4A & 4D and EIA-861S)

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/kWh)
Auburn Board of Public Works	NE	Municipal	1,904	24,543	2,229.0	9.08
Burt County Public Power Dist	NE	Political Subdivision	3,341	57,379	7,485.0	13.04
Butler Public Power District - (NE)	NE	Political Subdivision	4,603	60,903	6,778.0	11.13
Cedar-Knox Public Power Dist	NE	Political Subdivision	5,422	95,184	8,137.0	8.55
Cherry-Todd Electric Coop, Inc	NE	Cooperative	827	8,605	1,028.9	11.96
Chimney Rock Public Power Dist	NE	Political Subdivision	1,981	22,178	3,496.0	15.76
City of Alliance- (NE)	NE	Municipal	4,185	38,856	4,811.8	12.38
City of Beatrice - (NE)	NE	Municipal	5,782	67,896	6,458.0	9.51
City of Broken Bow - (NE)	NE	Municipal	1,896	22,092	2,182.6	9.88
City of Cambridge - (NE)	NE	Municipal	481	5,621	608.0	10.82
City of Central City	NE	Municipal	1,370	16,660	1,700.4	10.21
City of Crete	NE	Municipal	2,444	25,264	2,313.0	9.16
City of David City	NE	Municipal	1,207	14,264	1,658.0	11.62
City of Fairbury	NE	Municipal	2,672	30,922	3,235.0	10.46
City of Falls City - (NE)	NE	Municipal	2,135	24,033	1,959.0	8.15
City of Fremont - (NE)	NE	Municipal	12,345	136,546	12,646.0	9.26
City of Gering - (NE)	NE	Municipal	3,439	32,648	4,975.0	15.24
City of Gothenburg - (NE)	NE	Municipal	1,486	19,973	1,644.0	8.23
City of Grand Island - (NE)	NE	Municipal	21,467	213,241	20,960.0	9.83
City of Hastings - (NE)	NE	Municipal	10,882	108,725	10,058.1	9.25
City of Hebron - (NE)	NE	Municipal	743	8,756	805.0	9.19
City of Holdrege	NE	Municipal	2,564	28,541	2,675.4	9.37
City of Imperial	NE	Municipal	1,040	11,630	1,205.0	10.36
City of Kimball - (NE)	NE	Municipal	1,445	9,938	1,548.0	15.58
City of Lexington - (NE)	NE	Municipal	3,436	48,412	4,914.7	10.15
City of Madison - (NE)	NE	Municipal	793	9,420	897.0	9.52
City of Minden - (NE)	NE	Municipal	1,321	14,261	1,877.7	13.17
City of Nebraska City	NE	Municipal	4,759	52,445	5,692.5	10.85
City of Neligh - (NE)	NE	Municipal	869	9,207	961.0	10.44
City of North Platte	NE	Municipal	11,269	117,841	11,768.0	9.99
City of Ord - (NE)	NE	Municipal	1,126	15,973	1,371.0	8.58
City of Pierce - (NE)	NE	Municipal	999	12,057	1,050.0	8.71
City of Schuyler - (NE)	NE	Municipal	2,112	27,919	2,633.0	9.43
City of Seward - (NE)	NE	Municipal	2,788	28,494	3,312.0	11.62
City of Sidney - (NE)	NE	Municipal	4,065	29,988	3,692.0	12.31
City of South Sioux City	NE	Municipal	4,686	68,516	6,931.0	10.12
City of St Paul - (NE)	NE	Municipal	954	11,112	1,152.0	10.37
City of Superior - (NE)	NE	Municipal	1,023	9,608	1,047.0	10.90
City of Syracuse - (NE)	NE	Municipal	1,071	8,802	983.0	11.17
City of Tecumseh	NE	Municipal	809	7,920	954.3	12.05
City of Valentine - (NE)	NE	Municipal	1,422	22,017	1,939.7	8.81
City of Wahoo - (NE)	NE	Municipal	1,878	21,928	1,897.0	8.65
City of Wakefield - (NE)	NE	Municipal	566	4,676	507.4	10.85
City of Wayne	NE	Municipal	2,019	17,951	1,989.0	11.08
City of West Point - (NE)	NE	Municipal	1,490	14,430	1,677.0	11.62
Cornhusker Public Power Dist	NE	Political Subdivision	7,054	122,722	13,558.0	11.05
Cozad Board of Public Works	NE	Municipal	1,708	20,404	2,140.1	10.49
Cuming County Public Pwr Dist	NE	Political Subdivision	2,791	48,443	4,817.8	9.95
Custer Public Power District	NE	Political Subdivision	4,598	72,438	8,320.0	11.49
Dawson Power District	NE	Political Subdivision	15,642	237,391	24,392.0	10.28
Elkhorn Rural Public Pwr Dist	NE	Political Subdivision	5,917	103,210	10,150.0	9.83
High West Energy, Inc	NE	Cooperative	1,778	17,815	2,274.0	12.76
Highline Electric Assn	NE	Cooperative	751	8,162	1,009.3	12.37
Howard Greeley Rural P P D	NE	Political Subdivision	3,218	52,850	5,685.0	10.76
KBR Rural Public Power District	NE	Political Subdivision	3,345	35,811	4,765.0	13.31
LaCreek Electric Assn, Inc	NE	Cooperative	168	2,263	242.0	10.69
Lincoln Electric System	NE	Municipal	117,859	1,168,564	110,421.3	9.45
Loup River Public Power Dist	NE	Political Subdivision	14,993	227,342	22,541.0	9.92
Loup Valleys Rural P P D	NE	Political Subdivision	2,854	39,334	4,442.0	11.29
McCook Public Power District	NE	Political Subdivision	3,734	37,445	4,839.6	12.92
Midwest Electric Member Corp	NE	Cooperative	3,195	33,805	3,865.3	11.43
Nebraska Public Power District	NE	Political Subdivision	70,318	793,831	84,858.0	10.69
Niobrara Valley El Member Corp	NE	Cooperative	4,786	49,709	5,804.0	11.68
Norris Public Power District	NE	Political Subdivision	12,920	240,805	22,917.1	9.52
North Central Public Pwr Dist	NE	Political Subdivision	3,504	40,981	4,830.5	11.79
Northeast Nebraska P P D	NE	Political Subdivision	6,713	114,287	11,554.0	10.11
Northwest Rural Pub Pwr Dist	NE	Political Subdivision	1,439	20,529	3,038.6	14.80
Omaha Public Power District	NE	Political Subdivision	319,501	3,452,484	382,260.0	11.07
Panhandle Rural El Member Assn	NE	Cooperative	1,766	29,749	3,788.0	12.73
Perennial Public Power Dist	NE	Political Subdivision	3,587	64,402	6,303.0	9.79
Polk County Rural Pub Pwr Dist	NE	Political Subdivision	2,859	41,046	4,694.5	11.44
Roosevelt Public Power Dist	NE	Political Subdivision	2,081	29,726	3,509.0	11.80
Seward County Rrl Pub Pwr Dist	NE	Political Subdivision	3,152	56,679	5,988.0	10.56
South Central Public Pwr Dist	NE	Political Subdivision	3,802	62,198	5,793.5	9.31
Southern Public Power District	NE	Political Subdivision	15,045	233,136	23,455.9	10.06
Southwest Public Power Dist	NE	Political Subdivision	2,247	34,644	3,492.0	10.08
Stanton County Public Pwr Dist	NE	Political Subdivision	1,788	28,177	3,174.0	11.26
Twin Valleys Public Power Dist	NE	Political Subdivision	4,106	36,693	4,338.0	11.82
Wheat Belt Public Power Dist	NE	Political Subdivision	3,235	33,907	4,307.8	12.70
Wyrulec Company	NE	Cooperative	269	2,722	407.0	14.95
Adjustment 2015	NE	Other	28,101	301,053	34,709.1	

Appendix F: 2015 utility bundled retail sales - Industrial

2015 Utility Bundled Retail Sales- Industrial

(Data from forms EIA-861- schedules 4A & 4D and EIA-861S)

Entity	State	Ownership	Customers (Cou	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/kWh)
Auburn Board of Public Works	NE	Municipal	1	2,904	262.8	9.05
Burt County Public Power Dist	NE	Political Subdivision	685	22,750	3,413.0	15.00
Butler Public Power District - (NE)	NE	Political Subdivision	666	8,921	2,553.0	28.62
Cedar-Knox Public Power Dist	NE	Political Subdivision	1,198	24,805	3,774.0	15.21
Cherry-Todd Electric Coop, Inc	NE	Cooperative	226	16,566	2,032.1	12.27
Chimney Rock Public Power Dist	NE	Political Subdivision	928	18,039	2,361.0	13.09
City of Alliance- (NE)	NE	Municipal	12	29,093	2,868.4	9.86
City of Beatrice - (NE)	NE	Municipal	119	69,163	5,325.0	7.70
City of Broken Bow - (NE)	NE	Municipal	8	52,275	3,738.8	7.15
City of Cambridge - (NE)	NE	Municipal	1	33,788	2,059.0	6.09
City of Central City	NE	Municipal	11	5,851	609.0	10.41
City of Crete	NE	Municipal	3	63,323	4,062.0	6.41
City of David City	NE	Municipal	30	18,179	1,871.0	10.29
City of Fairbury	NE	Municipal	18	31,762	2,465.0	7.76
City of Falls City - (NE)	NE	Municipal	7	4,278	298.0	6.97
City of Fremont - (NE)	NE	Municipal	530	230,816	16,910.0	7.33
City of Gering - (NE)	NE	Municipal	40	18,185	2,085.0	11.47
City of Gothenburg - (NE)	NE	Municipal	15	22,654	1,889.0	8.34
City of Grand Island - (NE)	NE	Municipal	99	317,928	23,554.0	7.41
City of Hastings - (NE)	NE	Municipal	128	180,698	11,145.5	6.17
City of Holdrege	NE	Municipal	2	54,208	2,625.2	4.84
City of Imperial	NE	Municipal	45	4,321	357.0	8.26
City of Lexington - (NE)	NE	Municipal	5	115,517	7,792.3	6.75
City of Madison - (NE)	NE	Municipal	1	45,108	3,010.0	6.67
City of Nebraska City	NE	Municipal	34	69,297	5,922.0	8.55
City of North Platte	NE	Municipal	4	38,521	2,664.0	6.92
City of Pierce - (NE)	NE	Municipal	28	609	36.0	5.91
City of Schuyler - (NE)	NE	Municipal	127	97,418	7,295.0	7.49
City of Seward - (NE)	NE	Municipal	5	29,559	2,460.0	8.32
City of Sidney - (NE)	NE	Municipal	67	36,138	2,793.0	7.73
City of St Paul - (NE)	NE	Municipal	32	8,908	802.0	9.00
City of Superior - (NE)	NE	Municipal	15	6,017	560.0	9.31
City of Syracuse - (NE)	NE	Municipal	19	5,798	454.0	7.83
City of Tecumseh	NE	Municipal	5	7,485	643.8	8.60
City of Wahoo - (NE)	NE	Municipal	4	12,533	935.0	7.46
City of Wakefield - (NE)	NE	Municipal	1	36,630	2,556.0	6.98
City of West Point - (NE)	NE	Municipal	80	31,330	2,947.0	9.41
Cornhusker Public Power Dist	NE	Political Subdivision	2,287	152,835	14,106.0	9.23
Cozad Board of Public Works	NE	Municipal	1	4,301	371.8	8.64
Cuming County Public Pwr Dist	NE	Political Subdivision	326	14,653	1,688.4	11.52
Custer Public Power District	NE	Political Subdivision	4,911	98,225	13,236.0	13.48
Dawson Power District	NE	Political Subdivision	5,795	241,846	27,821.0	11.50
Elkhorn Rural Public Pwr Dist	NE	Political Subdivision	2,807	109,716	12,773.0	11.64
High West Energy, Inc	NE	Cooperative	1,196	71,167	8,048.0	11.31
Highline Electric Assn	NE	Cooperative	1,084	63,788	8,138.7	12.76
Howard Greeley Rural P P D	NE	Political Subdivision	1,445	39,213	4,140.0	10.56
KBR Rural Public Power District	NE	Political Subdivision	779	34,562	5,631.0	16.29
LaCreek Electric Assn, Inc	NE	Cooperative	46	2,432	277.0	11.39
Lincoln Electric System	NE	Municipal	184	487,115	32,121.3	6.59
Loup River Public Power Dist	NE	Political Subdivision	53	662,298	42,513.0	6.42
Loup Valleys Rural P P D	NE	Political Subdivision	2,245	72,081	7,113.0	9.87
McCook Public Power District	NE	Political Subdivision	910	101,832	8,620.5	8.47
Midwest Electric Member Corp	NE	Cooperative	2,058	141,936	17,330.1	12.21
Nebraska Public Power District	NE	Political Subdivision	56	1,170,406	66,056.0	5.64
Niobrara Valley El Member Corp	NE	Cooperative	1,203	64,229	7,544.0	11.75
Norris Public Power District	NE	Political Subdivision	1,869	460,966	33,847.5	7.34
North Central Public Pwr Dist	NE	Political Subdivision	1,109	38,128	5,903.1	15.48
Northeast Nebraska P P D	NE	Political Subdivision	673	12,689	2,341.0	18.45
Northwest Rural Pub Pwr Dist	NE	Political Subdivision	652	45,414	5,843.0	12.87
Omaha Public Power District	NE	Political Subdivision	174	3,299,315	201,969.0	6.12
Panhandle Rural El Member Assn	NE	Cooperative	847	36,869	6,048.0	16.40
Perennial Public Power Dist	NE	Political Subdivision	2,709	194,047	16,590.0	8.55
Polk County Rural Pub Pwr Dist	NE	Political Subdivision	1,289	21,702	4,335.4	19.98
Roosevelt Public Power Dist	NE	Political Subdivision	684	18,498	2,246.0	12.14
Seward County Rrl Pub Pwr Dist	NE	Political Subdivision	757	9,933	1,863.0	18.76
South Central Public Pwr Dist	NE	Political Subdivision	3,129	74,072	8,547.8	11.54
Southern Public Power District	NE	Political Subdivision	9,359	767,508	64,605.8	8.42
Southwest Public Power Dist	NE	Political Subdivision	1,280	116,678	12,314.0	10.55
Stanton County Public Pwr Dist	NE	Political Subdivision	594	93,517	7,461.0	7.98
Twin Valleys Public Power Dist	NE	Political Subdivision	1,246	27,471	4,768.0	17.36
WAPA-- Western Area Power Administration	NE	Federal	1	3,982	32.0	0.80
Wheat Belt Public Power Dist	NE	Political Subdivision	1,014	87,579	10,170.7	11.61
Wyrulec Company	NE	Cooperative	164	4,070	616.4	15.14
Y-W Electric Assn Inc	NE	Cooperative	72	6,131	774.0	12.62
Adjustment 2015	NE	Other	349	32,528	3,888.0	

Appendix G: Researchers' Biographies

Ernie Goss is the Jack MacAllister Chair in Regional Economics at Creighton University and is the initial director for Creighton's Institute for Economic Inquiry. He is also principal of the Goss Institute in Denver, Colo. Goss received his Ph.D. in economics from The University of Tennessee in 1983 and is a former faculty research fellow at NASA's Marshall Space Flight Center. He was a visiting scholar with the Congressional Budget Office for 2003-2004, and has testified before the U.S. Congress, the Kansas Legislature, and the Nebraska Legislature. In the fall of 2005, the Nebraska Attorney General appointed Goss to head a task force examining gasoline pricing in the state.

He has published more than 100 research studies focusing primarily on economic forecasting and on the statistical analysis of business and economic data. His book Changing Attitudes Toward Economic Reform During the Yeltsin Era was published by Praeger Press in 2003, and his book Governing Fortune: Casino Gambling in America was published by the University of Michigan Press in March 2007.

He is editor of Economic Trends, an economics newsletter published monthly with more than 11,000 subscribers, produces a monthly business conditions index for the nine-state Mid-American region, and conducts a survey of bank CEOs in 10 U.S. states. Survey and index results are cited each month in approximately 100 newspapers; citations have included the New York Times, Wall Street Journal, Investors Business Daily, The Christian Science Monitor, Chicago Sun Times, and other national and regional newspapers and magazines. Each month 75-100 radio stations carry his Regional Economic Report.

Jeffrey Milewski is a senior research economist at Goss & Associates. He received his master's degree in political economy from the London School of Economics and Political Science in 2013. He completed his bachelor's degree at Creighton University in 2007, having studied economics and finance. Milewski also has experience working in finance and as an entrepreneur. Recently, he has co-authored impact studies on a range of topics such as property-casualty insurance, highway expansion, cost/benefit analysis, and national sporting events.

State	Energy Rate, Residential Only (cents/kWh) 2004	2015	% Change
Washington	6.37	9.09	43%
Louisiana	8.05	9.33	16%
Lincoln Electric System	6.18	9.39	52%
North Dakota	6.79	9.62	42%
Arkansas	7.36	9.82	33%
Idaho	6.10	9.93	63%
West Virginia	6.23	10.08	62%
Oklahoma	7.72	10.14	31%
Kentucky	6.11	10.24	68%
Tennessee	6.90	10.30	49%
Nebraska	6.96	10.60	52%
Oregon	7.18	10.66	48%
Montana	7.86	10.88	38%
Utah	7.21	10.88	51%
Wyoming	7.21	10.97	52%
South Dakota	7.65	11.08	45%
Missouri	6.97	11.21	61%
Mississippi	8.21	11.27	37%
North Carolina	8.45	11.28	33%
Virginia	7.99	11.37	42%
Georgia	7.86	11.54	47%
Texas	9.73	11.56	19%
Indiana	7.30	11.57	58%
Florida	8.99	11.58	29%
Iowa	8.96	11.63	30%
Alabama	7.62	11.70	54%
Colorado	8.42	12.12	44%
Minnesota	7.92	12.12	53%
Arizona	8.46	12.13	43%
Kansas	7.74	12.34	59%
New Mexico	8.67	12.47	44%
Illinois	8.37	12.50	49%
South Carolina	8.12	12.57	55%
US Average	8.95	12.65	41%
Nevada	9.69	12.76	32%
Ohio	8.45	12.80	51%
District of Columbia	8.00	12.99	62%
Delaware	8.78	13.42	53%
Pennsylvania	9.58	13.64	42%
Maryland	7.80	13.82	77%
Wisconsin	9.07	14.11	56%
Michigan	8.33	14.42	73%
Maine	12.16	15.61	28%
New Jersey	11.23	15.81	41%
California	12.20	16.99	39%
Vermont	12.94	17.09	32%
New Hampshire	12.49	18.50	48%
New York	14.54	18.54	28%
Rhode Island	12.19	19.29	58%
Alaska	12.44	19.83	59%
Massachusetts	11.75	19.83	69%
Connecticut	11.63	20.94	80%
Hawaii	18.06	29.60	64%

Retail Choice Avg	15.27
% to Retail	-31%
% to US Average	-16%
Nebraska Rank	10
LES % to Retail*	-39%
LES % to US Average*	-26%

Source: U.S. Department of Energy - Energy Information Administration; Average Retail Price of Electricity

*LES rate is calculated as the total revenue divided by total energy sold, averaged over 12 months from EIA 826 data for 2004 and 2015

	Energy Rate, All Customer Classes (cents/kWh)		
State	**2004**	**2015**	**% Change**
Washington	5.80	7.40	28%
Louisiana	7.13	7.65	7%
Oklahoma	6.50	7.90	22%
Wyoming	4.98	7.97	60%
Lincoln Electric System	5.16	8.02	55%
Idaho	4.97	8.09	63%
West Virginia	5.13	8.11	58%
Kentucky	4.63	8.14	76%
Arkansas	5.67	8.19	44%
Iowa	6.40	8.35	30%
Utah	5.69	8.54	50%
Texas	7.95	8.70	9%
North Dakota	5.69	8.75	54%
Oregon	6.21	8.75	41%
Montana	6.40	8.90	39%
Nebraska	5.70	8.91	56%
Indiana	5.58	8.99	61%
Tennessee	6.14	9.30	51%
Virginia	6.43	9.31	45%
Alabama	6.08	9.33	53%
North Carolina	6.97	9.37	34%
Illinois	6.80	9.40	38%
Missouri	6.07	9.44	56%
South Dakota	6.44	9.47	47%
Nevada	8.56	9.48	11%
Minnesota	6.24	9.53	53%
Mississippi	7.00	9.53	36%
South Carolina	6.22	9.58	54%
Georgia	6.58	9.62	46%
New Mexico	7.10	9.62	35%
Colorado	6.95	9.94	43%
Ohio	6.89	9.98	45%
Kansas	6.37	10.14	59%
Pennsylvania	8.00	10.31	29%
Arizona	7.45	10.34	39%
US Average	7.61	10.41	37%
Florida	8.16	10.49	29%
Wisconsin	6.88	10.73	56%
Michigan	6.94	10.76	55%
Delaware	7.53	11.17	48%
District Of Columbia	7.47	12.07	62%
Maryland	7.15	12.07	69%
Maine	9.69	12.78	32%
New Jersey	10.29	13.74	34%
Vermont	11.02	14.41	31%
New York	12.55	15.28	22%
California	11.35	15.42	36%
New Hampshire	11.37	16.02	41%
Massachusetts	10.77	16.90	57%
Rhode Island	10.96	17.01	55%
Alaska	10.99	17.59	60%
Connecticut	10.26	17.77	73%
Hawaii	15.70	26.17	67%

Retail Choice Avg	12.67
% to Retail	-30%
% to US Average	-14.41%
Nebraska Rank	15
LES % to Retail*	-37%
LES % to US Average*	-23%

Source: U.S. Department of Energy - Energy Information Administration; Average Retail Price of Electricity

*LES rate is calculated as the total revenue divided by total energy sold, averaged over 12 months from EIA 826 data for 2004 and 2015