Exhibit No.: ____________
Issue: Generating Station Performance
Witness: Eldridge
Type of Exhibit: Rebuttal
Sponsoring Party: KCPL
Case No.: EC-99-553

REBUTTAL TESTIMONY

OF

M. MONIKA ELDRIDGE, P.E.

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Q. **PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A. My name is M. Monika Eldridge. I am a principal with Competitive Utility Strategies at 680 Hartford Drive in Boulder, Colorado 80303.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Kansas City Power & Light Company (KCPL).

Q. **PLEASE SUMMARIZE YOUR EXPERIENCE AND EDUCATION.**

A. I am a professional engineer with over 17 years of experience in the power generation field. From 1990 to 1999, I worked for Hagler Bailly until I became a founder and principal of Competitive Utility Strategies. As a principal with Hagler Bailly, I have evaluated the economic and regulatory performance of power plants. I have advised utilities on decisions relating to continued operation of power plants. I have evaluated the market potential of new business ventures relating to power generation. I have conducted numerous evaluations of benchmarking the performance and costs of power plants with the industry and have submitted testimony for utilities and minority owners in these matters.

Prior to joining Hagler Bailly, I worked for CMS Energy from 1982 to 1990 in three different positions. From 1987 to 1990, I was in Senior Reactor Operator training at Palisades Nuclear Plant. My position before operations was as a project engineer at Palisades, where I was responsible for design, cost, schedule, procurement, construction, and testing of plant modifications. Before project engineering, I was a lead auditor and responsible for managing technical specification and quality assurance audits. I evaluated programs including operations, maintenance, training, regulatory compliance, reactor physics, and radiation safety. I hold a BME in Mechanical and Aerospace Engineering from the University of Delaware and am a Registered Professional Engineer in the State of Michigan.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary objective of my testimony is to evaluate the performance of the generating stations that are owned and operated by KCPL. GST Steel Company (GST) requested the Public Service Commission of the State of Missouri to take action relating to issues associated with the adequacy and reliability of KCPL generating stations. My testimony addresses several specific issues raised by the GST complaint. In addition, testimony has been submitted by Jerry N. Ward. My testimony addresses a number of issues raised by Mr. Ward. I prepared and sponsor the report attached to my testimony.

Q. PLEASE SUMMARIZE THE MAIN POINTS OF YOUR REPORT AND TESTIMONY.

A. The main issues raised by the GST complaint and Mr. Ward's testimony relate to the performance of the KCPL base load generating stations. In my report titled "Evaluation of Generating Assets Owned and Operated by Kansas City Power & Light," I address the performance of the KCPL system as well as each individual KCPL unit. A copy of said report is attached hereto as Schedule MME-1. I evaluate the equivalent availability factor, forced outage rate, operating and maintenance costs, fuel costs, and significant outages of the KCPL units. I also evaluate the training issues raised by Mr. Ward.

Q. HOW DID YOU ARRIVE AT THE CONCLUSIONS PRESENTED IN YOUR REPORT?

A. The methodology that I use in my report is comparative analysis that benchmarks the performance of each KCPL unit to a peer group of units that are similar in design, vintage, and size. In addition, my report analyzes trends of performance both for the KCPL units as well as the industry. My report provides the details of the analysis as well as the findings of my analysis.

Q. WHAT HAVE PREVIOUS ANALYSES REVEALED REGARDING AVAILABILITY PERFORMANCE TRENDS OF THE INDUSTRY?

A. In previous analyses, I evaluated the trends of fossil and nuclear units that performed above average in equivalent availability and in costs. Taking a group of coal fired plants, I evaluated the performance from 1985 to 1997. I segregated the group into five categories based on 20 percent increments (80-100%, 60-79%, 40-59%, 20-39%, 0-19%) with 80-100% being the best performers. I found that the units with the best performance in 1985 declined to a level that was slightly above average by 1997. Meanwhile, the units that were below average began to improve performance until they were only slightly below average after 12 years.

Q. WHAT HAVE PREVIOUS ANALYSES REVEALED REGARDING OPERATING AND MAINTENANCE COSTS?

A. As with equivalent availability factor, the lowest cost units have trended toward the average in cost. The highest cost units have also trended toward the average. However, the industry average has also trended downward. Thus, even the lower cost units have continued to reduce costs only at a slower rate than the higher cost units.

Q. WHAT WERE THE CONCLUSIONS OF YOUR ANALYSIS?

A. The KCPL system operates within industry standards when considering accepted performance criteria included in this report. I analyzed:

- Equivalent Availability Factor
- Forced Outage Rate
- Operating and Maintenance Costs
- Fuel Costs
- Significant Outages.

When considering equivalent availability factor and forced outage rate, KCPL units performed above the industry average in the early 1990's and trended toward the industry average (as expected) in recent years.

When considering operating and maintenance costs alone, the KCPL units have been higher cost than the industry average. The industry average has been trending downward as the KCPL costs have. However, when including fuel costs as part of the operating and maintenance costs, KCPL costs are quite low and trending downward as is the industry average. In fact, latan was a recipient of the Electric Utility Cost Group (EUCG) fossil productivity committee's 1999 Top 5 Lowest Busbar Award for the five-year period from 1993-1997. The EUCG is an organization of regulated utilities that is the recognized standard for electric utility energy performance information.

I also evaluated outages that were greater in length than 60 days. I found that the number of outages experienced by the KCPL units is no different than the number of significant outages experienced at the KCPL peer units.

Q. WHILE ANALYZING THE PERFORMANCE OF THE KCPL UNITS, DID YOU FIND ANY PERFORMANCE CRITERIA THAT WAS NOT WITHIN INDUSTRY STANDARDS?

A. When comparing the KCPL units to their respective peers, I found the performance to be within industry standards.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

AFFIDAVIT

STATE OF Colorado)
) ss.
COUNTY OF Boulder)

On the 24th day of February, 2000, before me appeared M. Monika Eldridge, to me personally known, who, being by me first duly sworn, states that she is a Principal for Competitive Utility Strategies, and that she has participated in the preparation of the foregoing written testimony, in question and answer form, and believes that the statements therein are true and correct to the best of her knowledge, information and belief.

M. MONIKA ELDRIDGE

Subscribed and sworn to before me this 24 day of February, 2000.

Notary Public

My Commission Expires:

MY COMMISSSION EXPIRES: 9-18-02
3600 TABLE MESA DRIVE, BOULDER, CO 80303

E. M. PARKER NOTARY PUBLIC STATE OF COLORADO

EVALUATION OF GENERATING ASSETS OWNED AND OPERATED BY KANSAS CITY POWER & LIGHT COMPANY

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February 22, 2000

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EVALUATION OF GENERATING ASSETS OWNED AND OPERATED BY KANSAS CITY POWER & LIGHT COMPANY

E.S. EXECUTIVE SUMMARY

The primary objective of this report is to evaluate the performance of generating stations owned and operated by Kansas City Power & Light Company (KCPL). KCPL commissioned this evaluation because GST Steel Company (GST) requested the Public Service Commission of the State of Missouri (PSC) take action relating to issues associated with the adequacy and reliability of KCPL's generating stations. These issues are documented in "Petition for an Investigation as to the Adequacy of Service Provided by the Kansas Power & Light Company and Request for Immediate Relief," referred to as the GST complaint. Several specific issues were raised by the GST complaint as well as the Direct Testimony of Jerry N. Ward submitted on November 17, 1999.

KCPL engaged PHB Hagler Bailly to conduct an independent evaluation of KCPL's base loaded generating assets. In turn, PHB Hagler Bailly contracted with M. Monika Eldridge, PE, to conduct this evaluation and testify in this matter.

I, M. Monika Eldridge, PE, am a professional engineer with over 17 years of experience in the power generation field. From 1990 to 1999, I worked for Hagler Bailly until founding Competitive Utility Strategies. As a principal with Hagler Bailly, I have evaluated the economic and regulatory performance of power plants. I have advised utilities on decisions relating to continued operation of power plants. I have evaluated the market potential of new business ventures relating to power generation. I have conducted numerous evaluations of benchmarking the performance and costs of power plants with the industry and have submitted testimony for utilities and minority owners in these matters.

Before joining Hagler Bailly, I worked for CMS Energy from 1982 to 1990 in three different positions. From 1987 to 1990, I was in Senior Reactor Operator (SRO) training at Palisades Nuclear Plant. My position before operations was as a project engineer at Palisades, where I was responsible for design, cost, schedule, procurement, construction, and testing of plant modifications. Before project engineering, I was a lead auditor and responsible for managing technical specification and quality assurance audits. I evaluated programs including operations, maintenance, training, regulatory compliance, reactor physics, and radiation safety. I hold a BME in mechanical and aerospace engineering from the University of Delaware and am a Registered Professional Engineer in the State of Michigan.

The main issues raised by the GST complaint and Mr. Ward's testimony relate to the performance of the KCPL base loaded generating stations. In this report, I address the performance of the KCPL system as well as each individual KCPL unit. I evaluate the equivalent availability factor, forced outage rate, operating and maintenance costs, fuel costs, and significant outages of the KCPL units. I also evaluate the training issues raised by Mr. Ward.

The methodology used is comparative analysis that benchmarks the performance of each KCPL unit to a peer group of units that are similar in design, vintage, and size. In addition, I analyze trends of performance both for the KCPL units as well as the industry.

Although generating stations can be evaluated using several different performance measures, I limit the scope of this project to only include issues raised by the GST complaint. Thus, it should be noted that this analysis does not provide an overall evaluation of the stations. I only address the areas where the generating stations are cited for poor performance. All generating stations perform better in some performance measures and worse in other measures. By only evaluating measures where the generating stations have been cited as having poor performance, I am not able to report the many performance measures where the generating stations may have performed well.

The KCPL system operates within industry when considering accepted performance criteria included in this report. I analyzed:

- Equivalent Availability Factor
- Forced Outage Rate
- Operating and Maintenance Costs
- Fuel Costs
- Significant Outages.

In previous analyses, I evaluated trends of fossil and nuclear units that performed above average in equivalent availability and in costs. Taking a group of coal fired plants; I evaluated the performance from 1985 to 1997. I segregated the group into five categories based on 20 percent increments (80-100%, 60-79%, 40-59%, 20-39%, 0-19%) with 80-100% being the best performers. I found that the units with the best performance in 1985 declined to a level that was slightly above average by 1997. Meanwhile, the units that were below average began to improve performance until they were only slightly below average after 12 years.

When considering equivalent availability factor and forced outage rate, KCPL units performed above the industry average in the early 1990s and trended toward the industry average (as expected) in recent years. In fact, five of eight of the KCPL units have performed better than average with regard to forced outage rate in the past few years.

As with equivalent availability factor, the lowest cost units have trended toward the industry average. The highest cost units have also trended toward the average. However, the industry average has also trended downward. Thus, even the lower cost units have continued to reduce costs only at a slower rate than the higher cost units.

While KCPL's overall operating and maintenance costs, including fuel costs, are below the industry average, this is due to KCPL's extremely low fuel costs. When considering operating and maintenance costs alone, without reference to fuel costs, the KCPL units have been higher cost than the industry average. The costs including fuel costs are a better indication of the overall cost performance of the KCPL units since the two costs are directly related. The industry average of these costs is declining, as are KCPL's costs.

In fact, Iatan was a recipient of the Electric Utility Cost Group (EUCG) fossil productivity committee's 1999 "Top 5 Lowest Busbar Award" for the five year period from 1993 to 1997. The EUCG is an organization of regulated utilities that is the recognized standard for electric utility energy performance information.

I also evaluated outages that were greater in length than 60 days. I found the number of outages experienced by the KCPL units is the same as the number of significant outages experienced at the KCPL peer units.

Overall, when comparing the KCPL units to their respective peers, I found that the performance to be within industry standards.

1. INTRODUCTION

GST Steel Company (GST) requested the Public Service Commission (PSC) of the State of Missouri to take action relating to issues associated with the adequacy and reliability of Kansas City Power & Light (KCPL) generating stations. GST purchases all of its electricity from KCPL under an Amended and Restated Power Supply Agreement executed on August 12, 1994. This Agreement establishes GST as a special contract customer and provides that GST will receive incremental, cost-based pricing. Thus, GST benefits when KCPL generating stations produce power at lower costs; however, unlike a tariff rate, GST also assumes risks associated with those generating stations.

I, M. Monika Eldridge, PE, was retained through PHB Hagler Bailly to independently address the performance issues raised by the GST complaint as it relates to KCPL's generating assets. The overall objective of this analysis is to determine if KCPL has operated its plants in accordance with industry standards for the specific issues raised in the GST complaint.

I have conducted numerous projects that evaluate the performance of generating stations for international utilities and other clients. I have assessed the operation of power plants and recommended operating strategies to utilities on continued operation. This experience enables me to independently evaluate the operation and performance of KCPL's generating stations.

An integral part of my approach includes benchmarking to evaluate the performance of KCPL units with other units with similar operating characteristics. Benchmarking enables me to determine if KCPL's generating stations operate and perform within industry standards. Benchmarking is based on comparative analysis of historical performance to generating units in North America of a similar design, size, and vintage to the KCPL units. This requires the selection of peers, selection of performance indices measured, selection of data sources, and selection of time period analyzed.

KCPL wholly and partially owns and operates seven fossil units, one nuclear plant, and several gas/oil peaking units. In its data requests, GST defines generating assets in question as "all generating units wholly or partially owned by the Company and any other generating units in which the Company was a participant, including those through a lease or an asset-backed purchase." Thus, I included a unit that was partially owned but operated by another entity (i.e., Wolf Creek). I focused my analysis on the base load units, including:

- Hawthorn 5 — 515 MW_{gross} coal unit that began commercial operation in 1969 and is located in Kansas City, Missouri.
- Iatan — 726 MW_{gross} coal unit that began commercial operation in 1980 and is located in Weston, Missouri. Iatan, which is partially owned by KCPL (70%), is operated by KCPL.
- La Cygne — Two coal unit site rated at a total of 1,619 MW_{gross} that began commercial operation in 1973/1977 and is located in La Cygne, Kansas. La Cygne, which is partially owned by KCPL (50%), is operated by KCPL.
- Montrose — Three unit site with a total rating of 563 MW_{gross} that began commercial operation in 1958, 1960, and 1964.
- Wolf Creek — A single unit nuclear power site rated at 1,236 MW_{gross} that began commercial operation in 1985. Wolf Creek, which is partially owned by KCPL, is operated by Wolf Creek Operating Corporation, a company jointly owned by Wolf Creek's three owners in proportion to the owner's ownership interest in Wolf Creek (KCPL 47%, Western Resources 47%, KEPCo 6%)

I focus on issues identified in the complaint where performance can be benchmarked using independent industry data; thus, not all of the issues in the complaint are evaluated. Availability of the generating stations was cited several times in the complaint. Forced outages were another area of concern as well as specific extended forced outages. Declining maintenance expenses were identified as a cause of many of the outages. I was able to address these issues with industry performance measures.

Section 2 of this report provides a summary of the specific issues raised by the GST complaint, how I evaluated each issue, and a brief result of that evaluation. Herein, I only identify issues where I can use industry experience to evaluate the validity of the GST complaint.

Section 3 provides the overall methodology used for comparing the performance of each KCPL unit with the industry standard. The analysis sections discuss methodology in greater detail.

Peers for each of these five separate groups were selected, as discussed in Section 4. Because of the differences between coal fired units and nuclear power units, I segregate my analysis into two distinct sections. First, I address the coal unit analysis and then the Wolf Creek Nuclear analysis. The KCPL coal units were evaluated in four separate groups based on design, vintage, and size. Wolf Creek was evaluated based on the most accepted industry peer group, the Nuclear Regulatory Commission (NRC) design peer group.

Section 5 provides the analysis of production performance indicators such as equivalent availability factor, forced outage rate, and significant events for the four coal station groups. Section 6 provides the analysis of cost performance indicators such as operating and maintenance costs for the four coal station groups. Section 7 addresses all performance measures used to evaluate Wolf Creek.

Section 8 provides conclusions on the performance of the KCPL units when compared to the industry.

Appendix A provides all of the analyses for the KCPL base loaded plants as a system. Appendix B includes all of the analyses for Hawthorn. Appendix C includes all of the analyses for Iatan and La Cygne 2. Appendix D analyzes La Cygne 1. Appendix E analyzes Montrose 1, 2, & 3. Appendix F provides the analyses for Wolf Creek.

2. SPECIFIC ISSUES RAISED BY GST COMPLAINT AND DIRECT TESTIMONY

The scope of work is based on evaluating whether the specific issues raised by the GST complaint and direct testimony are valid. These issues are documented in "Petition for an Investigation as to the Adequacy of Service Provided by the Kansas Power & Light Company and Request for Immediate Relief," referred to as the GST complaint. Additional issues were raised by the Direct Testimony of Jerry N. Ward, November 17, 1999.

The primary purpose of this report is to determine whether the specific issues raised by GST in its complaint are valid. By using independent industry data, I use the benchmarking methods described herein to validate or refute these claims. In this section, I present each issue and provide the specific analysis that was conducted to address the complaint. A brief conclusion on the results of my analysis is also provided for each issue presented. I do not address every issue in the complaint because not all issues can be benchmarked using publicly available industry data. Thus, I only include those issues that can be independently evaluated.

Section I.C.5 of the GST complaint states:

> Any time one of KCPL's generating units is forced out of service, and is replaced either by a more expensive unit or by more expensive off-system power, GST is immediately impacted by the increased cost of power. For example, in August of 1998, a ruptured steam line at Hawthorn Generating Station Unit No. 5 ("Hawthorn 5") caused the unit to be off-line for all of September 1998. KCPL "thought that the Hawthorn 5 pipe was seamless." The pipe was in fact a welded pipe that had been omitted from KCPL's preventive maintenance program for the Hawthorn 5 unit.... This outage in large part caused GST's September 1998 power cost per kilowatt-hour to soar to levels roughly 75% higher than those experienced in September 1997.... This incident at Hawthorn 5 should not be confused with the boiler explosion that occurred at Hawthorn 5 on February 17, 1999. This steam pipe incident apparently did not serve as a sufficient warning sign to KCPL of problems at Hawthorn 5.

In order to evaluate the performance of KCPL units with respect to significant forced outages, I evaluated all forced outages that occurred at all peer units. I defined significant outages as those lasting greater than 60 days. The September 3, 1998 Hawthorn forced outage lasted 83 days. I assigned 60 days as the criteria for a significant outage because it allowed for an analysis based on months instead of days. Since the Hawthorn outage was greater than two months but less than three months, I defined a significant outage as an outage lasting 60 days or more.

Forced outages occurrences are not unusual for base loaded coal fired plants; however, there are only a few longer duration outages. Yet when evaluating the total number of forced outages greater than 60 days, I found that the KCPL units had not experienced any more than the peer units. This is discussed further in Section 5 of this report.

Section I.C.6 of the GST complaint states:

> Furthermore, it is likewise GST's understanding that in the month of September 1998, no generating unit operated and maintained by KCPL operated for all 30 days of the month. Each unit that KCPL has the responsibility to run was off-line at some time during the month.... GST's power costs are directly affected by these unplanned outages.

Although Hawthorn 5 was out of service during September 1998, the other KCPL units were not down for the entire month. In fact, Iatan and La Cygne 2 were down for less than a day during September. There was no time period where all of the KCPL units were out of service. In fact, the total system availability of the units during September 1998 was 78%.

Regardless, it is not appropriate to evaluate any plant performance on only one month of experience. To illustrate, I evaluated the Equivalent Availability Factor for only the month of

January 1998. Table 2-1 provides the Equivalent Availability Factor for each KCPL unit operated during January 1998.

Table 2-1
KCPL Unit Availability for January 1998

Hawthorn 5	100%
Iatan 1	99.84%
La Cygne 1	77.01%
La Cygne 2	98.01%
Montrose 1	100%
Montrose 2	100%
Montrose 3	100%
Wolf Creek	100%
System Availability	**96.78%**

During this time period there were five short outages as shown by Table 2-2. None of the KCPL units were down concurrently. The availability of the system varied from 78% in September 1998 to 97% in January 1998. This illustrates that performance cannot be evaluated based on a short duration such as one month.

Table 2-2
Outages at KCPL Units in January 1998

Unit	Date	Cause	Number of Outage Hours
La Cygne 1	1-7-98	Extraction Steam	4.37
La Cygne 1	1-19-98	Other Miscellaneous	4.92
La Cygne 1	1-19-98	Cyclone Furnace	84.45
La Cygne 1	1-23-98	Exciter Problems	6.58
La Cygne 2	1-31-98	Feedwater Regulator	9.5

Section II.B.12 of the GST complaint states:

> The explosion at the Hawthorn plant appears to be the culmination of the increasingly erratic and unreliable operation of the KCPL system. GST, to its own misfortune, has been at the front lines of KCPL's faltering system reliability.

I evaluated the reliability by benchmarking equivalent availability factor (EAF) and forced outage rate (FOR) to determine the reliability of KCPL's generating stations. I found that on average, KCPL's generating stations performed within industry standards. After evaluating the entire KCPL system as an aggregate, I found that EAF for the KCPL system has historically been above the industry average; except from 1995 to 1998 when the KCPL system has been close to average. During the 1995 to 1998 time frame, the KCPL system availability has been less than a percentage point lower than the expected average and still well within acceptable industry standards. This is discussed further in Section 5 of this report.

Section II.B.13 of the GST complaint states:

> These reliability problems encompass KCPL's entire system. GST believes that its recent power cost increases are due in part to the declining reliability of KCPL's generation units and an increasing forced outage rate. Each unit outage on the KCPL system requires KCPL to replace the power that unit would otherwise generate.

I evaluated the forced outage rate for the KCPL units. I found that the performance of the KCPL system with regard to forced outage rate was, with one exception, within industry standards during the past 10 years. Upon evaluating the entire KCPL system as an aggregate, I found that the forced outage rate of the KCPL system has always been within a percentage point of the industry average. In addition, five of eight of the units have forced outage rates that are better than industry average in recent years. This is discussed further in Section 5 of this report.

Section II.B.15 of the GST complaint states:

> Based upon the most recent information GST has been able to obtain, it is GST's understanding that in the first four months of 1998, KCPL experienced 26 unplanned outages at its La Cygne Nos. 1 and 2, Montrose Nos. 2 and 3, Hawthorn No. 5, and Iatan generating units. The units affected by these unplanned outages "lost" over 1,800 hours of electricity production. KCPL had at least one of its generating units in a forced outage situation in nearly 65% of the hours of the first four months of 1998.

There may be brief periods when any utility experiences forced outages that are greater in magnitude and duration. Thus, it is important to review not just short time periods, but also the consistency of performance over a longer duration. Overall, the forced outages for the KCPL units were within industry standards. Section 5 of this report discusses this further.

Section II.B.16 of the GST complaint states:

> While the causes of the reliability problems are far from clear, GST has suspected a change in KCPL's priorities in recent years. KCPL's own public filings provide evidence of these shifting priorities. In 1991 and 1992, KCPL spent roughly $81 million on the maintenance of its generating, transmission and distribution plant.... KCPL's maintenance expenses have consistently stayed below 1992 levels, as shown in the following chart:

Year	Maintenance Expense	Change Compared to 1992
1992	$81,163,000	
1993	$78,550,000	-3.2%
1994	$72,468,000	-10.7%
1995	$78,439,000	-3.4%
1996	$71,495,000	-11.9%
1997	$70,892,000	-12.7%
1998	$70,998,000	-12.5%

When evaluating the KCPL operating and maintenance costs, I found that the costs were higher than the industry average. In past studies of O&M costs for coal plants, I have found that plants where costs were higher would eventually decline to the industry average. This is particularly important as utilities prepare for deregulation. In addition, the overall average of O&M costs has been declining at fossil power plants as a whole. A reduction in costs at the KCPL plants show prudent operation in bringing costs more in line with the industry standard. Thus, for each of the KCPL peer groups, you can see a trend downward in costs. This is reasonable and expected. Additional details are included in Section 6 of this report.

Section II.B.16 of the GST complaint states:

> In spite of aging generating plants, aging transmission and distribution systems, and increasing load, KCPL has decreased the amount it spends on the maintenance of the facilities its customers rely on for the production and delivery of power.... GST is concerned that this cost cutting is negatively impacting generating unit and system reliability, and consequently requiring additional purchases of off-system power, the costs of which are disproportionately borne by GST. While *this general data suggests [sic] that maintenance has been declining* and the forced outage rate increasing, GST asks the Commission to analyze KCPL's operation of its generating plant and the impact that has on KCPL's purchased power costs in order to determine the adequacy, reliability, and prudence of KCPL's power supply.

As I stated previously, KCPL's overall operation and maintenance costs, including fuel costs, are below the industry average, this is due to KCPL's extremely low fuel costs. When considering operating and maintenance costs alone, without reference to fuel costs, the KCPL units have been higher cost than the industry average. The costs including fuel costs are a better indication of the overall cost performance of the KCPL units since the two costs are directly related. The industry average of these costs is declining, as are KCPL's costs. Additional details are included in Section 6 of this report.

Section XX.1 Section 4 of the Appendix of the GST complaint[1] states:

> KCPL informed GST at that meeting that one reason for the high power costs was an increase in the generating unit forced outage rate from 14% in 1997 to 18% in 1998, when the budgeted level was 10%.

As stated above, any forced outage rate for any specific short time period can be shown to be high, just as it can also be taken during other specific times and shown to be lower. My analysis benchmarks the forced outage rate using a three-year rolling average over a ten-year period to determine if the forced outage rate is within industry standards. This provides an evaluation of historical and current forced outage rates as well as the trend of performance. As shown in Section 5 of this report, the KCPL units perform within industry standards.

Section 14 of the Appendix D of the GST complaint states:

> Our experience in September 1998 is a good example of what happens to us as a result of KCPL reliability problems. As a result of the steam pipe explosion at Hawthorn 5 in August 1998, Hawthorn 5 was off-line for the entire month of September. In addition, we were informed by KCPL that every other unit they operate was out of service at some point during the month of September.

Although Hawthorn 5 was out of service during September 1998, the other KCPL units were not down for the entire month. In fact, Iatan and La Cygne 2 were down for less than a day during September 1998. There was no time period where all of the KCPL units were out of service. As discussed earlier, the KCPL units were 78% available in September of 1998.

1. Affidavit Of Ronald S. Mulhauser On Behalf Of GST Steel Company, May 5, 1999.

Direct Testimony of Jerry N. Ward (page 3, lines 8-15) states:

> KCPL operates generation resources that are primarily coal-fueled. For a number of years it has been attempting to prepare for deregulation of the electric utility industry. KCPL has also been intensely involved in at least two attempts to merge with other utility systems. It currently plans to merge with Western Resources. As will be detailed later in this testimony, KCPL has been engaged in a systematic program of reducing costs. The company also claims that improving plant availability is its highest priority. In KCPL's case, however, the company has cut costs but has not become more productive. In fact, production performance, particularly in terms of plant availability, has declined steadily.

I evaluated the performance of the KCPL system and more specifically the equivalent availability factor of the KCPL system. As shown in Exhibit A-1, the equivalent availability factor of the KCPL system was historically above average. The KCPL system has gone from above average performance from 1992 to 1996 to performance that is more in line with industry averages.

It is not unusual for generating stations to trend toward the industry average. In previous analyses, I evaluated trends of fossil and nuclear units that performed above average in equivalent availability and in costs. Taking a group of coal fired plants; I evaluated the performance from 1985 to 1997. I segregated the group into five categories based on 20 percent increments (80-100%, 60-79%, 40-59%, 20-39%, 0-19%) with 80-100% being the best performers. I found that the units with the best performance in 1985 declined to a level that was slightly above average by 1997. Meanwhile, the units that were below average began to improve performance until they were only slightly below average after 12 years.

Since KCPL generating stations on a whole performed above average, a period of lower performance would not have been unexpected. This statement is relative and the performance of the KCPL units must be compared to the performance of other similar units over an appropriate time period. Thus, while the performance of the KCPL system has trended down from its above average performance, it has remained within industry standards.

Direct Testimony of Jerry N. Ward (page 3, lines 16-21) states:

> KCPL's reduced corporate attention to the details of power plant management has shown up in a series of glitches, mistakes and oversights. Collectively, they are reflected in the trend of declining equivalent availability and increasing forced outage rates. Individually, they are represented in the chronic reliability problems GST experienced in 1998 and in more spectacular fashion by the August 1998 steam pipe rupture and the February 1999 boiler explosion that virtually destroyed Hawthorn Unit 5.

I reviewed the number of significant forced outages over the time period of 1989 to 1998. Significant forced outages were defined based on the length of the Hawthorn September 1998 outage. This outage was less than three months but greater than two months. For simplicity, I defined a significant outage to be greater than two months. I reviewed the number of significant forced outages and found that the KCPL units experienced the same number of significant forced outages as its peers. Section 5 of this report discusses this further.

Direct Testimony of Jerry N. Ward (page 4, lines 3-9) states:

> KCPL has been cutting production costs across the board for some time. The total number of employees had been reduced from over 3,130 in 1993 to 2,550 in 1998, a 19% reduction (FERC Form 1, 1989-98, page 323, Shown in Exhibit 2). This manpower reduction led directly to a reduction in operations costs of $138.3 MM in 1993 to $126.4 MM in 1998 — an 8.6% reduction. In this same period, the maintenance expenses were reduced from $39.5 MM to $32.6 MM- a 17.4% reduction (FERC Form 1, 1989-1993, page 320, Shown in Exhibit 3).

As I stated previously, KCPL's overall operating and maintenance costs, including fuel costs, are below the industry average, this is due to KCPL's extremely low fuel costs. When considering the operating and maintenance costs alone, without reference to fuel costs, the KCPL units have been higher cost than the industry average. The costs including fuel costs are a better indication of the overall cost performance of the KCPL units since the two costs are directly related. The industry average of these costs is declining, as are KCPL's costs. Additional details are included in Section 6 of this report.

Direct Testimony of Jerry N. Ward (page 4, lines 19-22 and page 5, lines 1-6) states:

> KCPL has consistently reduced the amount of capital expenditures forecasted to be spent on existing generating stations in each successive 5-year period. In 1994, KCPL predicted expenditures, over the next five years, of $191.6 MM for capital improvements on their existing generating stations. This amount was reduced to $155.3 MM in the 1995 projection; to $114.7 MM in their 1996 projection; and to $70.7 MM in their 1997 projection. Their 1998 projection increased to $113.1 MM, but the forecast was immediately reduced again in their 1999 projection to $81.2 MM. By comparing 5-year forecasts, the effect of a single large expenditure can be minimized, and general trends can be observed. (Construction Forecasts- Summary by Group, KCPL Budgets, Shown in Exhibit 4.)

Because of reporting requirements, analyzing capital costs is extremely difficult and FERC Form 1s do not provide a valid database. This is true for all U.S. utilities. All power plants in the United States are reducing costs and KCPL is no exception. Reductions in capital costs may be for many reasons. For example, the units may have conducted high capital cost projects in the early 1990s thus allowing the costs in a more recent five-year time period analyzed to be considered much lower. In addition, a large capital expenditure in one year can make it difficult to analyze capital costs in general.

Direct Testimony of Jerry N. Ward (page 5, lines 7-14) states:

> Q. HOW HAS THE PLANT STAFF AT HAWTHORN 5 BEEN AFFECTED BY THESE REDUCTIONS?
>
> According to the Plant Manager, James Teaney, the staff has been reduced from 115 people to 102, from 1995 to 1999 — an 11% reduction. Another example of impact on the staff is the number of training hours spent in a classroom for instruction other than required by OSHA. This had declined from a high of 8,318 hours in 1996 to 1,234 hours in 1998, a precipitous drop of 85% from 1996 and a 70% reduction from 1995 levels (Response to GST 3.48).

Training hours are a function of the number of new modifications to the units, the number of new employees, and new training programs initiated. Each of these areas can change significantly over a time period thus drastically increasing and decreasing the need for training hours. Because of this, the number of training hours cannot be evaluated on an annual basis.

The number of training hours for Hawthorn, the number of employees included in these training hours, and reasons for training are provided in Table 2-3. This shows that the number of training hours varies dramatically. For example, the number of operator training hours in 1996 were 1,996 hours, almost double the number of hours in 1995 while in 1993 the number of operator training hours were insignificant. In 1997, there were 1,022 training hours due to new equipment while in 1994 there were only 20 training hours due to new equipment. If Mr. Ward had chosen 1994 (the first year's data of the reference cited) the training hours would have increased by 1998.

These examples show how difficult it is to benchmark a measure such as number of total training hours. Thus, it is not valid to benchmark the number of training hours from year to year because of the many variables associated with training programs. By segregating the training hours into categories as shown in Table 2-3, the need to analyze the reasons behind training hours becomes more apparent.

In order to respond to Mr. Ward's testimony, I analyzed the actual purpose of the training hours and found that the total number of training hours originally reported in GST 3.48 were incorrect. In the original information provided by KCPL, many of the hours had been accounted for by two different systems and thus double counted. The training hours provided by Table 2-3 are more detailed and provide an accurate accounting of the training hours.

As shown by Table 2-3, the training hours in 1998 were very close to the total training hours in a typical year at Hawthorn when apprenticeship training is not ongoing.

The year 1996 was merely an outlier in that a significant amount of operator training was ongoing due to simulator qualifications.

Table 2-3
Training Hours for Hawthorn Personnel

Year	Training Hours	Number of Employees included in Training Hours	Training Hours
1989	3,434	133	Apprenticeships (dependent on number of new personnel) — 2,053 hours. Refresher courses (not necessarily conducted every year) — 274 hours. Operator training (required on an ongoing basis) — 280 hours. New equipment training (one time training) — 72 hours. Human Resources training — 755 hours.
1990	6,565	133	Apprenticeships — 3,515 hours. Refresher courses — 716 hours (increase due to pumps and circuits training). Operator training — 136 hours. Increase in Human Resources courses including: Handling Conflict, Stress Management, Personal Growth — 2,198 hours.
1991	6,608	143	Apprenticeships — 1,996 hours. Refresher courses — 643 hours. Operator training — 564 hours. New equipment training — 281 hours. New equipment includes: fly ash conveyor system, #5 combustion controls. Human Resources training — 3,124 hours.
1992	7,264	138	Apprenticeships — 2,566 hours. Refresher courses — 528 hours. Operator training — 816 hours. Equipment upgrade training — 82 hours. New equipment includes data acquisition system and 13 kV switchgear. Human Resources training — 3,272 hours.
1993	4,683	135	Apprenticeship — 1,402 hours. Refresher courses — 564 hours. Operator training — 24 hours. New equipment training — 711 hours. New equipment includes data acquisition system coal pulverizer steam inerting, ash recycle systems, sewage treatment system, data manager system. Human Resources training — 1,982 hours.

Table 2-3
Training Hours for Hawthorn Personnel

Year	Training Hours	Number of Employees included in Training Hours	Training Hours
1994	4,197	134	Apprenticeship — 608 hours. Refresher and computer training — 1,887 hours. Operator training — 563 hours. New equipment training — 20 hours. Human Resources training — 1,119 hours.
1995	4,354	120	Apprenticeship —complete. Refresher and computer — 2,228 hours. Operator training — 1,026 hours. New equipment training —352 hours. New upgrade to #5 unit combustion controls Max 1000 and Forney burner management. Human Resources training — 748 hours.
1996	7,241	122	Apprenticeship — complete. Refresher — 2,862 hours. New equipment training —289 hours. New equipment includes: Max 1 distributed control system retrofit, water lance soot blower, reverse osmosis, and Ronan data acquisition systems. Operator training — 1,996 hours. Number of operator training hours has significantly increased because of training on simulator. Human Resources training — 2,094 hours.
1997	4,776	122	Apprenticeship — complete. Refresher courses — 1,556 hours. Operator training — 648 hours. Number of operator training hours decreased since simulator training was complete in February 1997. New equipment training— 1,022 hours. Unit 6 CT, main boiler feed pump controls change, water lance soot blower. Human Resources Training — 1,550 hours.
1998	4,365	118	Apprenticeship — complete. Refresher courses — 927 hours. Operator training — none. New equipment training — 916 hours. Hawthorn #6 continuous emission monitoring. Human Resources training — 2,522 hours.
Average per year	5,349		Apprenticeship — 1,214 hours. It is not appropriate to present the number of apprenticeship hours as an average per year. It should be presented as hours per apprentice.

Table 2-3 Training Hours for Hawthorn Personnel			
			Refresher courses — 1,219 hours. Operator training — 605 hours. New equipment training — 375 hours. It is not appropriate to present the number of apprenticeship hours as an average per year or even as an average per project. Human Resources training — 1,936 hours.

Direct Testimony of Jerry N. Ward (page 6, lines 1-11) states:

> By all accounts, performance relative to unit availability is abysmal. Based on data reported to the Federal Energy Regulatory Commission (FERC), between 1994 and 1998, KCPL's total system unavailable capacity due to unplanned outages and derates, at the time of the monthly peak demand, increased from 2,064 MWs to 4,608 MWs, or it more than doubled (Shown in Exhibit 5 and Exhibit 5A). *This is a clear indication of declining performance.....During this* period, while most utilities were reducing their costs and increasing unit availability at KCPL's plants has been going in the exact opposite direction.

I evaluated the performance of the KCPL system and more specifically the equivalent availability factor of the KCPL system. As shown in Exhibit A-1, the equivalent availability factor of the KCPL system was historically above average. The KCPL system has gone from good performance from 1992 to 1996 to performance that is more in line with industry averages.

Direct Testimony of Jerry N. Ward (page 8, line 8-12) states:

> It is very unusual for a plant to demonstrate such a long period of escalating equivalent forced outage rates. Sometimes a plant will have a bad year, due to some difficult situation or major breakdown, but to see such a sustained period of *increasingly poor performance is unusual, and is an indication that management is* not placing the proper emphasis on plant operation.

As stated above, any forced outage rate for any specific short time period can be shown to be high, just as it can also be taken during other specific times and shown to be lower. My analysis benchmarks forced outage rate using a three-year rolling average over a ten-year time period. When evaluating the forced outage rate over an appropriate time period, I found the KCPL system performance to be within industry standards. Further details are provided in Section 5 of this report.

Direct Testimony of Jerry N. Ward (page 10, line 9, 16-21) states:

> In August 1998, a main high pressure steam pipe ruptured at Hawthorn 5...... In either case, the event caused Hawthorn 5 to be out of service for nearly three months (From August to November 11). This extended outage adversely affected the electricity costs charged to GST, particularly during the very high peak periods that occurred in September. Also, at some time in September 1998, all of KCPL's plants were out of service for one reason or other, except the Wolf Creek nuclear unit, which KCPL does not operate.

Although Hawthorn 5 was out of service during September 1998, the other KCPL units were not down for the entire month. In fact, Iatan and La Cygne 2 were down for less than a day during September, as shown earlier in Table 2-1.

There was no time period where all of the KCPL units were out of service, as shown earlier in Table 2-2.

Direct Testimony of Jerry N. Ward (page 19, line 3-6) states:

> I believe there is ample evidence of deteriorating conditions at Hawthorn 5. The declining performance of the unit over an extended period confirms there were problems. In effect, Hawthorn 5 was an accident waiting to happen — and in fact there had been several, as indicated by the extremely high Equivalent Forced Outage Rate during 1998.

As stated above, any forced outage rate for any specific short time period can be shown to be high, just as it can also be taken during other specific times and shown to be lower. My analysis benchmarks forced outage rate using a three-year rolling average over a ten-year time period. When evaluating the forced outage rate over an appropriate time period, I found the KCPL system performance to be within industry standards. Further details are provided in Section 5 of this report.

Direct Testimony of Jerry N. Ward (page 19, line 8-11) states:

> KCPL was cutting production-related costs without the necessary equivalent concentration on the results of its actions. By reducing manpower, expenses, and capital investment, KCPL allowed the performance of its plants to deteriorate, and the company failed to act appropriately.

As stated above, maintenance costs at the KCPL plants are higher than the industry average. The decrease in O&M costs at the KCPL plants are to be expected since costs should be decreasing to become more in line with industry averages. In addition, industry costs have also been trending downward.

My analysis of total O&M costs (O&M plus fuel) shows that the KCPL system costs are less than the industry average. Both the industry average and the KCPL costs are trending downward during the 1990s. Additional details are included in Section 6 of this report.

3. METHODOLOGY

In order to conduct a comparative analysis of the KCPL unit performance for the specific issues raised by the GST complaint, I completed the following tasks:

- Identified five peer groups based on the size, vintage, and design of the KCPL units. Four of these peer groups are associated with KCPL's coal fired units and the fifth peer group is used to analyze Wolf Creek. The five peer groups are discussed in Section 4.
- Identified a time period for the comparative analysis.
- Conducted a comparative analysis of each KCPL unit with its peer plants for the following performance measures:
  - Equivalent Availability Factor (EAF)
  - Forced Outage Rate (FOR)
  - Significant Events (forced outages greater than 60 days)
  - Operating and Maintenance (O&M) including fuel costs
  - O&M without fuel costs
  - Fuel Costs.

4. PEER GROUPS ESTABLISHED FOR KCPL UNITS

KCPL owns and/or operates seven base loaded coal units and one nuclear unit. KCPL also owns and/or operates several gas units that are used for peaking capacity. In this study, I only evaluate the base loaded units, thus I focus on the coal and nuclear units. The characteristics of the KCPL units are critical in determining which peer units should be chosen for comparison. Table 4-1 provides a summary of the characteristics used in identifying peer groups for each KCPL unit.

Table 4-1
KCPL Units and Characteristics Used to Choose Peer Groups

Unit	Design	Vintage	Capacity (MW_{gross})	Fuel Type	Other Important Design Characteristics
Hawthorn 5	Combustion Engineering (CE)	1969	514.4	Coal	Reheat
Iatan	Babcock &	1980	725.9	Coal	Reheat

Table 4-1
KCPL Units and Characteristics Used to Choose Peer Groups

	Wilcox (B&W)				
La Cygne 1	B&W	1973	893.4	Coal	Cyclone with a wet scrubber
La Cygne 2	B&W	1977	685.2	Coal	Reheat
Montrose 1	CE	1958	187.5	Coal	Reheat
Montrose 2	CE	1960	187.5	Coal	Reheat
Montrose 3	CE	1964	188.1	Coal	Reheat
Wolf Creek	Westinghouse	1985	1,214	Nuclear	Four loop

4.1 ESTABLISHING KCPL GROUPS

Because of similarities among the KCPL units I was able to include some units in the same group.

4.1.1 Hawthorn 5

Hawthorn 5 is a CE radiant reheat boiler that began commercial operation in 1969. This design and vintage is different than the other KCPL units; thus, it is included in a group of its own. This report will refer to this as the Hawthorn 5 peer group.

4.1.2 Iatan/La Cygne 2

Iatan is a B&W radiant reheat boiler that began operation in 1980. Iatan's design is very similar to La Cygne 2 with some small exceptions. Iatan has larger motors, pumps, and precipitators allowing control operators to easily load follow, ramp up, and run the boiler in an over-pressurized state.

La Cygne 2 is a B&W radiant reheat boiler that was put in service in 1977. La Cygne 2 is the earlier design on which the Iatan design was based and has less conservative sizing of motors, pumps, and precipitators. Since there is less margin in the La Cygne 2 design, it is not as flexible to load follow as Iatan.

The differences between these two units are slight; thus I selected a peer group based on both of these units. I refer to this group as the Iatan peer group.

4.1.3 La Cygne 1

La Cygne 1 is a B&W cyclone fired universal pressure boiler with a wet scrubber used for both sulfur and particulate control. The unit began operation in 1973. La Cygne 1 is different than most other coal boilers. It is a larger cyclone fired boiler with a wet scrubber and no precipitator.

La Cygne 1 was built to use local Missouri/Kansas coal, which was available at a lower cost than eastern bituminous and western coal since it was mined two miles from the La Cygne Station. The intent of the cyclone boiler design was to trade off higher maintenance costs by burning local coal to avoid the higher fuel prices. Wet scrubbers were also installed to meet clean air regulations. Scrubbers increase costs and reduce availability because of additional equipment that must be maintained — with more equipment, the potential for failure increases.

Because of the unique design, La Cygne is in a group of units based solely on design. This results in a group of units that tend to be much smaller than the La Cygne unit and older since most of the cyclone boilers are an older and smaller design. I conducted a regression analysis to address the size differences.

4.1.4 Montrose Units 1, 2, & 3

All three Montrose units are a CE radiant reheat design and are of comparable size and vintage. These units are included in the same peer group.

4.1.5 Wolf Creek

Wolf Creek Nuclear Generating Station is a Westinghouse four loop Pressurized Water Reactor (PWR) that was placed in service in 1985. The Nuclear Regulatory Commission (NRC) evaluates all of the nuclear power plants in the United States using a design peer group. The NRC evaluates Wolf Creek by comparison to other newer Westinghouse units. I used this NRC design peer group for my evaluation of Wolf Creek.

4.2 IDENTIFYING PEERS FOR EACH KCPL GROUP

First, I chose peers for the five selected groups. The criteria used to choose the peer groups included:

- design — boiler manufacturer
- size — capacity
- vintage — on line date
- fuel type — coal, nuclear
- type of service — base load
- availability of useful cost data.

The peer group selection criteria for each of the units are provided in Table 4-2.

Table 4-2
Peer Group Selection Criteria

Peer Group for KCPL Unit	Year Online Range	Size Range	Boiler Manufacturer
Hawthorn	1965-1975	350-650	CE
La Cygne 1	All	All	Cyclone Boilers
Iatan 1, La Cygne 2	1970-1985	550-850	B&W
Montrose	1955-1965	150-250	CE
Wolf Creek — Nuclear	Newer Westinghouse Three and Four Loop Plants		Westinghouse

4.2.1 Design

The design is based on the type of boiler manufacturer with the exception of the La Cygne Unit 1 peers. The boiler has a larger impact on performance than any other part of a unit, although the turbine can have a major impact as well. All four manufacturers produce boilers of comparable quality; however, boilers differ in many important design details, which impact performance.

A relatively small number of boilers built by B&W have cyclone furnaces and these furnaces have been particularly troublesome. As noted above, La Cygne 1 is a cyclone boiler type. This design type was developed in order to use dirtier coal than other plant designs. However, it turns out to have significant problems that cause both high costs and lower availability. There are fewer of these units as well. Thus, I developed a peer group of units that consisted of all cyclones that met the service criteria for La Cygne 1. To address size differences, I conducted a regression analysis, discussed in Section 4.4.

Other design characteristics that are significant include steam temperature and pressure, boiler circulation, reheat, turbine-generator manufacturer, and whether or not the unit has scrubbers. Because the peer group is already relatively small, I did not attempt to limit the peers by any of these characteristics. I did; however, address how scrubbers affect the performance of La Cygne 1; the only KCPL unit with scrubbers.

4.2.2 Unit Size

Larger units have more equipment to maintain, resulting in higher costs. Also, larger units tend to have more frequent outages. Each peer group has a range of sizes, smaller and larger than the KCPL units. I chose the range of sizes of the peer units such that the average size of the peers is close to the average size of the KCPL units for each group.

4.2.3 Vintage

The year that a unit came on line was used as a criteria for selecting the peer groups. Units that started up in the 1950s generally were the most conservative design. From 1960 to 1965, units were less conservatively designed than the 1950's units, and 1966-1975 units were even less conservative. After 1975, designs became more conservative, although they are still not as conservative as the 1950s units.

4.2.4 Fuel Type

Coal units have more equipment, and more difficult operating conditions, than oil or gas units. With the exception of Wolf Creek, all of the base loaded KCPL units are coal. Thus, I only include coal units in the peer groups for Hawthorn, Iatan, La Cygne, and Montrose.

4.2.5 Type of Service

The effect of light loading on the performance of a unit could be significant. A unit that is operated when available is obviously more valuable to a utility than a unit that is only operated some of the time. I would expect that a utility would spend more money on the more valuable units and achieve better performance. In the past I have found that, on average, units that spend more than 20% or 30% of the year on reserve shutdown have poorer performance than other comparable units. I reviewed the reserve shutdown hours of the KCPL units. I found that over a ten-year period, the KCPL units had an annual reserve shutdown factor of less than 10%.
I reviewed the reserve shutdown hours of all the units in the selected peer groups. I found 10% to be a reasonable limit that many of the units stayed below. The units higher than 10% tended to be significantly higher, leading to the conclusion that these were not base loaded units. Note that I used 10% as the dividing point (rather than 20% or 30%) to be sure that I only considered units that are given maximum attention by the utilities that operate them.

4.2.6 Availability of Useful Cost Data

Many of the units in the peer group are located on sites with more than one unit. Costs are frequently reported by the utility based on the site and not specifically the unit that I am interested in. Thus, I reviewed the peer group to determine if the sister units at each peer group site were within reasonable criteria based primarily on size, vintage, and design. Otherwise, the cost data (which is typically reported as a cost figure that is divided by the number of units on a site) would not be valid for that individual unit.

4.3 PEERS SELECTED

4.3.1 Hawthorn Peers

Table 4-3 provides Hawthorn peer unit names, location, capacity of each unit, online date, boiler manufacturer, and whether or not the unit has flue gas desulfurization (FGD or scrubbers) equipment.

Table 4-3
Hawthorn Peers

Unit Name	State	MW_{gross}	Online	Design	FGD?
AM Williams 1	SC	632.7	1973	CE	None
Baldwin 3	IL	634.5	1975	CE	None
Big Brown 1	TX	593.4	1971	CE	None
Big Brown 2	TX	593.4	1972	CE	None
Cayuga 1	IN	531	1970	CE	None
Cayuga 2	IN	531	1972	CE	None
Cheswick 1	PA	565.3	1970	CE	None
Colstrip 1	MT	358.4	1975	CE	Yes
Columbia 1	WI	512	1975	CE	None
Comanche 1	CO	350	1973	CE	None
Crystal River 1	FL	440.5	1966	CE	None
Crystal River 2	FL	523.8	1969	CE	None
Fort Martin 1	WV	576	1967	CE	None
Ghent 1	KY	556.9	1974	CE	Yes
Huntington 2	UT	446.4	1974	CE	None
Jim Bridger 1	WY	560.6	1974	CE	Yes
Jim Bridger 2	WY	560.6	1975	CE	Yes
Labadie 1	MO	573.8	1970	CE	None
Labadie 2	MO	573.8	1971	CE	None
Labadie 3	MO	620.5	1972	CE	None
Labadie 4	MO	620.5	1973	CE	None
Marshall 3	NC	648	1969	CE	None
Marshall 4	NC	648	1970	CE	None
Mill Creek 1	KY	355.5	1972	CE	Yes
Mill Creek 2	KY	355.5	1974	CE	Yes

Table 4-3
Hawthorn Peers

Morgantown 1	MD	626	1970	CE	None
Morgantown 2	MD	626	1971	CE	None
Mount Storm 1	WV	570.2	1965	CE	None
Mount Storm 2	WV	570.2	1966	CE	None
Mount Storm 3	WV	522	1973	CE	Yes
Petersburg 2	IN	471	1969	CE	None
WC Beckjord 6	OH	460.8	1969	CE	None

4.3.2 Iatan/La Cygne 2 Peers

Table 4-4 provides a list of the Iatan/La Cygne 2 peers, location, size in MW_{gross} rating, year online, design, and if the unit has FGD equipment.

Table 4-4
Iatan/La Cygne 2 Peer Units

Unit Name	State	MW_{gross}	Online	Design	FGD?
Belle River 1	MI	697.5	1984	BW	None
Belle River 2	MI	697.5	1985	BW	None
Big Cajun Two 3	LA	560	1983	BW	None
Brandon Shores 1	MD	685.1	1984	BW	None
Cardinal 3	OH	650	1977	BW	None
Crystal River 4	FL	739.3	1982	BW	None
Crystal River 5	FL	739.3	1984	BW	None
East Bend 2	KY	669.3	1981	BW	Yes
Flint Creek 1	AR	558	1978	BW	None
Gerald Gentleman 2	NE	681.3	1982	BW	None
Hatfields Ferry 2	PA	576	1970	BW	None
Hatfields Ferry 3	PA	576	1971	BW	None
Homer City 3	PA	692	1977	BW	None
JM Stuart 1	OH	610.2	1971	BW	None
JM Stuart 2	OH	610.2	1971	BW	None
JM Stuart 3	OH	610.2	1972	BW	None
JM Stuart 4	OH	610.2	1974	BW	None
Kintigh 1	NY	655.1	1984	BW	Yes
Laramie River 1	WY	570	1980	BW	Yes
Laramie River 2	WY	570	1981	BW	Yes
Laramie River 3	WY	570	1982	BW	Yes
Louisa 1	IA	738.1	1983	BW	None
Miller 2	AL	705.5	1985	BW	None
Monroe 1	MI	817.2	1971	BW	None
Monroe 4	MI	817.2	1974	BW	None
Monroe 2	MI	822.6	1973	BW	None
Monroe 3	MI	822.6	1973	BW	None

Table 4-4 (cont.) Iatan/La Cygne 2 Peer Units					
Unit Name	**State**	**MW_{gross}**	**Online**	**Design**	**FGD?**
Monticello 3	TX	793.3	1978	BW	Yes
Pirkey 1	TX	720.8	1985	BW	Yes
Thomas Hill 3	MO	670	1982	BW	Yes
Welsh 1	TX	558	1977	BW	None
Welsh 2	TX	558	1980	BW	None
Welsh 3	TX	558	1982	BW	None

4.3.3 La Cygne 1 Peers

Table 4-5 provides the La Cygne 1 peer units, location, capacity in MW_{gross}, year on line, design, and whether or not the unit has FGD equipment. Two analyses were done for La Cygne. A secondary peer group was chosen because the number of units in the peer group was small.
I extended the criteria for the secondary group that allowed for some sites that had smaller sister units on the site that are not in the peer group. This would affect costs since costs are reported by site, not unit. The actual peer size was not increased.

Table 4-5 La Cygne 1 Peer Units					
Unit Name	**State**	**MW_{gross}**	**Online**	**Design**	**FGD?**
Allen S King 1	MN	598.4	1968	BW	None
Baldwin 1	IL	623.1	1970	BW	None
Baldwin 2	IL	634.5	1973	BW	None
Big Stone 1	SD	456	1975	BW	None
Coyote 1	ND	450	1981	BW	Yes
Edgewater 4	WI	330	1969	BW	None
George Neal North 1	IA	147.1	1964	BW	None
Kammer 1	WV	237.5	1958	BW	None
Kammer 2	WV	237.5	1958	BW	None
Kammer 3	WV	237.5	1959	BW	None

Table 4-5 (cont.)
La Cygne 1 Peer Units

Unit Name	State	MW_{gross}	Online	Design	FGD?
Kincaid 1	IL	659.7	1967	BW	None
Kincaid 2	IL	659.7	1968	BW	None
MR Young 1	ND	235	1970	BW	None
MR Young 2	ND	439	1977	BW	Yes
New Madrid 1	MO	600	1972	BW	None
New Madrid 2	MO	600	1977	BW	None
Paradise 1	KY	704	1963	BW	Yes
Paradise 2	KY	704	1963	BW	Yes
Paradise 3	KY	1,150.2	1970	BW	None
Powerton 6	IL	892.8	1975	BW	None
Secondary (Included)					
Coffeen 2	IL	616.5	1972	BW	None
Merrimack 1	NH	113.6	1960	BW	None
Merrimack 2	NH	345.6	1968	BW	None
Sioux 1	MO	549.8	1967	BW	None
Sioux 2	MO	549.8	1968	BW	None
TH Allen 1	TN	330	1958	BW	None
TH Allen 2	TN	330	1959	BW	None
TH Allen 3	TN	330	1959	BW	None

Peer Group Selection Criteria Analysis — La Cygne 1 Peer Group

With all of the peer groups with the exception of La Cygne 1, I used size as a selection criterion. Because of La Cygne 1's unique design, I included all of the units of a similar design — all cyclone boilers. As a result, some units that were much larger as well as much smaller were included in order to include a sufficient number of units.

In order to validate my analysis, I used statistical techniques to determine how differences in capacity (size of the unit) would affect my analysis. My analysis uses three statistical techniques for validating the peer selection — analysis of means, analysis of variance, and analysis of sample size. Specifically, capacity versus O&M in $/kW are tested in order to validate the peer selection.

Table 4-6 provides information regarding the standard error, range of values, as well as means and standard deviations.

Table 4-6
Statistics for Selected Peer Group for Capacity of Unit

	Capacity	O&M in $/kW
La Cygne 1 Statistics		
Mean	893.4	23.8574
Standard Error	-	0.854117
Median	893.4	23.67536
Mode	893.4	#N/A
Standard Deviation	-	2.562352
Standard Variance	-	6.565647
Range	-	6.500835
Minimum	893.4	21.00098
Maximum	893.4	27.50181
Count	9	9
Confidence Level (95.0%)	-	1.969599
Peer Statistics:		
Mean	471.7606061	26.5886
Standard Error	14.2145425	1.127122
Median	450	22.92047
Mode	330	28.31811
Standard Deviation	244.9689897	19.42447
Sample Variance	60009.80591	377.31
Range	1090.2	253.0401
Minimum	60	11.55965
Maximum	1150.2	264.5997
Count	297	297
Confidence Level (95.0%)	27.97436336	2.218188

Analysis of Variance

The analysis of variance shown in Table 4-6 indicates that, when comparing the KCPL unit variance with that of the chosen peer group the two data sets are not statistically different. The test validates the chosen peer selection.

Analysis of Means

My concern is that the capacity of La Cygne is different than the mean of the capacity of the peer group. When comparing O&M in $/kW, the analysis of means indicates that the KCPL mean is within the mean of the chosen peer group. In the case of O&M, my statistical analysis found that the means are statistically equal.

Sample Size Analysis

In this analysis, I validate the number of observations used to define the peer group selection and the number of time series observations from 1989 through 1998. I use the following formula for determining sample size for a confidence interval for μ, the peer group mean.

A sample size:

$$n = \left(\frac{z_{\alpha/2}\sigma}{B} \right)^2$$

provides $100(1-\alpha)$ percent confidence that $\bar{x}$ (the sample mean) is within (the interval defined by) B units of the population mean μ.

Solving for B, I determined the confidence interval from the number of observations in my peer selection:

$$B = \frac{z_{\alpha/2}\sigma}{\sqrt{n}}$$

In the case of the La Cygne 1 peer group, there are 33 units, multiplied by nine years, or 297 observations. For a 99.9% degree of confidence, $z_{\alpha/2} = z_{0.025} = 3.090$, and in the case of O&M in $/kW:

$$B = \frac{3.090 * 26.5886}{\sqrt{297}} = 3.483$$

Using the above equations, I calculated that the confidence interval occurs between 30.07 and 23.11. In the case of La Cygne 1, the mean value for O&M of 23.86 is within the statistically determined confidence interval. The data suggest that the number of observations is adequate to determine a statistically viable peer group.

Statistical Validity of La Cygne 1 Peer Group

In this analysis, the peer group selected for KCPL La Cygne 1 is analyzed to statistically validate the criteria used for the peer selection. All of the tested statistics, with the exception average capacity (which was the reason for validating the capacity of the peer group), indicate that the selected peer group is correct and able to statistically benchmark KCPL's La Cygne 1 unit.

4.3.4 Montrose Peers

Table 4-7 provides all of the peer units for Montrose, the location, size, year on line, design, and if the unit has FGD equipment.

Table 4-7
Montrose Peer Units

Unit Name	State	MW_{gross}	Online	Design	FGD?
Chesapeake 4	VA	239.4	1962	CE	None
Dickerson 1	MD	196	1959	CE	None
Dickerson 2	MD	196	1960	CE	None
Dickerson 3	MD	196	1962	CE	None
Dunkirk 3	NY	218	1959	CE	None
Dunkirk 4	NY	218	1960	CE	None
John Sevier 1	TN	200	1955	CE	None
John Sevier 2	TN	200	1955	CE	None
John Sevier 3	TN	200	1956	CE	None
John Sevier 4	TN	200	1957	CE	None
Joppa 5	IL	183.4	1955	CE	None
Joppa 6	IL	183.4	1955	CE	None
Kingston 5	TN	200	1955	CE	None
Kingston 6	TN	200	1955	CE	None
Kingston 7	TN	200	1955	CE	None
Kingston 8	TN	200	1955	CE	None
Kingston 9	TN	200	1955	CE	None
Naughton 1	WY	163.2	1963	CE	None
Shawnee 10	KY	175	1956	CE	Yes
Shawville 3	PA	187.5	1959	CE	None
Shawville 4	PA	187.5	1960	CE	None

4.3.5 Wolf Creek Peers

Table 4-8 provides the NRC design peer group units that I used to evaluate the performance of Wolf Creek.

Table 4-8
Wolf Creek Peers

Unit	State	Rating MW_{gross}	Online	Design
Beaver Valley 2	PA	923	Dec-87	Westinghouse 3-loop
Braidwood 1	IL	1,225	Aug-88	Westinghouse 4-loop
Braidwood 2	IL	1,225	Nov-88	Westinghouse 4-loop
Byron 1	IL	1,225	Oct-85	Westinghouse 4-loop
Byron 2	IL	1,225	Sep-87	Westinghouse 4-loop
Callaway 1	MO	1,236	Jan-85	Westinghouse 4-loop
Catawba 1	SC	1,205	Jul-85	Westinghouse 4-loop
Catawba 2	SC	1,205	Sep-86	Westinghouse 4-loop
Comanche Peak 1	TX	1,215	Sep-90	Westinghouse 4-loop
Comanche Peak 2	TX	1,215	Sep-93	Westinghouse 4-loop
Diablo Canyon 1	CA	1,137	Jun-85	Westinghouse 4-loop
Diablo Canyon 2	CA	1,164	Apr-86	Westinghouse 4-loop
McGuire 1	NC	1,221	Dec-81	Westinghouse 4-loop
McGuire 2	NC	1,221	Mar-84	Westinghouse 4-loop
Millstone 3	CT	1,253	May-86	Westinghouse 4-loop
Seabrook	NH	1,197	Sep-90	Westinghouse 4-loop
Sequoyah 1	TN	1,221	Jul-81	Westinghouse 4-loop
Sequoyah 2	TN	1,221	Jun-82	Westinghouse 4-loop
Shearon Harris 1	NC	951	Jun-87	Westinghouse 3-loop
South Texas Project 1	TX	1,311	Sep-88	Westinghouse 4-loop
South Texas Project 2	TX	1,311	Jul-89	Westinghouse 4-loop
Summer 1	SC	963	Jan-84	Westinghouse 3-loop
Vogtle 1	GA	1,215	Jun-87	Westinghouse 4-loop
Vogtle 2	GA	1,215	Jun-89	Westinghouse 4-loop
Watts Bar 1	TN	1,270	Jun-96	Westinghouse 4-loop

4.3.6 Issues Associated with KCPL System Peers

In order to address the sections of the GST complaint that involve the entire KCPL system, I evaluated the entire KCPL system as an aggregate. The best way to conduct this evaluation would be if I were able to benchmark all of the KCPL generating units to other utilities with similar systems. After researching this possibility, I found that the number of similar systems is not sufficient and I would have to make too many adjustments for the comparison to be valid. Thus, I took the aggregate of all of the KCPL plants and compared it to the aggregate of all the peer group plants. There are several issues associated with conducting an analysis using an aggregated system from five different peer groups. Issues include:

First, the number of peers for each group should be relatively comparable such that there is equal weighting for all the units. The number of peers in each group is as follows:

- La Cygne 1 — 19
- Hawthorn — 31
- Montrose 1, 2, & 3 — 20 or 7 per unit
- Iatan/La Cygne 2 — 36 or 18 per unit
- Wolf Creek — 25.

This results in a gap of 7 to 31, which means that Montrose Units will be over represented while Hawthorn will be under represented.

Second, the comparison should be done to adjust for size difference, thus I use a $/kW measure for costs. There is no measure to compensate for size for the equivalent availability factor (EAF) and the forced outage rate (FOR) analysis.

The only plants included in the KCPL system were the base load plants analyzed in this report. No peaking units were included.

4.4 TIME PERIOD OF EVALUATION

For each performance measure, I analyzed the three-year rolling average because this smoothes out year-to-year variations which are primarily due to refueling and major maintenance outages. This also provides a trend analysis. I analyzed data from 1989 to 1998 (when available). I do not have cost data for the coal peer units for 1998.

I use a ten-year time period to reduce statistical variation, which is more prominent for shorter time periods. My analysis attempts to reduce this effect. In other words, longer time periods are better because one year of poor performance can overshadow many years of good performance.

5. COAL UNIT PRODUCTION — EQUIVALENT AVAILABILITY FACTOR AND FORCED OUTAGES

The greatest concern raised in the GST complaint was the availability of the units. I evaluated the EAF of the KCPL units compared to the peers to address these issues. I can evaluate production performance with several different measures including capacity factor (design electrical rating), capacity factor (maximum dependable rating), and availability factor. I chose EAF as the best measure of production for units in the United States. This is because of the effects of load following and the effect of light loading on performance as discussed below.

The second greatest concern raised in the GST complaint was the forced outage rate of the KCPL system. Thus I evaluated the FOR of the KCPL units compared to the peers. In addition, I analyzed the forced outages that are significant events defined as those outages that are greater than two months in duration. I chose this as significant outage criteria because the Hawthorn incident in September 1998 lasted more than two months but less than three months (83 days).

In this section, I address the following issues:

- EAF and FOR data sources
- specific issues related to EAF
- analysis of KCPL EAFs versus industry EAFs
- analysis of KCPL FORs versus industry FORs
- analysis of significant forced outage events.

5.1 EAF AND FOR DATA SOURCES

For peer units, reserve shutdown factors, EAF, and FOR were calculated using data reported to North American Reliability Council — Generating Availability Data System (NERC GADS). Most of the larger generating units and many smaller ones in the United States report data to NERC; however, the data is confidential for each unit. NERC cannot provide the information for specific units and can only provide data as an aggregate group or as an anonymous unit. Thus, for the KCPL units, I used data reported to me by KCPL which is the same data reported to NERC.

5.2 EAF SPECIFIC ISSUES

NERC GADS uses the following equation to calculate EAF:

$$\text{EAF} = \frac{\text{Available Hours} - \text{Equiv. Planned Derated Hours} + \text{Equiv. Unplanned Derated Hours} + \text{Equiv. Seasonal Derated Hours}}{\text{Period Hours}}$$

Because of the way EAF is calculated, there are three specific issues must be addressed, including:

- the effect of load following on EAF
- the effect of reporting of deratings on EAF
- the effect of unit rating on EAF.

5.2.1 Effect of Load Following on EAF

One common measure of generating unit performance is capacity factor (CF). The CF for a unit in a time period is the ratio of the power actually produced to the power than could have been produced had the unit operated perfectly. The CF for any unit over a long time period will inevitably be less than 100%, because of equipment failures and periodic maintenance. In addition, many plants produce less power than the equipment is capable of. Reduced output can result from reserve shutdowns (when a unit could operate but is shut down because more economic generation is available), load following (when a unit operates at reduced load because it is able to quickly increase load if other generation is suddenly lost). For simplicity, I will refer to all these factors as load following.

The seven KCPL coal units are essentially all fully base loaded. That is, they are almost always operated at the maximum electric output of which the equipment was capable of at the time. Most of the peers load follow and/or provide spinning reserve. Moreover, many of the peers spend at least some time in reserve shutdown (although this amount of time is less than 10%). Thus, the CFs for most peers understate how the unit could have performed if it had been fully base loaded. The EAF is supposed to measure the CF that a unit could have achieved had it been fully base loaded. However, there are two problems with the use of EAFs — the treatment of reserve shutdowns and the performance of units that are lightly loaded.

Treatment of reserve shutdown. In the traditional calculation of an EAF (equation shown above), a unit is considered to be 100% available during those times it is in reserve shutdown. This implicitly assumes that the unit would have run perfectly during that time, had it not been on reserve. This is unrealistic. In the case of a unit that is on reserve all year, the EAF would be 100%. However, it is obvious that, had the unit actually been operated all year, it could not have achieved a 100% CF.

The effect of light loading on performance. A unit that is operated whenever it is available is obviously more valuable to a utility than a unit that is only operated some of the time. I would expect that a utility would spend more money on the more valuable units, and achieve better performance. In the past I have found that, on average, units that spend more than 20% or 30% of the year on reserve shutdown have poorer performance than other comparable units.

In past studies, I have found that units with high reserve shutdown factors had lower costs and poorer performance than other units. Therefore, my benchmarking was based on the units with low (less than 10%) reserve shutdown factors.

5.2.2 Effect of Reporting Derating on EAF

When EAF is calculated, it is assumed that at any given moment, the unit could have operated up to its rated power or the level determined by a reported derating, whichever is lower. The calculation is done by looking at the time a unit was operating, and subtracting the impact of all reported deratings (limitations on the power output of the unit due to equipment). If a utility does not report a derating, the calculated EAF will be higher than the CF that actually could have been achieved. Minor deratings are often not reported; so calculated EAFs are generally slightly higher than they should be.

5.2.3 Effect of Unit Rating on EAF

The reported rating for a unit should be the average output the unit could achieve throughout the year, with all equipment working normally. In this case, a unit that operated perfectly throughout the year would have a CF of 100%. However, some utilities report ratings that are either higher or lower than what the unit could actually achieve on average throughout the year.

5.2.4 EAF Calculations

For each peer group, I requested NERC to calculate the reserve shutdown factor for each unit for the time period 1989 to 1998. I eliminated all the peers with a reserve shutdown factor of greater than 10% on average throughout the period. This was used as the final screening for the peer groups.

5.3 EQUIVALENT AVAILABILITY ANALYSIS

EAF was calculated for the KCPL system and for each group. The data is presented as follows:

- Exhibit A-1 for KCPL system
- Exhibit B-1 for Hawthorn
- Exhibit C-1 for Iatan/ La Cygne 2
- Exhibit D-1 for La Cygne 1
- Exhibit E-1 for Montrose 1, 2, & 3

The bar graphs in these exhibits (as well as the exhibits provided for other performance measures) present the absolute value of the KCPL units compared to the average of the peer group units. The variation within the peer groups is also represented with a standard deviation error-bar. If the KCPL unit is within the standard deviation error-bar for any given three-year period, it is considered to be within "bounds" or within the two standard deviations that these bars represent.

The peer variation is measured by using a tolerance interval based on standard deviation. In general, a tolerance interval contains a specified percentage of the individual measurements in a peer group. It follows that the one, two, and three standard deviation intervals around the peer average are tolerance intervals containing, respectively, 68.26%, 95.44%, and 99.73% of the measurements in a normal distributed population. Using two times the standard deviation tolerance interval is a conservative practice.

When evaluated as a system aggregate, the equipment availability factor for the entire KCPL system has historically been above the industry average; however, since 1996, the KCPL system has been slightly below average. It is expected that performance of a system would eventually trend toward the industry average. The KCPL system average has always within 2% of the industry average and well within industry standards, as shown by Exhibit A-1. In addition, each individual base loaded unit has performed within industry standards and no cases of lower than standard performance were identified.

5.4 FORCED OUTAGE RATE

Forced outage rate (FOR is a good indicator of the amount of time that a unit is not available for unplanned events. Often a unit can be down for planned maintenance that is then reflected in EAF. However FOR measures the magnitude of the down time. FOR is calculated as follows:

$$FOR = \frac{Forced\ Outage\ Hours}{(Forced\ Outage\ Hours + Service\ Hours)}$$

I calculated FOR for each group and presented the data as:

- Exhibit A-2 for the KCPL system
- Exhibit B-2 for Hawthorn
- Exhibit C-2 for Iatan/ La Cygne 2
- Exhibit D-2 for La Cygne 1
- Exhibit E-2 for Montrose 1, 2, & 3.

The forced outage rate of the KCPL system has always been within a percentage point of the industry average as shown in Exhibit A-2. Each KCPL unit has been within industry standards for FOR with one exception in one year. This exception occurred at La Cygne 1, which is a cyclone boiler design with scrubbers. Problems associated with scrubbers can cause frequent forced and planned outages that will not necessarily occur at the peer units that do not have scrubbers. The majority of peers (as shown by Exhibit 4-5) for La Cygne 1 do not have scrubbers and would not be expected to have the same performance problems resulting from this additional equipment. Five of the eight KCPL units have been above industry standards in recent years and have had a relatively low forced outage rate.

5.5 SIGNIFICANT EVENT ANALYSIS

The GST complaint identified a significant forced outage at Hawthorn 5. Forced outages occur at generating stations for several different reasons. It is often difficult to determine the true cause of an event with the limited description that is provided with NERC GADS data. Thus, I do not attempt to determine what caused the forced outage. I provide the description of the events that have occurred at the peers and the description of the events that have occurred at the KCPL units as reported to NERC.

5.5.1 Significant Forced Outages at Hawthorn and Its Peers

Table 5-1 provides a description of all of the events that have occurred at the Hawthorn peer units since 1989, the date the event occurred, the name of the unit, and the number of hours the unit was down as a result of the event.

Table 5-1
Significant Forced Outages at Hawthorn peers

Date of Event	Duration in Hours	Unit Name	Description of Event
1/2/89	2,528.20	Baldwin 3	Gen stator bar leaves failed where H20 CLG SYS hose connects 22 stator bars
6/12/90	3,775.46	Baldwin 3	Generator motorized while on turning gear
9/30/91	912.18	Jim Bridger #2	Turbine overhaul of LP rotors caused by bearing damage. A burnt coil.
8/25/92	929.90	Morgantown #1	Unknown
11/16/92	1,120.31	Cheswick #1	MU trip due to clavert bus fire
6/4/93	1,181.23	Labadie #2	Generator transformer fire
4/8/96	2,210.93	Cayuga #2	Generator rotor grounds
5/8/98	805.91	Comanche #1	Exciter failure
6/1/98	826.61	Cayuga #2	U2 rotor winding ground

The only significant forced outage at Hawthorn during this time period occurred on September 3, 1998 and resulted in the unit being down for 1,986.6 hours. The event description provided to NERC was external superheater link tubing.

5.5.2 Significant Forced Outages at Iatan/ La Cygne 2 and Their Peers

Table 5-2 provides all of the significant forced outages that occurred at the Iatan/ La Cygne 2 peer units since 1989.

Table 5-2
Significant Events at Iatan/ La Cygne 2 Peers

Date of Event	Duration in Hours	Unit Name	Description of Event
4/24/89	1,857.21	Laramie River #1	Generator bar failures
10/22/90	1,321.86	Welsh #2	Tripped unit — shrouds came off 4 sections of turbine blades
2/19/91	1,604.93	Monticello #3	Unit tripped due to high voltage ARC in PT cabinet
4/22/93	910.88	East Bend #2	Circuit Breaker 1463 failed
1/1/94	12,707.41	Monticello #3	Planned outage time expired — planned outage time stack failure 11-14-93 made return to service impossible
1/22/94	915.75	Cardinal #3	Unknown
4/9/94	730.20	New Madrid	Lost blade on HP impulse wheel
2/21/95	937.50	Big Cajun II #3	Economizer area duct work collapsed started repairs
9/29/96	1,053.26	Thomas Hill #3	Boiler tube leak/generator ground
5/27/98	719.16	Louisa #1	Generator transformer high pressure fault
7/29/98	2,686.20	Monroe #2	Rotor windings

On November 29, 1993, a forced outage lasting 804 hours occurred at Iatan. The event description provided to NERC was "due to stator windings, bushings, and terminals". On July 2, 1997, a forced outage lasting 1,521 hours occurred at La Cygne 2 because of bearing problems.

5.5.3 Significant Forced Outages at La Cygne 1

Table 5-3 provides a listing of all the significant forced outages at the La Cygne 1 peers.

Table 5-3
Significant Forced Outages at La Cygne Peers

Date of Event	Duration in Hours	Unit Name	Description of Event
9/20/89	5813.59	Allen #3	Tripped generator neutral ground
8/27/90	822.16	Coffeen #2	200-2 superheater stop valve
4/9/94	730.20	New Madrid #1	Lost blade on HP impulse wheel
4/13/94	1507.00	Powerton #6	62 boiler/unit-6 trip due to fault in B phase of unit main power
9/17/95	1868.18	Sioux #1	Bus breaker failure turbine bus 1B led to unit trip
3/11/98	1855.35	Paradise #2	2A generator stator windings phase lead burnt up
10/12/98	1270.25	Kammer #1	Unknown

There have been two extended outages at La Cygne 1. The first occurred on March 2, 1991 and was listed as a boiler explosion or implosion that lasted 1,653 hours. The second occurred on July 31, 1995 that was due to scrubber problems that lasted 2,206 hours.

5.5.4 Significant Forced Outages at Montrose Peers

There were no significant forced outages at the Montrose peers during the time period. I postulate that there are a few of reasons for this. First, the number of peer units in the Montrose group is relatively small. Second, these units are older and tend to have most problems resolved. Third, because of the size of these units, utility operators would be more likely to bring the unit down for reserve shutdown allowing for time to resolve the problem.

Montrose 2 experienced two significant forced outages during the time period. One occurred on June 3, 1992 because of bearings and lasted for 1,098 hours. The second occurred on April 28, 1989 and lasted for 1,575 hours due to stator windings, bushings, and terminals. A significant forced outage also occurred at Montrose 3 on July 1, 1991 due to brushes and brush rigging. The duration was 784 hours.

5.5.5 Explosions at Plants around the World

Major events occur at generating stations as a result of equipment failure and human error. These occurrences, although unfortunate, are not uncommon. Over the past 16 months, the following major steam boiler explosions have occurred:

1. Six workers died and 14 were injured at Detroit Edison Co's 42 year old River Rouge Power Station, when the fuel was not fully isolated as a boiler was being shut down for annual inspection. This, according to investigators, allowed an explosive mixture of gas to accumulate in the firebox.

2. Three workers were killed and 42 injured in a hydrogen explosion at the FJ Gannon Station, built by Tampa Electric Company in 1957, when an access cover to a generator cooling system was prematurely opened during a maintenance outage.

3. A transformer oil fire crippled the 38 year old Northeastern Unit 2 owned by Public Service Co of Oklahoma.

4. At State Line LLC Unit 3, owned by Southern Energy Inc, Atlanta, GA, 17 were injured when electrical sparks from a transformer ignited coal dust near a conveyor belt. The 1950s vintage unit was undergoing an extensive overhaul at the time.

6. COSTS

In the United States, going-forward costs at generating stations are typically segregated into the following categories:

- non-fuel O&M costs
- fuel costs
- capital additions costs.

Analyzing these costs as an aggregate as well as separately reveals different kinds of information. In this report, I evaluate both the O&M costs with the fuel costs. At some of the KCPL units, a decision was made during plant design to spend more on maintenance in exchange for lower fuel costs. Thus, it is important to evaluate the two costs together. The GST complaint specifically addresses maintenance costs; thus, I address O&M costs without fuel as well.

6.1 TOTAL OPERATIONS & MAINTENANCE COSTS INCLUDING FUEL

For the KCPL units, fuel costs have been quite a bit lower than the industry while the O&M costs have been generally higher than the industry. In this section, I present the total O&M costs, which is the aggregate of O&M and fuel costs to provide a more complete picture of KCPL's total costs. Herein, I refer to the O&M plus fuel as total costs.

Costs are reported by the owners of the plants to FERC and compiled by Utility Data Institute (UDI). I convert all costs to year 1998 using CPI (Consumers Price Index) as shown in Table 6-1.

Table 6-1
CPI Conversion

Year	Annual CPIu	Conversion Index
1989	124	0.760736196
1990	130.7	0.801840491
1991	136.2	0.835582822
1992	140.3	0.860736196
1993	144.5	0.886503067
1994	148.2	0.909202454
1995	152.4	0.934969325
1996	156.9	0.962576687
1997	160.5	0.984662577
1998	163	1

Costs reported to FERC are generally the total for a plant, no matter how many units the plant comprises. Therefore, I analyzed each plant as a separate entity and divided the total costs by the number of units at the plant to obtain the cost per unit for that plant. I accounted for differences in the sister units by eliminating plants with sister units that do not fit design, vintage, and size criteria.

I calculated O&M in $/kW for each group and presented the data as:

- Exhibit A-3 for KCPL system
- Exhibit B-3 for Hawthorn
- Exhibit C-3 for Iatan/ La Cygne 2
- Exhibit D-3 for La Cygne 1
- Exhibit E-3 for Montrose 1, 2, & 3.

Costs per kW provide an adjustment for size of the unit relative to the size of the peers.

I also provide the total O&M costs including fuel in millions of dollars as shown in the following:

- Exhibit A-4 for KCPL system
- Exhibit B-4 for Hawthorn
- Exhibit C-4 for Iatan/ La Cygne 2
- Exhibit D-4 for La Cygne 1
- Exhibit E-4 for Montrose 1, 2, & 3.

Total O&M costs are also provided in millions of dollars. Although costs per kW can account for size differences, when the peer plants are close in size, the total cost per year become a more accurate measure of the expected costs of a plant. This is because every plant has costs that it incurs regardless of its size. With a $/kW measure, larger plants tend to be rewarded for an economy of scale while smaller plants are penalized. Yet, the lower costs may be due to operating efficiencies and not necessarily economies of scale.

The analysis of total O&M costs (O&M plus fuel) shows that the KCPL system costs are less than the industry average. Both the industry average and the KCPL costs are trending downward during the 1990s. The detailed analysis is provided in Exhibit A-3.

As shown by Exhibit B-3, the total costs of Hawthorn are lower than the peer units. Hawthorn costs are trending downward as are the peer group costs. Exhibit C-3 shows that the total costs for Iatan and La Cygne 2 are lower than the industry average and are trending downward as are the peer group costs.

La Cygne 1 has scrubbers, which can add as much as 50% to O&M costs; therefore, costs would be expected to be higher than the peers that do not have scrubbers. At the start of the analysis period, the total costs for La Cygne 1 (Exhibit D-3) were at the industry average; however throughout the time period total costs have trended downward as did the peer group total costs.

The Montrose costs (Exhibit E-3) have been historically lower than the peer group total costs. These units are smaller and older and efficiencies have already been realized, thus it is not surprising that the costs have been relatively stable. The peer group costs have trended downward throughout the period.

6.2 NON-FUEL OPERATIONS & MAINTENANCE COSTS

I reviewed the non-fuel operations and maintenance (O&M) costs, that is, total O&M costs for everything except fuel.

I calculated O&M in $/kW for each group and presented the data as:

- Exhibit A-5 for KCPL system
- Exhibit B-5 for Hawthorn
- Exhibit C-5 for Iatan/ La Cygne 2
- Exhibit D-5 for La Cygne 1
- Exhibit E-5 for Montrose 1, 2, & 3.

I also provide the non-fuel O&M costs in millions of dollars as shown in the following:

- Exhibit A-6 for KCPL system
- Exhibit B-6 for Hawthorn

- Exhibit C-6 for Iatan/ La Cygne 2
- Exhibit D-6 for La Cygne 1
- Exhibit E-6 for Montrose 1, 2, & 3.

6.3 FUEL COSTS

I calculated fuel cost for each group and presented the data as:

- Exhibit A-6 for KCPL system
- Exhibit B-6 for Hawthorn
- Exhibit C-6 for Iatan/ La Cygne 2
- Exhibit D-6 for La Cygne 1
- Exhibit E-6 for Montrose 1, 2, & 3.

Fuel costs are provided as a cost per kWh.

6.4 CAPITAL ADDITIONS COSTS

Capital costs are reported to FERC as the total capital invested in the plant net of retirements. In other words, each time a generating station eliminates equipment or depreciates equipment because it is replaced, a reduction in capital is taken. Thus, it is very difficult (if not impossible) to evaluate the capital additions costs from year to year. Sometimes, it is possible to look at a long duration time period; however, I found that many of the peers record negative capital additions more often than not. This is consistent with other efforts to benchmark capital costs.

I was also provided with capital data from the EUCG; however, not enough of the peer units were included in the data to make an appropriate analysis. Thus I was not able to address capital additions costs. I did not pursue this analysis any further.

7. WOLF CREEK ANALYSIS

To evaluate the performance of Wolf Creek, I conducted an analysis very similar to those of the coal units. I evaluated the same performance criteria as for the coal units:

- EAF
- FOR
- Significant Events (forced outages greater than 60 days)
- Total O&M costs with fuel costs
- O&M without fuel costs
- Fuel Costs.

My evaluation is also based on the same time period.

One significant difference between my analysis of Wolf Creek and my analysis of the coal units is the data source. Data for nuclear power plants tend to be more available because regulatory reporting requirements ensure industry standardization. This standardization imposed upon the nuclear industry by the NRC improves the accuracy of comparative analysis. In order to benchmark the performance of Wolf Creek, I used PHB Hagler Bailly's proprietary Operating Plant Experience Code (OPEC) database that includes performance and costs of all U.S. nuclear operating plants. The source of this data is the NRC for production and UDI for costs.

7.1 EQUIVALENT AVAILABILITY FACTOR

The same equation for EAF was used to compare Wolf Creek to its peers as was used for the coal units. This equation is as follows:

$$EAF = \frac{\text{Available Hours} - \text{Equiv. Planned Derated Hours} + \text{Equiv. Unplanned Derated Hours} + \text{Equiv. Seasonal Derated Hours}}{\text{Period Hours}}$$

Typically, nuclear power units, including all the units in the Wolf Creek peer group, do not load follow or derate unless absolutely necessary. Thus, load following issues associated with EAF for coal units are not an issue for nuclear units.

The three-year rolling average of EAF for Wolf Creek compared to its peers are provided in Exhibit F-1. As shown by this analysis, Wolf Creek has consistently operated at a level above its peers and has provided KCPL customers with a reliable and efficient source of capacity and energy.

7.2 FORCED OUTAGE RATE

I used the same equation to analyze FOR for Wolf Creek and its peers as was used for the coal units. This equation is as follows:

$$FOR = \frac{\mathit{Forced\ Outage\ Hours}}{(\mathit{Forced\ Outage\ Hours} + \mathit{Service\ Hours})}$$

The three-year rolling average of FOR for Wolf Creek compared to its peers is provided in Exhibit F-2. Forced outages at Wolf Creek have been infrequent and have been trending downward. FOR performance for Wolf Creek is exceptional.

7.3 SIGNIFICANT FORCED OUTAGES

I reviewed all of the forced outages that have occurred at Wolf Creek and its peers since 1989. Table 7-4 provides a list of all the significant forced outages (forced outages greater than 60 days). These narratives are from licensee event reports (LERs), which are filed to the Nuclear Regulatory Commission by the utilities.

Table 7-4
Significant Forced Outages for Wolf Creek Peers

Unit	Event Date	Outage Hours	Narrative
McGuire 1	3\7\1989	1,507.1	The unit was manually tripped from 100% power due to a single tube rupture in a steam generator. Tube rupture leakage averaged approximately 540 gpm. Unplanned radioactivity releases occurred when 3 of 4 steam generator safety and/or power-operated relief valves (PORVs) opened for approximately 3 minutes and when steam generator activity was released through the unit vent by way of the condensate air ejectors. Planned releases occurred during steam generator blowdown that was necessary for the recovery procedure. All radioactivity releases were within Tech Spec limits. Equipment malfunctions after the trip include the following: (1) steam generator PORV SV-7 opened below setpoint (no details given). (2) Reactor coolant letdown isolation to regenerative heat exchanger valve did not operate properly (no details given). (3) A control rod data B failure occurred on the digital rod position indication. (4) steam generator blowdown radiation monitor did not initiate automatic blowdown isolation as expected because the demineralized water flush flow was valved into the radiation monitor, which diluted the activity. (LER# 8904)
South Texas Project 1	11\24\1990	1,233.2	Electrical arcing from the failed stator coil end turn to the stator cooling water system manifold caused the generator running ground fault relay to actuate. (LER# 8905). The governor running ground fault relay actuation caused a reactor trip from 100% power. Feedwater isolated and auxiliary feedwater actuated. (LER# 9025)
Braidwood 1	12\30\1990	1,455.6	The main generator tripped in turn causing a turbine trip and a reactor trip from 98% power. Auxiliary feedwater pumps auto-started to restore steam generator level. Onsite power supply disturbances caused by the main generator trip caused area radiation monitors to generate a containment ventilation isolation signal. (LER# 9023)

Table 7-4
Significant Forced Outages for Wolf Creek Peers

Unit	Event Date	Outage Hours	Narrative
Millstone 3	7\25\1991	4,542.7	Outage continuation to replace worn service water pipes.
McGuire 1	1\16\1992	811.7	The plant was shut down from 97% power due to a tube leak in a steam generator. Two tube leaks were found. (LER# 9201)
Sequoyah 1	3\19\1992	699	Outage continuation to replace cracking steam generator nozzles.
Millstone 3	9\30\1992	876.4	The plant technical specifications required the plant to shutdown because inoperability of the supplemental leak collection and release system (SLCRS) and problems with the auxiliary building ventilation system (ABVS) interaction with the SLCRS. General system operability issues included (1) Ability of auxiliary building filter system to assist SLCRS in drawing down within 50 seconds of diesel generator breaker closure, (2) Ability of system to operate automatically, and (3) Reliability of an operation. Specific equipment operability issues included: (1) Instability and cycling problems, (2) Time delays in SLCRS fan circuitry, (3) Lack of an interlock on the charging pump and component cooling water area ventilation supply and exhaust fans, and (4) Inability to detect failure of a filter fan. (LER# 9222)
South Texas Project 1	2\4\1993	8,586.0	The unit remained shutdown to address NRC concerns. NRC approval was required for restart.
Sequoyah 1	3\2\1993	880.7	The unit was shut down to evaluate the extraction steam piping condition following an extraction steam line rupture event on Unit 2. (LER# 2-9301)
Sequoyah 2	3\2\1993	5,599.4	The unit remained shutdown following an extraction steam line rupture event to evaluate the condition of the extraction steam piping. (LER# 9301)
McGuire 1	8\22\1993	839.9	Unit shutdown due to steam generator tube leak.
McGuire 1	1\22\1994	789.2	Shutdown to repair a 100 gallon/day tube leak in a steam generator.
Braidwood 2	4\5\1994	1,289	The main power transformer had a sudden pressure and a differential current trip, which caused a turbine trip followed by a reactor trip. The cause of the event was a high side B phase fault on the 2E main power transformer. The fault was initiated at the transformer and damage was extensive to the transformer. (LER# 9403)
Millstone 3	4\4\1996	19,713	The unit remained shutdown to address NRC concerns.

Table 7-4
Significant Forced Outages for Wolf Creek Peers

Unit	Event Date	Outage Hours	Narrative
McGuire 2	5\22\1996	922.2	The reactor tripped from 99% power due to low reactor coolant system flow. The X phase in reactor coolant pump motor stator shorted to ground, causing the motor circuit breakers to trip on high ground fault current. The upper end turns of the stator windings were not sufficiently secured to the stator surge ring. This allowed excess movement and vibration in the windings and degradation of the insulating material on the windings. This degradation resulted in the ground fault. (LER# 9603)
Beaver Valley 2	10\21\1996	1,009	Forced refueling outage extension to repair leaking seals on residual heat removal pumps.
Seabrook	12\16\1997	777.5	The plant remained shutdown as required by the technical specifications due to both trains of Control Room Emergency Makeup Air and Filtration Subsystems being inoperable. Train B was declared inoperable due to a compressor failure and Train A was declared inoperable due to degrading system performance. (LER# 9718)
Beaver Valley 2	12\16\1997	1,035.8	With the unit at 100% power, it was determined that the Control Room Emergency Ventilation System did not meet single active failure criteria as specified in the plant design bases. Review determined that certain A Train component failures could induce failures in B Train. As a result of this information, the unit went to hot shutdown. (LER# 9708)
Beaver Valley 2	2\19\1998	4,676.2	Outage continuation for repairs to three leaking pressurized operating relief valves.
Seabrook	6\11\1998	720.2	Both trains of the Control Room Air Conditioning (CBA) subsystem were declared inoperable due to degraded refrigerant compressor performance. At the time of the event, the plant was operating at 90% power and was subsequently shutdown to Cold Shutdown. (LER# 9806)

Wolf Creek has not had a significant forced outage during the time period.

7.4 OPERATIONS & MAINTENANCE COSTS

I reviewed the O&M costs for Wolf Creek using the same methodology as I did for the coal units. The issues associated with costs are the same since the data source (UDI) is the same. The only significant difference is that nuclear plant costs are typically more consistent for units because stations tend to have the same design, vintage, and size units at the same site. There are a few exceptions to this such as Millstone 3 where Millstone 1 and 2 are quite different nuclear plants. However, Millstone 3 reports costs separately from Millstone 1 and 2.

I calculated O&M including fuel and presented the data in two different formats. First, Exhibit F-3 provides the total cost/kW and F-4 provides the total annual cost in millions. The O&M costs without fuel are also provided in the same formats and are provided in Exhibit F-5 and F-6. Fuel costs are provided as a $/MWh and are documented in Exhibit F-7.

8. CONCLUSIONS

Although generating stations can be evaluated using several different performance measures, I limit the scope of this project to only include issues raised by the GST complaint. Thus, it should be noted that this analysis does not provide an overall evaluation of the stations. I only address the areas where the generating stations are cited for poor performance. All generating stations perform better in some performance measures and worse in other measures. By only evaluating measures where the generating stations have been cited as having poor performance, I am not able to report the many performance measures where the generating stations may have performed well.

The KCPL system operates within industry standards when considering standard performance criteria included in this report.

When considering equivalent availability factor and forced outage rate, KCPL units performed above the industry average in the early 1990s and trended toward the industry average (as expected) in recent years. With regard to forced outage rate, five of eight of the KCPL units have performed better than the industry average in recent years.

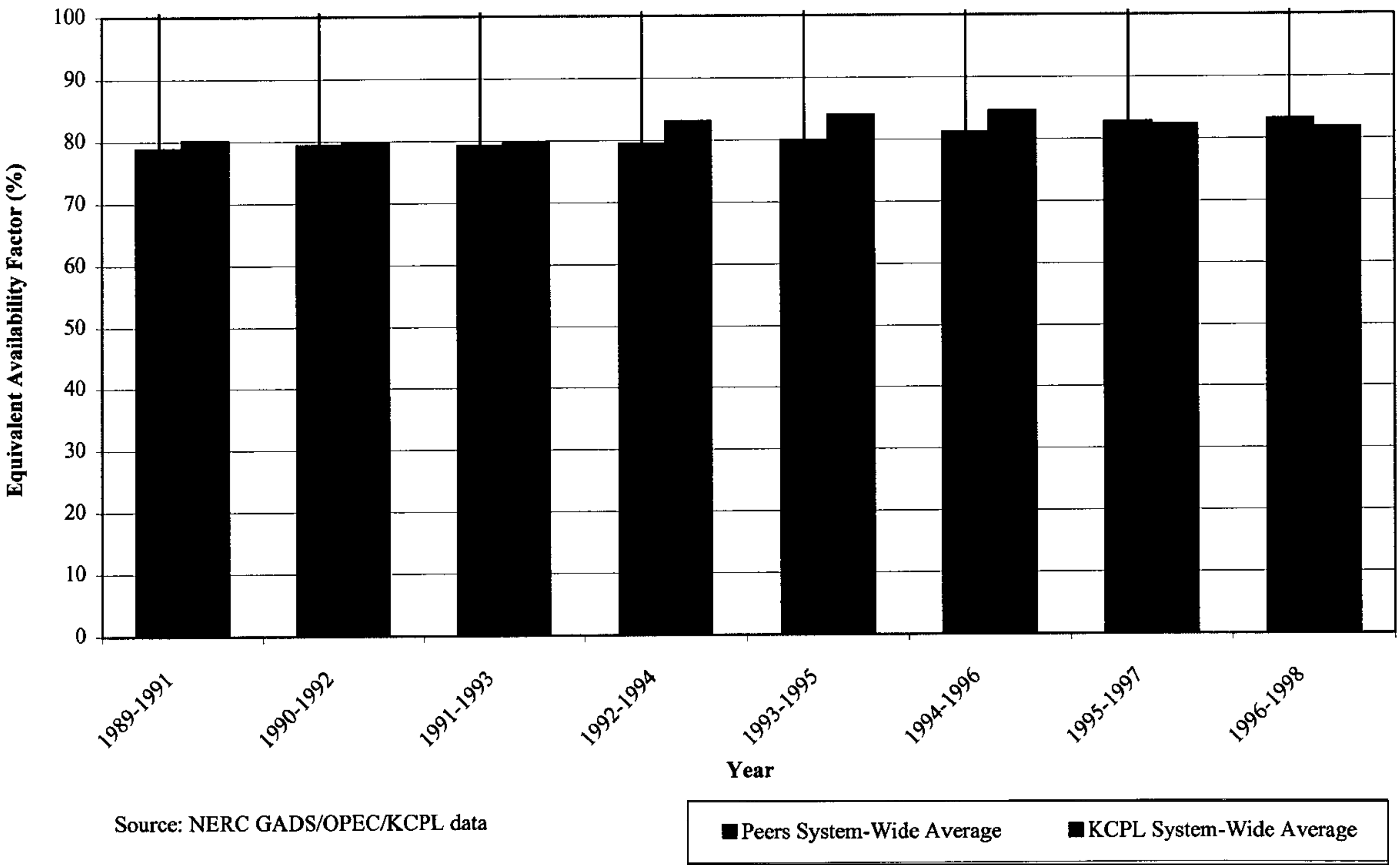
When considering operating and maintenance costs alone, the KCPL units have been more expensive than the industry average. The industry average has been trending downward as the KCPL costs have. However, when you include fuel costs as part of the operating and maintenance costs, KCPL costs are quite low and trending downward as is the industry average.

I also evaluated outages that are greater in length than 60 days. I found that the number of outages experienced by the KCPL units is no different than the number of significant outages experienced at the KCPL peer units.

Overall, I found the KCPL units to operate within industry standards.

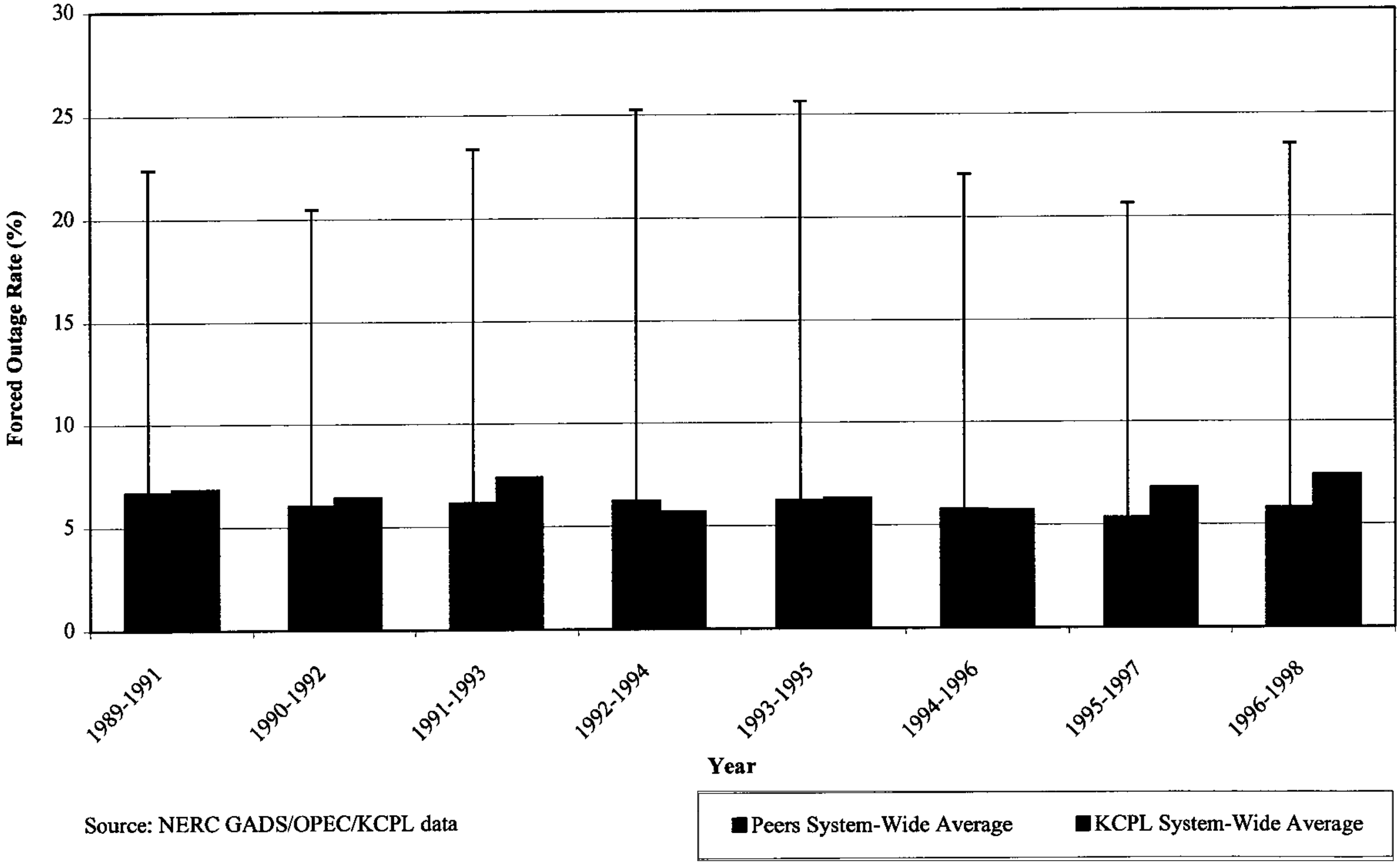
APPENDIX A
SYSTEM-WIDE DATA

Exhibit A-1
System-Wide Three-Year Rolling Average Equivalent Availability Factor



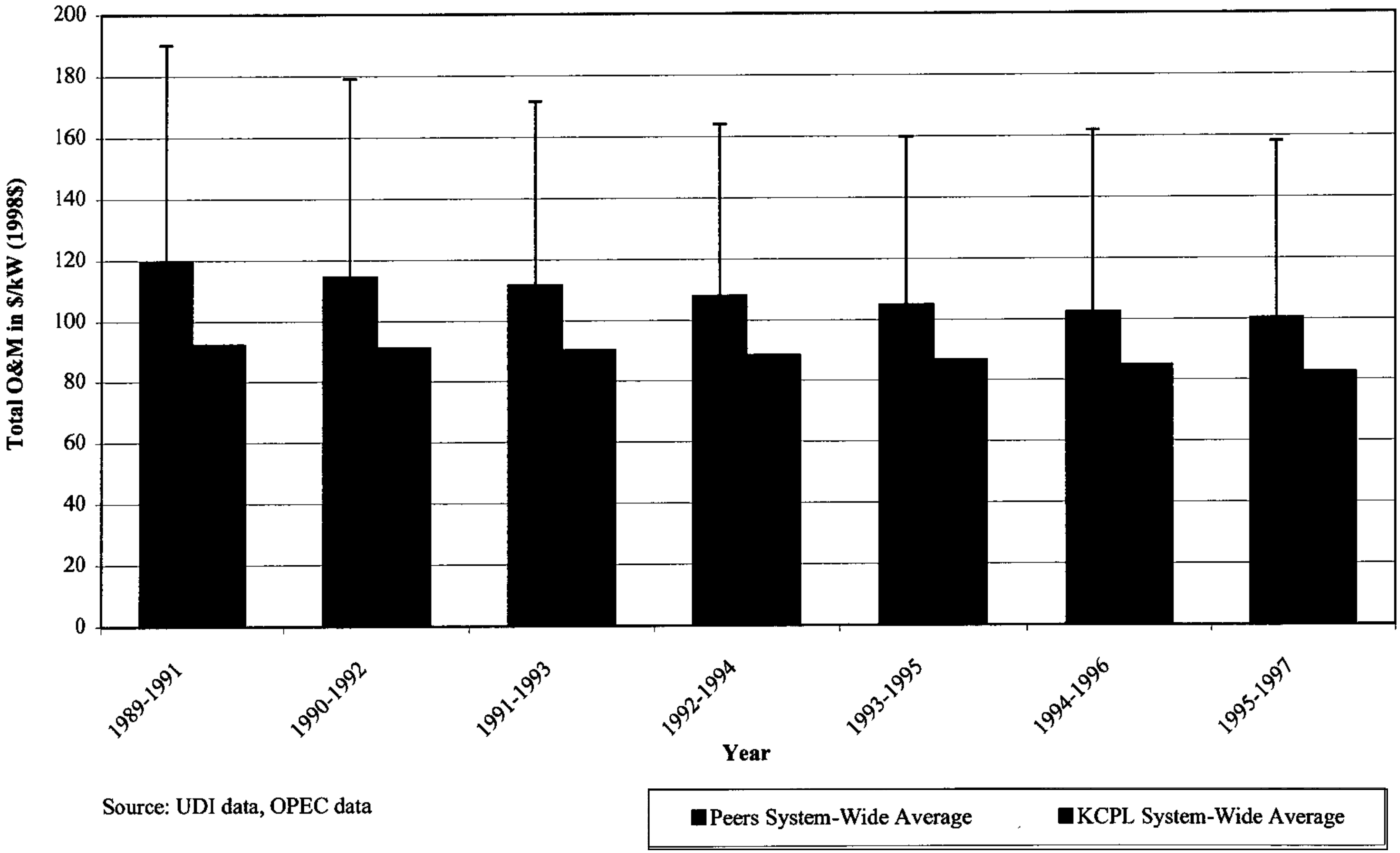
Source: NERC GADS/OPEC/KCPL data

Exhibit A-2
System-Wide Three-Year Rolling Average Forced Outage Rate



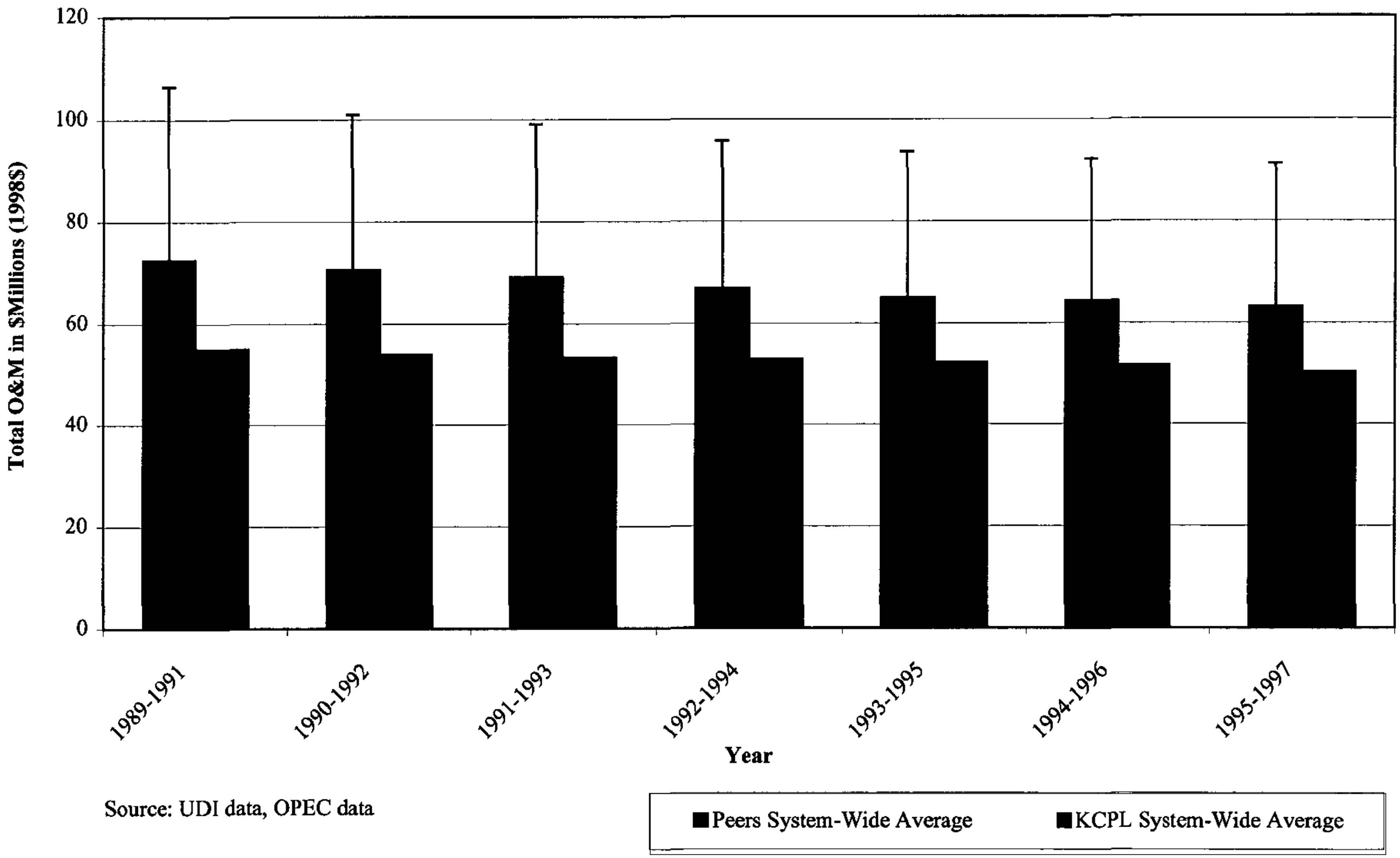
Source: NERC GADS/OPEC/KCPL data

Exhibit A-3
System-Wide Three-Year Rolling Average Total O&M Plus Fuel Costs in $/kW (1998$)



Source: UDI data, OPEC data

Exhibit A-4
System-Wide Three-Year Rolling Average Total O&M Plus Fuel Costs in $Millions (1998$)



Source: UDI data, OPEC data

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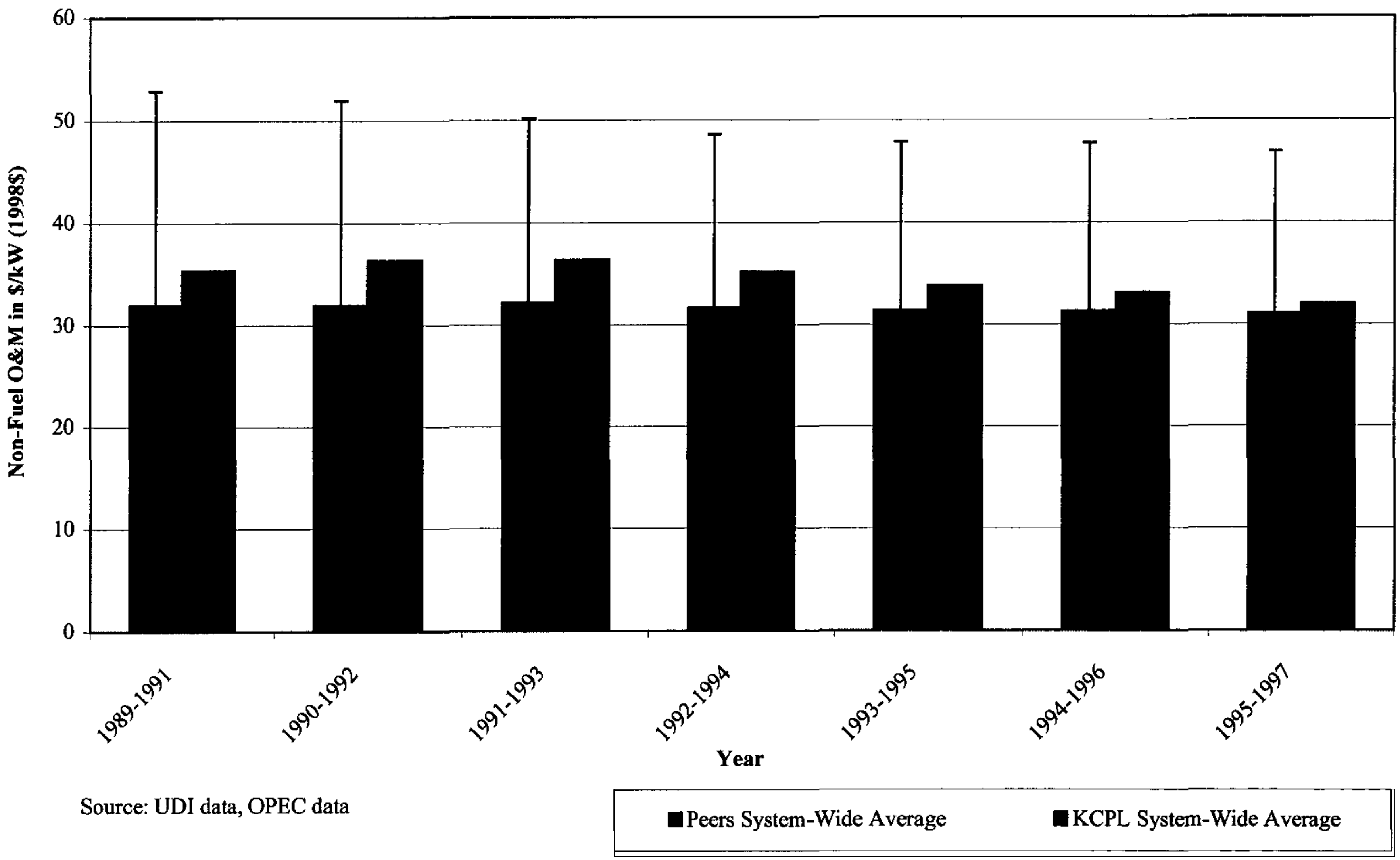
Exhibit A-5
System-Wide Three-Year Rolling Average Non-Fuel O&M Costs in $/kW (1998$)



Source: UDI data, OPEC data

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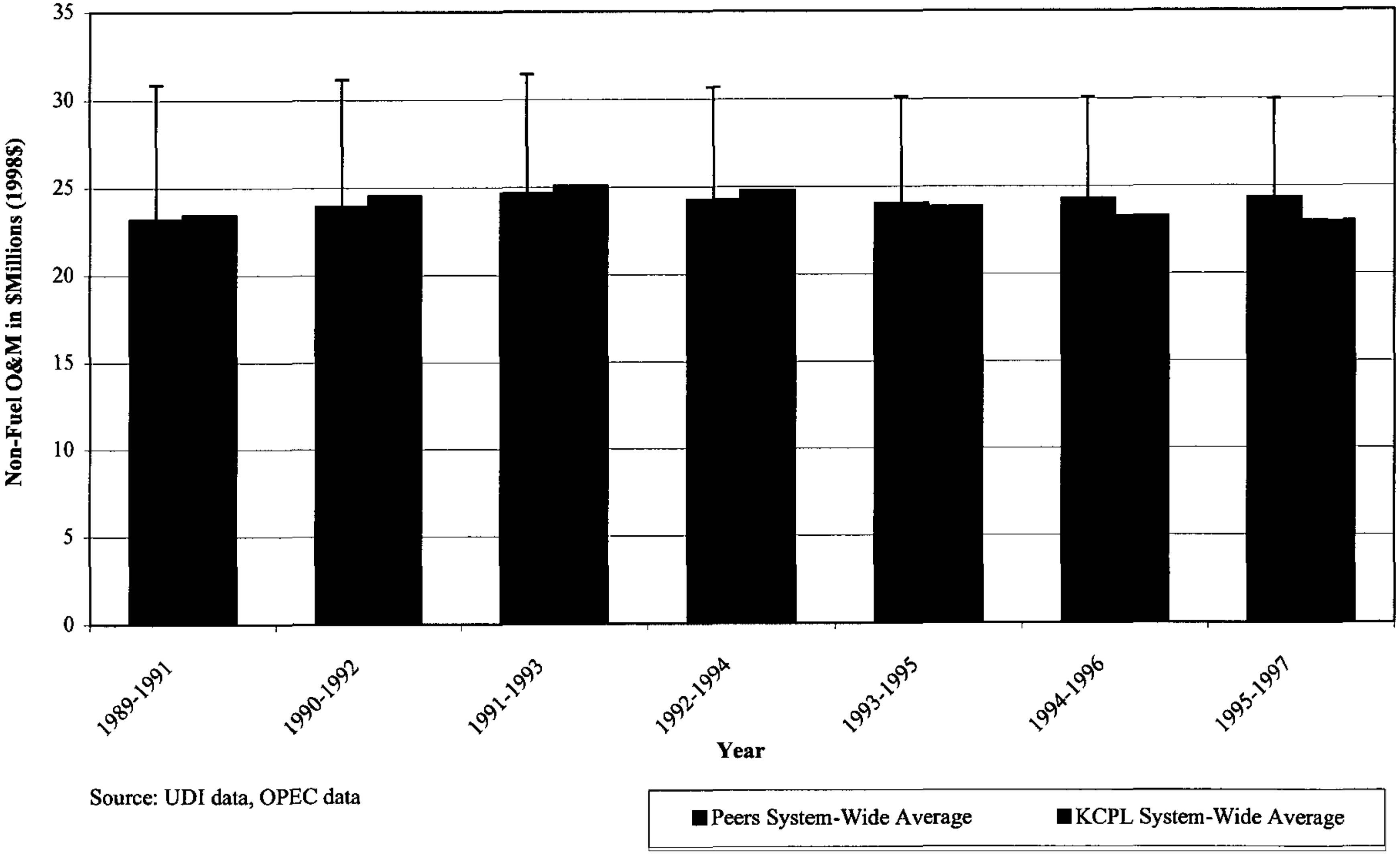
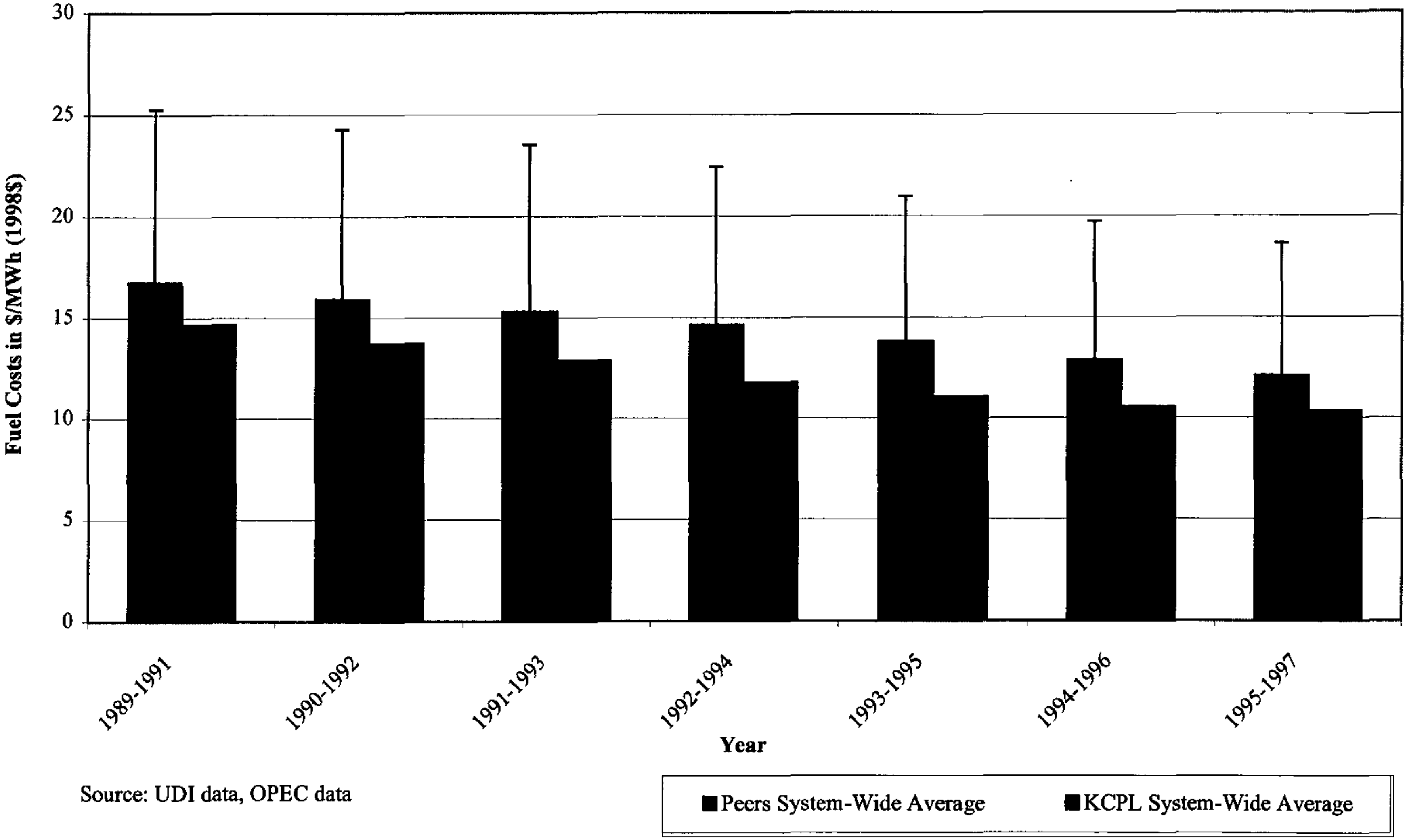
Page 57

Exhibit A-6
System-Wide Three-Year Rolling Average Non-Fuel O&M Costs in $Millions (1998$)



Source: UDI data, OPEC data

Exhibit A-7
System-Wide Three-Year Rolling Average Fuel Costs in $/MWh (1998$)



Source: UDI data, OPEC data

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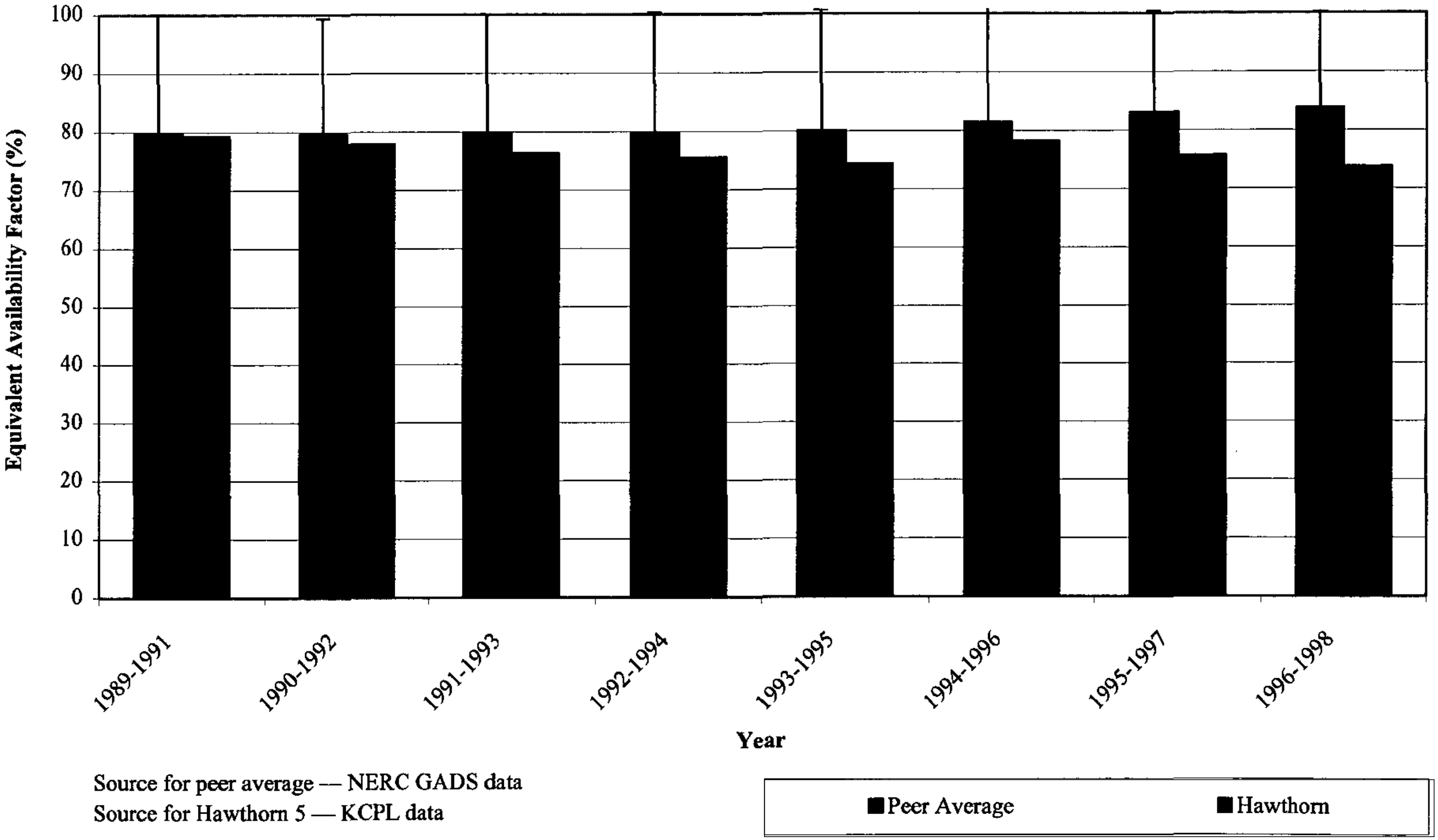
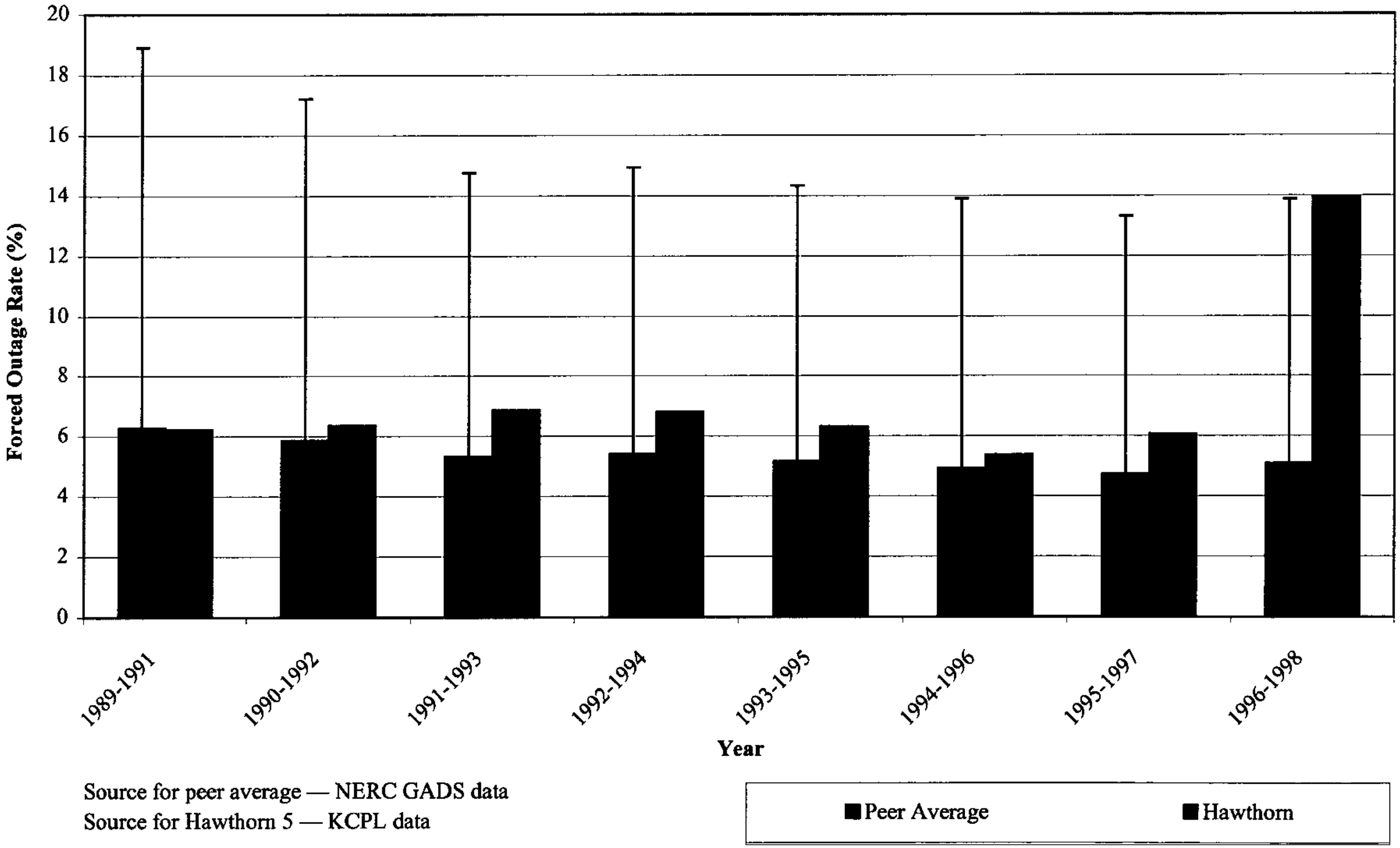
APPENDIX B
HAWTHORN

Exhibit B-1
Three-Year Rolling Average Equivalent Availability Factor
Hawthorn and Peers



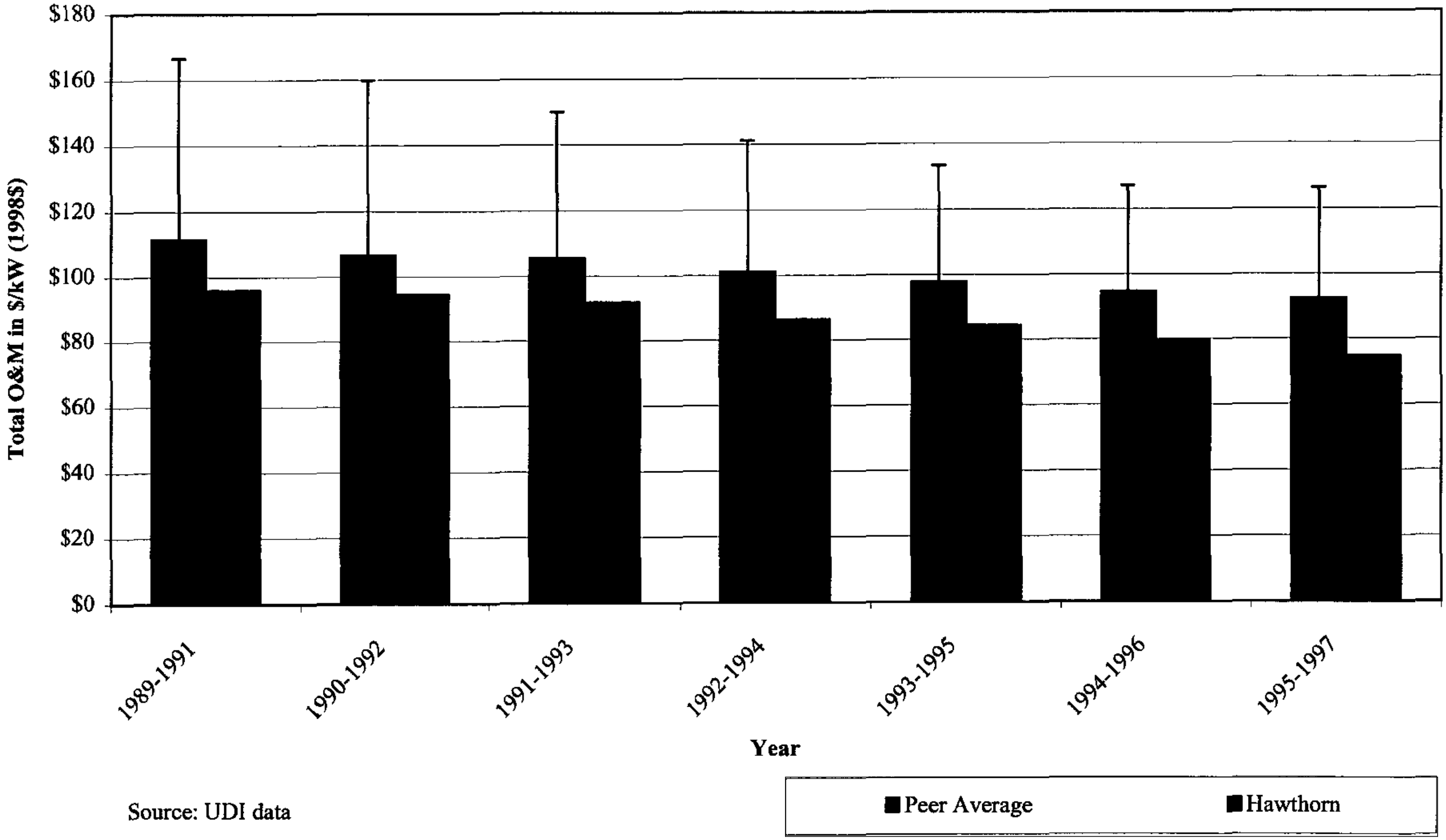
Source for peer average — NERC GADS data
Source for Hawthorn 5 — KCPL data

Exhibit B-2
Three-Year Rolling Average Forced Outage Rate
Hawthorn and Peers



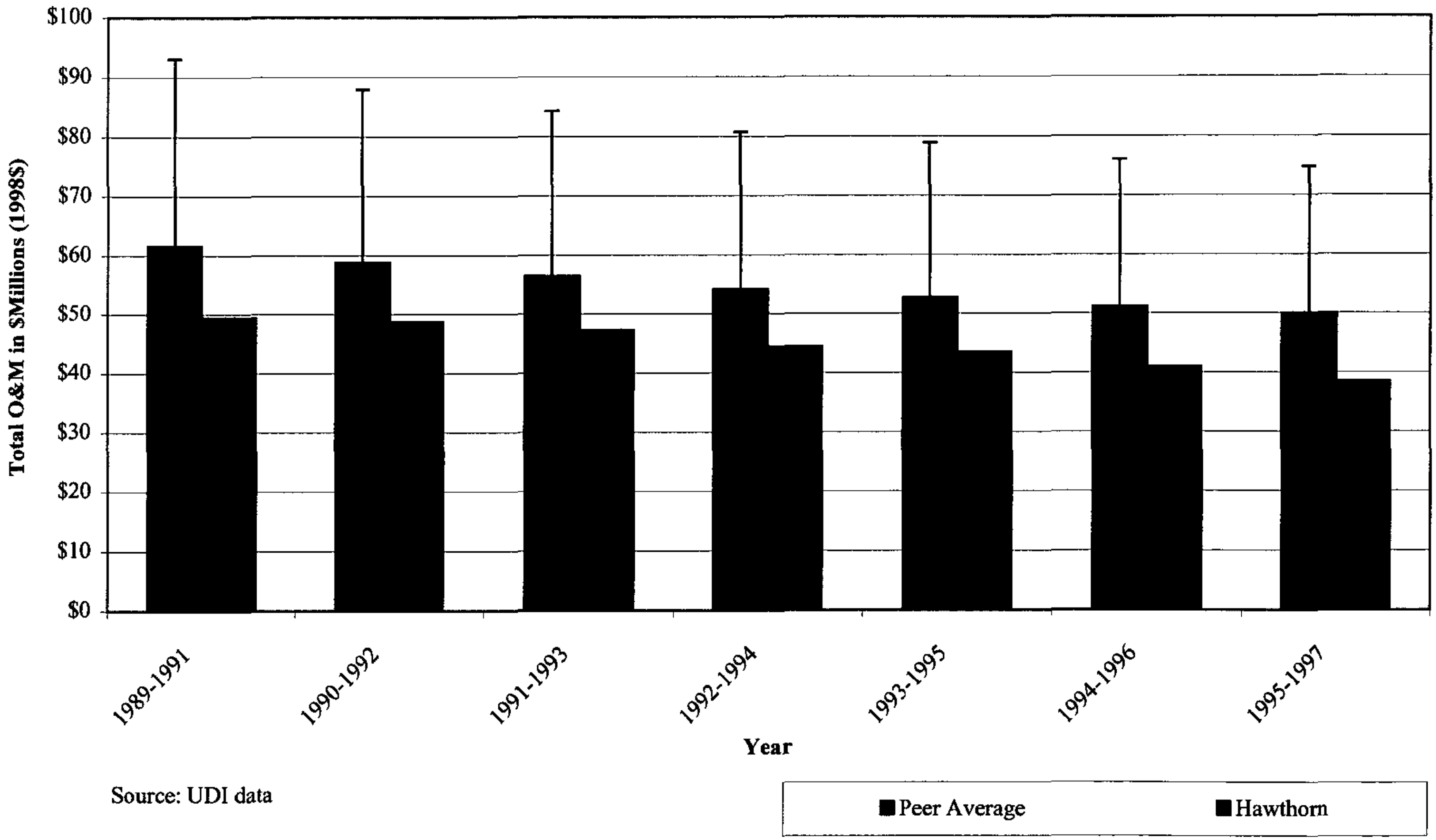
Source for peer average — NERC GADS data
Source for Hawthorn 5 — KCPL data

Exhibit B-3
Three-Year Rolling Average Total O&M Plus Fuel Costs in $/kW (1998$)
Hawthorn and Peers



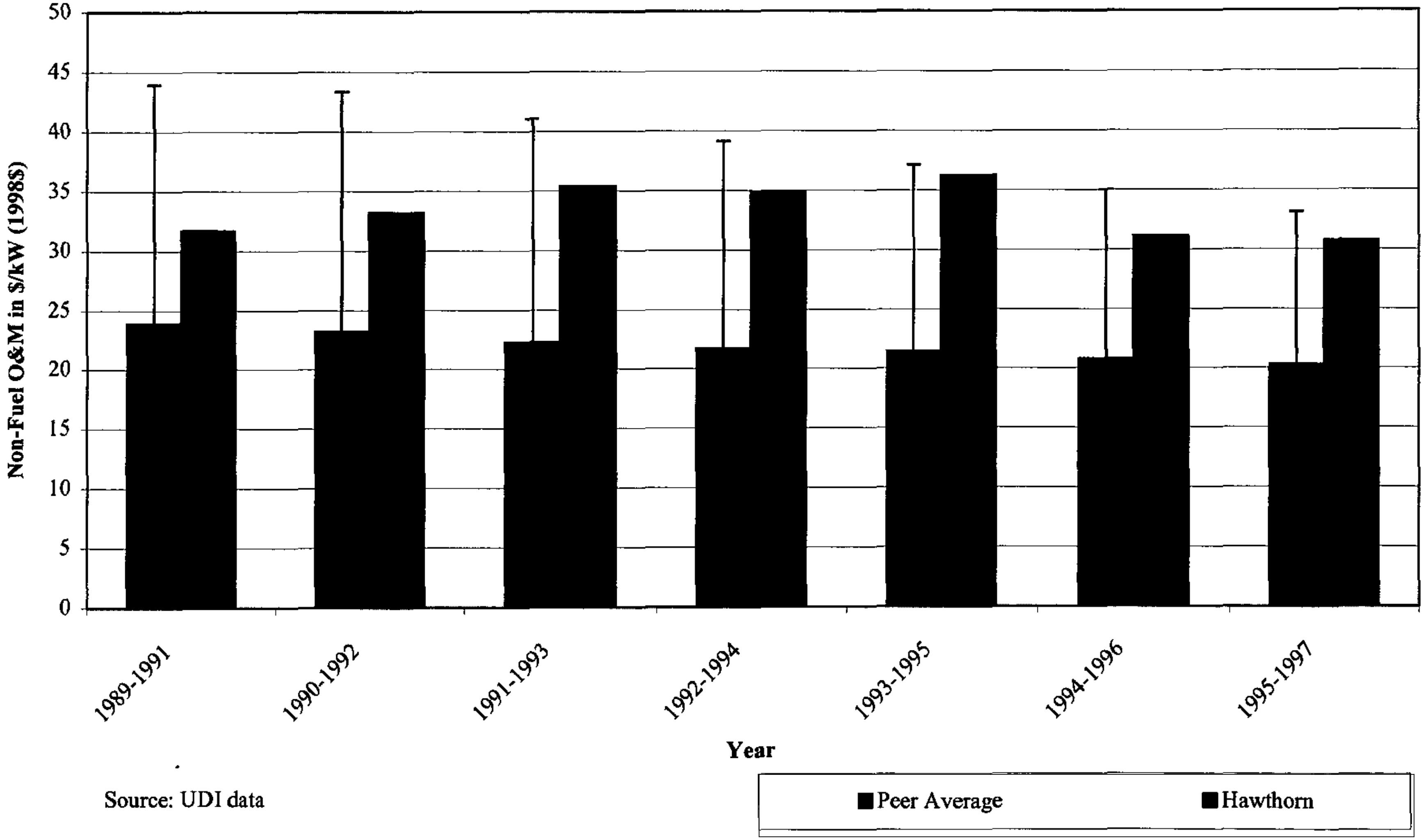
Source: UDI data

Exhibit B-4
Three-Year Rolling Average Total O&M Plus Fuel Costs in $Millions (1998$)
Hawthorn and Peers



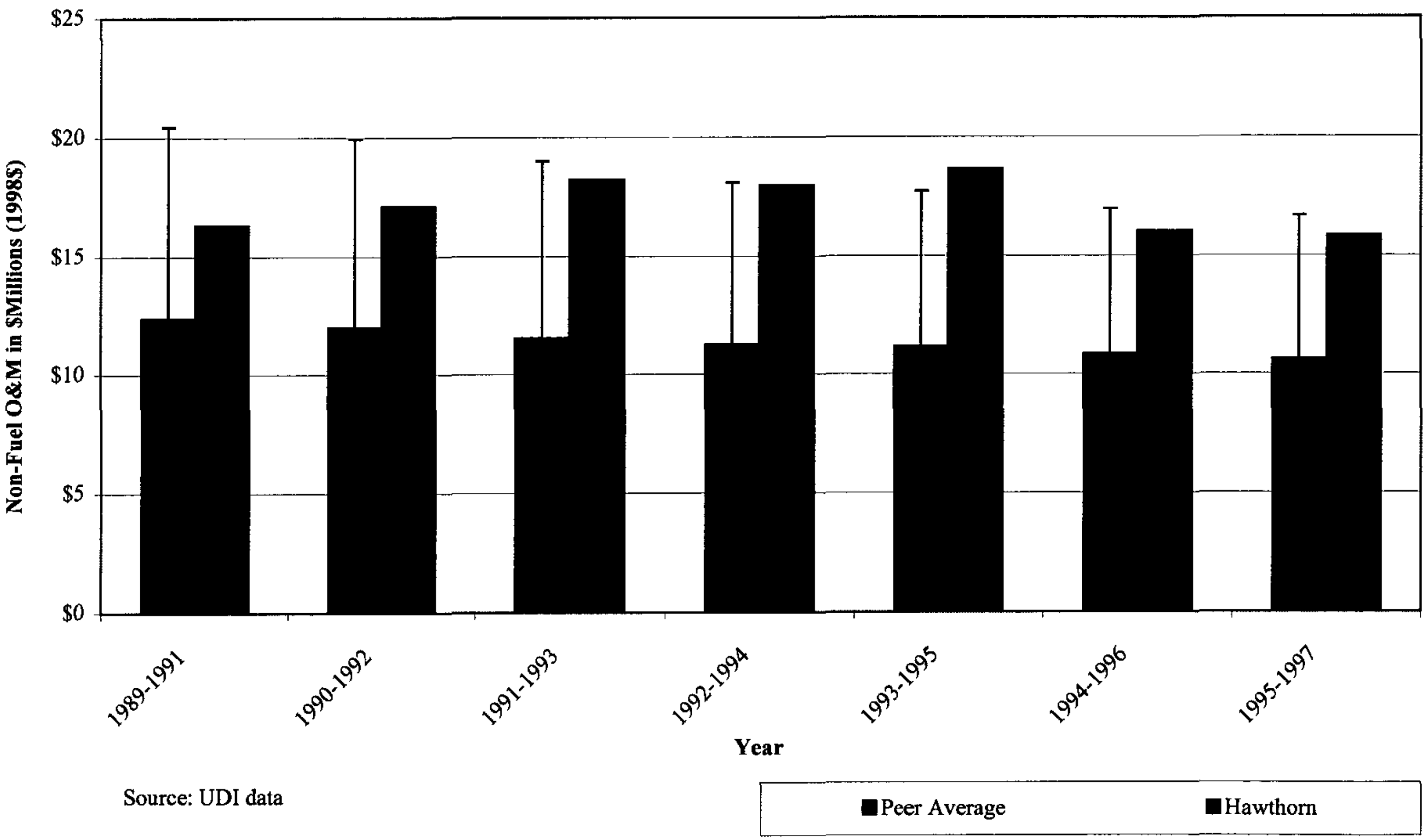
Source: UDI data

Exhibit B-5
Three-Year Rolling Average Non-Fuel O&M Costs in $/kW (1998$)
Hawthorn and Peers



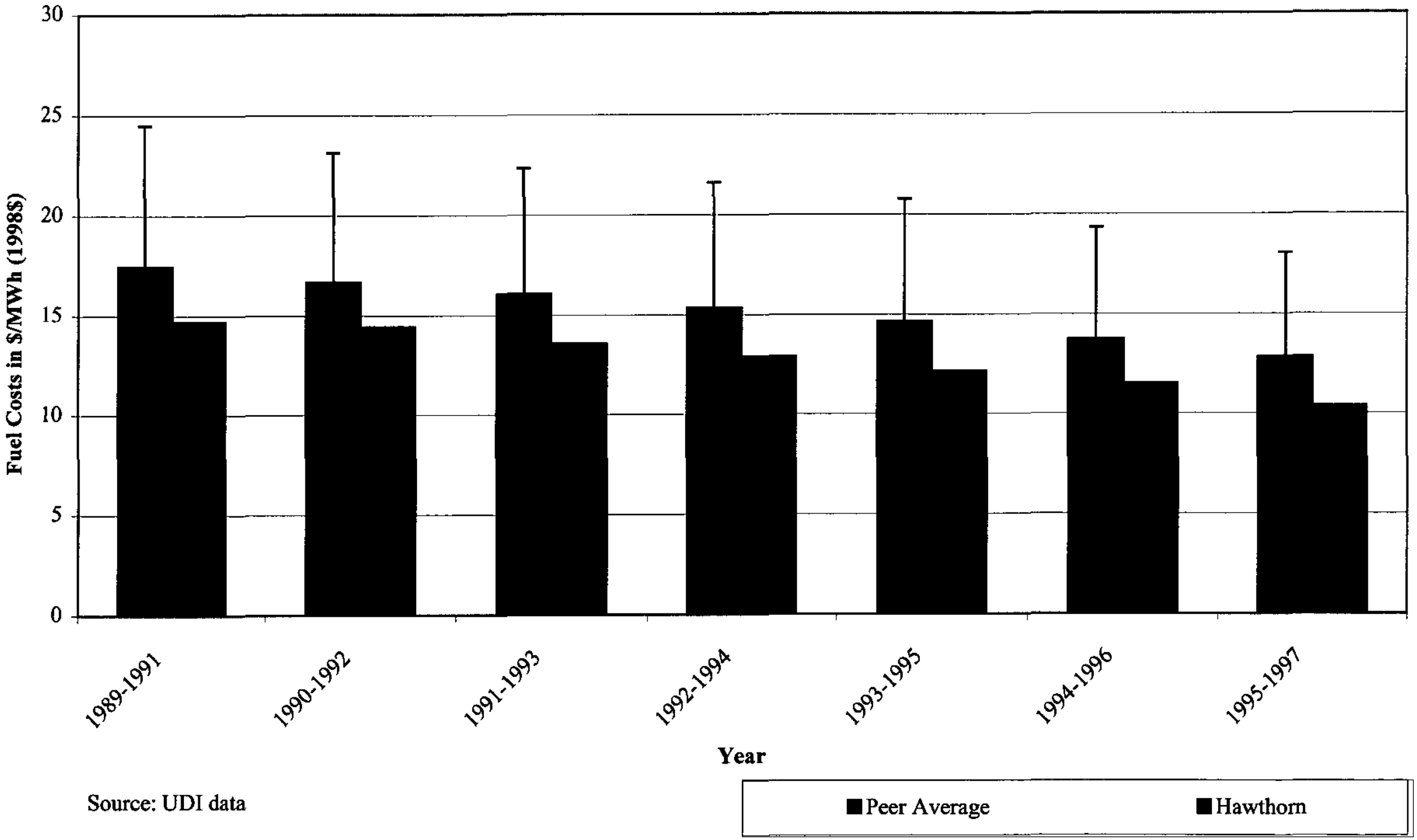
Source: UDI data

Exhibit B-6
Three-Year Rolling Average Non-Fuel O&M Costs in $Millions (1998$)
Hawthorn and Peers



Source: UDI data

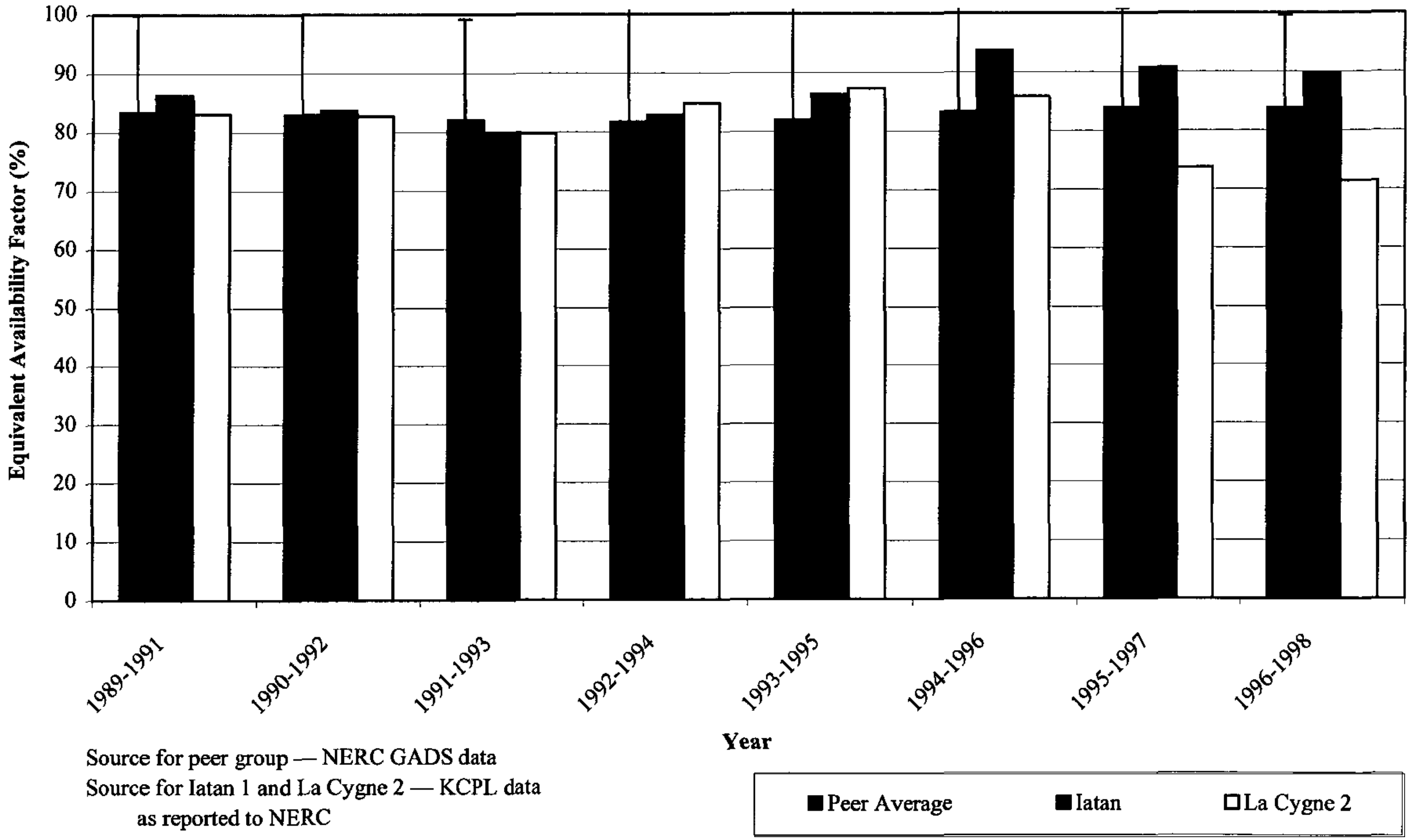
Exhibit B-7
Three-Year Rolling Average Fuel Costs in $/MWh (1998$)
Hawthorn and Peers



Source: UDI data

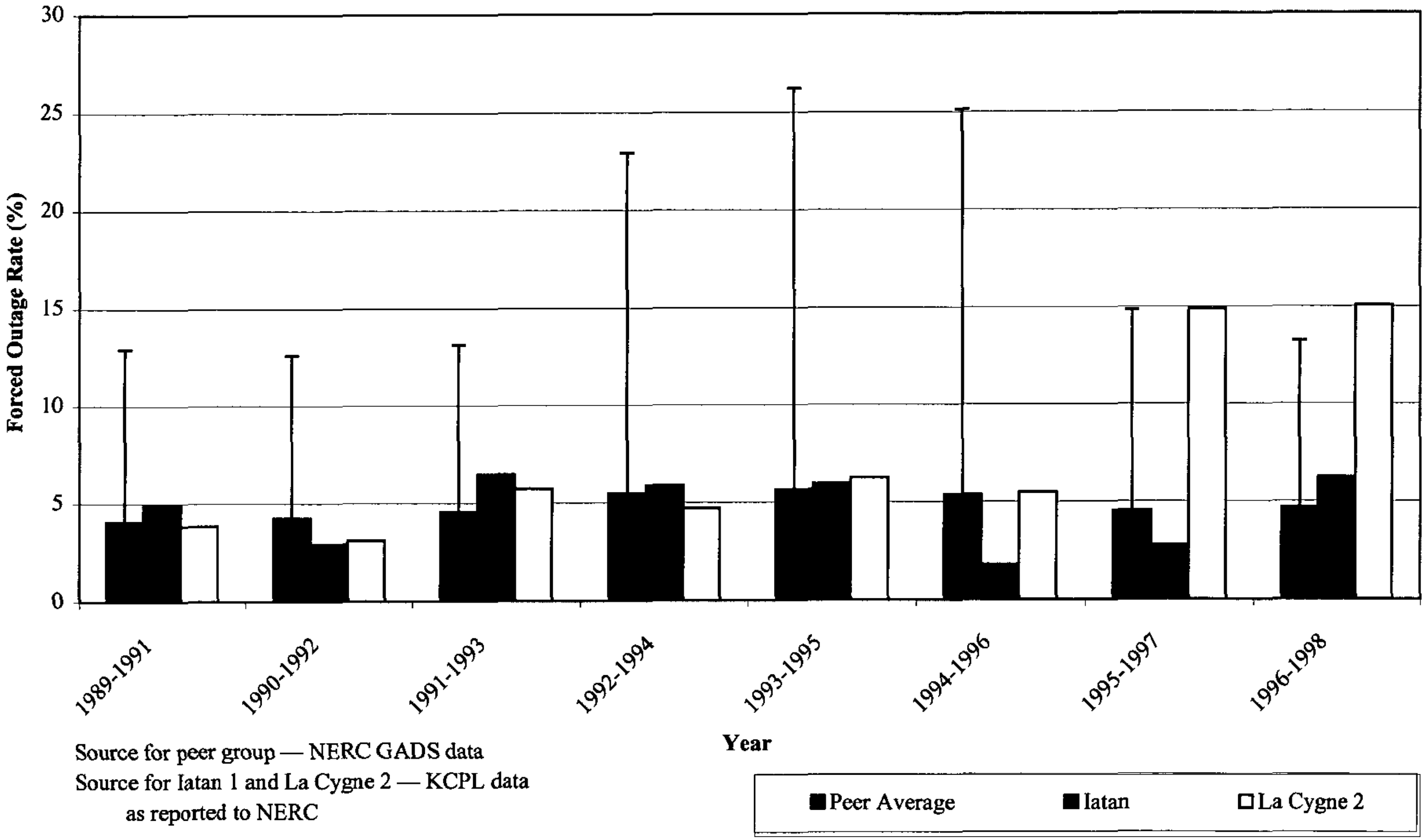
APPENDIX C
IATAN & LA CYGNE 2

Exhibit C-1
Three-Year Rolling Average Equivalent Availability Factor
Iatan & La Cygne 2 and Peers



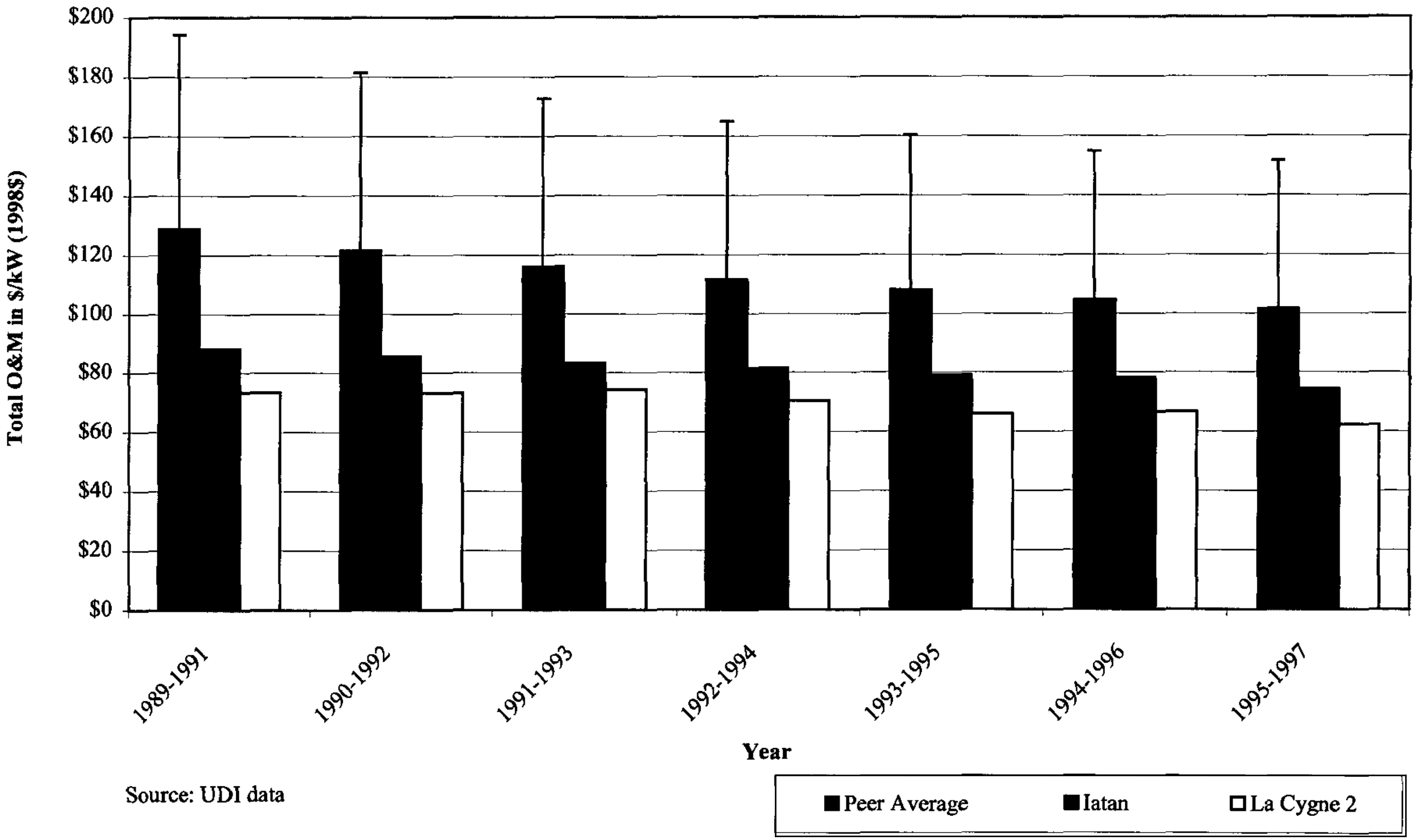
Source for peer group — NERC GADS data
Source for Iatan 1 and La Cygne 2 — KCPL data
as reported to NERC

Exhibit C-2
Three-Year Rolling Average Forced Outage Rate
Iatan & La Cygne 2 and Peers



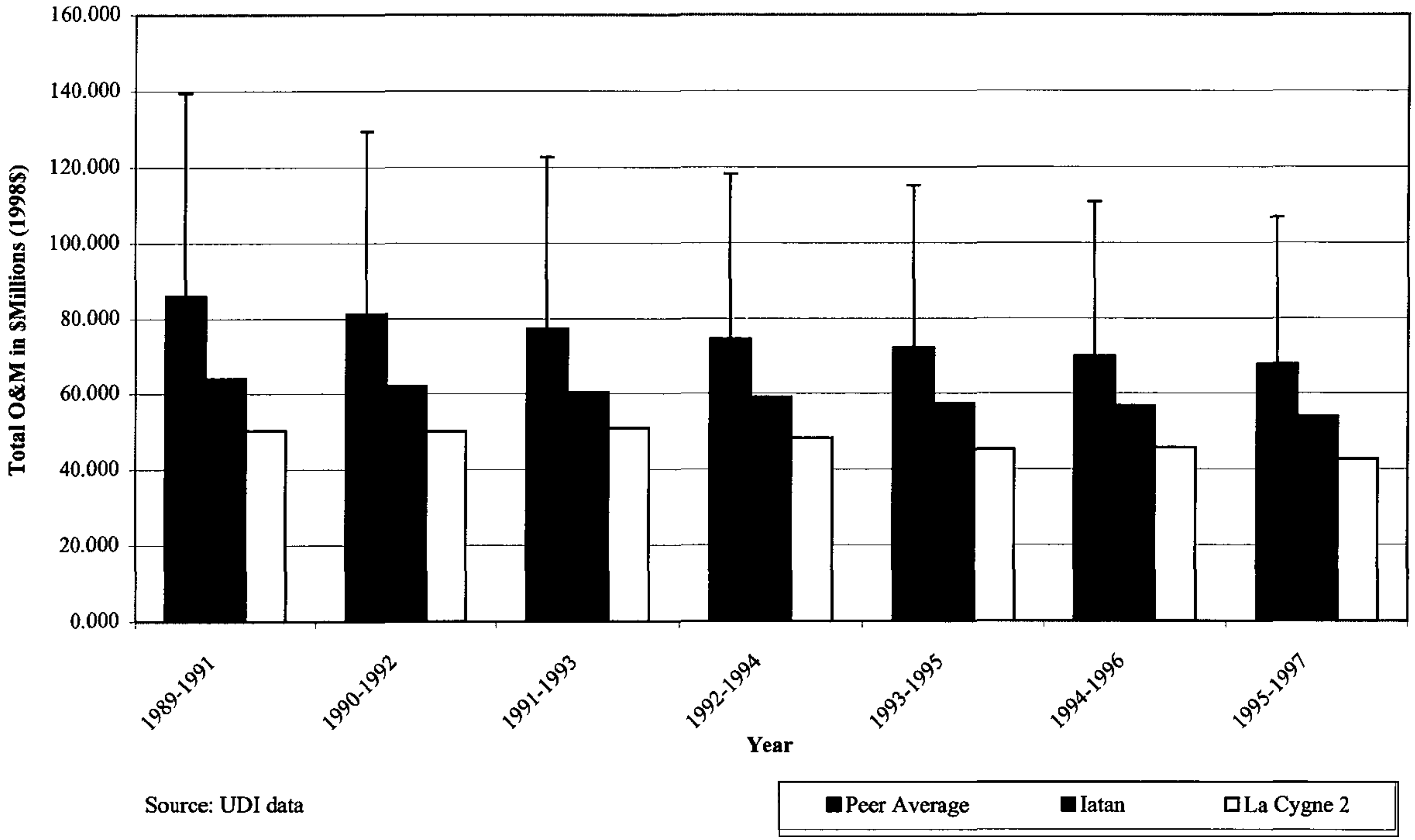
Source for peer group — NERC GADS data
Source for Iatan 1 and La Cygne 2 — KCPL data as reported to NERC

Exhibit C-3
Three-Year Rolling Average Total O&M Plus Fuel Costs in $/kW (1998$)
Iatan & La Cygne 2 and Peers



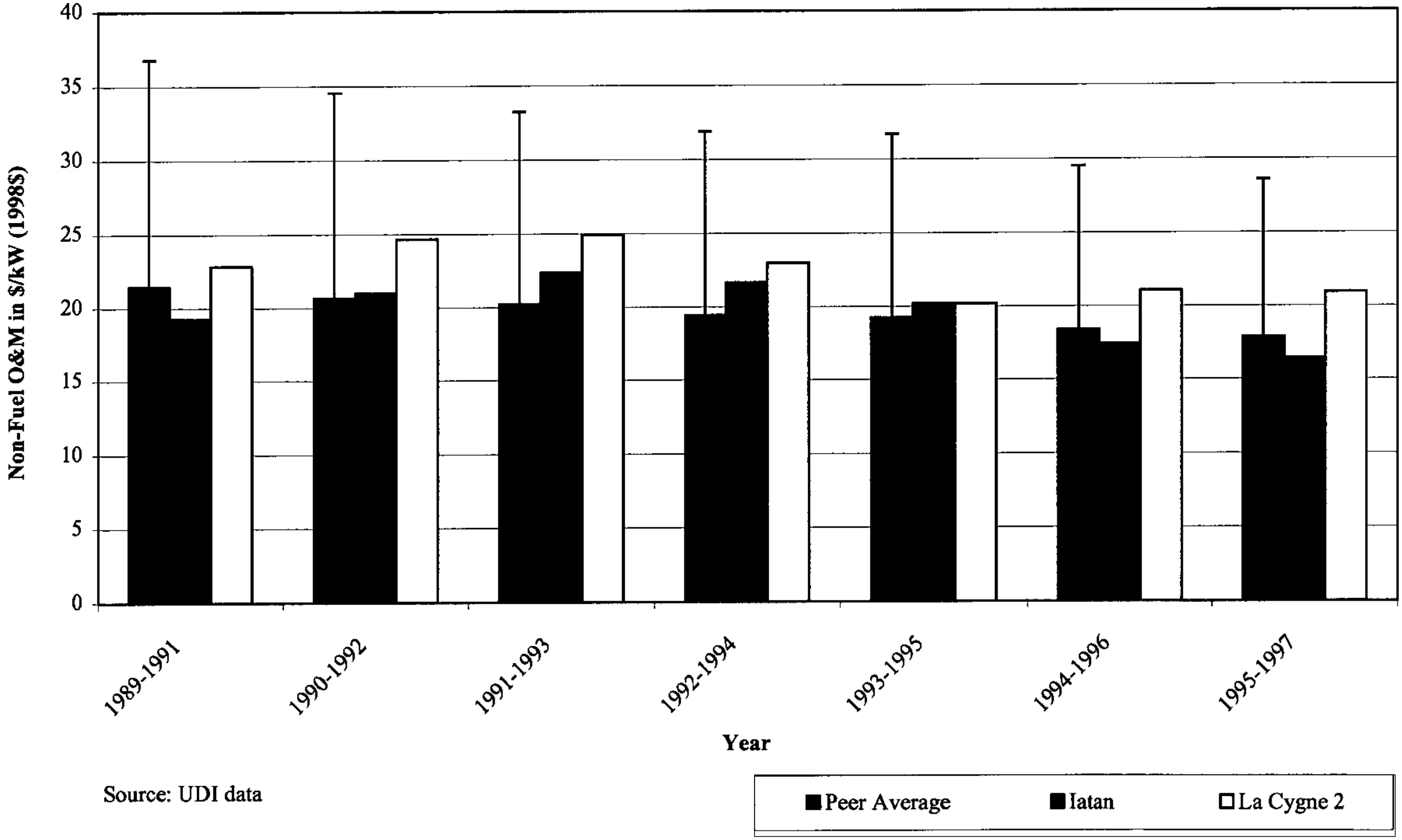
Source: UDI data

Exhibit C-4
Three-Year Rolling Average Total O&M Plus Fuel Costs in $Millions (1998$)
Iatan & La Cygne 2 and Peers



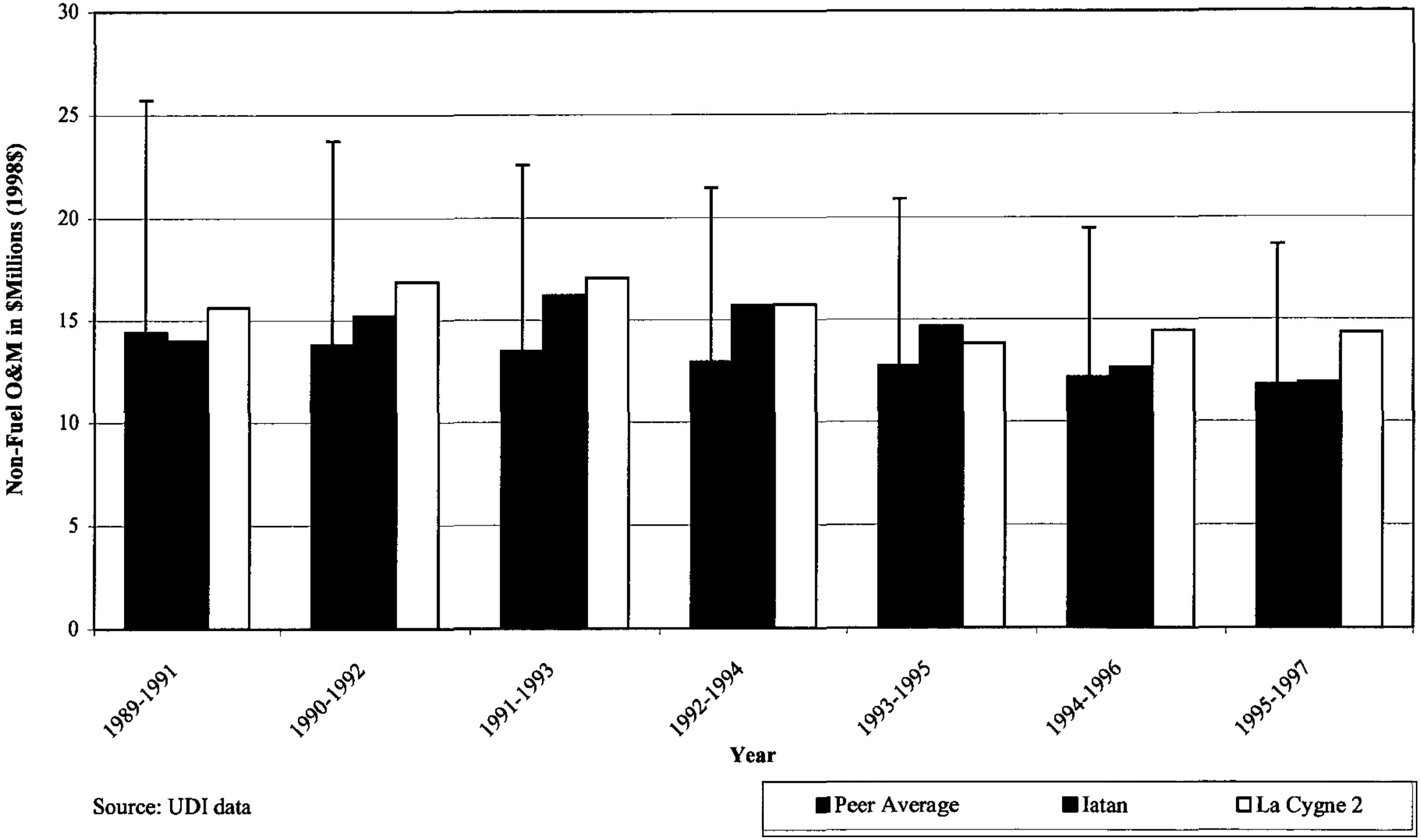
Source: UDI data

Exhibit C-5
Three-Year Rolling Average Non-Fuel O&M Costs in $/kW (1998$)
Iatan & La Cygne 2 and Peers



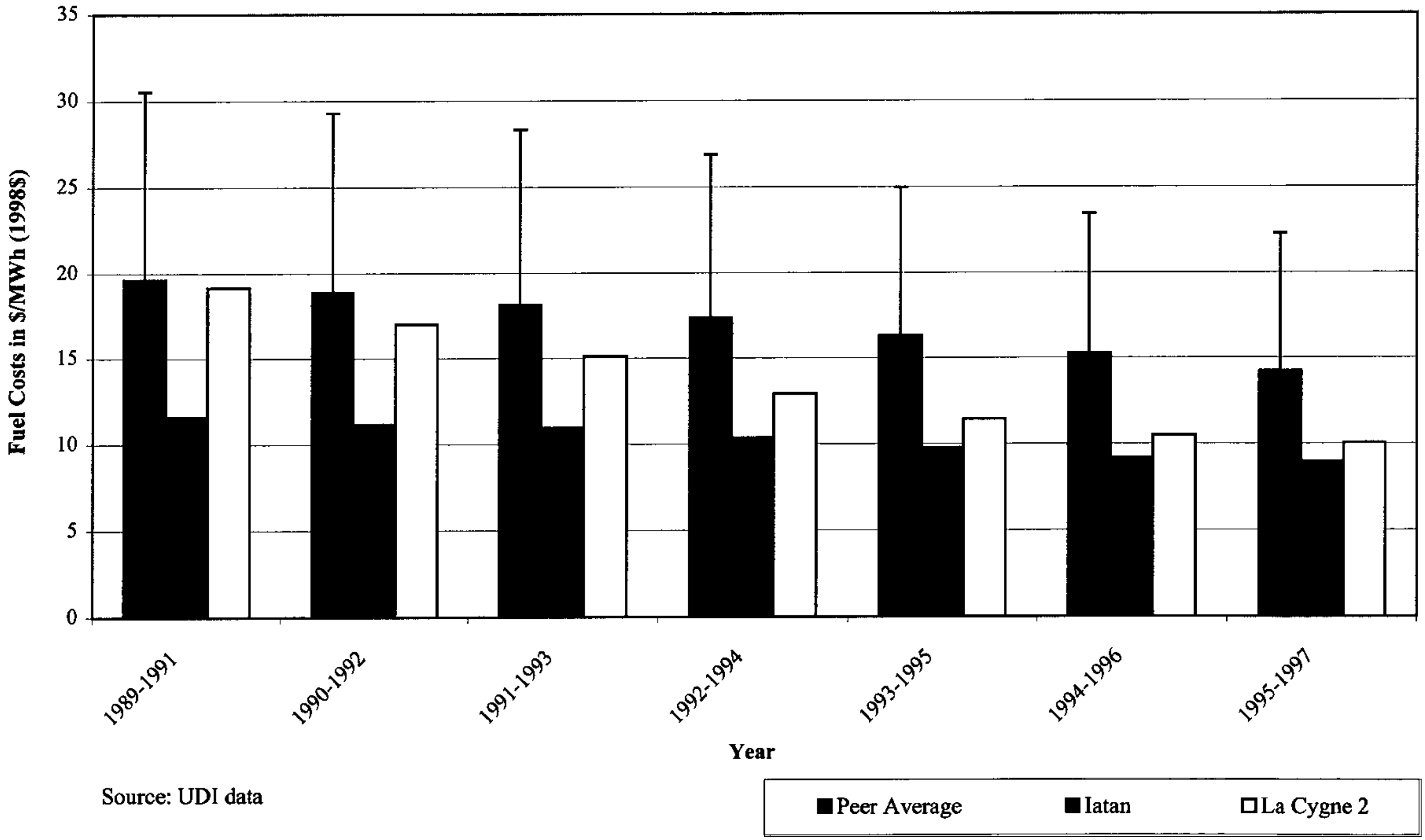
Source: UDI data

Exhibit C-6
Three-Year Rolling Average Non-Fuel O&M Costs in $Millions (1998$)
Iatan & La Cygne 2 and Peers



Source: UDI data

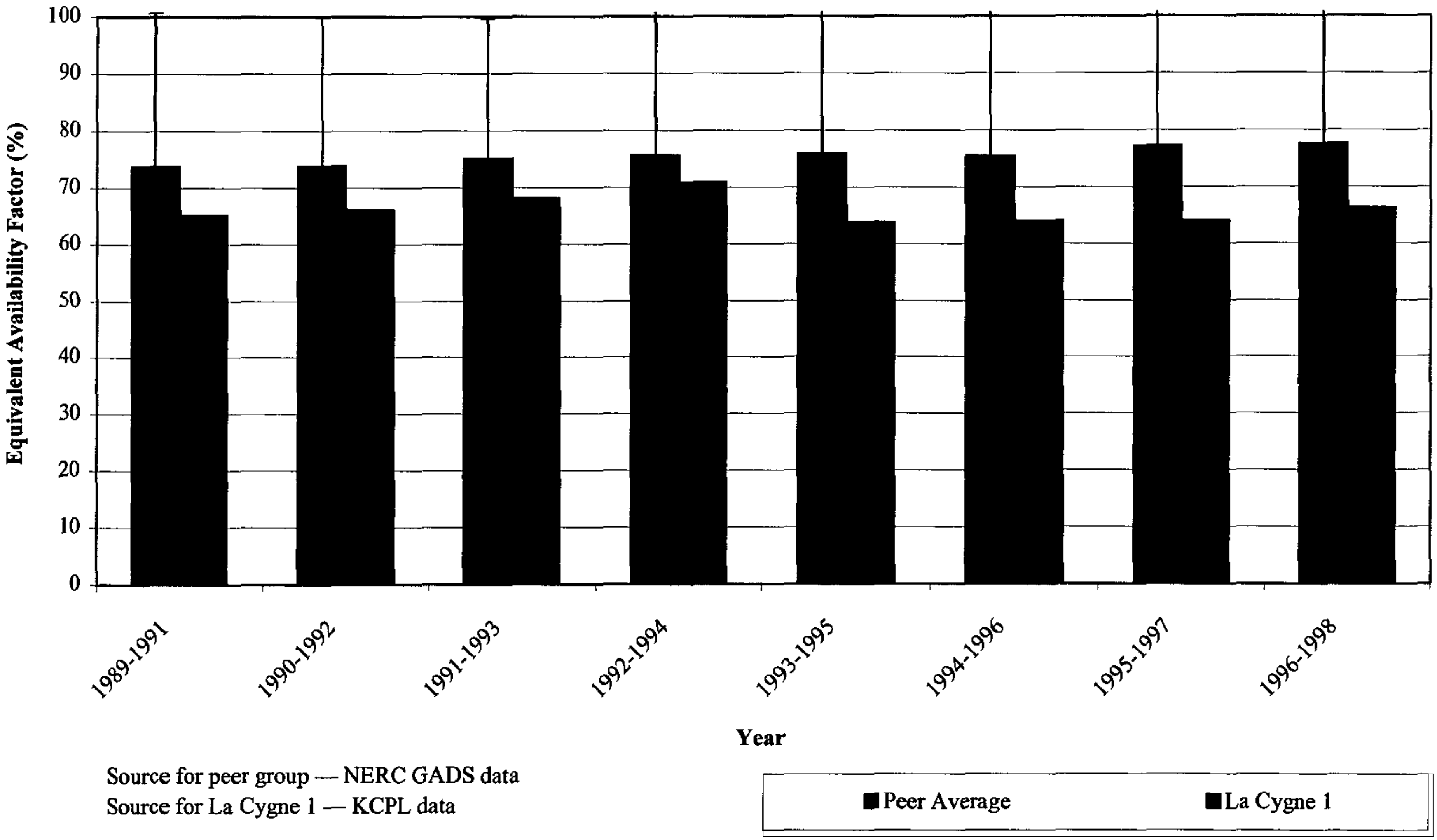
Exhibit C-7
Three-Year Rolling Average Fuel Costs in $/MWh (1998$)
Iatan & La Cygne 2 and Peers



Source: UDI data

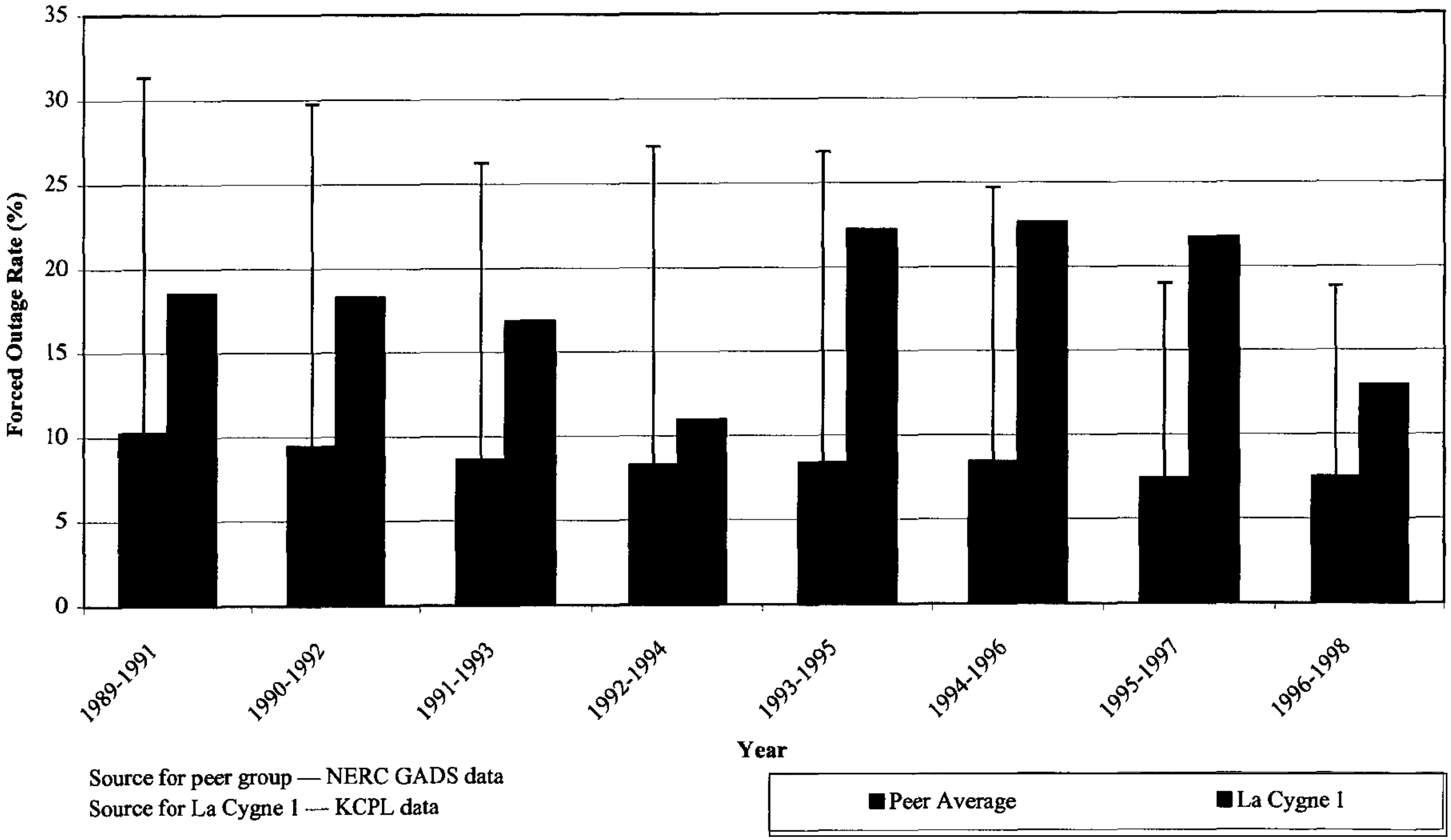
APPENDIX D
LA CYGNE 1

Exhibit D-1
Three-Year Rolling Average Equivalent Availability Factor
La Cygne 1 and Peers



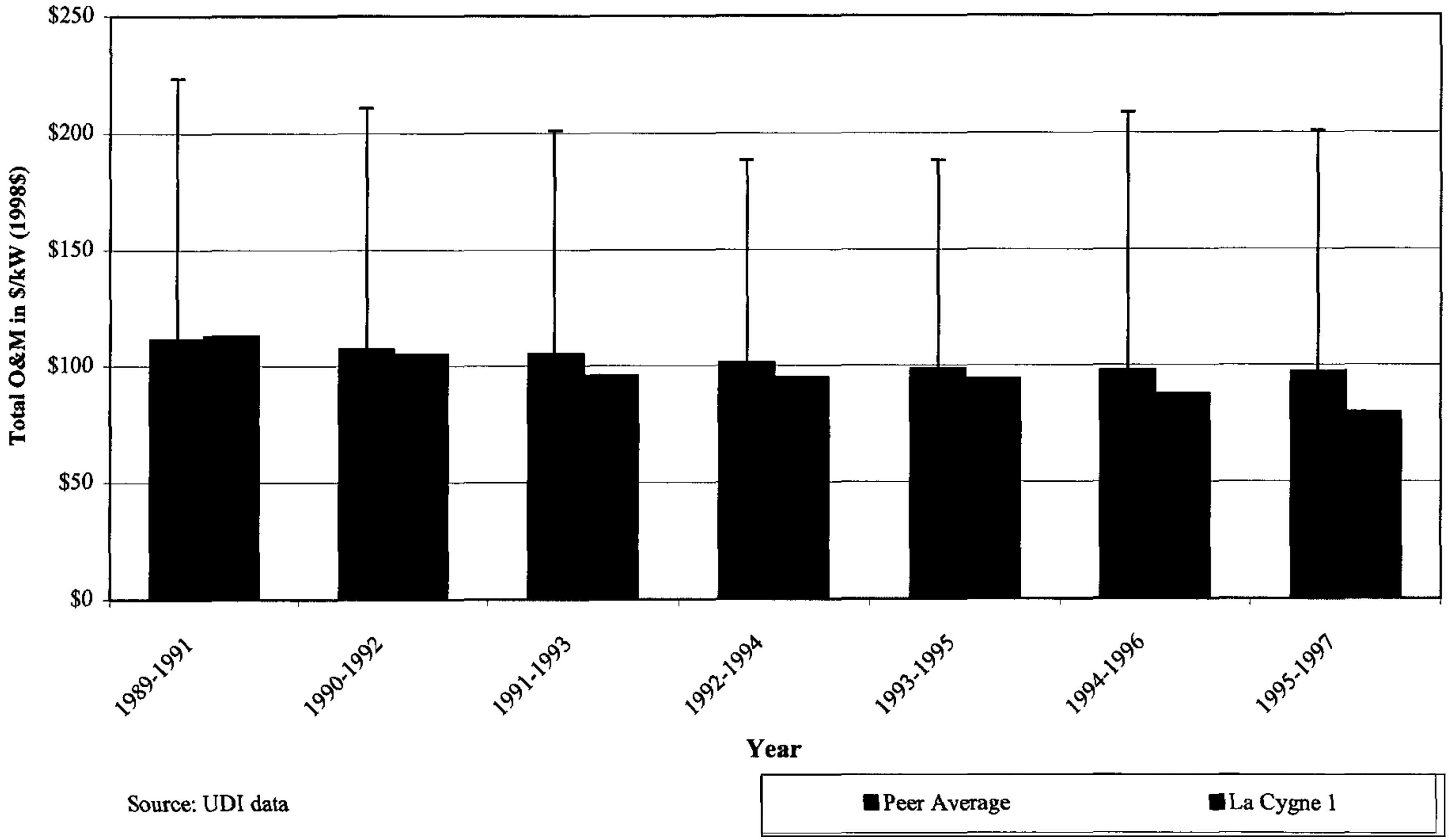
Source for peer group — NERC GADS data
Source for La Cygne 1 — KCPL data

Exhibit D-2
Three-Year Rolling Average Forced Outage Rate
La Cygne 1 and Peers



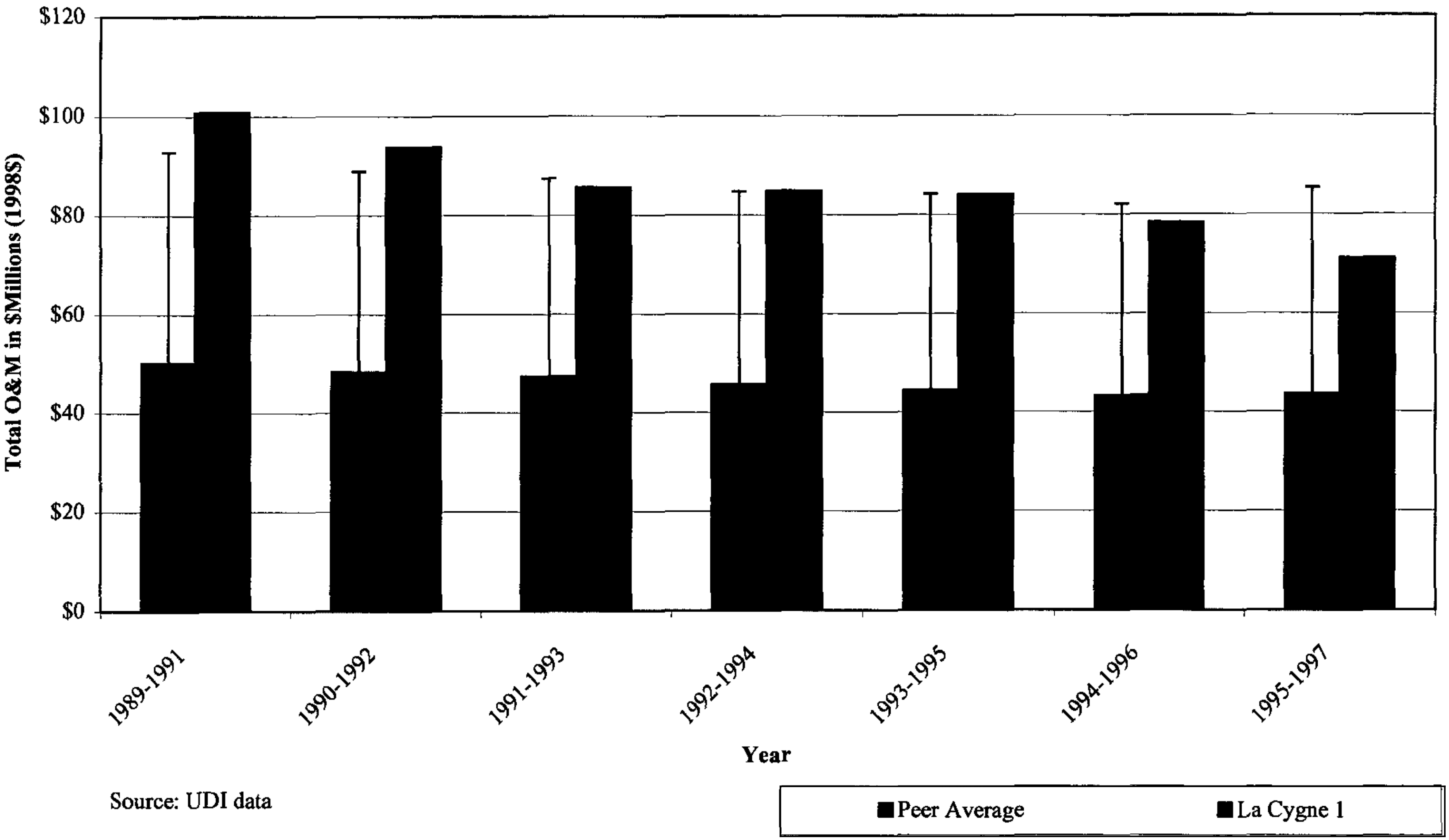
Source for peer group — NERC GADS data
Source for La Cygne 1 — KCPL data

Exhibit D-3
Three-Year Rolling Average Total O&M Plus Fuel Costs in $/kW (1998$)
La Cygne 1 and Peers



Source: UDI data

Exhibit D-4
Three-Year Rolling Average Total O&M Plus Fuel Costs in $Millions (1998$)
La Cygne 1 and Peers



Source: UDI data

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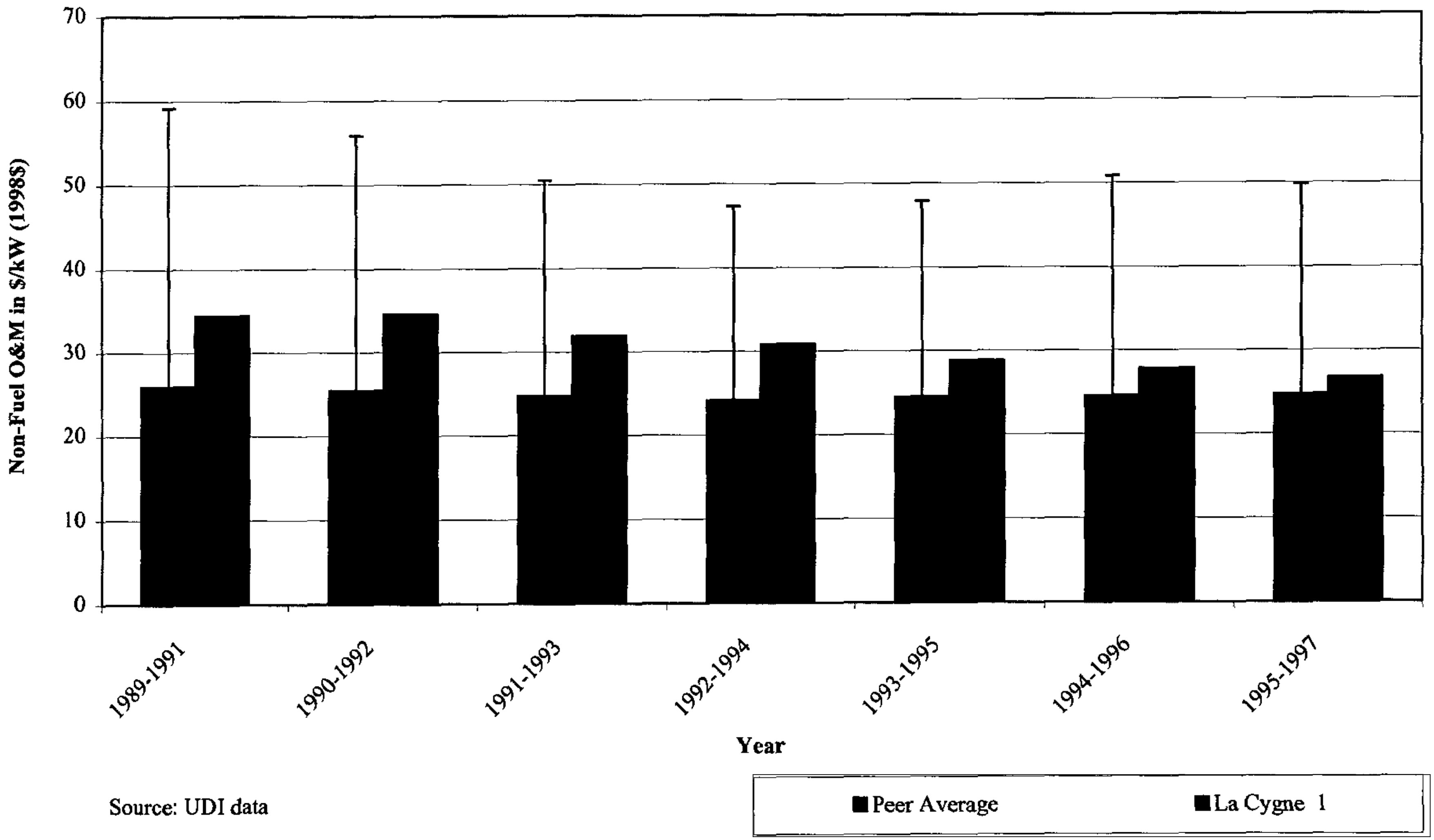
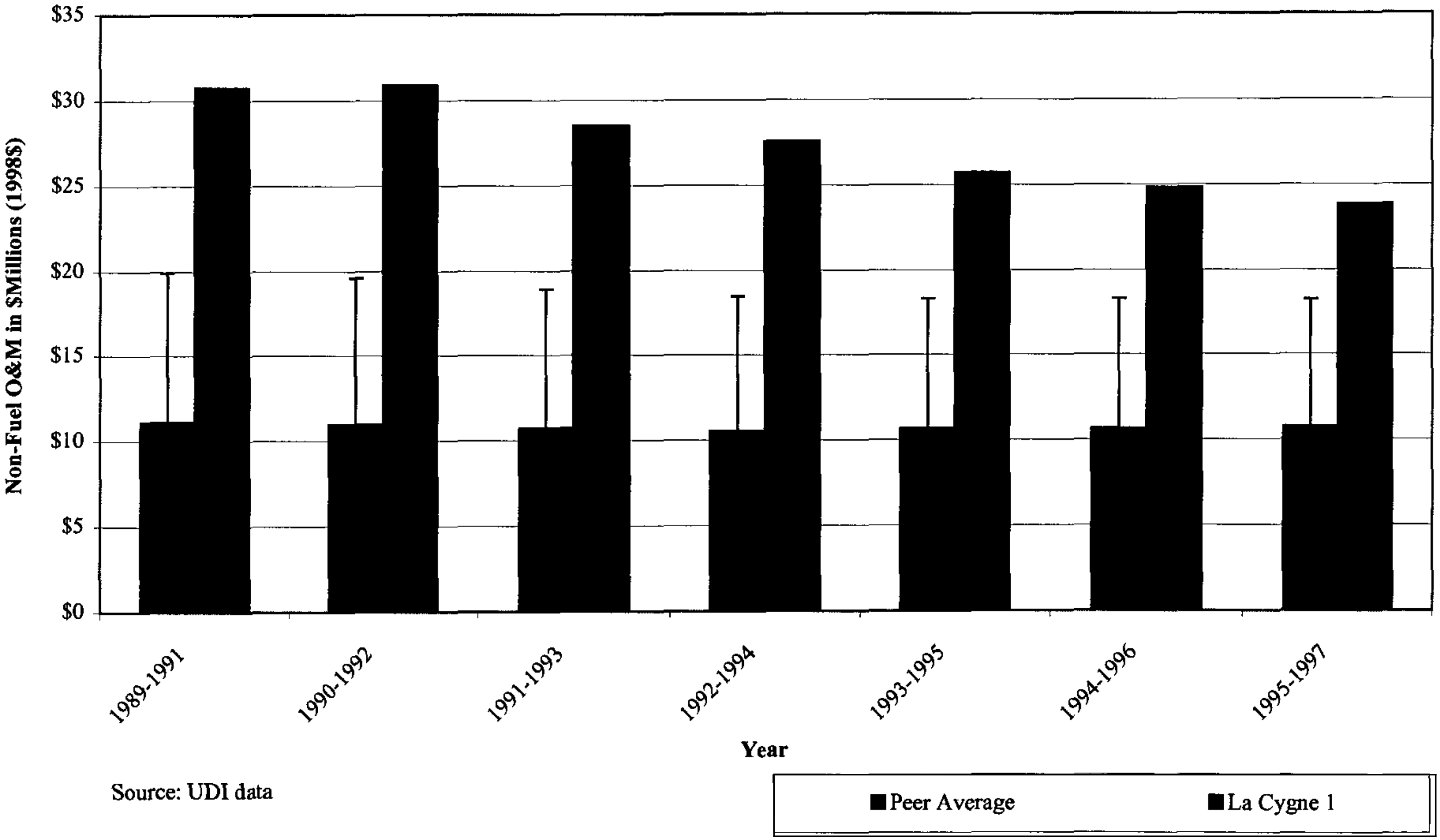
Exhibit D-5
Three-Year Rolling Average Non-Fuel O&M Costs in $/kW (1998$)
La Cygne 1 and Peers



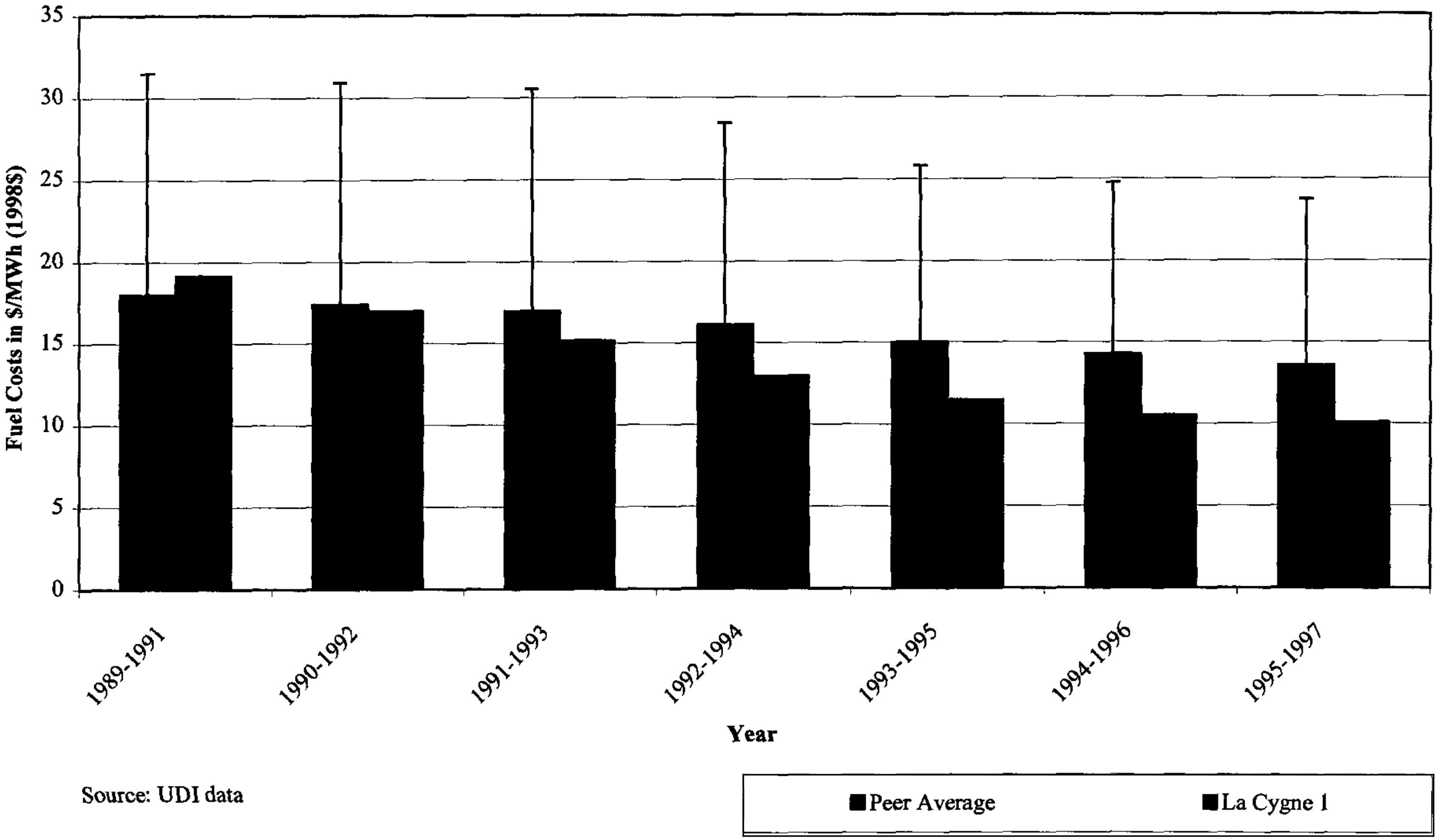
Source: UDI data

Exhibit D-6
Three-Year Rolling Average Non-Fuel O&M Costs in $Millions (1998$)
La Cygne 1 and Peers



Source: UDI data

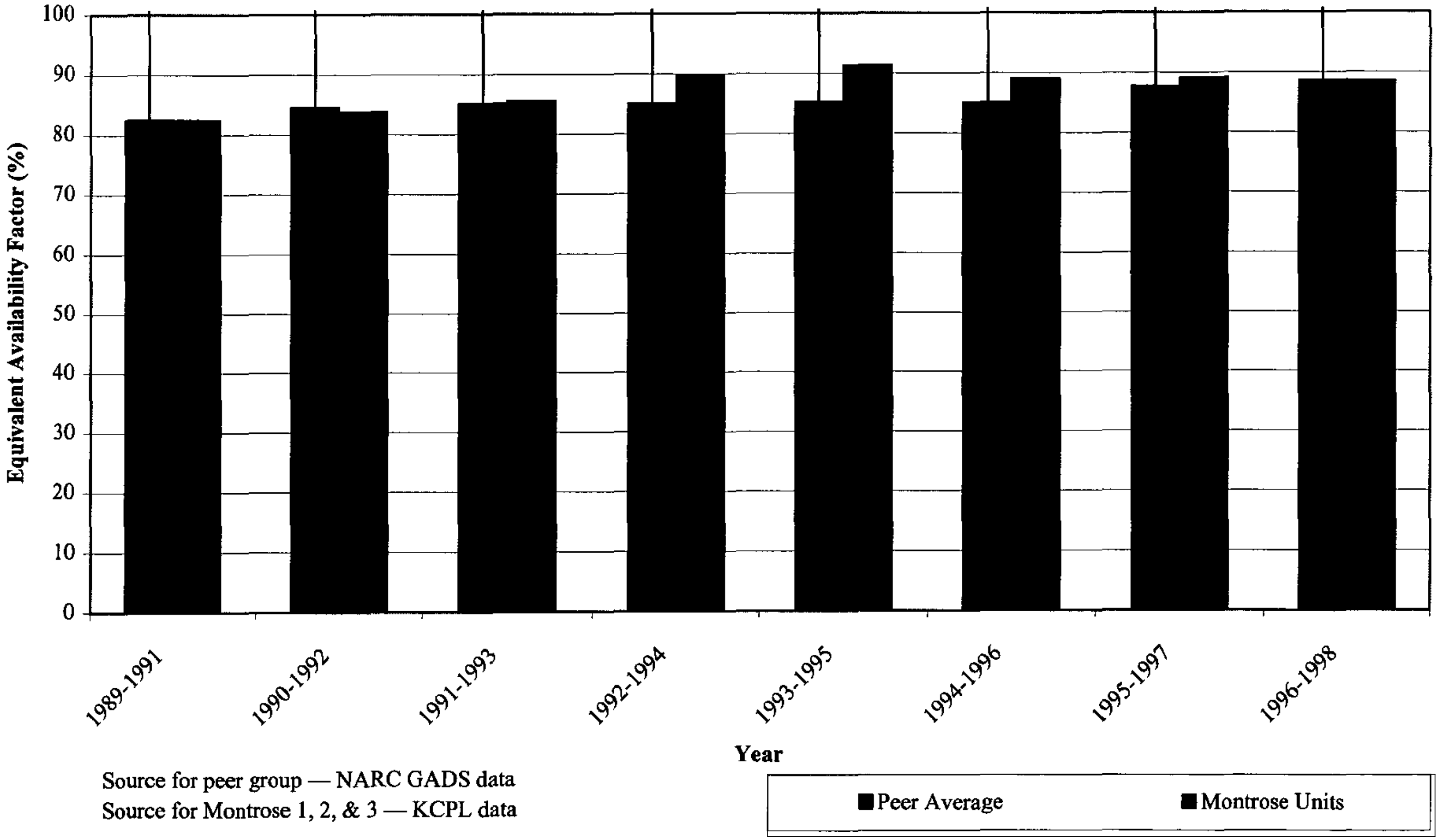
Exhibit D-7
Three-Year Rolling Average Fuel Costs in $/MWh (1998$)
La Cygne 1 and Peers



Source: UDI data

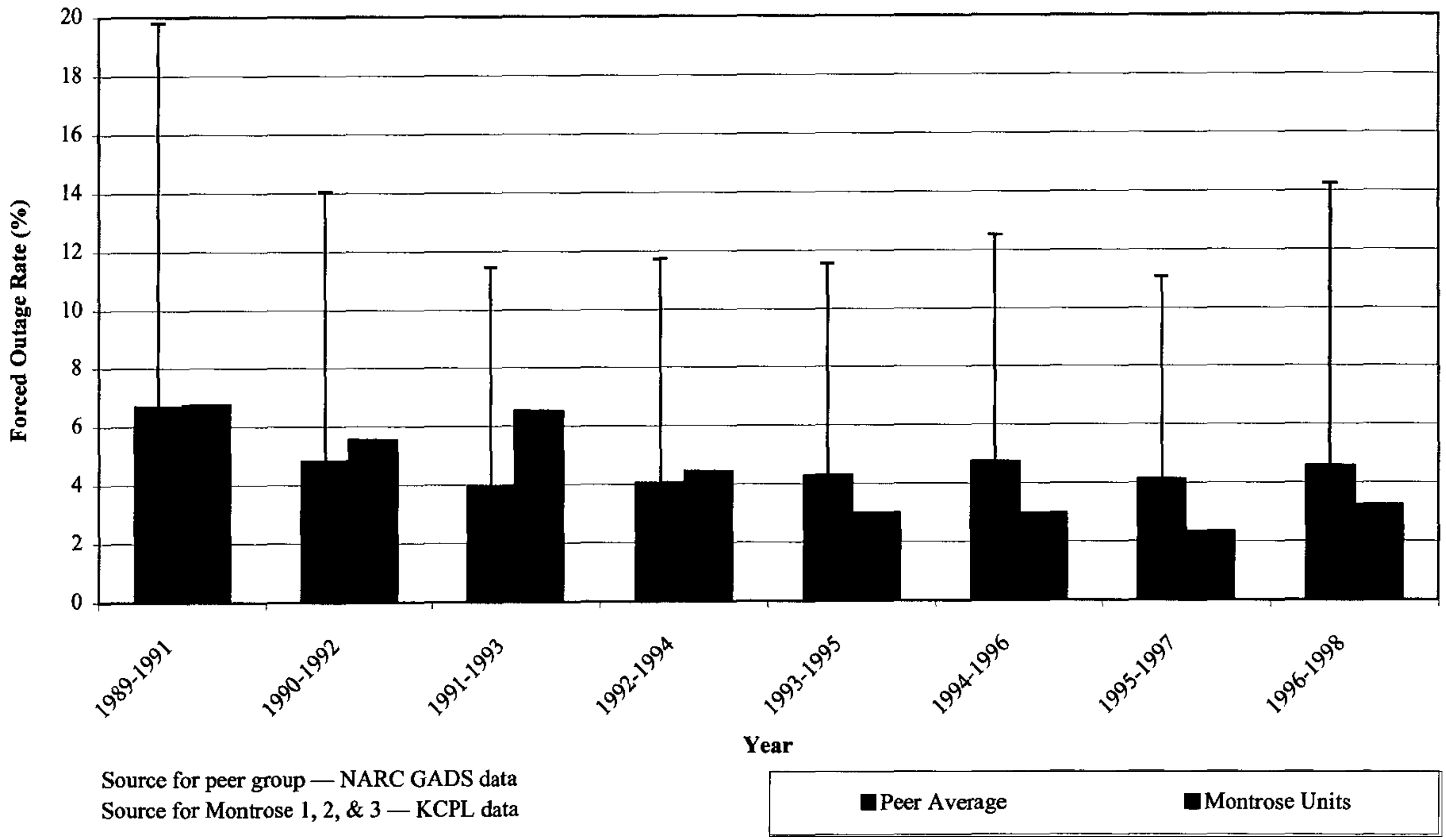
APPENDIX E
MONTROSE 1, 2, & 3

Exhibit E-1
Three-Year Rolling Average Equivalent Availability Factor
Montrose 1, 2, & 3 and Peers



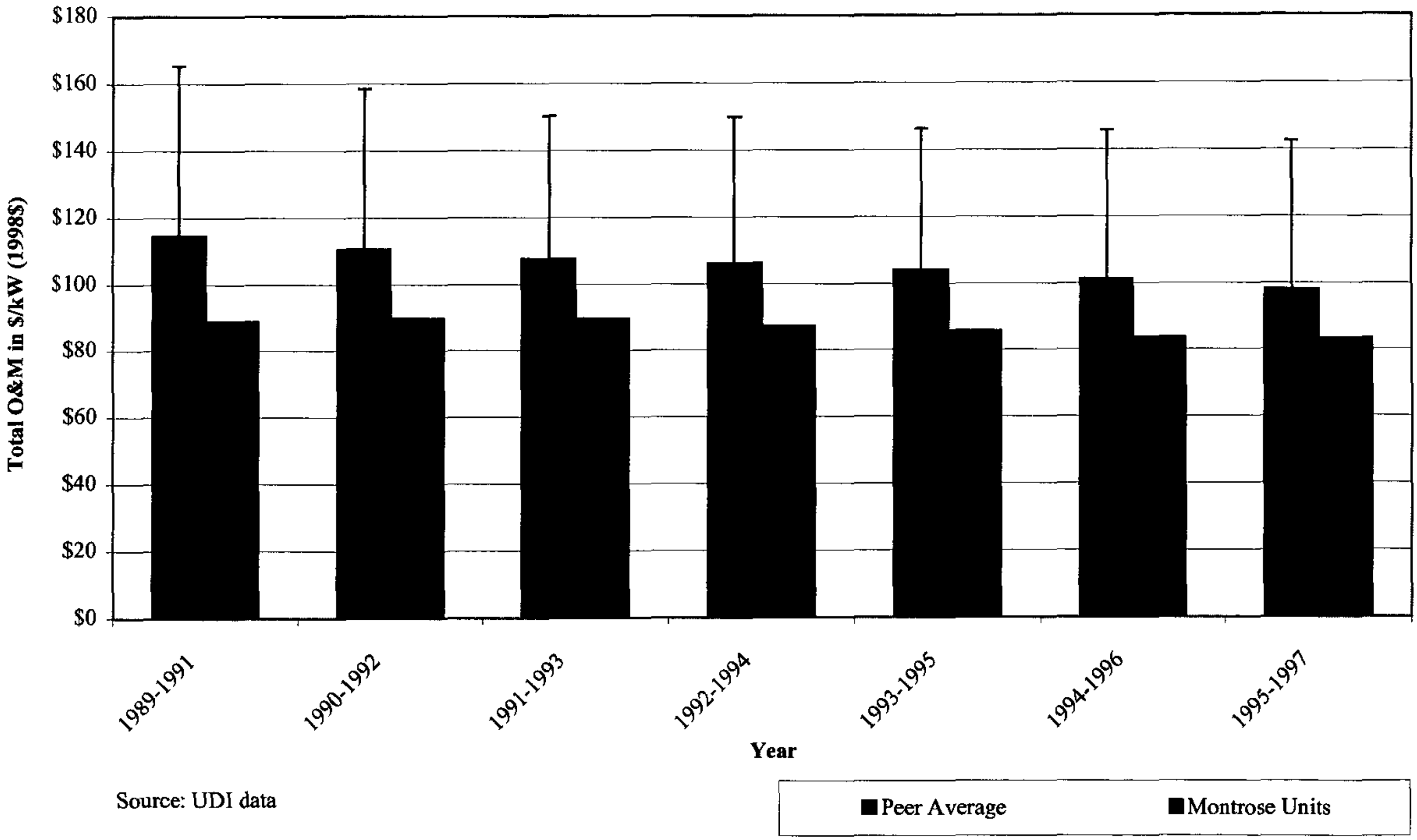
Source for peer group — NARC GADS data
Source for Montrose 1, 2, & 3 — KCPL data

Exhibit E-2
Three-Year Rolling Average Forced Outage Rate
Montrose 1, 2, & 3 and Peers



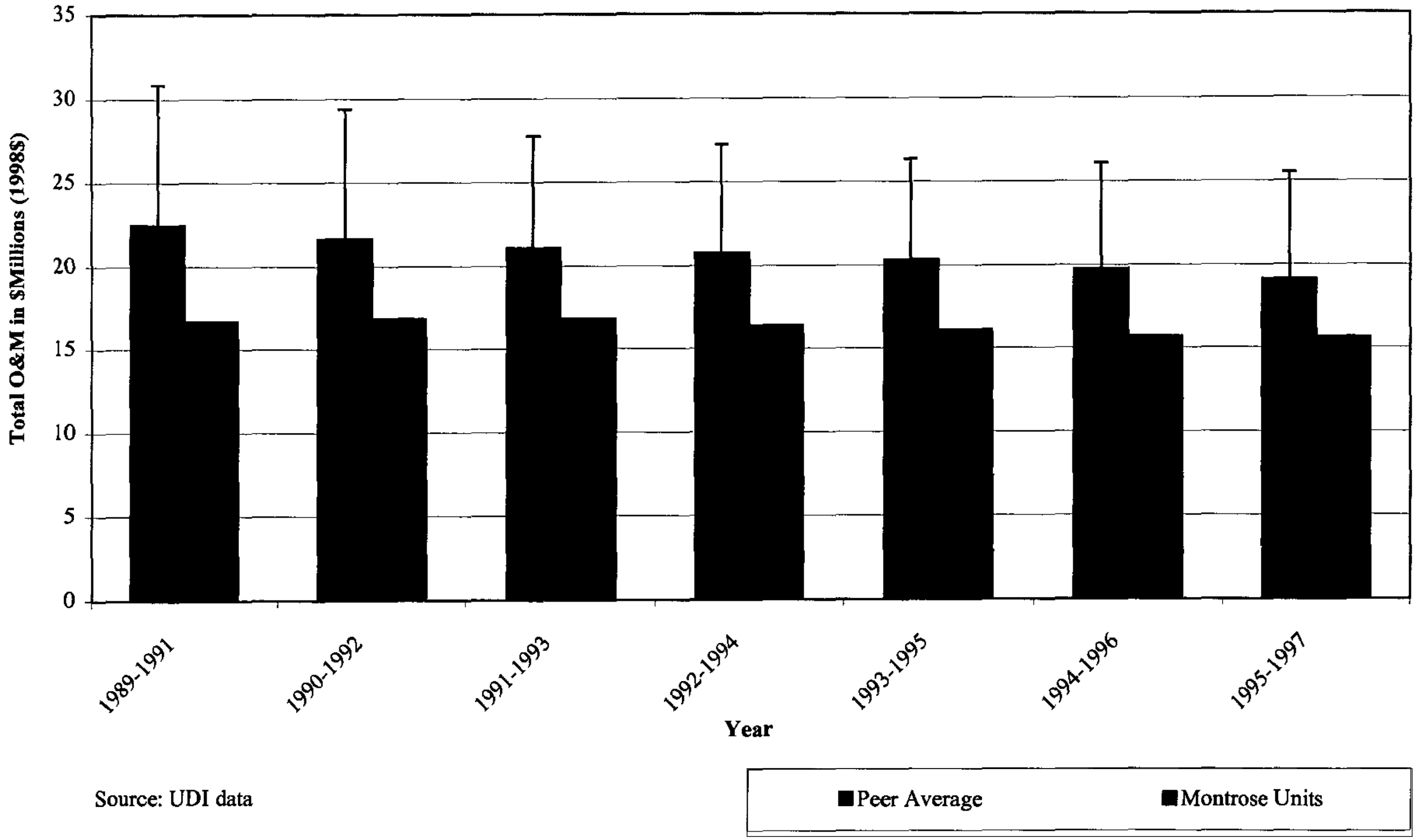
Source for peer group — NARC GADS data
Source for Montrose 1, 2, & 3 — KCPL data

Exhibit E-3
Three-Year Rolling Average Total O&M Plus Fuel Costs in $/kW (1998$)
Montrose 1, 2, & 3 and Peers



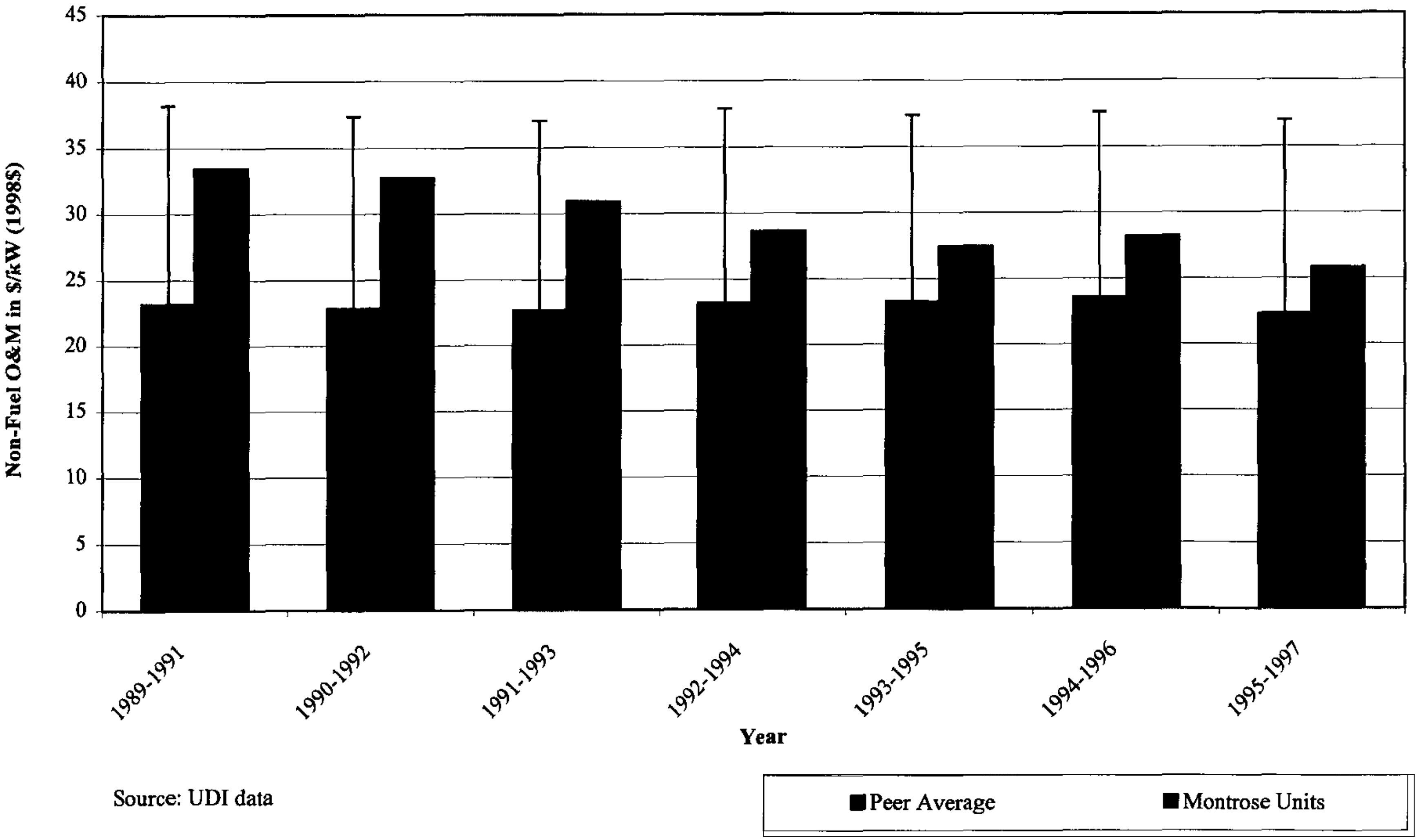
Source: UDI data

Exhibit E-4
Three-Year Rolling Average Total O&M Plus Fuel Costs in $Millions (1998$)
Montrose 1, 2, & 3 and Peers



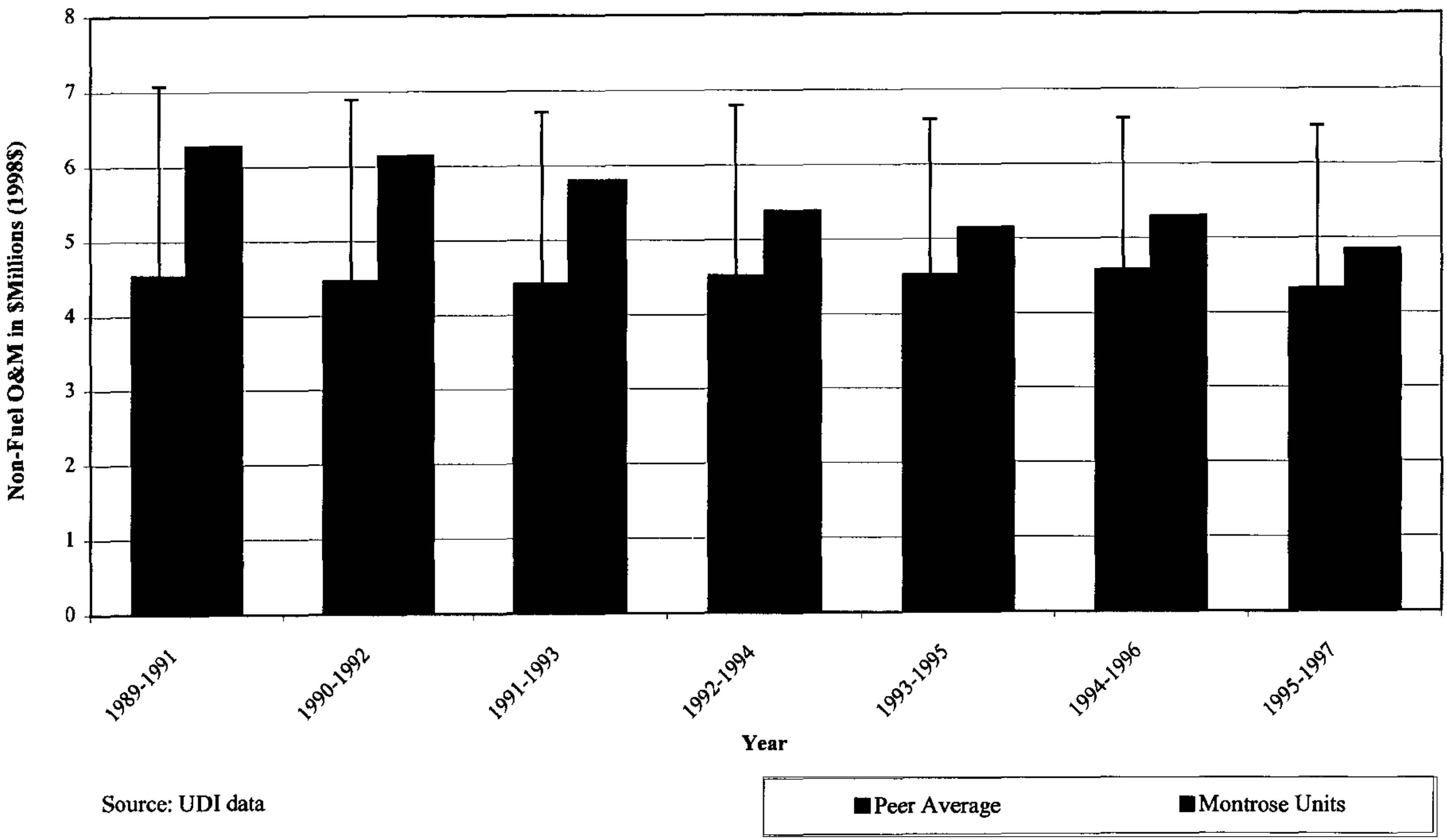
Source: UDI data

Exhibit E-5
Three-Year Rolling Average Non-Fuel O&M Costs in $/kW (1998$)
Montrose 1, 2, & 3 and Peers



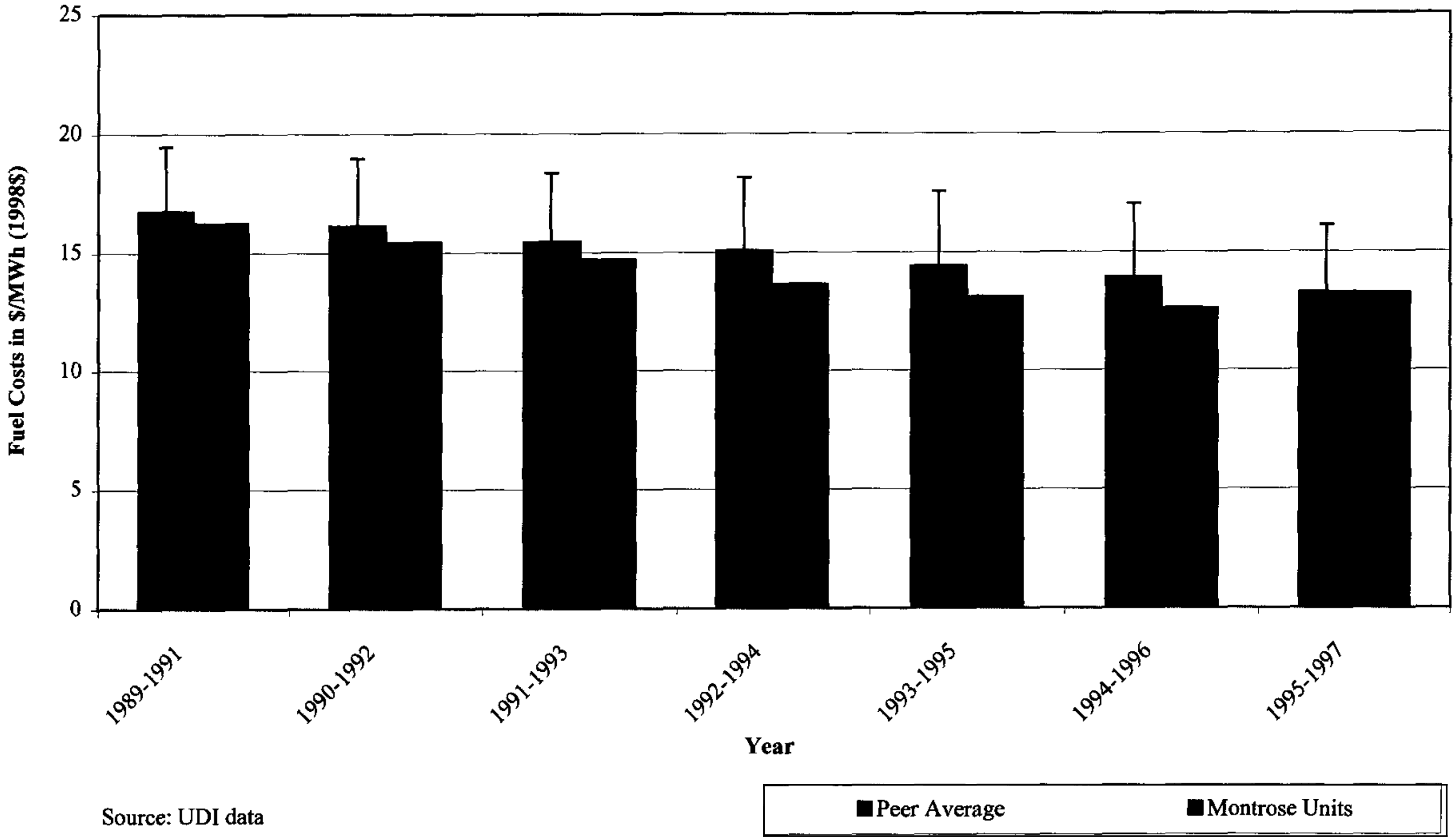
Source: UDI data

Exhibit E-6
Three-Year Rolling Average Non-Fuel O&M Costs in $Millions (1998$)
Montrose 1, 2, & 3 and Peers



Source: UDI data

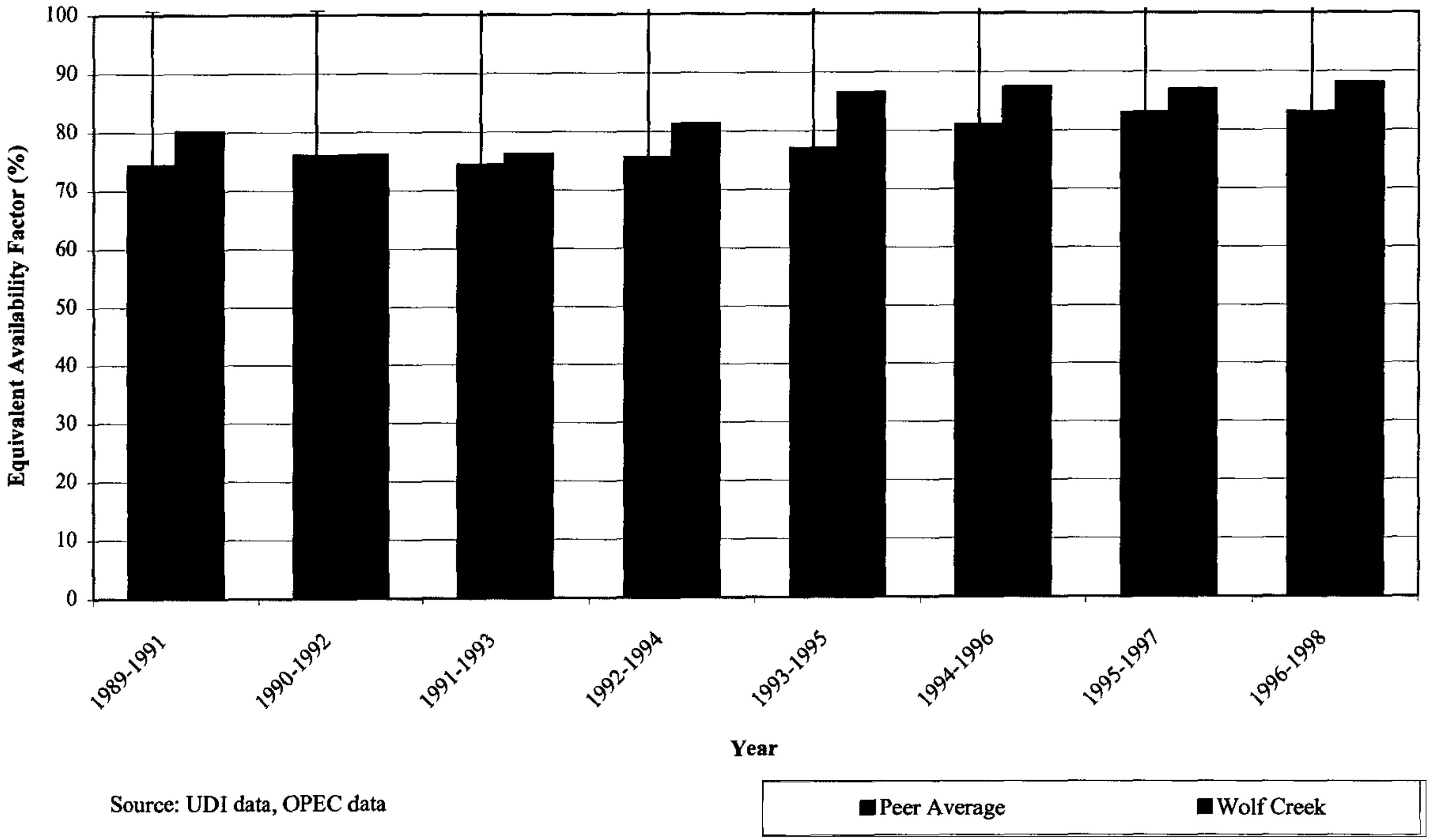
Exhibit E-7
Three-Year Rolling Average Fuel Cost per Unit in $/MWh (1998$)
Montrose 1, 2, & 3 and Peers



Source: UDI data

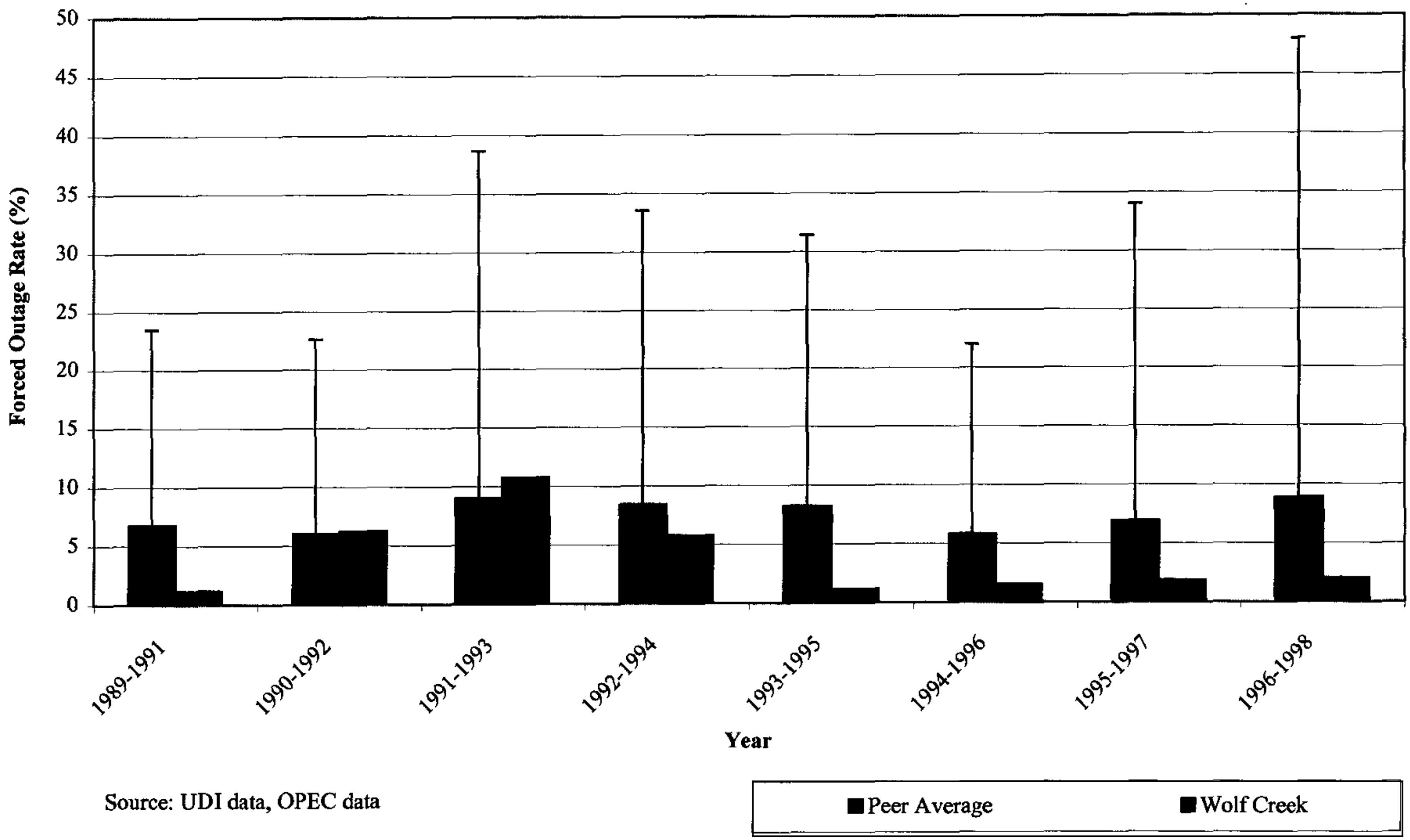
APPENDIX F
WOLF CREEK

Exhibit F-1
Three-Year Rolling Average Equivalent Availability Factor
Wolf Creek and Peers



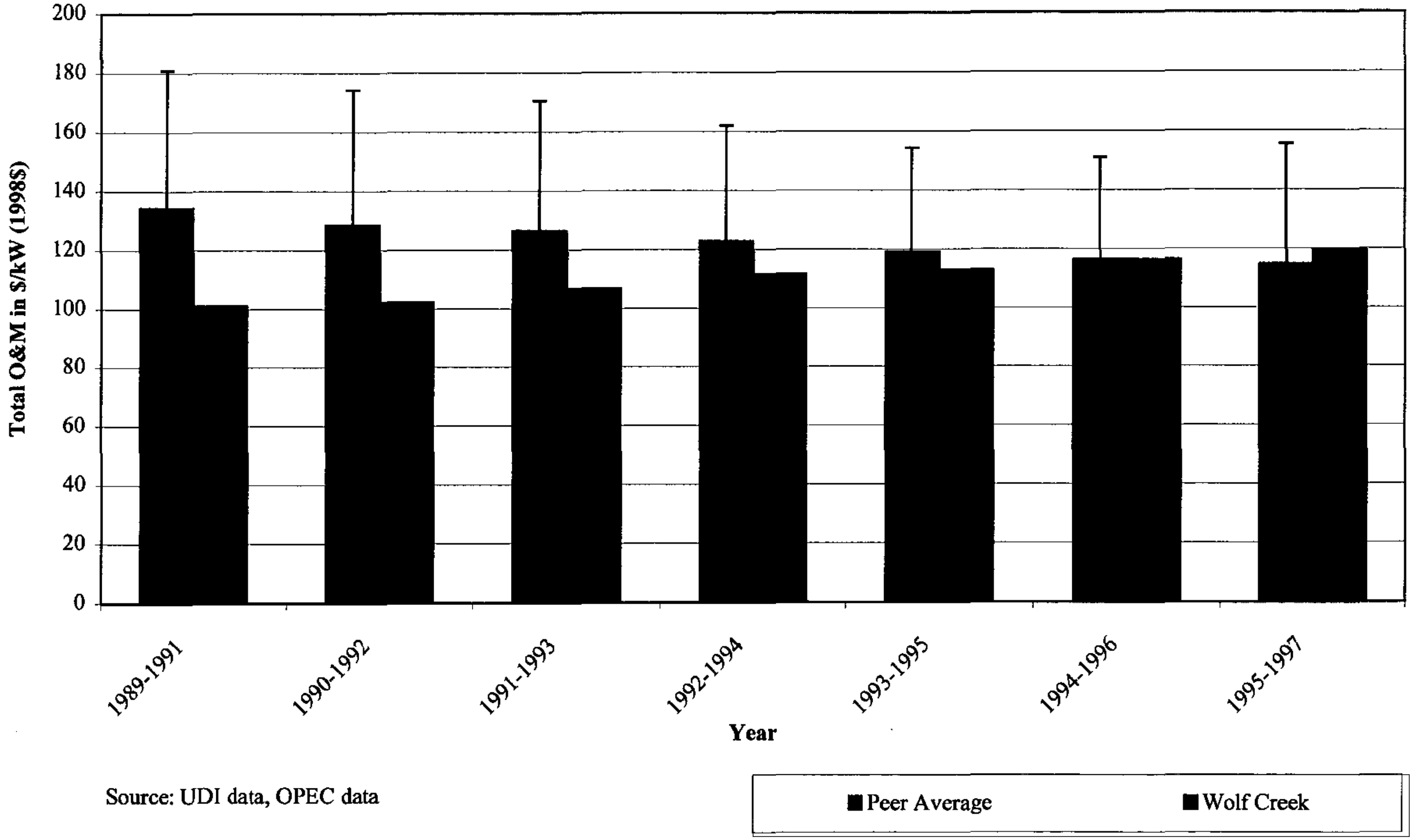
Source: UDI data, OPEC data

Exhibit F-2
Three-Year Rolling Average Forced Outage Rate
Wolf Creek and Peers



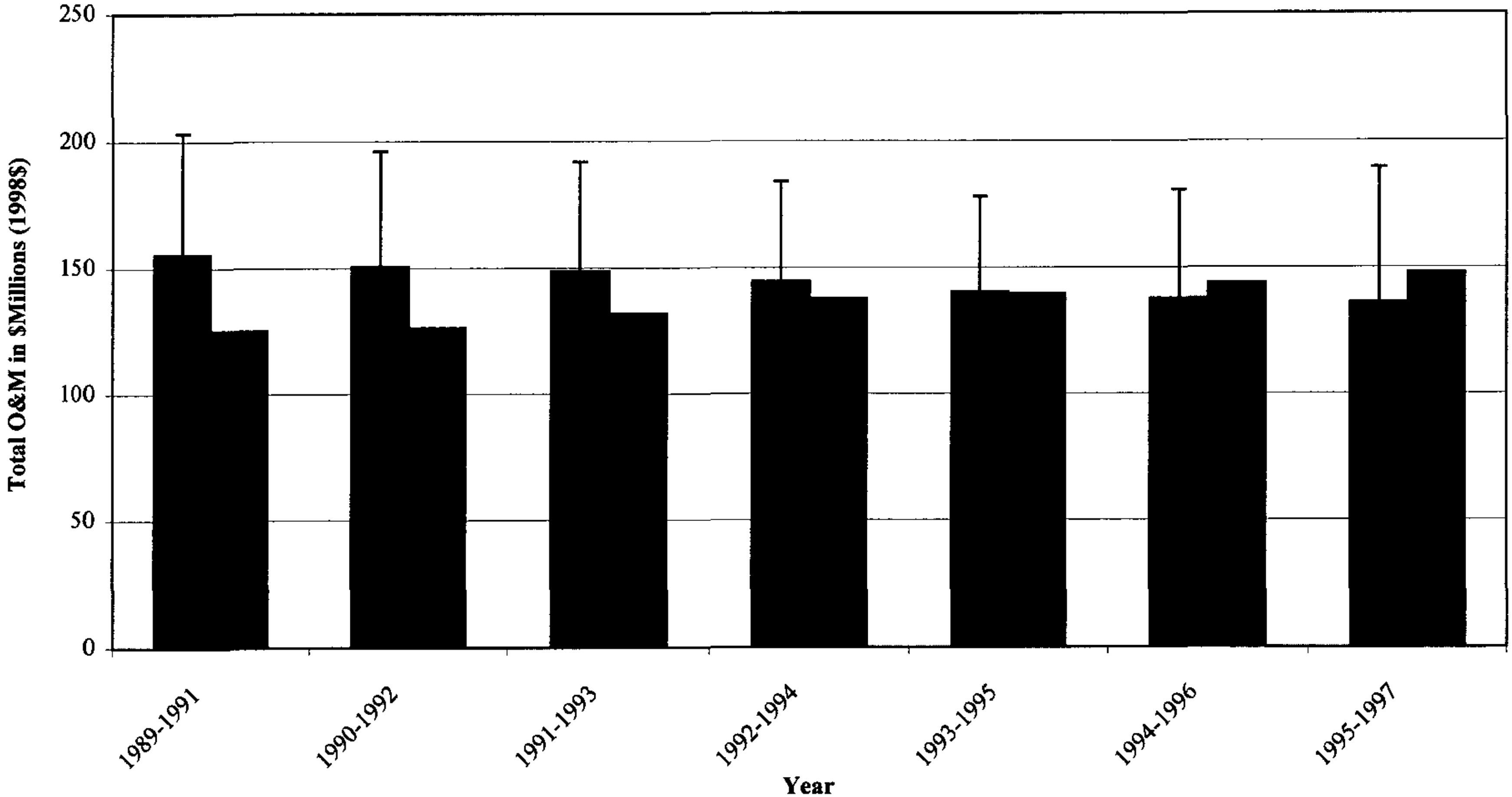
Source: UDI data, OPEC data

Exhibit F-3
Three-Year Rolling Average Total O&M Plus Fuel Costs in $/kW (1998$)
Wolf Creek and Peers



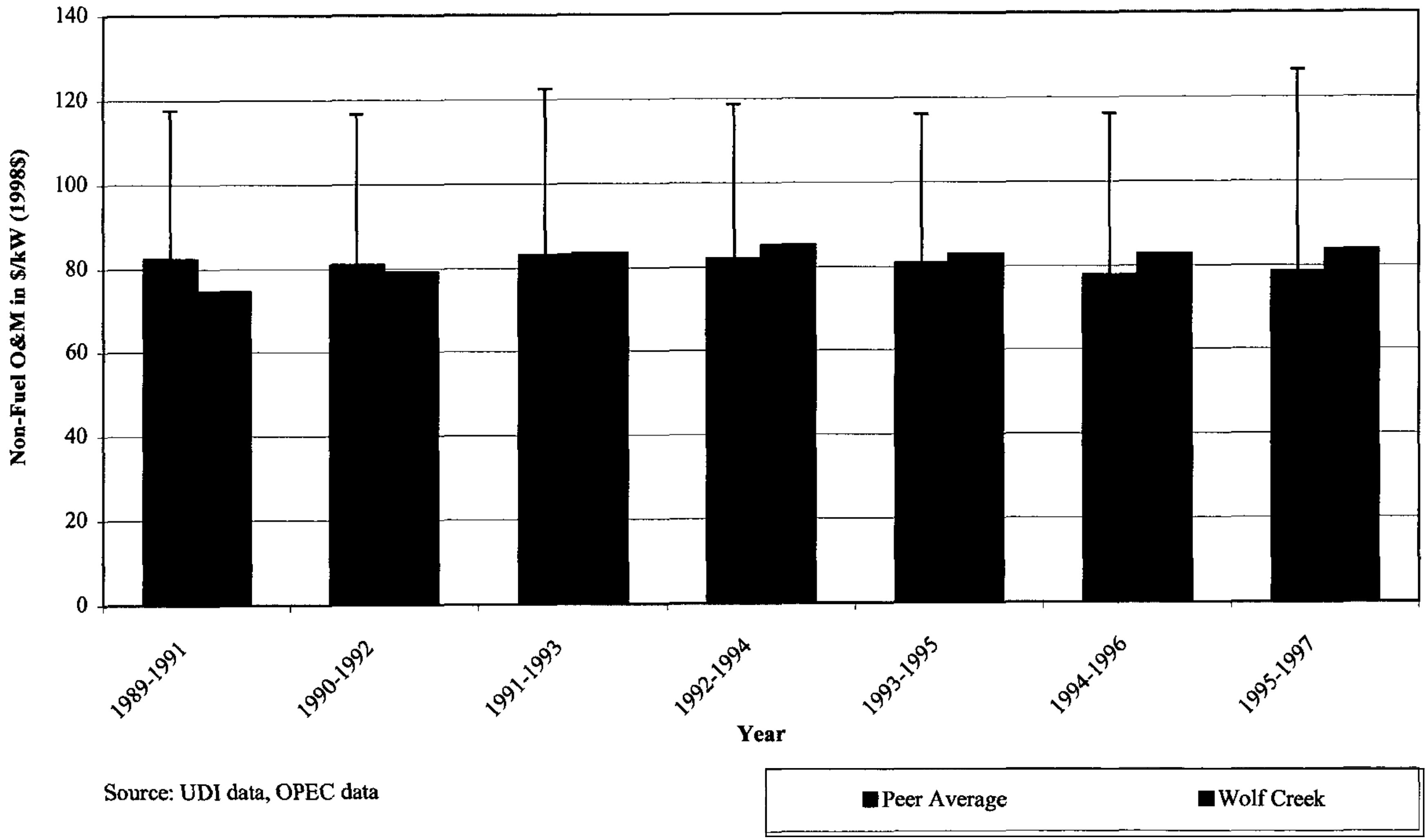
Source: UDI data, OPEC data

Exhibit F-4
Three-Year Rolling Average Total O&M Plus Fuel Costs in $Millions (1998$)
Wolf Creek and Peers



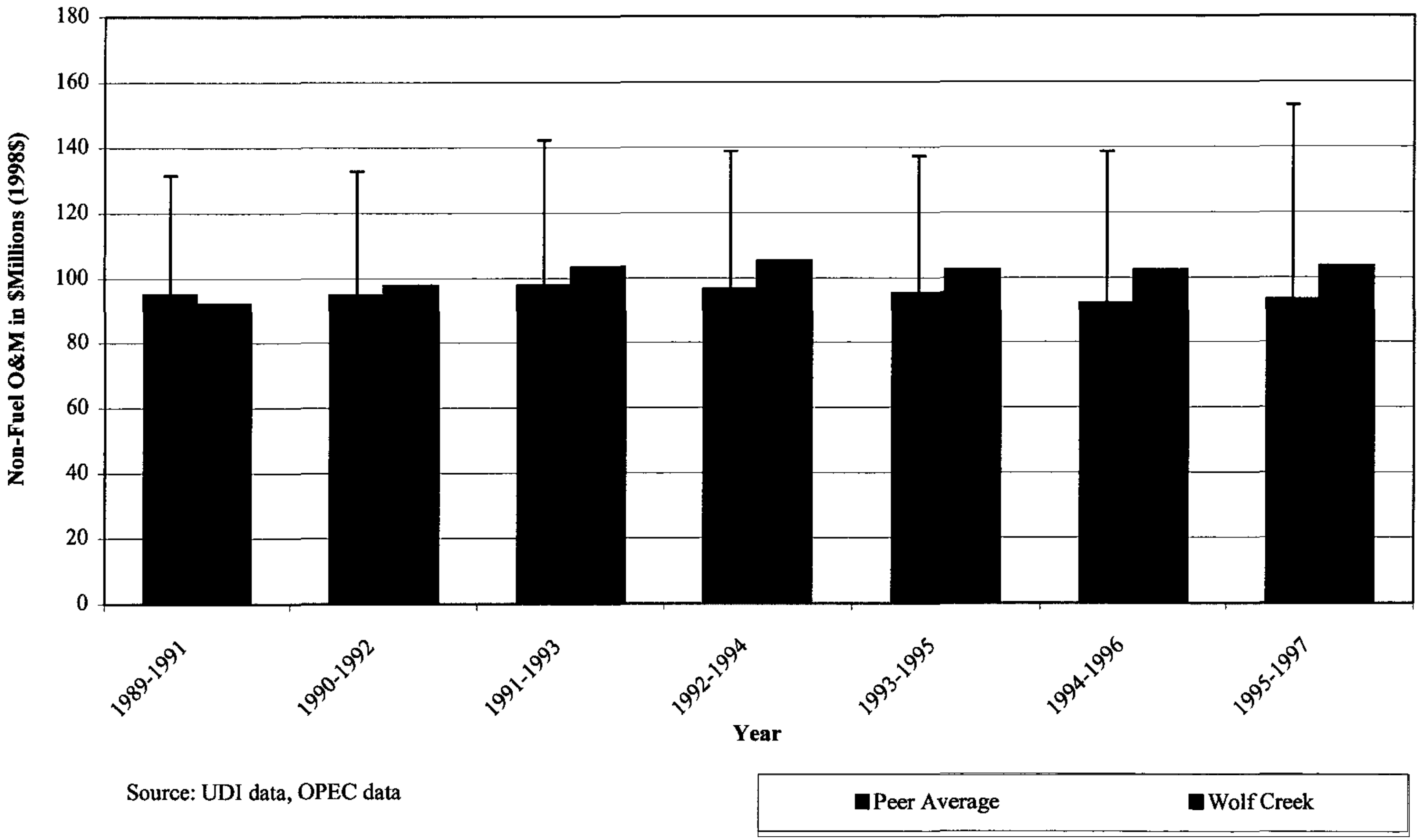
Source: UDI data, OPEC data

Exhibit F-5
Three-Year Rolling Average Non-Fuel O&M Costs in $/kW (1998$)
Wolf Creek and Peers



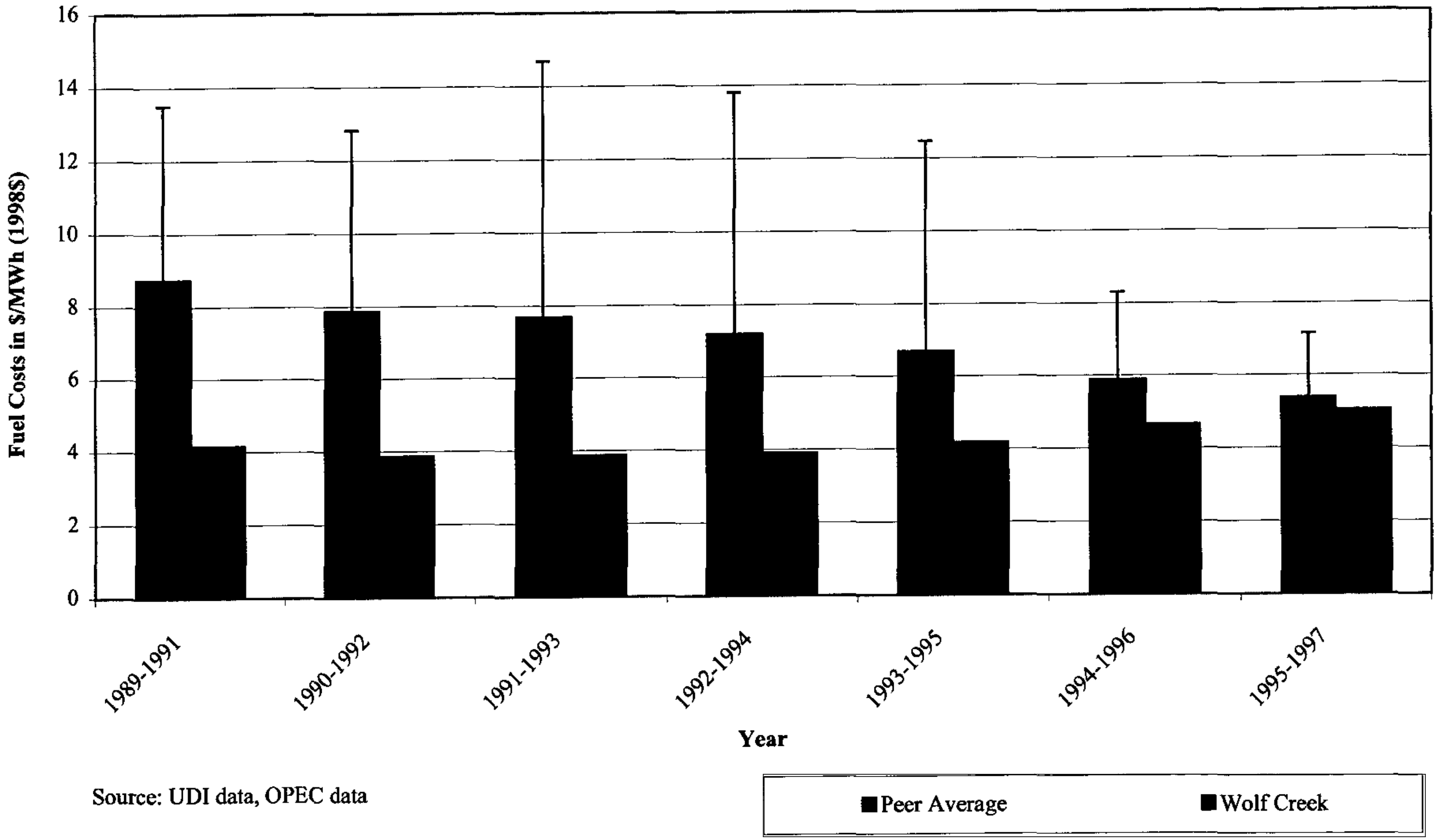
Source: UDI data, OPEC data

Exhibit F-6
Three-Year Rolling Average Non-Fuel O&M Costs in $Millions (1998$)
Wolf Creek and Peers



Source: UDI data, OPEC data

Exhibit F-7
Three-Year Rolling Average Fuel Costs in $/MWh (1998$)
Wolf Creek and Peers



Source: UDI data, OPEC data