UTILICORP UNITED INC.

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

FILED[2]

OCT 19 1999

Missouri Public Service Commission

In the matter of the Joint Application of UtiliCorp United Inc. and St. Joseph Light & Power Company for authority to merge St. Joseph Light & Power Company with and into UtiliCorp United Inc. and, in connection therewith, certain other related transactions	)))))))	Case No. EM-2000-292

UtiliCorp United Inc. and St. Joseph Light & Power Company Merger

Direct Testimony

October 19, 1999

Exhibit No.:	
Issue:	Transmission Operations
Witness:	Richard C. Kreul
Type of Exhibit:	Direct Testimony
Sponsoring Party:	UtiliCorp United Inc.
Case No.:	

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Richard C. Kreul

October 19, 1999

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF RICHARD C. KREUL
ON BEHALF OF UTILICORP UNITED INC.

CASE NO.

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Richard C. Kreul. I am employed by UtiliCorp United Inc. ("UCU"), within the operating group UtiliCorp Energy Delivery ("UED"), as Vice President of Transmission Services, a position I've held since October, 1996. I joined UtiliCorp in 1994 with UtiliCorp's acquisition of what is now known as UtiliCorp Pipeline Systems, Inc. ("UPL"), as President of UPL. My business address is 10700 East 350 Highway, P.O. Box 11739, Kansas City, MO 64138.

Q. For whom are you testifying in this case?

A. I am testifying on behalf of UCU and its operating divisions Missouri Public Service ("MPS"), WestPlains Energy-Kansas ("WPE-KS"), WestPlains Energy-Colorado ("WPE-CO"), and West Virginia Power ("WVP").

Q. Please describe your educational background.

A. I hold both a Bachelor of Science and a Master of Science in Mechanical Engineering from the University of Arkansas -- Fayetteville. I am a licensed Professional Engineer in the states of Arkansas, Texas, and Oklahoma. I have 20 years of experience in the energy industry. My responsibilities during the past three years include the management of UtiliCorp's electrical and natural gas transmission systems.

Q. Have you previously filed testimony before any state or federal agencies?

A. Yes, I have filed testimony before the Missouri Public Service Commission ("Commission") on behalf of Missouri Pipeline Company and Missouri Gas Company, subsidiaries of UPL.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to provide an overview and generally describe the configurations of high voltage transmission systems and their operations for both Saint Joseph Light & Power ("SJLP") and UCU, as these entities are today, and as they are planned to be in the future after the proposed merger.

Q. Do you sponsor any Schedules associated with this application?

A. Yes. I am sponsoring the following: Schedule RCK-1 through Schedule RCK-4 which are high voltage transmission system maps of SJLP and UtiliCorp's three domestic divisions that have transmission systems; Schedule RCK-5 illustrates voltage level and thermal limit information and data for all first tier interconnections of SJLP and the three UCU operating divisions that have transmission; Schedule RCK-6 through Schedule RCK-9 are system schematic representations of all transmission voltage levels, loads and losses for SJLP and the three primary UCU operating divisions; and Schedule RCK-10 is a summary of a recent study of a direct high voltage interconnection between SJLP and MPS.

Q. Were these Schedules prepared by you or under your direction?

A. Yes.

DESCRIPTION OF ST. JOSEPH LIGHT & POWER SYSTEM

Q. Please generally describe the SJLP high voltage transmission system.

A. SJLP operates a control area in the Eastern Interconnected Grid providing service to approximately 61,500 electric retail customers in Northwest Missouri. SJLP does not serve wholesale customers. It has two 345 kV and one 161 kV direct interconnections to the south with Kansas City Power & Light Company ("KCPL"). SJLP also has 161 kV direct interconnections to the north with Mid-American Energy Company ("MEC") and Associated Electric Power Cooperative ("AEC"), and AmerenUE ("UE"). SJLP is a participant with six other utilities, namely KCPL, AEC, MEC, Nebraska Public Power District ("NPPD"), Omaha Public Power District ("OPPD") and Lincoln Electric System ("LES"), in a 345 kV line from St. Joseph, MO to Fairport, MO to Cooper, NE known as the Cooper-Fairport-St. Joseph 345 kV Interconnection ("CFSI"). Fifty percent of the CFSI line is reserved contractually for reliability and emergency purposes. The other fifty percent can be used equally by the seven participants – one fourteenth of the line each way for two-way flows – for any other kind of firm or non-firm power and energy transaction that does not infringe upon the reliability and emergency functions.

Q. Please describe SJLP's interconnections with KCPL.

A. The direct SJLP interconnections with KCPL are: 1) at 161 kV near SJLP's Lake Road power plant; 2) at 345 kV near Edgerton, MO; and 3) at the jointly owned Iatan generating station near Weston, MO. Schedule RCK-1 illustrates the SJLP high voltage transmission system and its first tier interconnections. SJLP is also contractually interconnected with UE at Maryville and with Empire District Electric ("EDE") at Iatan.

Q. Please describe SJLP's interconnection with OPPD.

A. SJLP and OPPD jointly own a 345 kV line that runs from the Cooper Nuclear Station located south of Brownville, NE to SJLP's St. Joseph substation located northeast of St., Joseph. Ownership of the line changes where the line crosses the Missouri River, with

OPPD owning the northern portion, and SJLP owning the southern portion.

Q. How would you characterize SJLP's transmission system with respect to native load?

A. At the present time the SJLP transmission system is adequate for its own native load. Through its direct and indirect interconnections there may be substantial opportunity for seasonal diversity interchange transactions between the northern and southern regions of the Midwest. SJLP and MPS will be operated as a single regional control area once the two companies have merged.

DESCRIPTION OF UTILICORP SYSTEMS

Q. Please briefly describe the transmission systems for the four domestic UCU divisions.

A. UCU has four non-contiguous, non-interconnected, domestic electric operations. MPS, WPE-KS, and WVP which are located in the Eastern Interconnected Grid; and WPE-CO, which is located in the Western Interconnected Grid.

Q. Please briefly describe the MPS system.

A. MPS operates a control area in the Eastern Interconnected Grid and provides service to approximately 193,000 customers – including eight wholesale customers -- in western and north central Missouri. MPS has direct high voltage interconnections with five utilities: KCPL, Western Resources ("WR"), UE, AEC, and the City of Independence, MO. It has a non-synchronous connection with EDE and KAMO, (a transmission cooperative in KS, MO, and OK), but these interconnects are operated normally open. MPS is a joint owner with KCPL and WR in a 345 kV interconnection from Wichita, KS to Sibley, MO, and another 345 kV Missouri interconnection from Sibley to UE's Overton substation. MPS transmission rights through these interconnections are over approximately 58 miles of line in MPS' service territory from Stilwell, KS to UE's

Overton substation. MPS owns a 8 percent or 174 MW share of the Jeffrey Energy Center located in the WR service territory, and has reserved transmission capacity through a Jeffrey Transmission Agreement with WR to deliver MPS energy from Jeffrey to MPS at its Stranger Creek interconnection with WR. MPS remotely operates its transmission system through a Supervisory Control and Data Acquisition ("SCADA") system from its Operations Center in Lee's Summit, MO. Schedule RCK-2 is the map that illustrates the MPS high voltage systems.

Q. Please briefly describe the WPE-KS system.

A. WPE-KS also operates a control area in the Eastern Interconnected Grid. WPE-KS provides service to approximately 67,000 customers -- including 23 wholesale customers -- in West Central Kansas. WPE-KS is interconnected to four other utilities: WR, Midwest Energy ("ME"), Sunflower Electric Power Corporation ("SEC"), and Southwestern Public Service Company ("SPS"). Like MPS, WPE-KS is also an 8 percent or 174 MW co-owner in the Jeffrey Energy Center located in WR's service territory, and has a reserved Jeffrey Transmission Agreement with WR to deliver WPE-KS 174 MW of energy to its East Manhattan interconnection with WR. Similar to MPS, WPE-KS remotely operates its transmission system through a SCADA system from its Operations Center in Great Bend, Kansas. Schedule RCK-3 is a map that illustrates the WPE-KS high voltage systems.

Q. Please briefly describe the WPE-CO system.

A. WPE-CO is located in the Western Interconnected Grid, and serves approximately 80,000 retail customers in southeastern Colorado, including one wholesale customer. It is operated under the Public Service Company of Colorado ("PSCO") control area. WPE-

CO has direct interconnections with PSCO, the City of Colorado Springs, CO, Western Area Power Administration ("WAPA"), Tri-State Generation and Transmission Association ("TS") and the Arkansas River Valley Power Authority ("ARPA"). There is no interconnection between WPE-CO and WPE-KS, nor does UCU have any firm transmission rights across any ties between the Western and Eastern grids. Similar to MPS and WPE-KS, WPE-CO remotely operates its transmission system through a SCADA system from its Operations Center in Pueblo, CO. Schedule RCK-4 is a map that illustrates the high voltage WPE-CO system.

Q. Please briefly describe the WVP.

A. The WVP serves approximately 25,000 retail customers in south central West Virginia. WVP does not have any generation or high voltage transmission facilities, and does not operate any control area services. It is a distribution utility, directly connected to -- and served as a full requirements wholesale customer by – Appalachian Power Company, a subsidiary of American Electric Power Company ("AEP"). UCU has recently announced plans to sell this property to Allegheny Energy Inc.

Q. You said that both MPS and WPE-KS are interconnected with WR, and receive energy from the Jeffrey Energy Center through transmission agreements with WR. Doesn't this imply that MPS and WPE-KS are interconnected?

A. No. Firm energy only flows *from* the Jeffrey Energy Center on WR, either *to* the MPS Stranger Creek interconnection, or *to* the WPE-KS East Manhattan interconnection.

Q. Can those Transmission Agreements with WR be used to provide wholesale transmission service to third parties other than MPS or WPE-KS?

A. No. The two firm transmission reservations embedded in the Jeffrey Transmission

Agreements are specifically for the two 8 percent, or 174 MW each, shares of Jeffrey Energy Center generation. Those two separate shares, and the respective transmission rights, are operated at very high capacity factors for base load power and energy. WR does allow the combined Jeffrey transmission entitlements of MPS's 174 MW and WPE-KS's 174 MW, a total of 348 MW, to be transmitted to either MPS at Stranger Creek or WPE-KS at East Manhattan, in total or portions thereof.

UTILICORP'S OPEN ACCESS TARIFFS

Q. Do SJLP and the three UCU operating divisions have Open Access Transmission Tariffs on file with the Federal Energy Regulatory Commission ("FERC") and in place in the marketplace?

A. Yes. The SJLP tariff is titled "Order 888A Pro Forma Open Access Transmission Tariff." SJLP was exempted from the FERC Order 889 standards of conduct requirements in FERC Docket OA96-72-000, and the Open Access Same-Time Information System ("OASIS") requirements in FERC Docket No. OA97-554-000. All four UCU domestic divisions have Open Access Transmission Tariffs in place. An updated application was made for MPS, WPE-KS and WPE-CO on June 7th, 1999 in FERC Docket No. ER99-3163-000.

Q. Does the FERC Docket No. ER99-3163-000 include the WVP ?

A. No.

Q. How were the Open Access Transmission Tariffs developed for SJLP and the three UCU divisions?

A. The Order 888A compliance tariffs for SJLP were developed in a somewhat conventional fashion, with all transmission facilities rated at 69 kV and above. These tariffs are two tiered, with one set of rates for 161 kV and above deliveries, and separate rates for 69 kV deliveries. The tariff language is the FERC's pro-forma tariff. For ancillary generation services, SJLP does not make separate or additional charges for (i) Scheduling, System Control and Dispatching Service, and (ii) Reactive Supply and Voltage Control from Generation Sources Service if a wholesale customer's power factor is maintained at a reasonable level. SJLP does have separate rates for (iii) Regulation and Frequency Response Service, (iv) Energy Imbalance Service, (v) Operating Reserve – Spinning, and (vi) Operating Reserve – Supplemental. As stated previously, SJLP was exempted from the FERC Order 889 OASIS requirements.

The approach of developing UCU's Order 888A compliance tariffs for MPS, WPE-KS and WPE-CO have some differences from SJLP's approach. In those filings, the radial facilities were not considered as a part of the transmission function for the MPS, WPE-KS and WPE-CO systems, resulting in lower open access transmission rates than would have been developed if all facilities (which included radial facilities) previously classified as "transmission" had been included in the rates. The open access filing included separate tariffs for each of the three UCU divisions, with the tariff language for these three divisions being FERC's pro-forma tariff. The rate structure in these three tariffs are for 345/161 kV and 69/34 kV deliveries for MPS; 115 kV/above and 34 kV for WPE-KS; and 115 kV and 69 kV for WPE-CO. All three tariffs contain separate ancillary generation charges for (i) Scheduling, System Control and Dispatching, (ii) Reactive Supply and Voltage Control from Generation Sources Service, (iii) Regulation and Frequency Response Service, (iv) Energy Imbalance Service, (v) Operating Reserve – Spinning, and (vi) Operating Reserve – Supplemental.

Q. When SJLP and MPS are merged, will the Open Access Transmission Tariffs be integrated?

A. Yes. With SJLP and MPS interconnected and functioning as one control area, it is only logical that the two transmission entities be operated as one, with one Open Access Transmission Tariff. Depending upon the RTO development in the region, it may be possible to place all the MPS and SJLP transmission facilities under an RTO and avoid the need to build additional transmission facilities by subscribing to the RTO's network service. If the RTO development does not provide for this possibility, then a transmission line will be constructed between the MPS and SJLP systems. I'll also speak more about that later in this testimony.

Q. How will the SJLP and MPS open access rates be affected with the integration of the two systems?

A. It's premature to determine if the same concept will be used for the merged entities as was used in the MPS, WPE-KS, and WPE-CO rates. More consideration, particularly with RTO development will be given prior to making any decision in this regard.

Q. You state that merged entities will be interconnected either by placing all load under an RTO tariff or constructing a transmission line. What regulatory approvals will be required?

A. Both SJLP and MPS are entirely located in the state of Missouri, so presumably the Missouri Public Service Commission will have jurisdiction over some or all of the situation.

Q. You said the merged SJLP and MPS systems would function as one regional control area. Would you please explain?

A. Yes. Ultimately, the transmission systems of both entities will be operated from the MPS Operations Center in Lee's Summit, MO, with the required SCADA system additions. Additions to the EMS/SCADA system will need to consolidate the SJLP/UCU systems at an approximate cost of one million dollars. These changes provide for the gathering of SCADA data from the SJLP power plants and third party tie-lines through dual ported remote terminal units (RTUs). In order to minimize costs, the existing RTUs at SJLP will be converted to a common protocol for scanning by the UCU SCADA master station, rather than changing out the existing RTUs. Data will be brought into the UCU Lee's Summit Operations Center (LSOC) by communications lines through multiplex and microwave equipment. Additional system workstations are included for the existing UtiliCorp EMS at the SJLP site and the LSOC site.

Q. What effects will this change have on transmission safety and reliability?

A. Transmission system safety and reliability will be maintained. For the most part, it is anticipated that the same personnel who are operating and maintaining the existing SJLP and MPS transmission systems will operate and maintain the consolidated systems, with the only exception being that the generation dispatch and transmission system operations will be carried out from the MPS Operations Center in Lee's Summit, MO. The same high standards of safety that both companies have demonstrated in the past will not be disturbed.

Q. You said that one of several possibilities for interconnecting SJLP and MPS was to construct a transmission line between the two systems, and you have conducted a study of such an interconnection between SJLP and MPS. Would you please explain that study?

A. Yes. Schedule (RCK-10) illustrates the existing SJLP and MPS 345 kV and 161 kV systems, and various construction options that are being considered. The first sheet titled "Existing System" illustrates the proximity of the two systems to each other, near the MPS Nashua 161 kV Substation – through a KCPL owned leg from just south of the

SJPL Lake Road power plant to the KCPL Nashua substation -- and the MPS 161 kV line to WR's Stranger Creek interconnection, which is within two miles of the KCPL, SJLP and EDE owned Iatan power plant. Option 1-A involves construction of a 345/161 kV Sparta Substation at the crossing of the SJLP – Iatan 345 kV line and the Lake Road – Nashua 161 kV line, purchasing the Lake Road – Nashua 161 kV line from KCPL, and rebuilding the line from the new Sparta Substation to Nashua. The cost of this option is estimated to be $9.9 million, plus the purchase price of the Lake Road – Nashua line. We understand that any sale of a transmission line by KCPL would likely require Commission approval.

Option 1-B involves construction of the 345/161 kV Sparta Substation at the crossing of SJLP – Iatan 345 kV line and the Lake Road – Nashua 161kV line, and purchasing the Lake Road – Nashua 161 kV line from KCPL. A new 161 kV line would then be built from the new substation to Nashua. This option is estimated to be $11.5 million. Option 2-A involves purchasing the Lake Road – Nashua 161 kV line from KCPL and rebuilding it. This option is estimated to be $5.6 million plus the purchase price of the KCPL Lake Road – Nashua line. Option 2-B involves construction of a new 161 kV line from just south of the Lake Road Substation to Nashua. This option is estimated to be $7.9 million. Option 3 involves purchasing the Edgerton – Nashua portion of the SJLP – Hawthorn line and constructing a 345/161 kV substation at Nashua. This option is estimated to be $5.5 million plus the purchase price of the Edgerton – Nashua line. Option 4 involves constructing a 345/161 kV substation just east of the Iatan power plant and connecting the new substation to the Platte City – Stranger Creek 161 kV line. This option is estimated to be $7.9 million. It is believed that of all the options considered, either Option 2-A or Option 2-B provides the greatest improvement to the electrical system reliability, with the least losses and the lowest estimated cost.

Q. Which option, if any, will UCU pursue?

A. Obviously, Option 2-A or 2-B is the preferred option, and we will diligently pursue both of these. From recent discussions with KCPL representatives, Option 2-A is not a viable option, due to KCPL's lack of interest of selling their line. But from these same discussions has come an additional option, let's call it 2-C, one not considered in our interconnect study. Option 2-C would entail KCPL rebuilding their Nashua to Lake Road 161 kV line, then leasing it to MPS. Given this, we plan to earnestly pursue Option 2-B or 2-C, with the hopes of coming to a definitive conclusion by Fall 1999.

Q. You also mentioned that another possibility for interconnection was to place all native load under Network Service in an RTO or regional tariff. Please explain this option.

A. Under both the SPP regional tariff and Midwest ISO tariff, as they are now structured, the MPS and SJLP native loads could be put under Network Service, and the transmission between the systems would be provided under the Network Tariff. This option will be continuously evaluated as the Midwest ISO and SPP RTO continue to develop.

Q. What impact will this merger have on the transmission employees of both MPS and SJLP?

A. It is anticipated that most transmission operations and maintenance personnel will stay in place, except for system operations, which will eventually be moved to the MPS Operations Center in Lee's Summit.

REGIONAL TRANSMISSION ORGANIZATIONS (RTO's)

Q. You mentioned earlier in your testimony that UCU is giving serious consideration to how the Open Access tariffs will be structured for the merged SJLP and MPS pending development of area RTO's. What are UtiliCorp's views on RTO's?

A. UtiliCorp filed Initial Comments in response to the FERC NOPR on RTO's on August 16, 1999. For convenience, we attach that exact filing in Schedule RCK-11, prepared with the help of our FERC counsel, which includes the key characteristics in the formation and the operation of an RTO and addresses the questions of regional control and reliability.

Q. If this Commission ultimately decides that RTO's are in order, which RTO will the SJLP/MPS merged systems join?

A. That really depends on what RTO(s) develop in the region. If an RTO turns out to be the Eastern Interconnected Grid, the Western Interconnected Grid and the Electric Reliability Council of Texas ("ERCOT"), then the merged SJLP/MPS systems, WPE-KS would join the Eastern Interconnected Grid. If the RTO's turn out to be the existing North American Electric Reliability Council ("NERC") regions, then the merged SJLP/MPS systems and WPE-KS would most likely join either the Mid-Continent Area Power Pool ("MAPP") RTO or the Southwest Power Pool ("SPP") RTO. There is also the Midwest ISO to the east of MPS, and consideration is being given to it.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

Schedule RCK-5

Voltage Level and Thermal Limit Data
First Tier Transmission Interconnections

St. Joseph Light & Power Interconnections

Interconnecting Line/Transformer From	To	Inter-connecting Utility	Line Ownership*	Thermal Line Rating** MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
St. Joseph Substation (MO)	MO-NE State Line	OPPD	SJLP	1098	345	Closed	956	terminal equipment
Fairport Substation	Cooper Substation (NE)	NPPD	"MINT" Owners	1218	345	Closed	956	terminal equipment
St. Joseph Substation	Fairport Substation	AECI	"MINT" Owners	1218	345	Closed	956	terminal equipment
Maryville	Maryville AEC	AECI	SJLP	209	161	Closed	198	terminal equipment
Maryville	Clarinda Substation	MEC	SJLP	175	161	Closed	167	terminal equipment
(Near) Lake Road Power Plant	Nashua	KCPL	KCPL	153	161	Closed	153	conductor clearance
St. Joseph Substation	Iatan Power Plant	KCPL	SJLP	1098	345	Closed	956	wavetraps
St. Joseph Substation	(Near) Edgerton Substation	KCPL	SJLP	1000	345	Closed	1000	conductor 90 deg C

Contractual Interconnections

Maryville	Maryville AEC	UE	SJLP	209	161	Closed	50	Contractual Interconnection
** St. Joseph Substation	Iatan Power Plant	EDE	SJLP	1098	345	Closed	80	Contractual Interconnection

* Line ownership is by specific sections, usually changing at the existing service area boundary.

Utility Names:
Missouri-Iowa-Nebrask Tie ("MINT" Line) Owners:
SJLP - St. Joseph Light & Power Company
KCPL - Kansas City Power & Light Company
MEC - Mid American Electric
AECI - Associated Electric Cooperative, Inc.
NPPD - Nebraska Public Power District
OPPD - Omaha Public Power District
LES - Lincoln Electric System

Other: UE- Union Electric
EDE- Empire District Electric

** - The 80 MW interconnection with EDE at Iatan is dependent upon Empire's use of their 80 MW share of the Iatan plant. If EDE is taking their 80 MW share, SJLP cannot sell to EDE, but EDE could sell up to 160 MW to SJLP. If EDE is not taking their 80 MW share, an 80 MW transaction can take place going either direction between the companies.

Missouri Public Service Interconnections

Interconnecting Line/Transformer		Inter-connecting Utility	Line Ownership*	Thermal Line Rating** MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
From	To							
Archie 161 kV Substation Bus	Montrose Plant	KCPL	KCPL	224	161	Closed	448	Montrose and Stilwell Line Capacity
	Stilwell Substation	KCPL	KCPL	224	161	Closed		
	Adrian Substation		MPS	251	161	Closed		
	Harrisonville Substation		MPS	251	161	Closed		
Martin City 161-69 kV Substation Bus	Martin City (KCPL)	KCPL	KCPL	293	161	Closed	301	Grandview East Line and Transformer Capacity
	Southtown	KCPL	KCPL	224	161	Closed		
	Grandview East		MPS	251	161	Closed		
	161-69 kV Transformer		MPS	50	161-69	Closed		
Roanridge Substation Bus	Weatherby	KCPL	KCPL	273	161	Closed	301	TWA Line and Transformer Capacity
	Nashua	KCPL	KCPL	293	161	Closed		
	Barry	KCPL	KCPL	293	161	Closed		
	TWA		MPS	251	161	Closed		
	161-69 kV Transformer		MPS	50	161-69	Closed		
Duncan Road Substation	KCPL Duncan 60 kV Bus	KCPL	KCPL	60	161-69	Closed	60	161-69 kV Transformer
Sibley 161 kV Substation	Eckles Road Substation	IPL	IPL	251	161	Closed	251	Eckles Road Line
Nashua Substation	KCPL Nashua Substation	KCPL	MPS, KCPL	335	161	Closed	335	Substation Bus
Sedalia West 161 kV Substation	Norton Substation	AECI	AECI	111	161	Closed	111	Norton Line Wave Trap
Butler 161-69 kV Substation	161-69 kV TRansformer	AECI	AECI	50	161-69	Closed	50	Transformer Capacity
Platte City Substation	Stranger Creek Substation	WR	MPS, WR	400	161	Closed	400	345-161 kV Transformer at Stranger Creek
Sedalia East Substation	Overton 345-161 kV Substation	AE	MPS, AE	251	161	Closed	251	Transmission Line
AECI Clinto 161 kV Substation Bus	Sedalia West 161 kV Substation	AECI	MPS	251	161	Closed	351	Transmission Line and 161-69 kV Transformer
	MPS 161-69 kV Substation	AECI	AECI	100	161	Closed		
Liberty 69 kV Substation	Claycomo Substation	KCPL	KCPL, MPS	55	69	Closed	55	Transmission Line
Concordia 69-34 kV Substation	Sweet Springs Substation	KCPL	KCPL, MPS	8.5	34	Open	11	Transmission Line
Warsaw 69 kV Substation	Hermitage Substation	EDE	MPS, EDE	37	69	Open	37	Transmission Line
Blue Ridge 69 kV Substation	ILP Substation N	IPL	IPL, MPS	35	69	Open	35	Transmission Line
Eldorado Springs SW Tower	RUS Eldorado Springs Substation	AECI	MPS	55	69	Open	55	Transmission Line
Lamar 69 kV Substation	Boston Corners	EDE	MPS	27	69	Open	27	Transmission Line
Mayview Tap	Amoco Pipeline	KCPL	KCPL	71	69	Closed	71	Transmission Line

*Line ownership is by specific sections, usually changing at the existing service area boundry.
** Summer peak rating.

Utility Names:
MPS - Missouri Public Service Division of UtiliCorp United Inc.
KCPL - Kansas City Power & Light Company
IPL - City of Independence Department of Power & Light.
EDE - The Empire District Electric Company
AECI - Associated Electric Cooperative, Inc.
AE - AmerenEnergyUE
WR - Western Resources

WestPlains Energy - Kansas Interconnections

Interconnecting Line/Transformer		Inter-connecting Utility	Line Ownership*	Thermal Line Rating MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
From	To							
Harper Substation	Gill Substation	WR	WR, WPE-Ks	110	138	Closed	110	Transmission Line
WR/KPL St. John Substation	Hutchinson Substation	WR	WR	80	115	Closed	120	Transmission Lines to Larned and Hutchinson
	Larned Substation	WR	WR	40	115	Closed		
	Mullergren Power Plant		WPE-Ks	91	115	Closed		
	Pratt Substation		WPE-Ks	91	115	Closed		
Greenleaf Substation	Knobhill Substation	WR	WR, WPE-Ks	91	115	Closed	91	Transmission Line
Mullergren 230 kV Bus	Circle Substation	WR	WPE-Ks	320	230	Closed	320	Transmission Line
Concordia West Substation	East Manhattan	WR	WR, WPE-Ks	205	230	Closed	205	345-230 kV Transformer
Cimarron Power Plant	North Cimarron	SEC	SEC	133	115	Closed	133	Transmission Line
Mullergren 239 kV Bus	Heizer 115 kV Bus	MEI	WPE-Ks, WR	110	230-115	Closed	110	230-115 kV Transformer
Plainville Substation	Hays Substation	MEI	MEI, WPE-Ks	133	115	Closed	133	Transmission Line
Liberal Substation	Texas County Substation	SPS	SPS, WPE-Ks	112	115	**Closed	112	Transmission Line
Spearville 230 kV Bus	Spearville 345 kV Bus	SEC		336	345-230	Closed	336	345-230 kV Transformer

*Line ownership is by specific sections, usually changing at the existing service area boundry.
**A phase shifting transformer was installed during the Spring of 1996 that allowed this tie to be closed.

Utility Names:
WPE-Ks - WestPlains Energy - Kansas Division of UtiliCorp United Inc.
WR - Western Resources
SEC - Sunflower Electric Cooperative
MEI - Midwest Energy, Inc.
SPS - Southwestern Public Service Company (in the Western Interconnected Grid)

WestPlains Energy - Colorado Interconnections

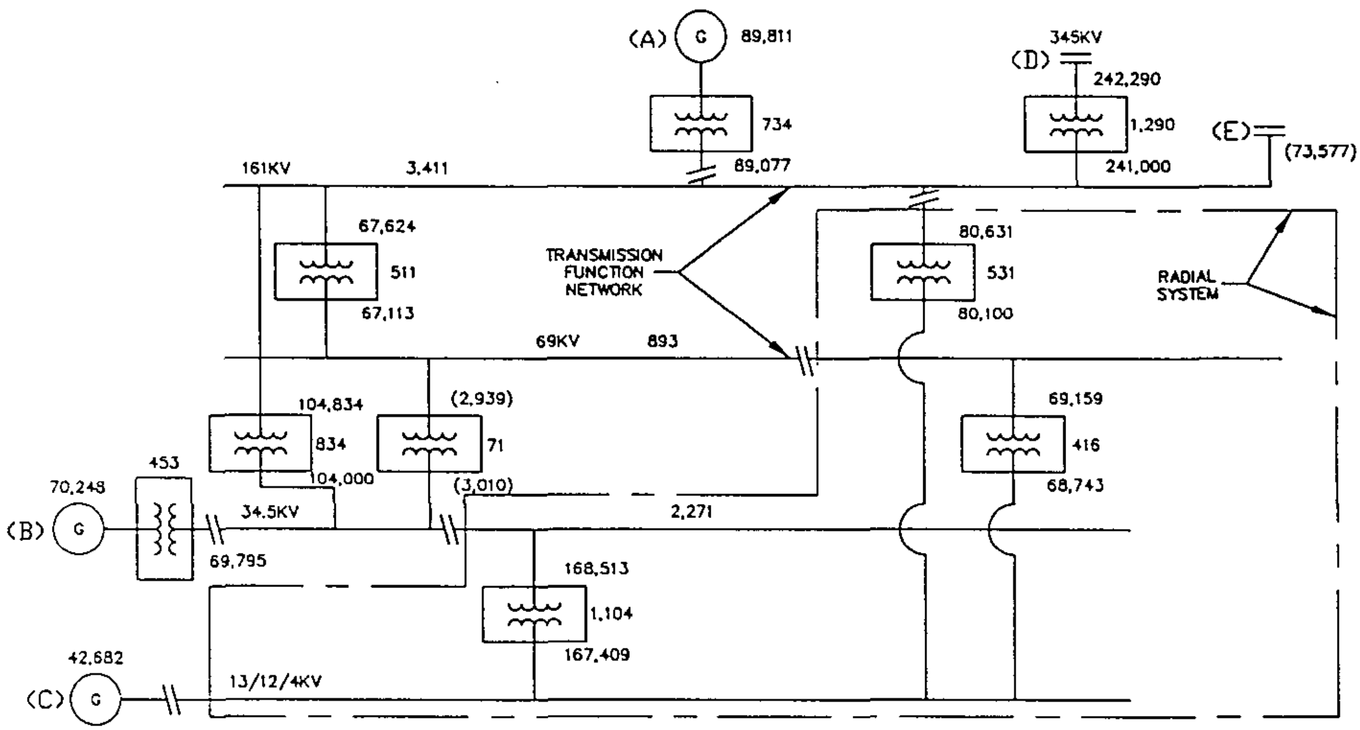
Interconnecting Line/Transformer		Inter-connecting Utility	Line Ownership*	Thermal Line Rating** MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
From	To							
Reader Substation Bus	Comanche 115 kV Bus	PSCO	PSCO	217	115	Closed	217	Transmission Line
West Station Substation	Midway WAPA Substation Bus	WAPA, CoSpg TS	WPE-Co	115	115	Closed	115	Transmission Line
Canon Plant Substation	Poncha Substation	PSCO	WPE, PSCO	133	115	Closed	133	Transmission Line
West Station	Walsenburg	TS	TS	136	115	Closed	136	Transmission Line
PSCO Midway Substation	West Station	PSCO	WPE, PSCO	115	115	Closed	100	230-115 kV Transformer
	Boone Substation	PSCO	WPE, PSCO	115	115	Closed		
PSCO Boone Substation	PSCO Midway Substation	PSCO	WPE, PSCO	115	115	Closed	150	230-115 kV Transformer
	WPE-Co LaJunta Substation	PSCO	WPE-Co	115	115	Closed		
	WPE-Co Boone Tap	PSCO	WPE-Co	33	115-69	Closed		
LaJunta Substation	*Las Animas Substation*	ARPA	WPE, ARPA	63	69	Open	63	Transmission Line

*Line ownership is by specific sections, usually changing at the existing service area boundry.

Utility Names:
WPE-Co (WPE) - WestPlains Energy-Colorado Division of UtiliCorp United Inc.
PSCO - Public Service Company of Colorado
CoSpg - City of Colorado Springs
TS - *Tri-State Generation and Transmission Association*
ARPA - Arkansas River Valley Power Association
WAPA - Western Area Power Administration

Schedule RCK-6

System Schematic Diagram
Power Input, Loads, Line Losses and Transformation Losses
St. Joseph Light & Power Company

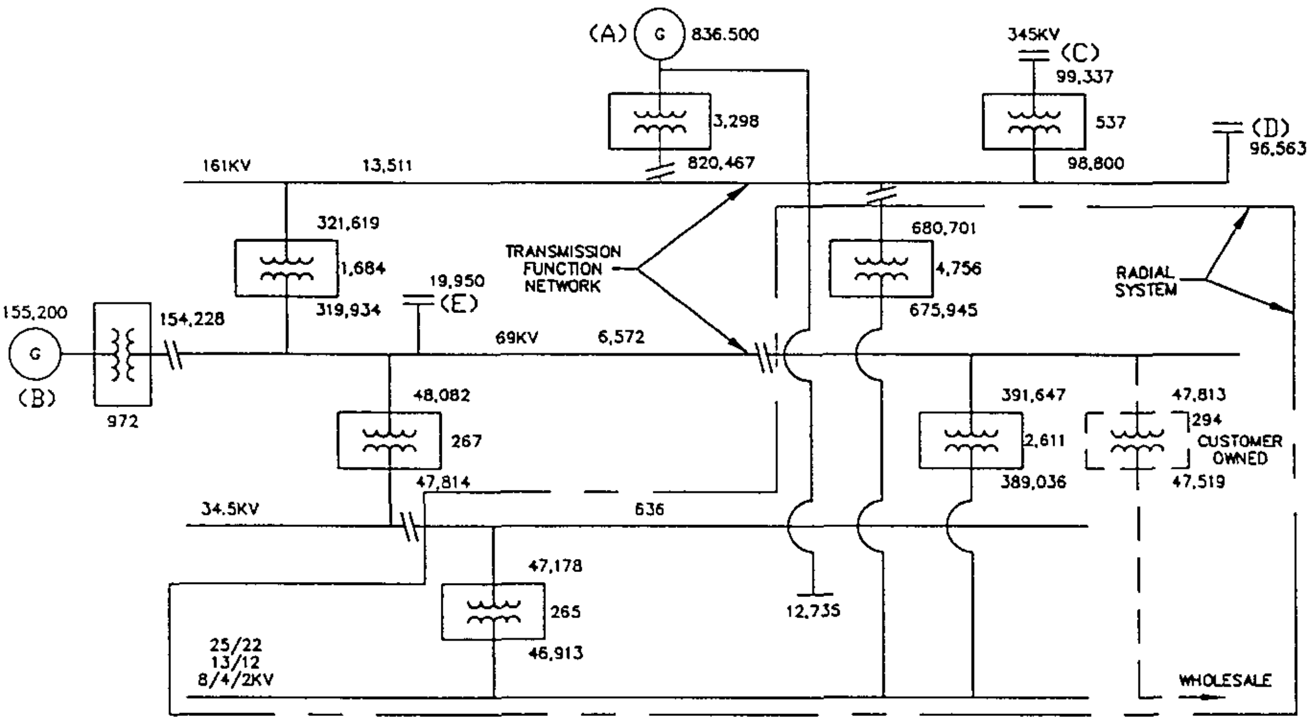


(A) Lake Road 4
(B) Lake Road 5, Lake Road 6, Lake Road 7
(C) Lake Road 1, Lake Road 2, Lake Road 3
(D) AEC, KCPL
(E) AEC, KCPL, MEC, OPPD

NO.	BY	DATE	DESCRIPTION			
REVISIONS				1998 SUMMER 1CP LOADS VALUES IN KW ST. JOSEPH LIGHT& POWER	DRAWN BHALL CAD REF. MPSICP98 W.O. NO. SCALE NTS SHEET 1 OF 1	DATE 6/18/98 CHK. BY

Schedule RCK-7

System Schematic Diagram
Power Input, Loads, Line Losses and Transformation Losses
Missouri Public Service Division
UtiliCorp United Inc.



(A) Jeffrey, Sibley, Greenwood, KCI
(B) Ralph Green, Nevada
(C) KCPL, UE
(D) KCPL, UE, AEC
(E) AEC

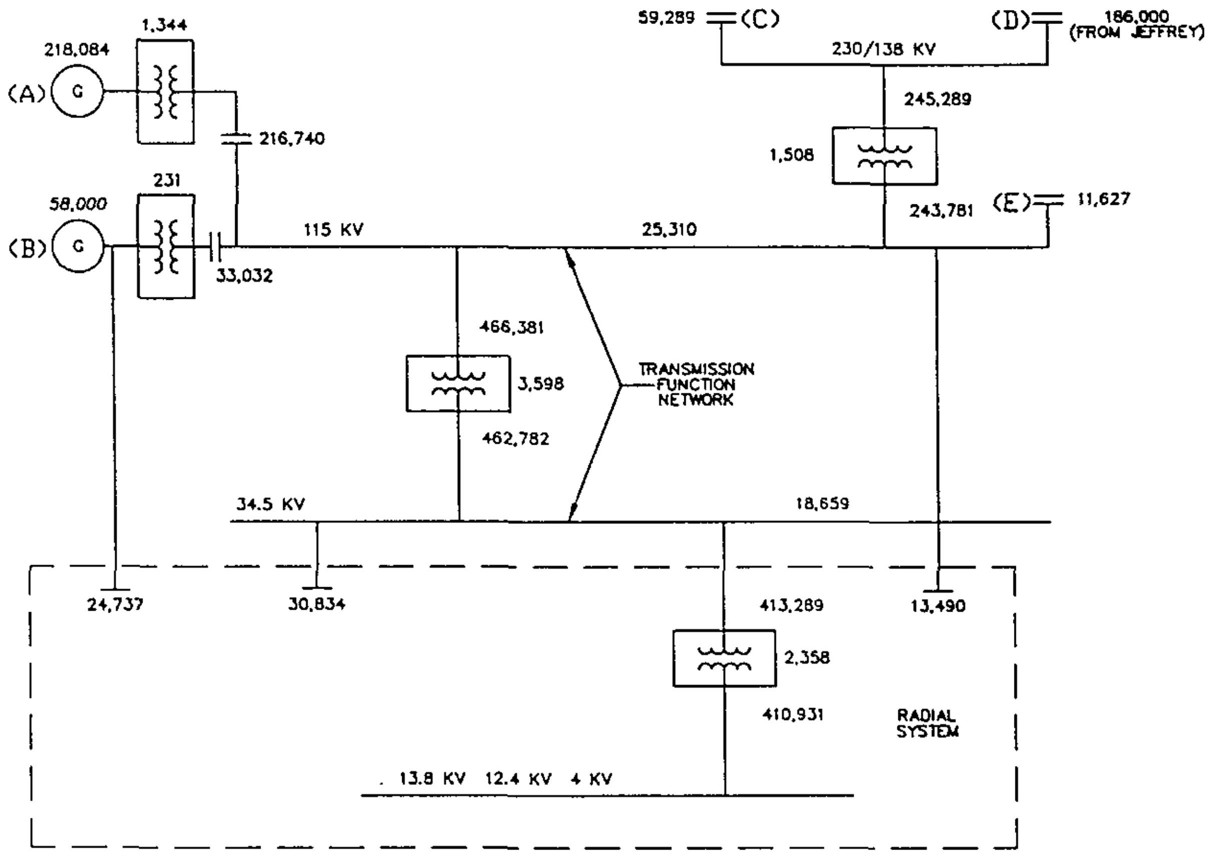
NO.	BY	DATE	DESCRIPTION

1998 SUMMER 1CP LOADS
VALUES IN KW
MISSOURI PUBLIC SERVICE

DRAWN	DATE
CAD REF.	CHK. BY
W.O. NO.	
SCALE	
SHEET OF	

Schedule RCK-8

System Schematic Diagram
Power Input, Loads, Line Losses and Transformation Losses
WestPlains Energy-Kansas Division
UtiliCorp United Inc.



(A) Judson Large, Mullergren
(B) Cimarron River
(C) WR, Sunflower
(D) Jeffrey
(E) MWE, SPS, WR, Sunflower

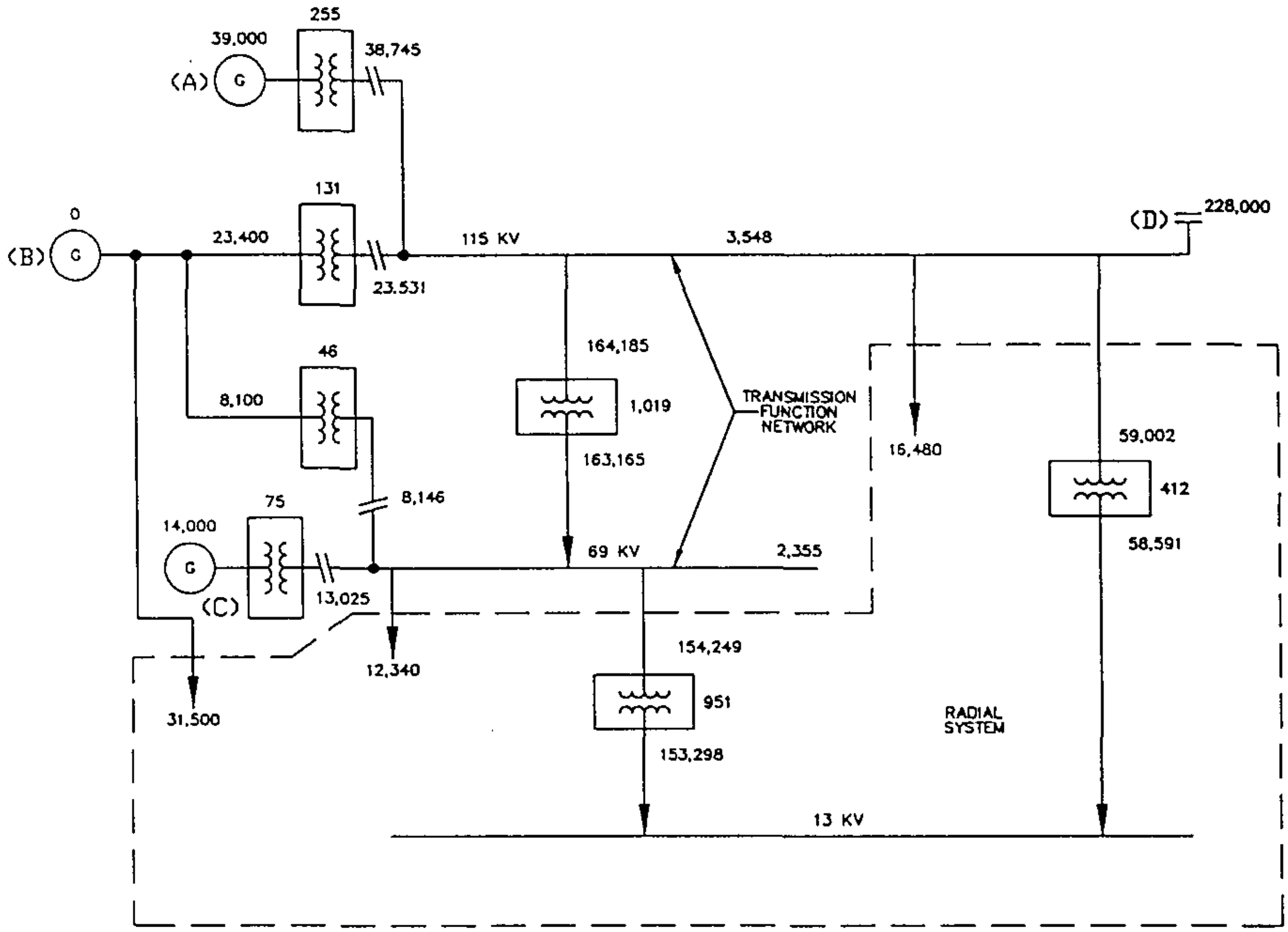
NO.	BY	DATE	DESCRIPTION

1998 SUMMER ICP LOADS
VALUES IN KW
WEST PLAINS ENERGY (KANSAS)

DRAWN | DATE
CAD REF. | CHK. BY
W.O. NO.
SCALE
SHEET OF

Schedule RCK-9

System Schematic Diagram
Power Input, Loads, Line Losses and Transformation Losses
WestPlains Energy-Colorado Division
UtiliCorp United Inc.



(A) Canon City
(B) Pueblo Steam
(C) Pueblo Diesel, Rocky Ford
(D) WAPA, Tri-State, PSCO, ARPA, Colorado Springs

NO.	BY	DATE	DESCRIPTION	1998 SUMMER ICP LOADS VALUES IN KW WEST PLAINS ENERGY (COLORADO)	DRAWN	DATE
					CAD REF.	CHK. BY
					W.O. NO.	
					SCALE	
					SHEET OF	

Schedule RCK-10

Summary Result
Direct High Voltage Transmission Interconnection
Between
St. Joseph Light & Power Company
And
Missouri Public Service Division
UtiliCorp United Inc.

I. INTRODUCTION

The purpose of this study was to determine the preferred option for physically connecting the UtiliCorp United (UCU) electrical transmission system with the St. Joseph Light & Power (SJLP) electrical transmission system. Seven options for achieving this objective are discussed in this report.

A preferred solution was required for two categories of options. The first category of options were options that required Kansas City Power & Light (KCPL) participation. The second category of options were options that were achievable without KCPL participation.

Each option is discussed separately in the body of this report with regards to contingency analysis, estimated costs, and MW losses.

II. CONTINGENCY ANALYSIS

Loadflow models were created to simulate the existing transmission system. Initial loadflows were based on the year 2000 Southwest Power Pool summer peak models. Contingency analysis was performed for the existing system and each option to examine the transmission system's ability to perform adequately during a single-contingency situation.

The following contingencies were analyzed:

All facilities 161kV and above in the MPS system
All facilities 161kV and above in the SJLP system
All facilities 161kV and above in the KCPL system
All facilities 115kV and above in the NPPD system
All facilities 115kV and above in the OPPD system
All facilities 115kV and above in the MEC system
Iatan - Stranger Creek 345kV line
Stranger Creek - Craig 345kV line
Stranger Creek - Hoyt 345kV line
Hoyt - JEC 345 line
Fairport - St. Joseph 345kV line
Fairport - Cooper 345kV line
Kelley - Humboldt 161kV line
Lathrop - Fairport 161kV line

In total, 941 contingencies were analyzed for the year 2000 scenarios. 955 contingencies were analyzed for the 2008 scenarios.

Contingency analysis was repeated using a heavy north to south transfer scenario. This analysis provided an additional assessment of the transmission system's ability to withstand a single-contingency situation while the system is stressed. Although the LR - Nashua line is often removed from service during heavy flow situations, this line was left in service for the heavy transfer contingency analysis. This was done with the understanding that it could be removed from service as a remedial action to alleviate overloading on this line.

During the course of this study (after the year 2000 contingency analysis was completed), the preferred options were identified. Contingency analysis was repeated for the existing system and preferred options for a year 2008 model (both normal transfer scenarios and heavy transfer scenarios).

Percentage overloads as discussed in this report refer to the line's emergency rating.

III. EXISTING SYSTEM

A. System Configuration

The existing SJLP system has three transmission lines (161kV and above) that extend south towards the UCU system and provide possible interconnection points (see diagram on the following page). All three of these transmission lines interconnect with KCPL.

The St. Joseph - Hawthorn line is a 345kV line that runs from SJLP's St. Joseph Substation to KCPL's Hawthorn generating station. Ownership of this line changes at the Buchanan/Platte County border near Edgerton. The meter for this line is located at St. Joseph Substation and, therefore, KCPL pays for the losses on this line. This line is bundled 795 ACSR conductor rated at 956 MVA.

The St. Joseph - Iatan line is a 345kV line that runs from SJLP's St. Joseph Substation to KCPL's Iatan generating station. SJLP is an 18% co-owner of the 670 MW Iatan unit along with KCPL and Empire District. SJLP owns the line to Iatan, however, the meter is located at St. Joseph Substation and, therefore, KCPL pays for the losses on this line. This line is bundled 795 ACSR conductor rated at 956 MVA.

The Lake Road - Nashua line is a 161kV line that runs from SJLP's Lake Road Substation to KCPL's Nashua Substation. Ownership of this line changes approximately ½ mile south of Lake Road Substation. The meter for this line is located at Lake Road and, again, KCPL pays for the losses on this line. This line is currently 397.5 ACSR conductor, in poor structural condition, and is only rated for 153 MVA normal/ 172 MVA emergency. Because of the limited capability of this line, current operating practice calls for this line to be opened up during potential overload situations.

The practice of operating the Lake Road - Nashua line normally open to avoid overloading the line impacts reliability at the Lake Road plant and the City of St. Joseph. Served by a total of three 161KV lines, including the Lake Road - Nashua line, the plant and city are often times operated radially when one of the 161kV lines into Lake Road is already down for maintenance (or contingency) and then the LR - Nashua line is opened up to prevent overloading.

B. Loadflow and Contingency Analysis

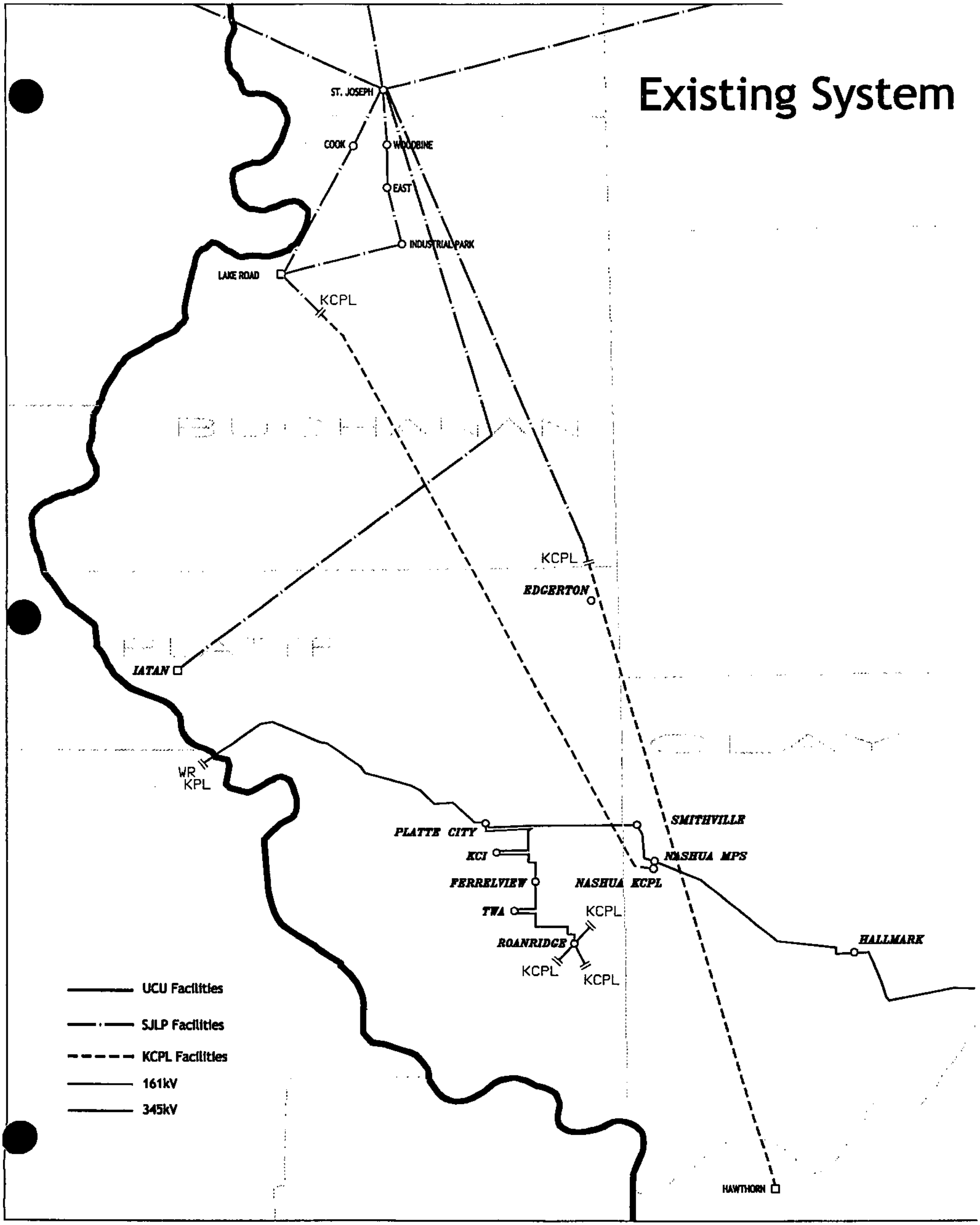
The base case loadflow for the existing system (normal transfer scenario) is shown on page 6. In this case, the flow on the LR-Nashua line was 104 MW. The flow on this line for the heavy transfer scenario was 169 MW and exceeded the normal rating of the line (see page 7). Therefore, a second heavy transfer scenario was created with the LR-Nashua line taken out of service (as is the practice for heavy flow situations). The results of this loadflow are shown on page 8.

The existing system performed adequately at summer peak during all contingency situations for the normal transfer scenario. However, for the heavy transfer scenario, performance dropped dramatically (see table on page 37). The Lake Road - Nashua line overloaded for 904 contingency situations (including the base case) with a maximum overload of 149% (outage of the St. Joe - Hawthorn line). The St. Joe - Hawthorn line overloaded to 103% for a contingency of the Iatan - Stranger Creek 345kV line.

The 2008 model (normal and heavy transfer scenarios) did not reveal any new transmission system problems. The 2008 scenario performed better than the 2000 scenario in the area of concern primarily due to added generation at Hawthorn (1,021 MW in 2008 scenario vs. 150 MW in 2000 scenario).

C. *Losses*

Losses for the base case totaled 27.3 MW for the UCU and SJLP systems. KCPL losses were 51.5 MW (see table on page 38 for a loss summary).


Existing System
ST. JOSEPH
COOK
WOODBINE
EAST
INDUSTRIAL PARK
LAKE ROAD
KCPL
KCPL
EDGERTON
IATAN
WR
KPL
PLATTE CITY
SMITHVILLE
KCI
NASHUA MPS
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
KCPL
KCPL
HALLMARK
HAWTHORN
UCU Facilities
SJLP Facilities
KCPL Facilities
161kV
345kV

IV. OPTION 1 - Sparta Substation

The first option for connecting the UCU and SJLP electrical systems involves the construction of a 345/161kV substation at Sparta (model and estimate used a 336 MVA autotransformer). Sparta is located at the crossing of the St. Joseph - Iatan 345kV line and the Lake Road - Nashua 161kV line (SJLP already owns the property at this location). Option 1 was further broken down into two parts: Option 1-A and Option 1-B as discussed below.

V. OPTION 1-A

A. *System Configuration*

Option 1-A completes the interconnection between UCU and SJLP by purchasing the Lake Road - Nashua 161kV line from KCPL (see diagram on the following page). This line would then be rebuilt (model and estimate used 1192 ACSR) from Sparta to Nashua and the terminal would be moved from KCPL's Nashua Substation to UCU's Nashua Substation (the two substations are side-by-side).

B. *Estimated Cost*

The estimated cost for this option is $9.9 million plus the purchase price of the KCPL LR-Nashua line. The costs for this option are broken down as follows:

Construct 345/161kV Sparta Substation - $5.3 million
UCU Nashua Sub terminal change - $0.7 million
Purchase Lake Road to Nashua line from KCPL - unknown
Rebuild Sparta to Nashua line to 1192 ACSR - $3.9 million

C. *Loadflow and Contingency Analysis*

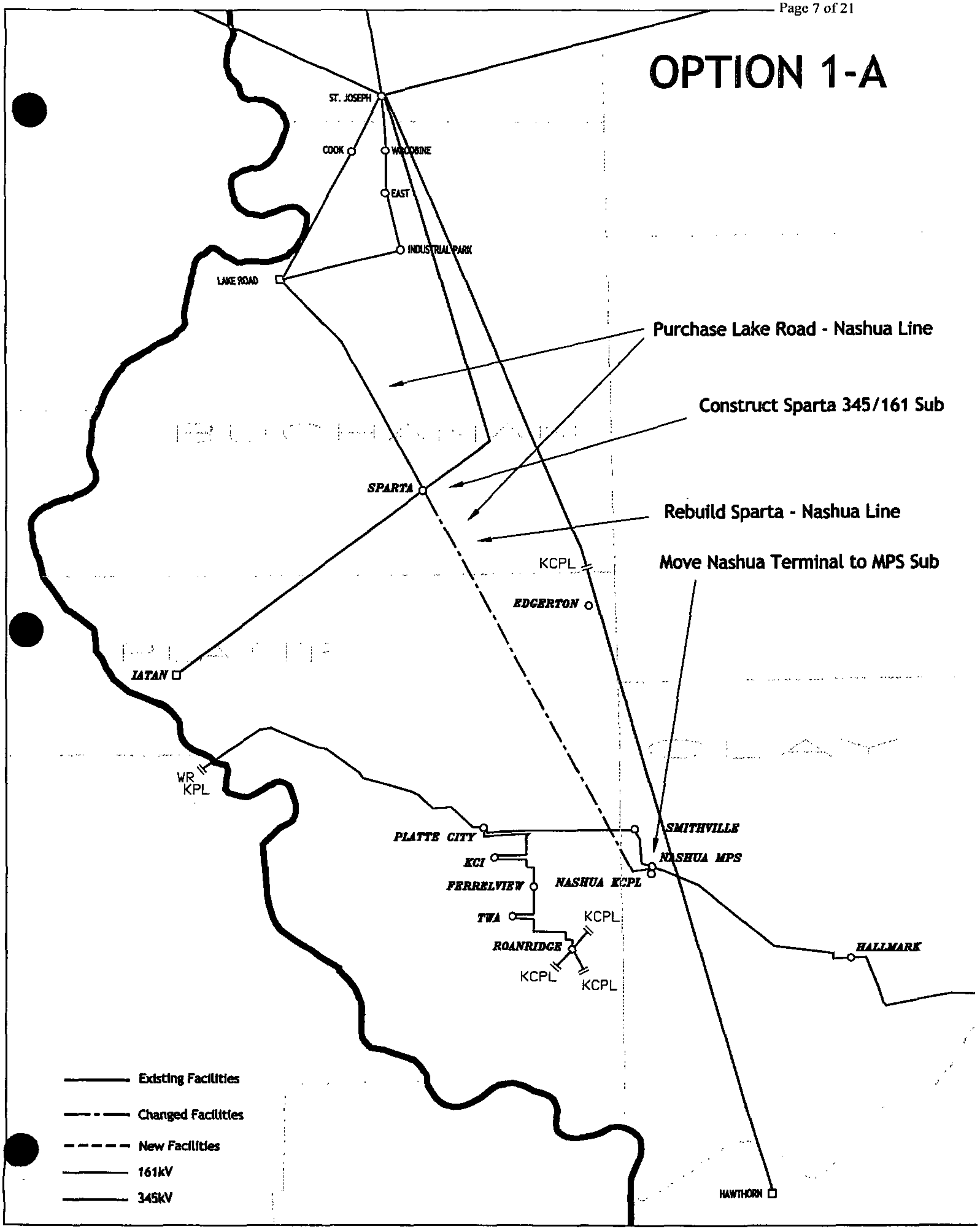
In the normal transfer scenario for this option, flow was reduced (compared to the existing system) on the LR-Sparta line to 34 MW (see page 11). Flow through the new Sparta Substation was 123 MW. For the heavy transfer scenario, flow on the LR-Sparta line was 97 MW (see page 12) and flow through the Sparta Substation was 135 MW.

This option performed adequately at summer peak during all contingency situations for the normal transfer scenario. For the heavy transfer scenario, two contingencies caused the Sparta-Nashua line to overload as much as 116% (maximum overload during an outage of the Stranger Creek - Iatan line). Although the Sparta - Nashua line may need to be opened during these overloads, this option does improve the reliability to Lake Road, allowing three 161kV lines to be closed into the plant at all times.

Also, an outage of the Sparta transformer caused the LR - Sparta portion of the line to overload to 103%. See the table on page 37 for a contingency summary.

D. *Losses*

In the loadflow model for this option, the billing meter on the St. Joseph - Iatan line was moved from St. Joseph to Sparta. Also, the billing meter on the Lake Road - Nashua line was moved from Lake Road to Nashua. Therefore, SJLP losses increased in this case over the base case due to the additional line ownership of the LR - Nashua line and the additional responsibility for losses on the St. Joseph - Sparta line. Losses for this option totaled 30.2 MW for the UCU and SJLP systems. KCPL losses were 46.7 MW (see table on page 38 for a loss summary).


OPTION 1-A
ST. JOSEPH
COOK
EAST
INDUSTRIAL PARK
LAKE ROAD
Purchase Lake Road - Nashua Line
Construct Sparta 345/161 Sub
SPARTA
Rebuild Sparta - Nashua Line
KCPL
Move Nashua Terminal to MPS Sub
EDGERTON
IATAN
WR
KPL
PLATTE CITY
SMITHVILLE
NASHUA MPS
KCI
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
KCPL
KCPL
HALLMARK
HAWTHORN
Existing Facilities
Changed Facilities
New Facilities
161kV
345kV

VI. OPTION 1-B

A. System Configuration

Option 1-B completes the interconnection between UCU and SJLP with the construction of a new 161kV line (estimate and model used 1192 ACSR) between Sparta Substation and the UCU Nashua Substation (see diagram on the following page).

B. Estimated Cost

The estimated cost for this option is $11.5 million. The costs for this option are broken down as follows:

Construct 345/161kV Sparta Substation - $5.3 million
UCU Nashua Substation - $0.7 million
Construct 161kV Sparta to Nashua line (1192 ACSR) - $5.5 million

C. Loadflow and Contingency Analysis

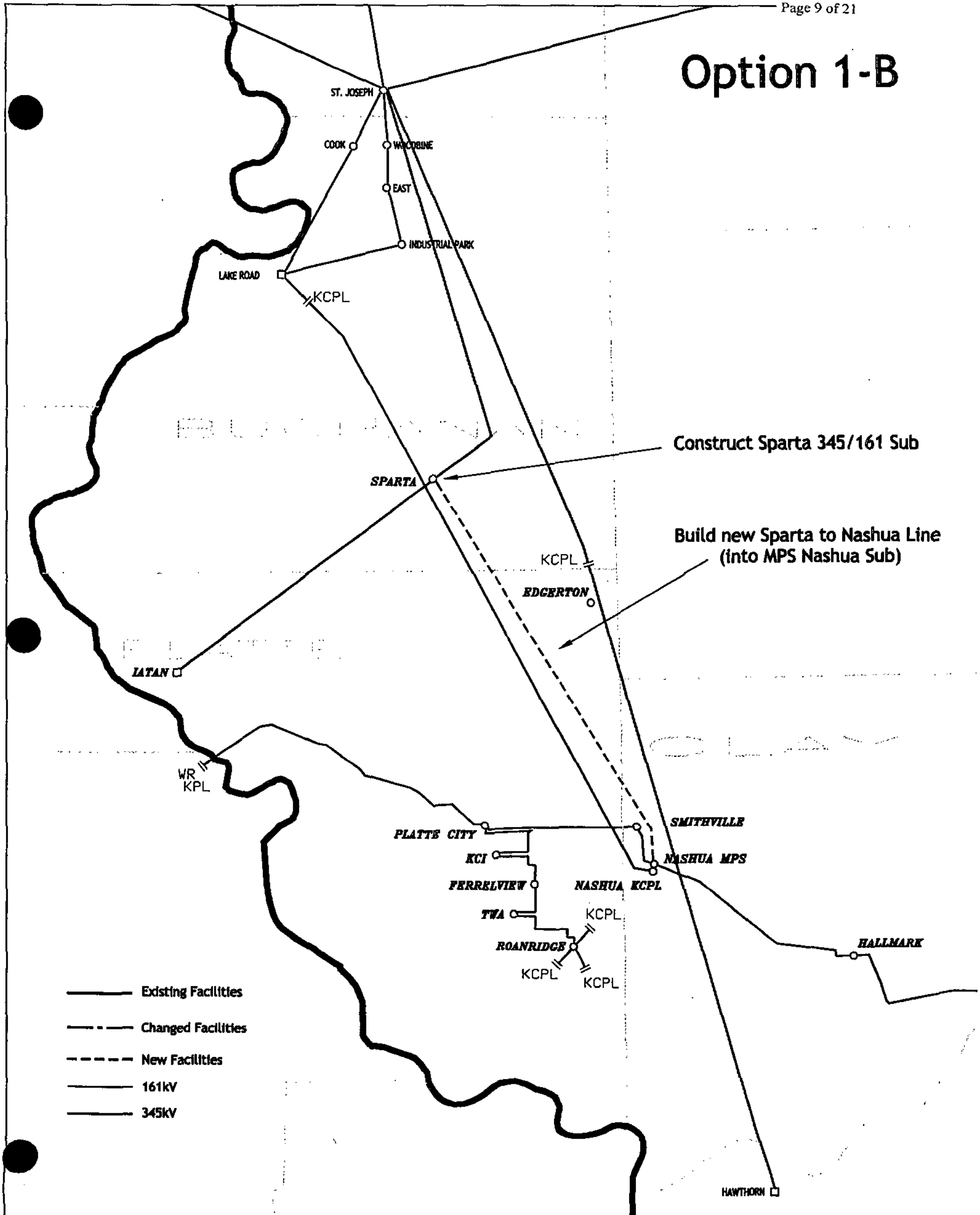
In the normal transfer scenario, the flow on the LR-Sparta line were reduced (compared to the existing system) by only 20% to 83 MW (see page 15). Flow through the new Sparta Substation was 131 MW. For the heavy transfer scenario, flow on the LR-Nashua line was 141 MW (see page 16) and flow through the Sparta Substation was 176 MW.

This option performed adequately at summer peak during all contingency situations for the normal transfer scenario. However, for the heavy transfer scenario, five contingencies caused the Lake Road - Nashua line to overload as much as 120% (maximum overload during an outage of the St. Joseph - Hawthorn line). Although this option does improve the reliability to Lake Road somewhat, it still does not eliminate the need to open the Lake Road - Nashua line during heavy flow situations (leaving the Lake Road plant connected to only two transmission lines). See the table on page 37 for a contingency summary.

D. Losses

In the loadflow model for this option, the billing meter on the St. Joseph - Iatan line was moved from St. Joseph to Sparta. The billing meter on the Lake Road - Nashua line was left at LR with KCPL paying the losses. SJLP losses increased in this case over the base case due to the additional responsibility for losses on the St. Joseph - Sparta line. Losses for this option totaled 28.7 MW for the UCU and SJLP systems. KCPL losses were 48.2 MW (see table on page 38 for a loss summary).

Option 1-B


ST. JOSEPH
COOK
WOODBINE
EAST
INDUSTRIAL PARK
LAKE ROAD
KCPL
Construct Sparta 345/161 Sub
SPARTA
Build new Sparta to Nashua Line
(into MPS Nashua Sub)
KCPL
EDGERTON
IATAN
WR
KPL
SMITHVILLE
PLATTE CITY
KCI
NASHUA MPS
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
KCPL
KCPL
HALLMARK
Existing Facilities
Changed Facilities
New Facilities
161kV
345kV
HAWTHORN

VII. OPTION 2 - Upgrading the Lake Road - Nashua Line

The second option for connecting the UCU and SJLP electrical systems involves upgrading the existing Lake Road - Nashua line. Option 2 was further broken down into two parts: Option 2-A and Option 2-B as discussed below.

VIII. OPTION 2-A

A. System Configuration

Option 2-A simply involves purchasing and rebuilding the Lake Road - Nashua 161kV line (estimate and model used 1192 ACSR) and moving the line terminal at Nashua from KCPL's Nashua Substation to UCU's Nashua Substation (see the diagram on the following page).

B. Estimated Cost

The estimated cost for this option is $5.6 million plus the purchase price of the KCPL LR - Nashua line. The costs for this option are broken down as follows:

UCU Nashua Substation - $0.7 million
Lake Road Substation - $0.2 million
Purchase Lake Road to Nashua line from KCPL - unknown
Rebuild Lake Road to Nashua line to 1192 ACSR - $4.7 million

C. Loadflow and Contingency Analysis

As expected, the flow on the LR - Nashua line for this option increased above the existing system flow. The flow on this line was 112 MW in the normal transfer scenario (see page 19). For the heavy transfer scenario, the flow increased to 181 MW (see page 20). The increased flow is acceptable due to the higher line rating (312 MVA) for the LR-Nashua line in this option.

This option performed adequately at summer peak during all contingency situations for the normal transfer scenario. For the heavy transfer scenario, only one contingency resulted in an overload. An outage of the Iatan - Stranger Creek line caused the St. Joseph - Hawthorn line to overload to 102%. This option greatly increases the reliability to the Lake Road plant by completely eliminating the need to open the Lake Road - Nashua line during heavy flow situations.

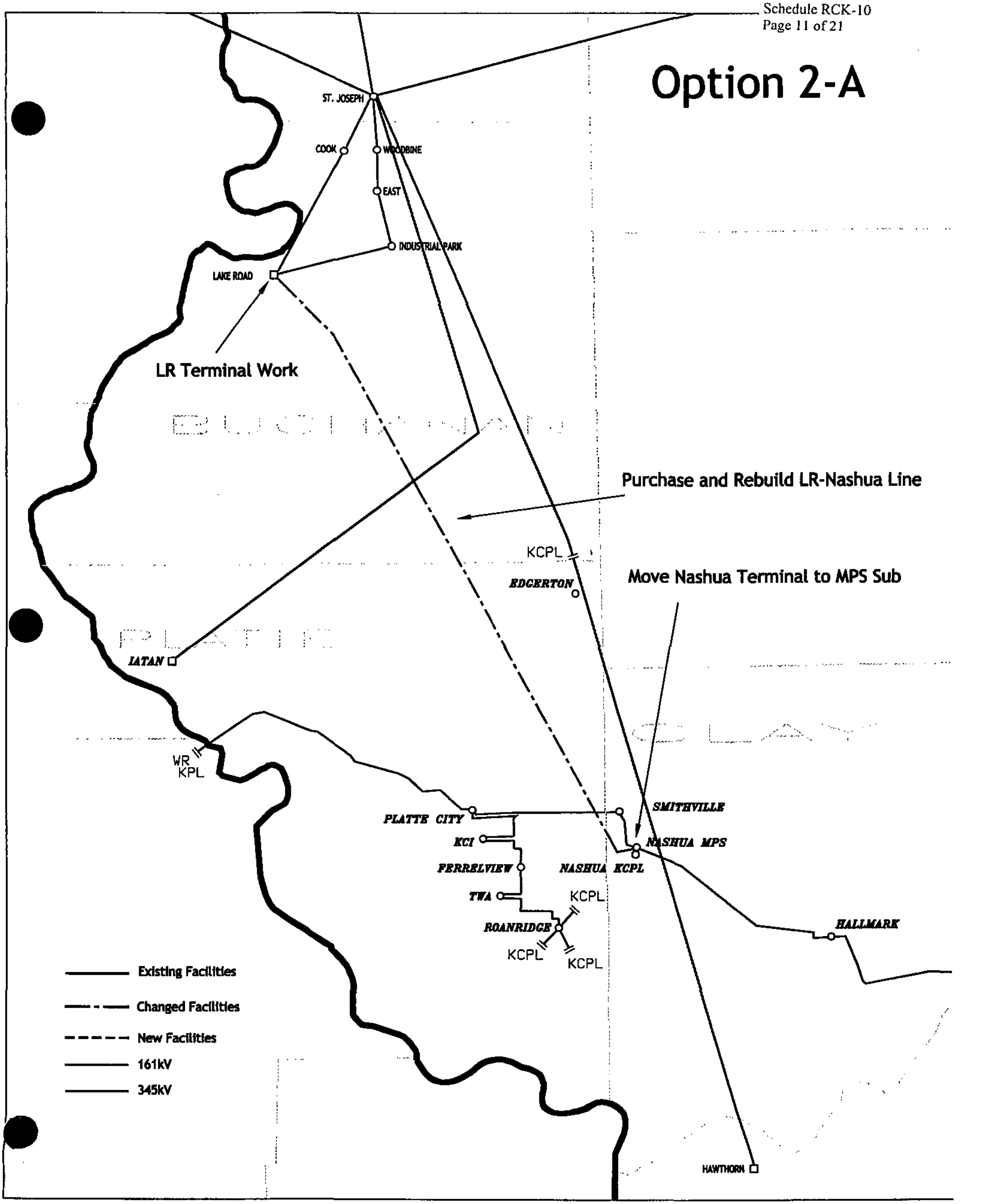
See the table on page 37 for a contingency summary.

The 2008 model (normal and heavy transfer scenarios) did not reveal any new transmission system problems. The 2008 scenario performed better than the 2000 scenario in the area of concern primarily due to added generation at Hawthorn (1,021 MW in 2008 scenario vs. 150 MW in 2000 scenario).

D. Losses

In the loadflow model for this option, the billing meter on the Lake Road - Nashua line was moved to UCU's Nashua Substation. SJLP losses increased in this case over the base case due to the additional line ownership. Losses for this option totaled 28.4 MW for the UCU and SJLP systems. KCPL losses were 47.9 MW (see table on page 38 for a loss summary).

Option 2-A


ST. JOSEPH
COOK
WOODBINE
EAST
INDUSTRIAL PARK
LAKE ROAD
LR Terminal Work
Purchase and Rebuild LR-Nashua Line
KCPL
EDGERTON
Move Nashua Terminal to MPS Sub
IATAN
WR
KPL
SMITHVILLE
PLATTE CITY
KCI
NASHUA MPS
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
HALLMARK
KCPL
KCPL
Existing Facilities
Changed Facilities
New Facilities
161kV
345kV
HAWTHORN

IX. OPTION 2-B

A. System Configuration

Option 2-B involves constructing a new 161kV line (estimate and model used 1192 ACSR) in parallel with the existing LR - Nashua line. This new line would extend from approximately ½ mile south of the Lake Road Substation to UCU's Nashua Substation. This point is where SJLP ownership of the line ends and is referred to as Lake Road South in this report. The ½ mile long line section from Lake Road to Lake Road South would be rebuilt to 1192 ACSR (see the diagram on the following page).

B. Estimated Cost

The estimated cost for this option is $7.9 million. The costs for this option are broken down as follows:

UCU Nashua Substation - $0.7 million
Lake Road Substation - $0.2 million
Rebuild line from Lake Road to Lake Road South and then construct new line to UCU's Nashua Substation - $7.0 million

C. Loadflow and Contingency Analysis

The flow on the existing LR - Nashua line decreased (compared to the existing system) for this option to 72 MW in the normal transfer scenario (see page 23). For the heavy transfer scenario, the flow decreased to 116 MW (see page 24).

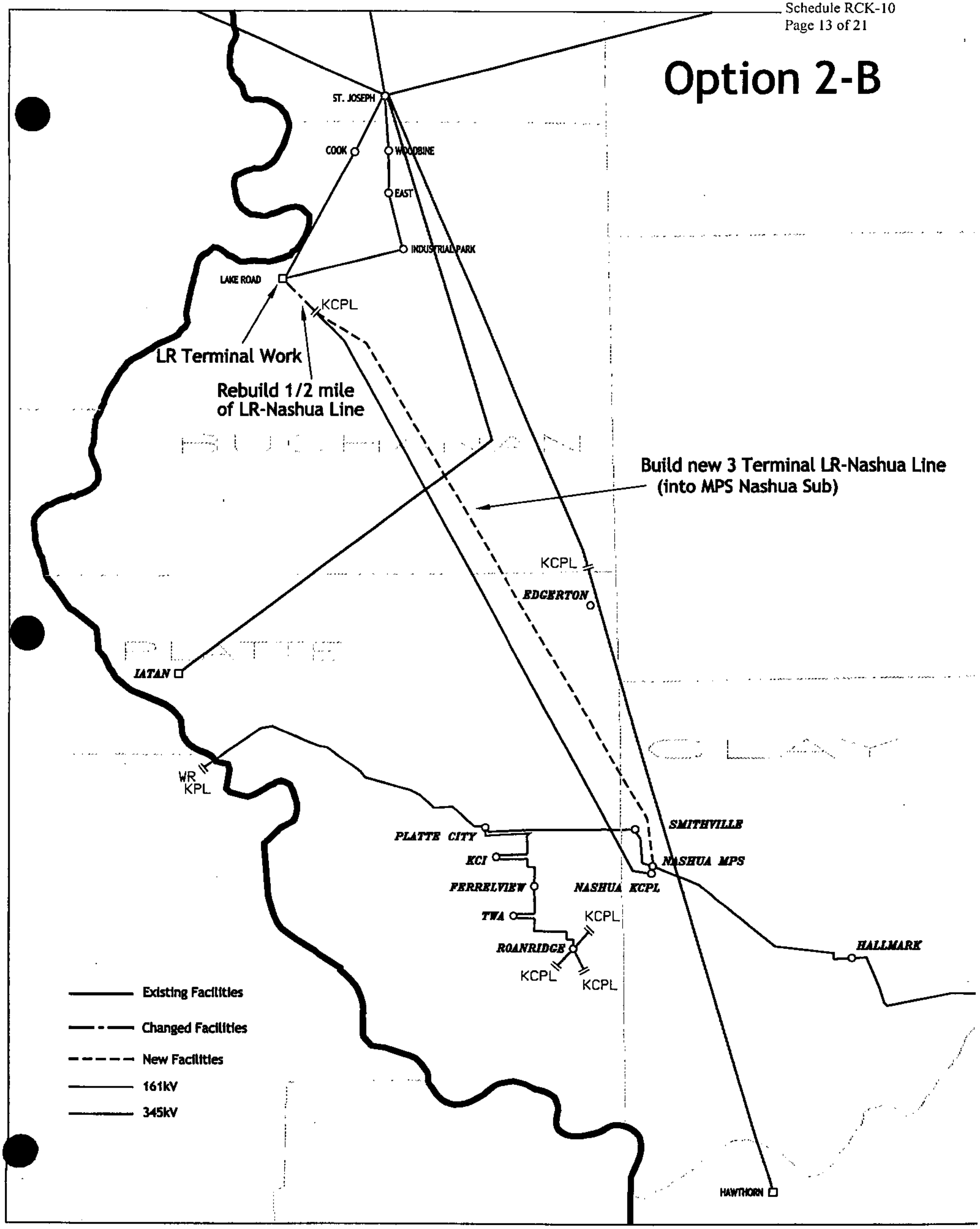
This option performed adequately at summer peak during all contingency situations for the normal transfer scenario. For the heavy transfer scenario, two contingencies resulted in severe overloads. An outage of either the Iatan - Stranger Creek line or the St. Joseph - Hawthorn line caused the existing Lake Road South - Nashua line to overload to 117%. If this option were to be pursued as is, the Lake Road - Lake Road South line could be built to greater than 1192 ACSR to alleviate these overloads. Although the existing Lake Road South - Nashua line may need to be opened during heavy flow situations, this option still maintains three 161kV lines to Lake Road, improving reliability to the plant. See the table on page 37 for a contingency summary.

The 2008 model (normal and heavy transfer scenarios) did not reveal any new transmission system problems. The 2008 scenario performed better than the 2000 scenario in the area of concern primarily due to added generation at Hawthorn (1,021 MW in 2008 scenario vs. 150 MW in 2000 scenario).

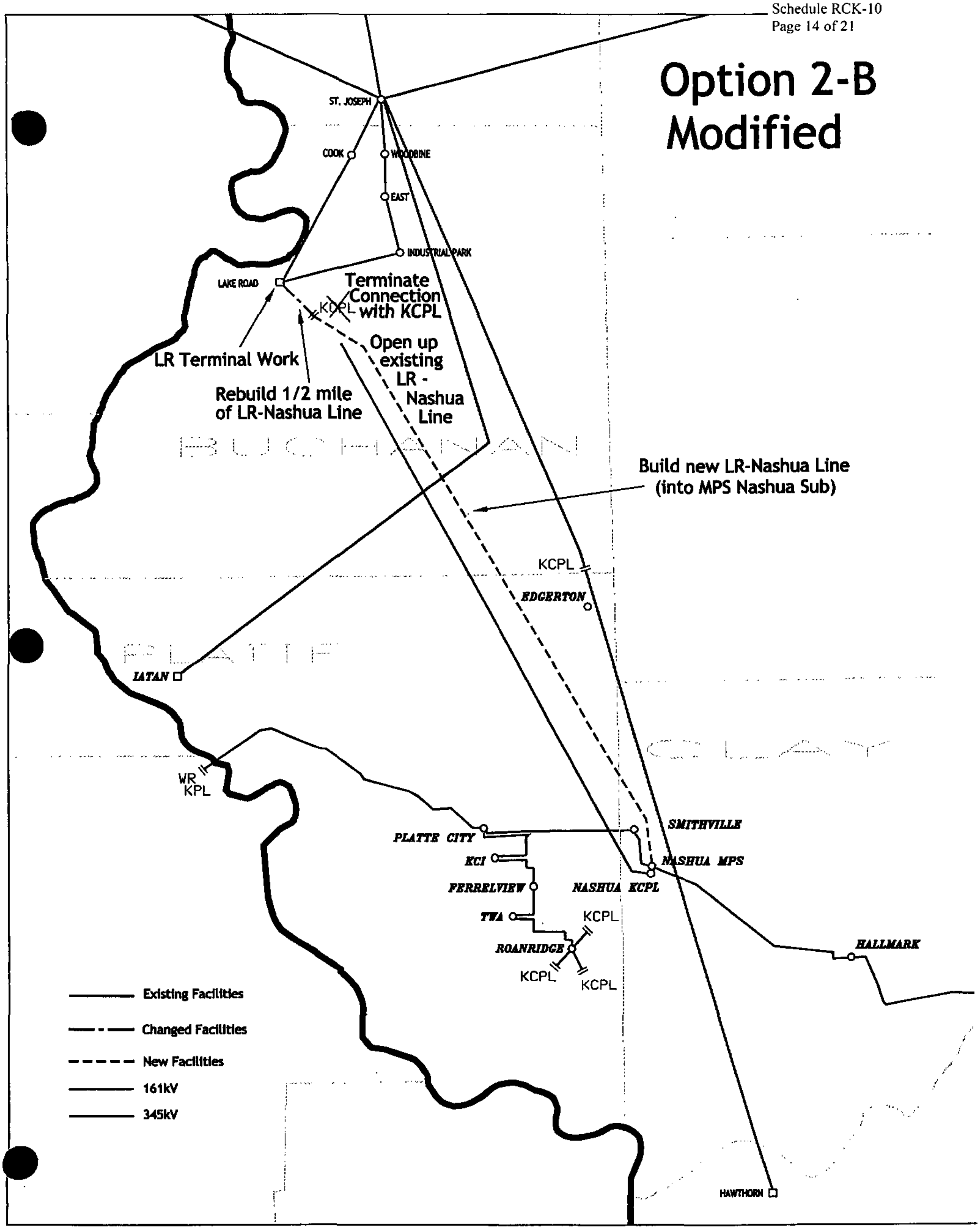
D. Losses

In the loadflow model for this option, the billing meter on the existing Lake Road - Nashua line was moved to Lake Road South. SJLP losses increased in this case over the base case due to the additional line ownership (new LR South line) and the additional responsibility for losses on the existing LR South - Nashua line. Losses for this option totaled 27.4 MW for the UCU and SJLP systems. KCPL losses were 49.0 MW (see table on page 38 for a loss summary).

Option 2-B


ST. JOSEPH
COOK
WOODBINE
EAST
INDUSTRIAL PARK
LAKE ROAD
KCPL
LR Terminal Work
Rebuild 1/2 mile of LR-Nashua Line
Build new 3 Terminal LR-Nashua Line (into MPS Nashua Sub)
KCPL
EDGERTON
IATAN
WR KPL
PLATTE CITY
SMITHVILLE
NASHUA MPS
KCI
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
KCPL
KCPL
HALLMARK
HAWTHORN
Existing Facilities
Changed Facilities
New Facilities
161kV
345kV

Option 2-B Modified



X. OPTION 3 - Nashua 345/161kV Substation

A. System Configuration

Option 3 involves purchasing the Edgerton to Nashua portion of the St. Joseph - Hawthorn line (currently SJLP owns the portion from St. Joseph to Edgerton). The St. Joseph - Hawthorn line would be routed into UCU's Nashua Substation (see the diagram on the following page) and a 345/161kV substation would be constructed at UCU's Nashua Substation (a 336 MVA autotransformer was used in the model and estimate).

B. Estimated Cost

The estimated cost for this option is $5.5 million plus the purchase price of the KCPL Edgerton - Nashua 345kV line. The costs for this option are broken down as follows:

Construct 345/16kV at UCU Nashua Substation - $5.0 million
Route 345kV line into Nashua substation - $0.5 million
Purchase Edgerton to Nashua 345kV line from KCPL - unknown

C. Loadflow and Contingency Analysis

The flow on the existing LR - Nashua line decreased for this option (compared to the existing system) to 87 MW in the normal transfer scenario (see page 27). For the heavy transfer scenario, the flow decreased to only 147 MW (see page 28).

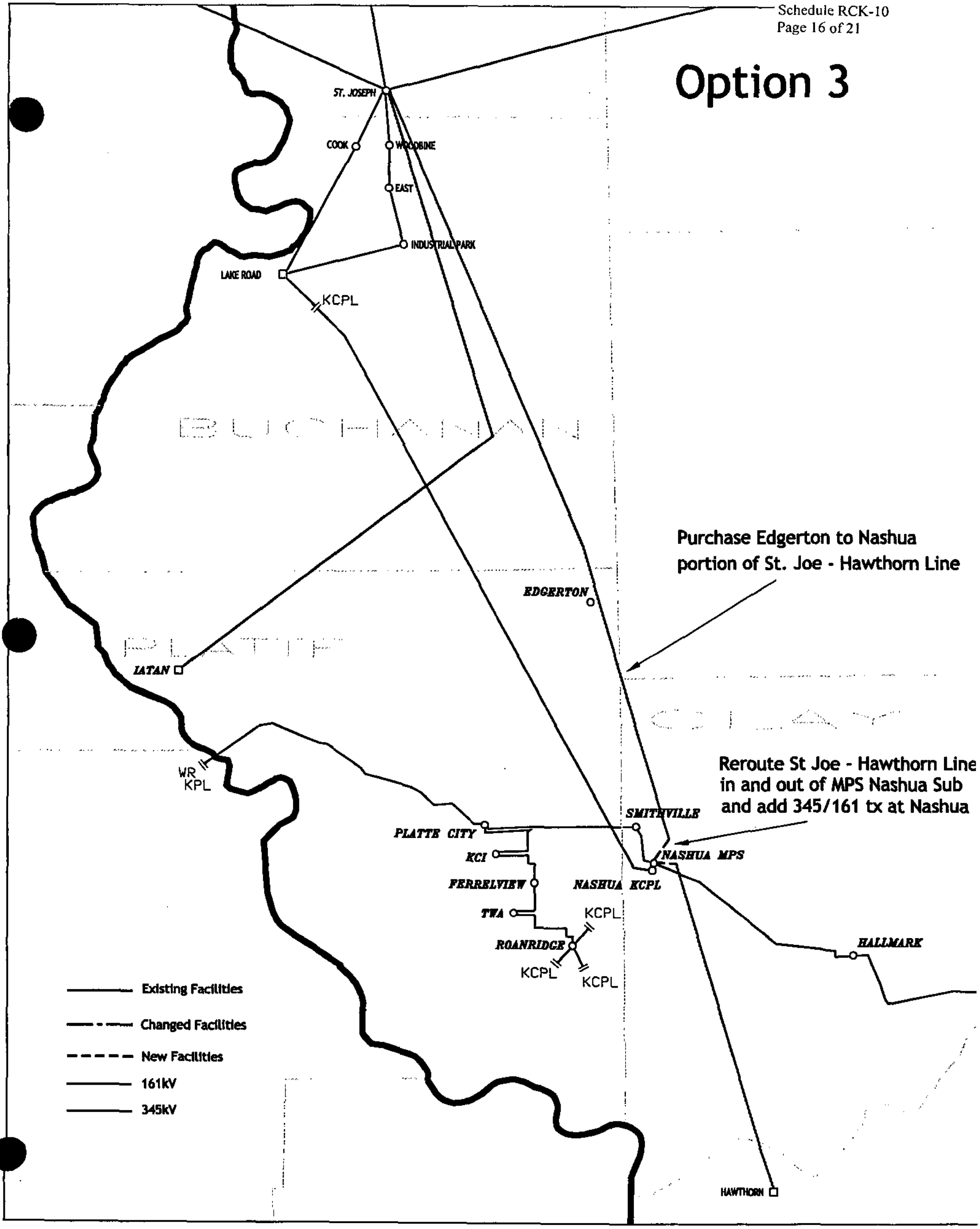
This option performed adequately at summer peak during all contingency situations for the normal transfer scenario. For the heavy transfer scenario, five contingencies resulted in the LR - Nashua line being loaded beyond 95% of its emergency rating. The most severe overloading occurred during an outage of the St. Joseph - Nashua 345kV line (overloaded the LR - Nashua line to 151%). Although this option does improve the reliability to Lake Road somewhat, it still does not eliminate the need to open the Lake Road - Nashua line during heavy flow situations (leaving the Lake Road plant connected to only two transmission lines).

Also, the new 345/161kV transformer overloaded to 129% with an outage of the Nashua - Hawthorn 345kV line. The St. Joseph - Nashua 345kV line overloaded to 111% with an outage of the Iatan - Stranger Creek line. See the table on page 37 for a contingency summary.

D. Losses

In the loadflow model for this option, the billing meter on the existing St. Joseph - Hawthorn line was moved to Nashua. SJLP losses increased in this case over the base case due to the additional responsibility for losses on the existing St. Joseph - Nashua line and the additional losses on the Nashua 345/161kV transformer. Losses for this option totaled 30.5 MW for the UCU and SJLP systems. KCPL losses were 47.1 MW (see table on page 38 for a loss summary).

Option 3


ST. JOSEPH
COOK
WOODBINE
EAST
INDUSTRIAL PARK
LAKE ROAD
KCPL
BUCHANAN
Purchase Edgerton to Nashua portion of St. Joe - Hawthorn Line
EDGERTON
PLATTE
IATAN
CLAY
WR KPL
Reroute St Joe - Hawthorn Line in and out of MPS Nashua Sub and add 345/161 tx at Nashua
SMITHVILLE
PLATTE CITY
NASHUA MPS
KCI
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
KCPL
KCPL
HALLMARK
Existing Facilities
Changed Facilities
New Facilities
161kV
345kV
HAWTHORN

XI. OPTION 4 - Iatan East 345/161kV Substation

A. *System Configuration*

Option 4 involves constructing a 345/161kV substation (a 336 MVA autotransformer was used in the model and estimate) on the St. Joseph - Iatan line east of Iatan (designated Iatan East Substation in this report). A 161kV line would be constructed from Iatan East to UCU's Platte City - Stranger Creek 161kV line, approximately 4 miles southeast of Iatan East (designated Weston Switching Station in this report - see the diagram on the following page).

B. *Estimated Cost*

The estimated cost for this option is $7.9 million. The costs for this option are broken down as follows:

Construct 345/16kV at Iatan East Substation - $5.0 million
Construct Weston Switching Station - $2.0 million
Construct 161kV line from Iatan East Substation to Weston Switching Station - $0.9 million

C. *Loadflow and Contingency Analysis*

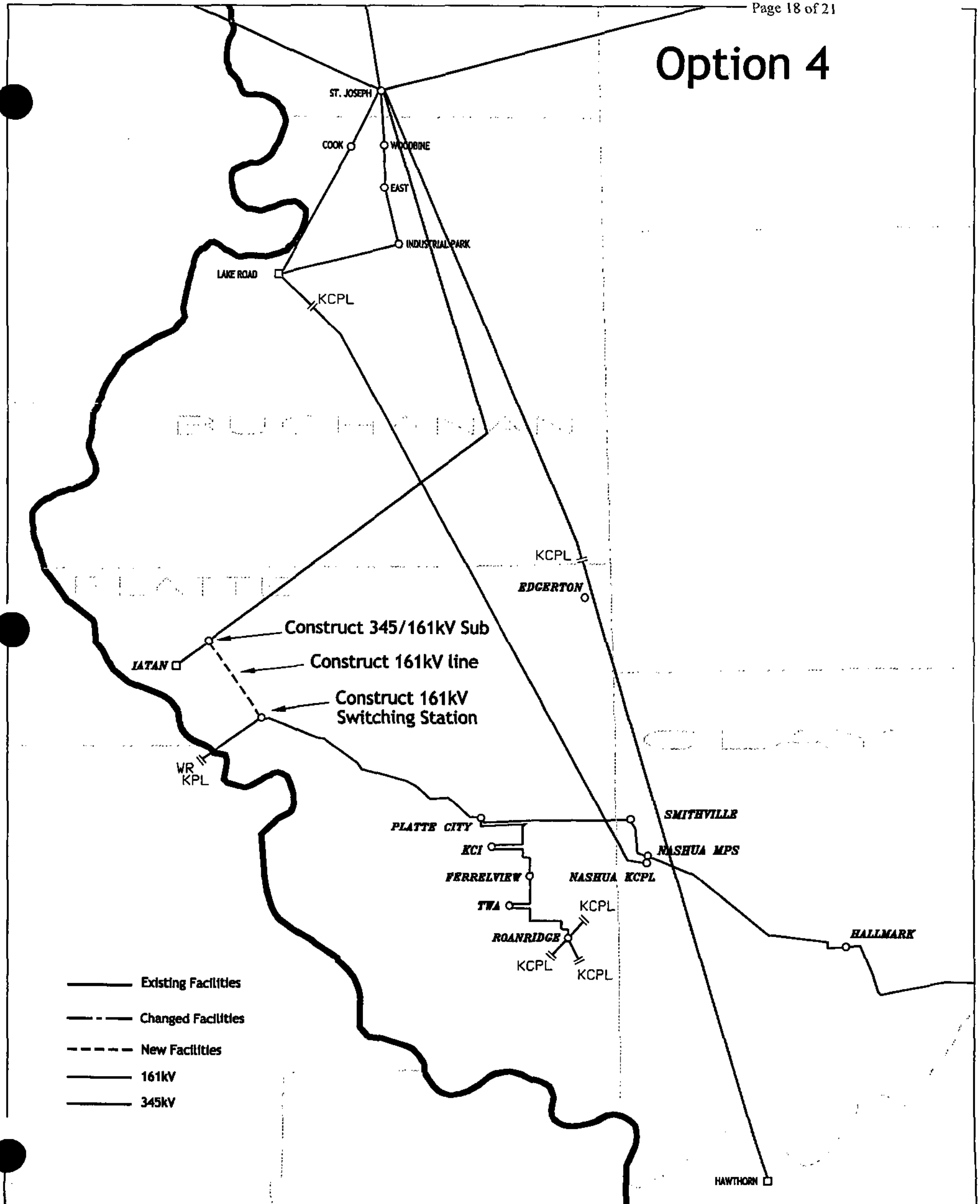
The flow on the existing LR - Nashua line decreased for this option (compared to the existing system) to 93 MW in the normal transfer scenario (see page 31) and to 155 MW for the heavy transfer scenario (see page 32).

This option performed adequately at summer peak during all contingency situations for the normal transfer scenario. For the heavy transfer scenario, fourteen contingencies resulted in the LR - Nashua line being loaded beyond 95% of its emergency rating. The most severe overloading occurred during an outage of the St. Joseph - Hawthorn 345kV line (overloaded the LR - Nashua line to 135%). Although this option does improve the reliability to Lake Road somewhat, it still does not eliminate the need to open the Lake Road - Nashua line during heavy flow situations (leaving the Lake Road plant connected to only two transmission lines).

Also, an outage of the Iatan - Stranger Creek line overloaded the new 345/161kV transformer to 110% and the Iatan East - Weston 161kV line to 117%. See the table on page 37 for a contingency summary.

D. *Losses*

In the loadflow model for this option, the billing meter on the existing St. Joseph - Iatan line was moved to Iatan East. SJLP losses increased in this case over the base case due to the additional responsibility for losses on the existing St. Joseph - Iatan East line and the additional losses on the Iatan East 35/161kV transformer and 161kV line to Weston. Losses for this option totaled 29.0 MW for the UCU and SJLP systems. KCPL losses were 48.4 MW (see table on page 38 for a loss summary).


Option 4
ST. JOSEPH
COOK
WOODBINE
EAST
INDUSTRIAL PARK
LAKE ROAD
KCPL
KCPL
EDGERTON
Construct 345/161kV Sub
Construct 161kV line
Construct 161kV Switching Station
IATAN
WR KPL
PLATTE CITY
SMITHVILLE
KCI
NASHUA MPS
FERRELVIEW
NASHUA KCPL
TWA
KCPL
ROANRIDGE
KCPL
KCPL
HALLMARK
Existing Facilities
Changed Facilities
New Facilities
161kV
345kV
HAWTHORN

XII. OPTION 5 - Purchasing Firm Transmission Capacity

Option 5 involves buying firm transmission capacity from Kansas City Power & Light Company (KCPL) between the UCU and SJLP systems. This option would not alter the existing electrical system; it would only allow UCU and SJLP to exchange energy across the KCPL system. Therefore, the system configuration, system reliability, and system losses would not change from the existing system.

A. *Estimated Cost*

The required amount of interconnection capability between the UCU and SJLP systems is based upon the loss of the largest unit on either of the two systems.

The largest unit in the SJLP system is a 121 MW share of the Iatan plant. The loss of SJLP's share of Iatan can be backed up from UCU generation (UCU has greater than 121 MW excess generation during portions of the year), so the minimum required rating of the interconnection would be 121 MW.

The largest unit in the UCU system (in Missouri) is the Sibley 3 unit which is rated at about 400 MW. SJLP does not have adequate generation to back up the loss of this unit. At minimum load conditions SJLP's maximum excess generation is approximately 270 MW (378 MW of generation capability minus approximately 108 MW minimum load). However, it is unlikely that SJLP would ever have this much capacity to provide to UCU. It is also unlikely that it would be economical or necessary to utilize SJLP peaking units to supply energy to UCU during off-peak periods. Therefore, for the sake of this analysis, 121 MW will be carried forward as the required amount of Firm Transmission Capacity between the two systems, with the understanding that it may be a greater amount still.

According to KCPL's current OASIS posting, there is more than 121 MW of ATC available between UCU (MPS) and SJLP. The cost of firm point-to-point transmission service on the KCPL system is $880/MW-Mo. Using the minimum required rating of the interconnection, the monthly cost of 121 MW of firm point-to-point transmission service would be $106,480 (approximately $1.28 million annually). Assuming an 11% discount rate, the present value of this $106,480 monthly expense over 30 years is $11.28 million (higher if the required capacity is greater than 121 MW).

XIII. SUMMARY

A. *Options Involving KCPL*

Three of the seven options considered in this report require KCPL cooperation. These three options are Option 1-A, Option 2-A, and Option 3. Of these three options, Option 2-A had the least losses at peak, performed the best in the heavy transfer contingency analysis, and provided the greatest reliability improvement to Lake Road. It is also less expensive than Option 1-A and comparable in estimated cost to Option 3 (likely less cost than Option 3 when losses are considered). Therefore, Option 2-A is the preferred option requiring KCPL involvement.

B. *Options not Involving KCPL*

Option 1-B, Option 2-B, Option 4, and Option 5 (assuming KCPL is required to sell any available ATC that is requested) do not require KCPL cooperation. Of these four options, Option 2-B had the least losses at peak (with the exception of Option 5), performed the best in the heavy transfer contingency analysis, and provided the greatest reliability improvement to Lake Road. It is also less expensive than Option 1-B and Option 5 and equal in estimated cost to Option 4. Therefore, Option 2-B is the preferred option not requiring KCPL involvement.

C. *Comparing the Preferred Options*

In the event that KCPL elects not to sell the Lake Road - Nashua line and Option 2-B becomes the preferred option, it is recommended that the course of action be altered from constructing Option 2-B, as is. If the new Lake Road South - UCU Nashua 161kV line is constructed as in Option 2-B, it is recommended that the connection at Lake Road South to the existing Nashua line be eliminated (see diagram on the following page). In this event, Option 2-B becomes electrically equivalent to Option 2-A. In addition, costs are reduced since there is no longer a need to create a three terminal line.

Therefore, if Option 2-B is equivalent to Option 2-A, then the maximum value of the Lake Road - Nashua line is clear: The Option 2-A cost ($5.6 million + LR to Nashua line purchase) must be less than or equal to the Option 2-B cost ($7.9 million). And the maximum value (to UCU and SJLP) of the existing Lake Road to Nashua line is $2.3 million.

D. *Recommendations*

The recommended course of action is to pursue the purchase of the Lake Road to Nashua 161kV line with a maximum purchase price of $2.3 million and complete Option 2-A. In the event that KCPL elects not to sell the line or UCU and SJLP are unable to negotiate the purchase price below $2.3 million, Option 2-B (as modified in the discussion above and shown on page 36) should be pursued.

E. *Benefits of the Preferred Option*

There are additional benefits to the preferred option beyond providing a physical interconnection between the UCU and SJLP systems. Among these benefits:

1. Reliability Enhancement - The increased transmission capacity between Lake Road and Nashua will allow this line to remain closed during heavy load periods, increasing the reliability at both Lake Road and Nashua.

2. Increased Transfer Capability (Regional Benefit) - This line is a limiting facility for certain ATC and transfer calculations. Upgrading the capability of this line will result in an increased regional ATC of approximately 700 MW.

   To estimate this amount of increased ATC, the Lake Road - Nashua line was taken out of service in the heavy transfer case (as is the practice during heavy loading periods). The most severe contingency for this case was an outage of the Iatan - Stranger Creek line, which overloaded the St. Joseph - Hawthorn line to 118%. The north - south transfer was then backed down until the loading on the St. Joseph - Hawthorn line reached approximately 100% loading. This occurred at 70% of the heavy transfer case (or a 1,621 MW transfer). Since the St. Joseph - Hawthorn line is loaded to approximately 100% for this same outage in Option 2-A (for the heavy transfer case - 2,316 MW), it can be concluded that rebuilding the LR - Nashua line adds about 700 MW (2,316 MW minus 1,621 MW) in north - south transfer capability.

3. Loss Reduction - Although UCU and SJLP losses increased in the preferred option (due to additional line ownership), area losses were reduced. KCPL's loss reduction was estimated to be 3.56 MW. Lower area losses means lower energy requirements year round which translates into lower costs and reduced environmental impacts.

F. Transmission Capacity of the Preferred Option

Because the preferred option has a slightly lower transmission capacity rating than some of the other options (312 MVA vs. 336 MVA - transformer size in 345/161kV options), it is necessary to examine how much transmission capacity is required between the UCU and SJLP systems. The required amount of interconnection capability between the UCU and SJLP systems is based upon the loss of the largest unit on either of the two systems.

The largest unit in the SJLP system is a 121 MW share of the Iatan plant. The loss of SJLP's share of Iatan can be backed up from UCU generation (UCU has greater than 121 MW excess generation during portions of the year), so the minimum required rating of the interconnection would be 121 MW.

The largest unit in the UCU system (in Missouri) is the Sibley 3 unit which is rated at about 400 MW. SJLP does not have adequate generation to back up the loss of this unit. At minimum load conditions SJLP's maximum excess generation is approximately 270 MW (378 MW of generation capability minus approximately 108 MW minimum load).

Therefore, the maximum required transmission capacity required between the two systems is 270 MW. The preferred option's capacity rating of 312 MW is sufficient.

G. KCPL's Options

KCPL has at least two incentives to sell the Lake Road - Nashua line. Assuming that UCU and SJLP pursue the modified Option 2-B as described above, the electrical system will end up the same whether or not KCPL chooses to sell the line. Therefore, if KCPL does not elect to sell the line, they will be left with an abandoned Lake Road - Nashua line (along with the expense required to tear it down) and they would not receive any revenue negotiated by selling the line.

Initial Comments of
UtiliCorp United, Inc.
filed in response
to the Federal Energy Regulatory Commission
Notice of Proposed Rulemaking Regarding
Regional Transmission Organizations

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Notice of Proposed Rulemaking	)	
Regarding Regional	)	Docket No. RM99-2-000
Transmission Organizations	)	

INITIAL COMMENTS OF UTILICORP UNITED, INC.

In response to the above-captioned Notice of Proposed Rulemaking, UtiliCorp United Inc. ("UtiliCorp") is pleased to submit its Initial Comments.

As the Federal Energy Regulatory Commission ("Commission") itself has pointed out in the NOPR, "Competition in wholesale electricity markets is the best way to protect the public interest and insure that electricity consumers pay the lowest price possible for reliable service." (NOPR at 6). The Commission also states, and UtiliCorp agrees, that regional approaches are necessary in order to move toward the elimination of continuing impediments to competitive electricity markets in the United States. The Commission has stated as its objective in that regard that all transmission entities in the nation, including non-jurisdictional entities, should place their transmission facilities under the control of appropriate regional transmission institutions in a timely manner. UtiliCorp supports this objective and offers the following specific comments for the Commission's consideration.

UtiliCorp's Role in the Energy Industry

Because of the diverse nature of UtiliCorp's energy business, which encompasses natural gas and electricity, and traditional regulated utility and competitive energy marketing operations, UtiliCorp believes that it is in a position to provide a balanced perspective to the Commission regarding the competitive market issues implicated by the NOPR. On the regulated side of its business, UtiliCorp provides electric service to retail and wholesale customers in the States of Missouri, Kansas, Colorado and West Virginia, and also owns natural gas utilities in eight states. As an owner of electric transmission facilities, UtiliCorp will be directly affected by the requirements imposed on such owners by the final rule adopted in the current proceeding.

Moreover, UtiliCorp has been a leading player in the market for competitive sales of energy, including sales of both electricity and natural gas. Its power marketing subsidiary, Aquila Energy Marketing Corporation ("AEMC"), purchases and sells electric power in virtually every region of the country and is currently ranked number two in overall energy sales. In its Merchant Energy Partners entity, UtiliCorp owns interests in sixteen independent and qualifying generation facilities in six states. In its capacity as a leading power marketer and owner and operator of generation in other markets, UtiliCorp will thus be directly affected by the final rule adopted herein, and the potential new market opportunities that will be created as a result of the further reduction of structural impediments to competition.

Finally, UtiliCorp also has significant ownership interests in utility operations in Australia, New Zealand, and the United Kingdom,1/ each of which are well down the road to restructuring their electric utility industries in order to gain the benefits of competitive markets in the generation sector. The experience UtiliCorp has gained as a result of its business operations in those ground-breaking jurisdictions places the Company in a uniquely advantageous position from which to comment knowledgeably on the matters at issue in this proceeding.

UtiliCorp's Long-Standing Support for the RTO Concept

UtiliCorp first "went on record" with its position in favor of action by this Commission to promote regional transmission organizations in its comments in response to the March 29, 1995 Notice of Proposed Rulemaking on Open-Access Transmission. 2/ In those comments four years ago, UtiliCorp anticipated developments that have occurred in the industry since that time, in the form of proposals for independent system operators and privately owned transmission entities. Further developments of this kind are now in position to be accelerated significantly by a final rule in this proceeding. We take this opportunity to salute the Commission in issuing the current NOPR, both for its initiative in requiring

1/ UtiliCorp also owns interests in utility or generation operations in Western Canada and in Jamaica.

2/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Standed Costs by Public Utilities and Transmitting Utilities, Docket No. RM95-8-000 et al.

jurisdictional utilities to confront the issue of forming or joining an RTO and for its forbearance in declining to propose overly prescriptive mandates regarding the implementation issues, which often involve complex business and legal considerations among the parties affected. Nevertheless, the Commission in the NOPR has been clear as to the basic principles that it will apply in promoting the creation and approving the establishment of RTOs. The balance struck by the Commission is a good one and is worthy of praise.

The primary motivating force behind the initiation of this rulemaking is, quite properly, the Commission's recognition in the NOPR that under present industry conditions, there is not fair and open access to transmission for those who wish to compete with the large transmission-owning utilities for wholesale customers. In its business operations as a power marketer in numerous regional markets, UtiliCorp has experienced such discriminatory behavior directly and significantly, one instance of which the Commission has specifically acknowledged at page 71 of the NOPR. 3/ By removing control over access to transmission from the remaining large transmission owning utilities, and placing such control in properly structured regional transmission organizations, the Commission will go a

3/ The NOPR cites the case of Aquila Power Corporation v. Entergy Services, Inc., Docket No. EL98-36-30, Amended and Restated Complaint at 6 (filed June 23, 1998).

long way toward eliminating the remaining obstructions to effective competition in wholesale markets for electric power. 4/

The Commission's Proposed Minimum Characteristics and Functions of an "RTO"

In its decision to refrain from issuing a mandate to jurisdictional utilities to form or join an RTO, the Commission has proposed an alternative approach based on the adoption of incentives for the creation of RTOs that have certain minimum characteristics and perform certain minimum functions. Such preferred, qualifying "RTOs", according to the NOPR, may be entitled to certain regulatory benefits under consideration by the Commission, including more favorable rates of return on equity, possible incentive pricing opportunities, expedited approvals, and other forms of preferential treatment not accorded to proposed transmission entities that do not possess such features. Such an approach has much to commend it, but places a daunting responsibility on the Commission to get both the minimum characteristics and the incentives right. In its comments herein, UtiliCorp wishes to focus attention on those aspects of the NOPR that UtiliCorp considers most determinative of the likely success or failure of a final rule adopted in this proceeding. Our comments are presented in the order in which the

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4/ We note as a caveat, however, that such action cannot be completely effective unless the Commission also strengthens and enforces its policies and precedent prohibiting utility discrimination against wholesale users of transmission in favor of their own uses of transmission for native load. See Amended and Restated Complaint cited in footnote 3, supra, and authorities cited therein.

Commission has addressed the RTO characteristics and functions and other issues in the NOPR.

The Characteristics of an RTO

(a) Independence - It comes as no surprise that "independence" is established as the Commission's number one criterion for a qualifying RTO. In the NOPR, the Commission reaffirms its earlier statement, made in the context of ISOs, that "the principle of independence is the bedrock on which the [RTO] must be built." (NOPR at 119). It states that this criterion can be achieved if three conditions are satisfied: first, that the RTO, its non-stakeholder governing board, and its employees must have no financial interests in market participants; second, that its decision making must not be "controlled" by any market participants; and third, that it must have complete authority to file changes to its transmission tariff.

Subject to the provisos noted below, UtiliCorp supports the concept that the governing board of an RTO should not include members having a financial interest in any market participant and that similar prohibitions should apply to the employees of an RTO. 5/ The first proviso is that the *decisional* structure of an RTO should incorporate an entity or other formal mechanism providing for stakeholder input to the non-stakeholder board. Such input would not bind the independent board, but would operate to make sure that the views of stakeholders are

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5/ Exception should be made for the pension rights of former utility employees who become employees of an RTO. Otherwise, RTOs could face significant difficulties in hiring qualified and experienced transmission personnel.

considered. The stakeholder entity should be broadly inclusive of all market participants having a (defined) threshold economic interest in the RTO's policies and actions.

The second proviso concerns the *ownership* structure of an RTO. In its discussion of this matter in the NOPR, it appears that the Commission has, perhaps inadvertently, unduly restricted the ability of market participants to have an ownership interest in an RTO, as distinct from a role in its decision making. In that regard, UtiliCorp believes that the proposed one-percent ownership limitation mentioned in the NOPR is unduly restrictive and may potentially choke off significant sources of capital needed for the formation of the kind of entity that the Commission seeks to encourage.

This concern becomes self-evident when the concept of the for-profit, transco-type RTO ("Transco") is considered. If Commission policy is intended to encourage the transfer of control over assets to properly structured Transco entities, sufficient latitude must be provided for recognition of the value of such contributions. Given the start-up difficulties in raising money for newly created entities of this kind, an RTO is not likely to have access to cash resources sufficient to purchase the assets it will require. It will thus be necessary in most instances to permit transfers of assets in return for ownership interests in the RTO. With the use of certain kinds of business organizations (e.g., partnerships and limited liability corporations), control of the enterprise for decision-making can be separated from ownership of the assets. Parties should be permitted considerable business latitude to attempt to work out such arrangements, subject to the caveat that the resulting distribution of ownership interests leave no owner in a position of undue influence or, worse, de facto control. The caveat would generally be satisfied in situations where the RTO is of sufficient geographical size and scope such that any individual owner's percentage share, in the context of the overall distribution of other ownership interests, would be significantly diluted to the point that it could not reasonably be suggestive of undue influence on or *de facto* control of an independent board. 6/ UtiliCorp submits that this judgment should be made on a case-by-case basis, considering all relevant facts, and that adoption of an arbitrary percentage limitation on ownership of an RTO by an individual participant should be avoided.

The concerns described may not arise to the same extent in the context of RTOs that are organized as non-profit Independent System Operators ("ISOs"); however, UtiliCorp submits that it would be a mistake for the Commission to adopt policies that favor RTOs organized in the form of ISOs and that discourage the formation of properly structured, for-profit "Transcos". In the past, UtiliCorp has advocated large, for-profit transmission entities, regulated by this Commission, as the best long-term business model for regional transmission organizations. We continue in that belief: entities that are properly organized and incented to

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6/ By contrast, the Transco proposed by Entergy in Docket No. EL 99-57 would not pass muster under the approach described, unless it were joined by a sufficiently large number of other transmission-owning utilities to dilute Entergy's currently exclusive ownership interest to a satisfactory extent.

maximize the value of transmission assets as a stand-alone business are most likely to be accountable to their shareholders, to their customers and to this Commission. At the same time, we realize that intermediate stages of development of RTOs may be required in the ultimate progression to the establishment of such entities on the largest scale. In that evolution, the formation of ISOs may be a necessary interim step in some circumstances. 7/ However, we submit that the ultimate objective should be the establishment of privately-owned, regulated transmission entities, which are subject to the discipline of the marketplace, possessed of the proper incentives for efficient performance, and empowered to make investments pursuant to long-term plans properly vetted before regulators and affected parties.

We note, in that regard, that the Commission should take steps in any final rule issued in this proceeding to ensure that the next stage of implementation of RTOs does not become the last. The danger in recognizing the potential need for intermediate stages in the development of RTOs is that, having once been formed, such interim entities may become subject to the inertia and resistance to change that is often characteristic of large, bureaucratic institutions. Those tendencies can be especially pronounced in entities that are structured to accommodate the direct participation of a variety of conflicting interests in the RTO's decision-making process. The result of a proliferation of such entities after issuance of a final rule

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7/ An example of such circumstances would be a situation where the participation by non-jurisdictional utilities in an RTO is deemed beneficial or essential, but could not be accommodated within the legal framework of a for-profit Transco RTO.

herein could be a freeze on further evolution and a semi-permanent balkanization of the grid. We suggest that the Commission, in its final order, should adopt a specific schedule for future reporting and evaluation of all RTOs proposed as a result of this rulemaking and should make it clear that continuing improvement, consolidation and enlargement of RTOs are expected and, if necessary, will be required.

(b) Appropriate Scope and Regional Configuration. UtiliCorp's public position on this issue has been that RTOs should be as large as practicable, subject only to the physical constraints within and between the existing major Interconnections in the U.S. As we read the NOPR, the Commission has endorsed that principle; however, UtiliCorp believes the Commission is also correct in its decision not to propose regional RTO boundaries on its own. Instead, the Commission has identified certain "relevant factors" in the NOPR that it will use when evaluating the boundaries of a proposed RTO, including whether such boundaries (a) allow the RTO to perform its essential functions, (b) support trading over a large area, (c) thwart the exercise of market power, (d) encompass existing control areas, regional transmission entities, a contiguous geographic area, and "a highly interconnected portion of the grid" and (e) take into account existing regional and international boundaries. Those factors seem to us to be appropriate. 8/

8/ UtiliCorp notes again here its belief in the importance of the RTO's ability to thwart market power, especially in the context of eliminating participating utilities' capabilities and incentives to obtain undue preferences for transmission used to serve native load.

In its 1995 comments, UtiliCorp suggested that a Commission-approved RTO should be no smaller than the NERC Reliability Council in which it was located. It is apparent from recent industry developments and discussions that RTOs are being considered for regions that extend well beyond the boundaries of the individual NERC reliability regions.

As a national energy trading company, UtiliCorp starts from the position that the configurations of RTOs should, at a minimum, reflect the actual trading patterns in the principal power marketing areas of the United States. Using that frame of reference, the Western Interconnection could all be included in a single RTO (subject to caveats regarding the need for continuing to recognize separate control areas, discussed further below). For obvious reasons, ERCOT would continue as a separate system, and a Florida RTO would probably make sense (at least initially), given its relative isolation from the other transmission systems in the Southeast. 9/ Leaving aside the existing ISOs in New England, New York, PJM and the Midwest, which will be the subject of subsequent inquiry by the Commission, 10/ the remaining NERC regions in the Eastern Interconnection present some interesting potential RTO configurations. Regarding MAPP, SPP, ECAR, SERC and MAIN, various combinations of transmission systems are under

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9/ We note, however, that to the extent that the Commission authorizes multiple RTOs within the Eastern Interconnection, it should require such RTOs to develop pricing mechanisms and operating policies that make transmission service across such RTOs as seamless as reasonably possible.

10/ See NOPR at 208-209.

active consideration and may be proposed as RTOs. UtiliCorp does not wish to anticipate or prejudge the results of those discussions with its comments herein. With respect to MAPP and SPP, in particular, UtiliCorp will be facing its own business decision as to which of several RTO entities currently under discussion makes the most sense for its energy customers, utility ratepayers and shareholders. UtiliCorp commends the Commission for its willingness to permit the affected participants to agree on the appropriate scope of RTOs in this region, at least in the first instance.

(c) Operational Authority Over all Transmission Facilities. UtiliCorp supports the Commission's determination in the NOPR that an RTO meeting its requirements must have "operational control" of the transmission facilities under its control (NOPR at 140). This characteristic is, without question, an essential one. In exercising such control, the NOPR states that the RTO "may choose to directly operate facilities . . ., delegate certain tasks to other entities . . . or use a combination of the two approaches." Such practical flexibility is also desirable. We support the proposition that the RTO is not necessarily required to operate a single control area, which is a particularly important factor in the Midwest. However, UtiliCorp strongly endorses the Commission's statement that the RTO "must have ultimate responsibility for providing non-discriminatory transmission service for all market participants and for ensuring the short-term reliability of the grid." (NOPR at 142).

Finally, we strongly support the Commission's position that the RTO must be the security coordinator for the transmission facilities that it controls, for the following reasons: (1) there will otherwise be competing entities responsible for reliability functions within the RTO area, and (2) an independent RTO will thus not be able to achieve the Commission's objectives of independent management of the transmission network if ultimate control remains in the hands of security centers controlled by a few (and in some cases, one) market participants.

At present, there are twenty-three security centers in NERC, five of which are in SERC. Aquila Energy's experience with Entergy leads us to conclude that the security function should be managed by entities that are independent of market participants. If RTOs are designated to be those independent entities, the security center functions should be transferred to the RTO.

There is also the potential for overlap between RTOs and NERC reliability councils, because RTOs that cross reliability council boundaries may perform their reliability-related functions differently than the local reliability councils perform them. Unless NERC reliability councils become RTOs themselves (which is under active discussion in certain regions), there will need to be a clear demarcation of responsibilities assigned to RTOs and the regional reliability councils.

(d) <u>Exclusive Authority to Maintain Short-Term Reliability</u>. The Commission proposes in the NOPR that an RTO must be responsible for maintaining short-term reliability and therefore should have the authority to review and implement interchange schedules, order generation dispatch, authorize scheduled maintenance outages of transmission facilities, monitor equipment availability and loading and establish facility ratings. Regarding the matter of generation dispatch, UtiliCorp concurs with the Commission's statement that an RTO "must have some degree of control over some generation," but that control should not necessarily extend to initial unit commitment or central dispatch (NOPR at 148). In the Midwest, where there is no structure for central dispatch across utility boundaries, it would be counterproductive to require such authority or capability of an RTO. UtiliCorp believes that it is fully sufficient, for purposes of the objectives sought by the NOPR, that an RTO have the ability to redispatch generation for reliability and for handling transactions between control areas.

Minimum Functions of an RTO

The Commission has identified seven functions in the NOPR as the minimum functions that an RTO must perform. They are discussed, in turn, as follows:

(1) *The RTO must administer its own tariff and employ a pricing system that will promote efficient use and expansion of transmission and generation facilities.* UtiliCorp endorses this minimum RTO function. Specifically, we support the proposed requirements that the RTO must be the sole provider of service over the facilities it controls and the sole administrator of its open-access tariff, that the RTO must have sole authority to act on requests for transmission service and new interconnections, and that the RTO must ensure non-pancaked transmission rates.

These requirements are fundamental to the concept and purpose of any regional transmission entity. UtiliCorp also believes that it is important that an RTO tariff cover all transmission facilities within the RTO's region of operation (in contrast to the situation in NEPOOL where a transmission customer must obtain service from the NEPOOL ISO for the use of pool facilities and from individual transmission providers for the use of non-pool facilities).

(2) The RTO must create market mechanisms to manage transmission congestion. UtiliCorp supports this proposed function as well and specifically concurs with the Commission's further comments that a congestion management system should establish tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and give market participants the opportunity to hedge locational differences in energy prices. We also concur with the Commission's stated objectives regarding congestion management -- i.e., that the generators dispatched in the presence of transmission constraints should be the least-cost units able to serve load (given the constraints) and that limited transmission capacity should be used by market participants that value such use most highly. (The effective ceiling on the value of such use would be the differential cost of the generation on the other side of the constraint.)

(3) The RTO should develop and implement procedures to address parallel path flow issues within its region and within other regions. In UtiliCorp's experience, this is one of the most important problems facing adjoining regions

today and may be a significant contributing factor to the problems of line loading relief and congestion. The Commission has proposed in the NOPR that RTOs be required to address parallel path flow issues between regions within three years. In UtiliCorp's view, a three-year time frame seems reasonable for full implementation, and not simply for filing a plan to seek approval. UtiliCorp believes the Commission would be on sound ground to require that RTOs be required to file their plan within one year and have it fully operational within two years thereafter, if not sooner.

(4) The RTO must serve as a supplier of last resort for ancillary services required in Order No. 888. UtiliCorp supports this requirement and endorses the further point that the RTO must ensure public access to real-time balancing information.

(5) The RTO must operate a single OASIS site for all transmission facilities under its control and must have exclusive responsibility for determining Available Transmission Capability ("ATC"). This proposed requirement for an RTO is, in our view, absolutely essential. In this connection, UtiliCorp strongly supports the Commission's observation in the NOPR that "there is widespread dissatisfaction with the reliability of posted ATC numbers." Specifically, UtiliCorp is one of those which the NOPR identifies as having alleged "that transmission providers who also compete in power markets against their competitors have both the incentive and ability to post unreliable ATC numbers." We submit that the same thing is true in the case of Capacity Benefit Margin ("CBM") calculations. This issue is at the core

of the discriminatory behavior UtiliCorp and other power marketers have experienced at the hands of certain large transmission-owning utilities, which have appeared to use ATC and CBM calculations in attempts to shield their high-cost generation from effective competition. Where the RTO is not itself the control area operator, the RTO must have the ability and the authority to determine independently the control area operator's transmission needs as they affect ATC and CBM calculations.

(6) The RTO is required to monitor markets to identify problems, measure market power, and propose appropriate remedies. Regarding this proposed function for RTOs, UtiliCorp departs somewhat from its generally supportive comments on other issues and suggests that caution is in order here. It is not at all clear to us why a market monitoring function should be viewed as essential or even appropriate for an RTO, especially since the Commission itself will continue to have market oversight responsibilities, including the continuing judicial function and responsibility to entertain complaints alleging discriminatory behavior. For one thing, there is a material difference between a technical organization, such as an ISO, that is responsible for transmission network management and associated reliability functions, and a commercial entity focused on pricing and market issues. The skill sets are different, and UtiliCorp has experienced this difference firsthand in analogous power pool situations. On the other hand, assignment of market-monitoring functions to a <u>commercial</u> entity, such as a Transco (other than those functions concerned strictly with transmission pricing) may raise other problems,

including antitrust concerns, both for the Transco and its customers. We submit that the Commission should be very circumspect in any delegation of such functions to an independent transmission organization, regardless of whether such entity is organized as a non-profit or as a privately owned transmission provider.

(7) The RTO should plan and facilitate necessary transmission additions and upgrades and is responsible for coordinating such efforts with state regulators. As to this function, UtiliCorp notes especially the Commission's further comment that the planning and expansion process must encourage market-driven operations and investments for preventing and relieving congestion. As we pointed out above, UtiliCorp believes that the best guarantee that such investment will occur is, ultimately, the creation of properly structured region-wide "Transcos." One of the most frequently heard industry complaints about ISOs is the absence of economic incentives for ISOs to make the investments required to increase transmission capacity and improve efficiency. Because of the uncertainties attendant to the varied approaches to the restructuring of electric utilities by the state authorities, many needed investments in transmission have been postponed by the transmission-owning utilities, or canceled altogether. It is incumbent on this Commission, in its final rule, to ensure that it creates the proper incentives to encourage such investment and, at a minimum, that it take no action having the effect of imposing further delay of such investments.

Incentives for the Formation of RTOs

The most important, and arguably the most innovative, tool proposed by the Commission for the encouragement of the formation of RTOs is found at pages 199-200 of the NOPR, where the Commission states, "We would be willing to consider, on a case-by-case basis, allowing the transmission owners that bring about [RTO] benefits to share in them through incentive pricing for public utility transmission owners that turn over control of their transmission facilities to an RTO." UtiliCorp views this pronouncement by the Commission as a significant policy departure, and we commend it for expressing an open mindedness to this concept. Initially, UtiliCorp notes that there are two distinct types of incentives that the Commission needs to consider in the context of a final rule: first, incentives for transmission-owning utilities to form or join RTOs, and second, incentives for RTOs to perform at optimum efficiency after they are formed.

Given the Commission's decision in the NOPR to encourage, but not require, jurisdictional utilities to join RTOs, the issue of what incentives to adopt is necessarily a critical consideration. One of the basic challenges facing the Commission in this regard is the fact that for many large, transmission-owning utilities, state regulatory authorities effectively determine the rate of return on equity on all but a relatively small percentage of their transmission assets. For utilities that enjoy higher state-allowed rates of return on equity than those permitted under the policy and precedent of this Commission, there will naturally be resistance to any substantial revenue reductions occasioned by the transfer of such assets to an RTO that is regulated under the traditional rate-making policies of this Commission. In the situations described, the crux of the problem is to remove disincentives to the formation of RTOs.

When seen in this context, UtiliCorp submits that the proper metaphor for "incentive" returns on equity is "basic sustenance", rather than regulatory "candy", as some have suggested. Unless and until the Commission decides to take mandatory action forcing jurisdictional utilities to join RTOs, it will have no choice but to entertain proposals for higher permitted returns on equity than it has traditionally allowed, assuming utilization of a standard cost-of-service approach for the pricing of transmission services by an RTO. In entertaining such proposals, however, the Commission should -- indeed, is required to -- scrutinize carefully the asserted bases for the returns requested. As both an owner of transmission assets in its own territory and a user of transmission services in other parts of the country, UtiliCorp has revenue concerns on both sides of this issue and believes that the proper balance will have to be determined by the Commission on a case-by-case basis.

Another incentive option mentioned by the Commission in the NOPR is a rate-making approach in which transmission rates would be allowed to be kept at current levels (or levels to be determined upon formation of the RTO) for a defined period of time, even though RTOs are expected to achieve cost savings in their operations, as compared to current levels. Based on the experience of several foreign jurisdictions that have tried this approach, it can produce significant benefits, although the determination of the proper fixed rates on the front end will obviously be an important action, of interest to all affected parties. Certainly, it is helpful that the Commission has shown itself open to the receipt of such proposals. The essential first step is that such proposals be elicited in the first instance, after which the appropriate scrutiny can be applied.

Finally, the Commission has also shown itself open to the consideration of allowing accelerated cost recovery for new facilities constructed, owned and operated by RTOs meeting the Commission's criteria. UtiliCorp supports this concept, especially in view of the urgent need for new investment in the transmission grid in this country. We do not read the NOPR to suggest, and would not support, the elimination of regulatory oversight with respect to such proposals. The details will be important, and all affected parties -- owners and transmission customers alike -- should have a say in these matters, in the traditional regulatory context.

The Power Exchange Issue

Finally, UtiliCorp wishes to go on record as supporting the Commission's proposal to allow each region to decide whether a power exchange should be established and whether the RTO should also operate the power exchange. UtiliCorp is generally opposed to the mandatory power exchange model and notes that certain foreign jurisdictions (e.g., the UK) which had previously adopted that model are now moving to a more open approach. In any event, we believe that the complex and controversial issues connected with the establishment of a mandatory power exchange should not be folded into a proceeding such as this one, in which the focus is properly on the establishment of Regional Transmission Organizations to reduce or eliminate the remaining barriers to access to transmission on equal and nondiscriminatory terms.