

Report on Electric Utilities' Response to the Cold Wave of January 1994

Report by the
Blue Ribbon Task Force
to the NERC Board of Trustees



**North American
Electric
Reliability
Council**

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*Approved by the NERC Board of Trustees
April 11, 1994*

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Executive Summary

A major cold wave, with record-setting low temperatures, swept across the Midwest and through the mid-Atlantic states during the week of January 16, 1994. The prior week, much of the same area was covered by ice storms. Faced with unusually high demands for electricity that far exceeded expectations, and cold-weather-related problems with generators and fuel supplies, electric utilities with generation shortages imported large blocks of power over their transmission systems from other utilities throughout the Eastern Interconnection. As available reserves dwindled, utilities turned to their established capacity emergency procedures. Two of the Eastern Interconnection's control areas — PJM and Virginia Power — had to institute the final step in these emergency procedures, the manual curtailment of "firm" customers (rotating blackouts), to maintain the reliability of the bulk electric supply system.

As a result of these events, NERC Chairman E.R. Brooks appointed a Blue Ribbon Task Force to review the electric utilities' response to the Cold Wave of 1994. Formed on January 21, 1994, the Chairman asked the Task Force to assemble the basic facts, including loads, resources, reserves, generator availability, fuel problems, and the effectiveness of public appeals, curtailment of interruptible loads, and rotating blackouts. The Task Force was also to assess the degree of compliance by the control areas to the NERC Operating Criteria and Guides, which detail the control areas' obligations. The true value of this report for all utilities is in the lessons learned from experiences like these.

The Task Force commends the system operators of PJM and Virginia Power, who had to make tough decisions to implement manual curtailment of "firm" customers. These steps were necessary because:

1. PJM and Virginia Power were using all of their own available generating resources,
 2. Transmission paths into these two systems were approaching their transfer capability, precluding additional capacity purchases, and
 3. NERC Operating Guide III requires manual load shedding when all other designated steps prove inadequate for a control area to balance its generation and interchange schedules to load.
- In short, PJM and Virginia Power followed the "rules." This conclusion is substantiated by the data collected and included in this report.
- The Task Force also commends all those other system operators who contributed to maintaining the reliability of the Eastern Interconnection. Many utilities throughout the Eastern Interconnection took steps to reduce their own demand through interruptible customers, public appeals, and voltage reductions to make additional generation available to support deficient areas. Special recognition goes to utilities in Canada and Florida, who supplied nearly 70% of the transfers into the Midwest and mid-Atlantic area over the study period.
- Other conclusions and observations pertaining to the eight-hour period, hour ending 0700 through hour ending 1400 Eastern Standard Time, of January 19, 1994 are:
1. Utilities began their special preparations for the cold weather forecasted for the week of January 16 as early as January 12.
 2. The extraordinarily prolonged icy conditions that began in the Midwest and mid-Atlantic area on January 6, the extreme sub-zero temperatures, and the disruptions to fuel supplies to generating plants were the major contributors to generator availability problems.

Executive Summary

3. Transmission paths from the west and north into PJM and Virginia Power were loaded throughout the period studied near their first contingency total transfer capabilities. With virtually no room left on the transmission system, the issue of how much additional generating capacity was available for sale throughout the Eastern Interconnection was academic.
4. After-the-fact analysis showed there was very little additional generating capacity for sale throughout the Eastern Interconnection. Capacity for sale varied from 3,500 MW at hour ending 0900 to almost 10,000 MW at hour ending 1300. This generating capacity was scattered among many different control areas, some as far as 1,000 miles away.
5. Several other transmission paths, not directly connected to PJM and Virginia Power, were also near their first contingency total transfer capability. Florida utilities recalculated first contingency transfer capability into Georgia using real-time conditions, raising the south-to-north limits from 1,300 MW to 3,000 MW. New York Power Pool performed similar calculations, raising transfer limits to PJM by 600 MW. Canadian utilities in the East loaded their transmission into the United States to its first contingency limits, contributing up to 7,000 MW during some hours.
6. At no time was the Eastern Interconnection close to the loss of load or collapse due to low fre-

quency. The lowest Interconnection frequency recorded was 59.91 Hz at about 0700 EST, immediately following the loss of two generating units totaling 1,380 MW. Automatic underfrequency load shedding begins on the Eastern Interconnection at 59.7 Hz (with a very small amount at 59.82 Hz) and underfrequency generator tripping below that, depending on the unit type. Prolonged underfrequency operation leaves the Interconnection with less "room" to recover from generator failures, which during extremely widespread cold and icy weather, can be expected to occur frequently. The NERC Operating Criteria and Guides contain specific actions for utilities to follow to minimize their control error (avoiding prolonged under- or over-generation) and keep Interconnection frequency at 60 Hz.

The Eastern Interconnection met the challenge of the Cold Wave of 1994. This grid of generating plants and transmission lines transferred tremendous amounts of electricity to those parts of the Midwest and East that ran short of generating capacity. The integrity of the Interconnection was never in jeopardy because utilities followed NERC's Operating Criteria and Guides as well as their own well-practiced procedures, which included the difficult decision to shed some firm load customers. And through teamwork and customer cooperation, the electricity supply system that covers the United States and Canada from the Rockies to the Atlantic remained at our service.

Discussion

This section explains how the seven Regions in the Eastern Interconnection dealt with the cold weather during the week of January 16, 1994. When explaining that an event or situation occurred in a Region, it may not have necessarily been Region-wide. Also, this report is a considerable condensation of the detailed information the Regions provided, and is meant to give a general picture of the problems the utilities were dealing with.

Systems Included in This Report

This report contains information from the following Regions that comprise the Eastern Interconnection (Figure 1 shows the four Interconnections in North America):

East Central Area Reliability

Coordination Agreement — ECAR

Mid-Atlantic Area Council — MAAC

Mid-America Interconnected Network — MAIN

Mid-Continent Area Power Pool — MAPP

Northeast Power Coordinating Council — NPCC

Southeastern Electric Reliability Council — SERC

Southwest Power Pool — SPP

Data from SERC does not include Peninsular Florida. While Florida provided considerable

assistance, the cold weather did not extend into the state.

Data from NPCC does not include Hydro-Québec or the Maritime provinces.

Preparations

Twice each year, NERC publishes an assessment of the projected demand and generation available for the upcoming peak demand seasons, summer and winter. Information for these assessments is obtained from the Regional Councils, and is based on Regional and interregional forecasts and transfer studies. In November 1993, NERC published its *1993/94 Winter Assessment* covering the December through February period. The summary to that report reads in part "Generating Capacity: Adequate," with the following caveat: "Generating capacity will be adequate in all areas of the United States and Canada. Equipment problems and extreme weather in any Region, however, can combine to strain margins even when the projected margins are adequate."

Utilities in the Midwest and mid-Atlantic states began preparing for the expected cold weather as early as Wednesday, January 12, and continued for the next several days. These preparations included:

- Deferring maintenance on all generators and transmission lines.
- Setting up purchase power arrangements with other control areas.
- Converting dual-fueled generators from gas to oil in expectation of natural gas interruptions.
- Scheduling interchange to conserve local energy resources.

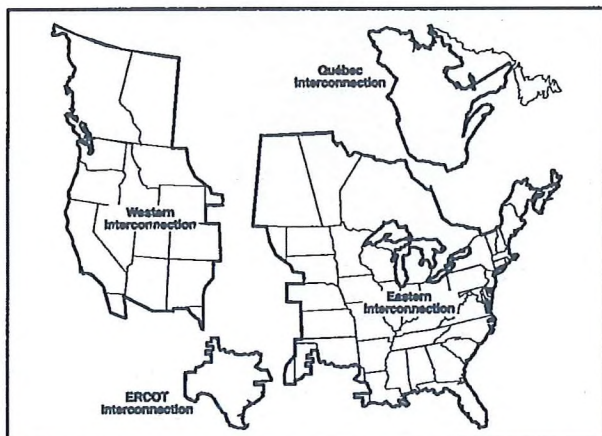


Figure 1 — The four Interconnections.

- Dispatching hydro and pumped storage generation to conserve these limited resources to ensure they would be available when needed.
- Restarting generators with long startup times, such as large coal-fired units.
- Starting combustion turbines, as well as other fossil-fired steam units, on January 18 to ensure they would be available the next day.

Communications

Utility control system operators are in constant contact with each other, even during normal operations. There are many communications systems used in the Eastern Interconnection. To name a few:

- Eastern Interconnection Hotline — A preset conference call system that connects the seven Eastern Interconnection Regions via a selected control area in each Region.
- Operating Representatives of the Northeast Systems (ORNS) — Simultaneously connects many of the utilities in MAAC, NPCC, and ECAR, plus Virginia Power.
- Dedicated telephone circuits — Individual telephone circuits between control areas. These may be leased circuits from the telephone company, or private wire, fiber, microwave, or carrier current circuits.

In addition, utilities regularly use the public switched telephone network.

During the morning of January 19, PJM chose to use the ORNS network while Virginia Power made individual phone calls to other control areas to secure

emergency assistance. Carolina Power & Light Company used the Eastern Interconnection Hotline via Southern Company. All three control areas received good responses from their communications with other systems, and the Task Force does not suggest that any of these systems should have used other means of communications.

The Task Force does, however, note two general problems with communications in the Eastern Interconnection that became apparent after reviewing this incident:

1. After the message for assistance was placed on the Eastern Interconnection Hotline, many systems were slow to learn of the emergency.
2. Relying on a telephone "tree" system like the Hotline makes it difficult for control areas to find and schedule capacity from long distances throughout the Interconnection.

Therefore, the Task Force recommends that the NERC Operating Committee continue to pursue better communications, especially throughout the Eastern Interconnection. Specifically, the Operating Committee should review the use and effectiveness of the Eastern Interconnection Hotline during emergencies.

Generation

The extremely cold and icy weather had various detrimental effects on the generation supply. These included natural gas interruptions, oil delivery problems due to icy roads and rivers, frozen coal, and the ubiquitous "equipment problems." Table 1 shows the generation unavailable in each Region.

Discussion

Fuel Problems

Coal — Coal inventory was not a problem. Coal handling was. Problems ranged from frozen coal piles to frozen conveyor belts to frozen mine equipment. Frozen coal can plug hoppers and slide off conveyor belts, or destroy the belts completely.

Natural Gas — The natural gas supply system was also encountering an extremely high demand. Interruptible natural gas was interrupted to some utilities in all seven Regions. Utilities anticipated this, and many had already converted to burning oil in their dual-fueled generators before January 19. No Region reported that firm gas had been curtailed, but in many cases, utilities voluntarily limited their use of firm gas, or switched from firm gas to oil, or did not generate with units that burned only natural gas.

Oil — With utilities burning oil in their normally gas-fired boilers and combustion turbines, oil supply became an important issue. Utilities in ECAR, MAAC, MAIN, and SERC reported problems with oil deliveries. In many cases, economic pressures were cited as the reason that oil inventories were kept low. Under normal conditions, this has not been a problem; however, in this extreme case, areas in these four Regions had been plagued with icy

roads and waterways for days before January 19. The weather, plus the heavy demand for the fuel, slowed oil deliveries, so that some generating plants ran out of oil, or had depleted their reserves to the bare minimum needed to allow the utility to black-start the unit. Finally, some oil began to gel in the tanks because of the extreme cold.

Other Equipment Problems

Other than the fuel-handling systems, generation equipment fared pretty well in the extreme cold. Some units were derated because their scrubbers or precipitators had trouble in the cold weather.

Generation Reserves

Generation reserves consist of on-line reserves (spinning reserves, in the broadest sense) and off-line reserves.

On-Line Reserve — Total on-line reserve (Appendix C — "Demand and On-Line Reserves") in the Interconnection during the morning of January 19 ranged from about 32,500 MW to a minimum of 14,200 MW. The control areas need this reserve to follow the variations in their customers' demands, and to

	ECAR	MAAC	MAIN	MAPP	NPCC	SERC	SPP	TOTAL
Fuel Related	5,309	4,829	3,367	554	299	1,048	200	15,606
Equipment Failure	6,476	6,580	5,969	827	3,624	9,487	2,778	35,741
Start Failure	718	818	104	120	20	450	0	2,230
Miscellaneous	877	1,506	986	1,310	4,487	3,995	0	13,161
Planned	7,080	4,985	5,720	491	7,697	5,803	3,780	35,556
Total	20,460	18,718	16,146	3,302	16,127	20,783	6,758	102,294

Table 1 — Generation unavailability, January 19, 1994, hour ending 0900 (MW)

recover from generation failures. Of this total, some reserve was available for additional sales during the period. However, the total reserves for sale in the Eastern Interconnection dropped dramatically from about 15,000 MW at hour ending 0700 to only 3,500 MW at hour ending 0900. These available reserves were found mostly in MAIN, MAPP, SPP, and NPCC, and were scattered among many control areas. Transmission limits into PJM through NPCC (specifically, New York Power Pool to PJM and Ontario Hydro to both New York and Michigan) prevented PJM and Virginia Power from scheduling additional capacity from NPCC. Also, transmission limits were being approached along the ECAR-to-PJM/Virginia Power interface, which made scheduling additional capacity into PJM and Virginia Power from Regions to the west (MAIN, MAPP, and SPP) very difficult, if not impossible.

SERC (with the exception of Peninsular Florida) had no capacity of any significance for sale until hour 1100 when about 400 MW became available. This increased to about 2,500 MW by hour 1400, but by that time, PJM's and Virginia Power's firm load shedding had ended.

Off-Line Reserve — This category consists of "quick-start" generators, like combustion turbines, that are available in one hour or less, and "eight-

hour" generators, such as steam units that need considerably more time to start and become available for service.

Off-line, quick-start reserves ranged from 12,700 MW to 7,500 MW, predominately in ECAR, MAIN, MAPP, NPCC, and SPP. And, again, approaching transmission limits into PJM through ECAR and NPCC prevented purchases from this reserve. SERC did not have a significant amount of off-line reserves until hour 1200.

Demand

Peak Demand

The table below shows the integrated net peak demand for each Eastern Interconnection Region compared to the projected peak demand for the winter season from the 1993/94 *Winter Assessment*. (Hour ending 0900 was the Eastern Interconnection's "coincident" peak demand hour. Some Regions' individual peak demands occurred in other hours that morning.)

	ECAR	MAAC	MAIN	MAPP	NPCC*	SERC*	SPP	TOTAL
Actual	76,191	40,557	33,940	22,352	63,366	100,238	40,673	374,871
Forecast	72,351	39,293	33,524	27,427	64,668	84,987	39,253	361,503
% Difference	5.3	3.2	1.2	(18.5)	(2.0)	17.9	3.6	3.7
Hour	0900	0900	1200	1000	1000	0800	0900	0900

Table 2 — Peak demand, January 19, 1994 (MW). Actual demand is demand served after the demand reductions in Table 3 were implemented.

**Data from NPCC does not include Hydro-Québec or the Maritime provinces. Data from SERC does not include Peninsular Florida.*

Discussion

	ECAR	MAAC	MAIN	MAPP	NPCC	SERC	SPP	TOTAL
Demand-Side Management	77	400	0	52	0	664	0	1,193
Interruptible Load	1,319	600	0	81	0	2,358	0	4,358
Public Appeals	1,590	Not Available	0	0	0	400	0	1,990
Voltage Reductions	238	600	0	0	278	540	0	1,656
Interruption of Firm Load	0	Note 1	0	0	0	800	0	800
Total	3,224	1,600	0	133	278	4,762	0	9,997

Table 3 — Effects of demand reduction measures, January 19, 1994, hour ending 0900 EST (MW). Note 1: Interruption of firm load in MAAC (PJM) occurred at 0705–0741, and 0922–1307.

Demand Reductions

ECAR, MAAC, MAPP, NPCC, and SERC implemented various kinds of demand reduction measures during the morning of January 19 as shown in Table 3.

Interconnection Frequency

After the Northeast Blackout of 1965, the electric utilities in North America developed coordinated underfrequency load shedding plans. The control areas in all the Interconnections employ underfrequency load shedding relays to automatically trip customer load when the Interconnection frequency drops to a certain point. The most probable way this may happen would be from a major generation deficiency. This usually occurs when a part of a control area is left with insufficient generating capacity after it separates from the Interconnection. The underfrequency load shedding quickly restores the generation-to-demand balance to return the frequency to near 60 Hz in the islanded part of the bulk electric system.

It is conceivable that the entire Interconnection could suffer a generation loss great enough to trigger underfrequency load shedding relays throughout the Interconnection, although this has never happened. The generation level in the Eastern Interconnection was sufficient to keep the frequency well above the point at which underfrequency load shedding would occur. On the morning of January 19, the frequency in the Interconnection briefly dipped to 59.91 Hz. However, at no time was the Interconnection close to the loss of load or collapse due to low frequency. Appendix B explains this in more detail.

Actions to Return Frequency to 60 Hz — NERC Operating Criteria and Guides do not allow any control area to make a unilateral decision to undergenerate, or "lean" on the Interconnection, which decreases Interconnection frequency. Nor do the NERC Operating Criteria and Guides allow control areas with extra reserves to unilaterally "push" on the Interconnection by overgenerating. That could cause transmission overloads in already stressed areas. This explains why so many utilities implemented load reduction actions (see Table 3, and Appendix A, "Sequence of Events"), which was

capped by PJM's and Virginia Power's decision to manually shed firm customer load. This load shedding action, plus voltage reductions, public appeals, and voluntary curtailments of demand by industry, commercial and residential customers, and government offices, brought the frequency back to 60 Hz at about hour 1030. In fact, the Interconnection frequency remained generally above 60 Hz until hour 1800, probably because the demand was dropping quite rapidly that afternoon. However, the NERC Operating Criteria and Guides do not allow control areas to lean on the Interconnection even when the Interconnection frequency is above 60 Hz.

Transmission

The transmission system performed very well. Transmission limitations, often called First Contingency Total Transfer Capability (FCTTC), were known and respected. In several cases, utilities reassessed transfer limits using real-time data, and some limits were upgraded. In other situations, utilities adjusted generation levels, going off economic dispatch, to increase transmission transfer capabilities. But at no time was the transmission system in jeopardy of becoming disconnected through a cascading failure. The details follow:

Equipment — The cold weather caused some problems for pneumatic and SF6 circuit breakers. These devices rely on the high pressure of compressed air to operate or special gases for electrical insulation, and the cold temperatures depressed the gas pressure. However, it seems these problems were sporadic and did not contribute materially to transmission limitations. Electric heaters are commonly used on "air" circuit breakers during cold weather.

Interchange — Appendix D — "Scheduled Interchange," shows the base¹ and actual power transfers throughout the Eastern Interconnection. The arrows show the scheduled interchange, and the number in the Region or area "bubble" shows the net MW purchased or sold. (Negative is a net purchase and positive a net sale.) The electricity supplied by the Peninsular Florida and Canadian utilities is especially notable.

Transfer Capabilities — The transmission transfer limitations that were reached are listed in Table 4.

¹Base power transfer from NERC 1993/94 Winter Assessment

From	To	First Contingency Total Transfer Capability — MW
NYPP	PJM	3,000, raised to 3,600 at 1112 hour
NEPEX	NYPP	1,100
Ontario Hydro	NYPP	2,500
Allegheny Power System	PJM and Virginia Power	Reliability Coordination Plan Level II — No action was taken to reduce transfers because utilities were shedding load.
Ontario Hydro	ECAR	2,100 (at Ontario-Michigan interface)
Florida	Southern	1,300, raised to 3,000 in 500 MW blocks as security studies showed the limit could be raised. Transmission constraints on the Southern Company System limited the actual transfer to 2,930 MW.

Table 4 — Electricity transfer limitations on January 19, 1994.

Recommendations

The North American Electric Reliability Council believes it is important to analyze experiences like these for "lessons learned," and to share those lessons in reports like this one.

The Eastern Interconnection worked very well during the week of January 16 — a period of extremely cold, icy weather and high electric demands. The Task Force does not suggest that either PJM or Virginia Power should have done anything differently. However, the Blue Ribbon Task Force offers the following recommendations to all electric systems throughout the United States and Canada. Each electric system must consider these recommendations in light of their unique system conditions and circumstances.

Recommendation 1

Communications among utilities implementing the major load reduction measures was excellent. As with any incident of this nature, there are lessons to be learned so that utilities will be even better prepared for future emergencies. With this in mind, the NERC Operating Committee should continue to pursue better communications and information sharing. Specifically, it should review the circumstances and procedures for using the Eastern Interconnection Hotline, and the responsibilities that each Reliability Council has to disseminate information on the Hotline to their member control areas.

Recommendation 2

Control areas and Regions should develop the capability to calculate the first contingency transfer capability in real time. For example, utilities in Florida recalculated their first contingency transfer capability into Georgia "on the fly" and found they could raise the limit significantly. Normally, flows on this interface are in the opposite direction. As an alternative, inter- and intraregional study groups should periodically calculate transfer capability even for seldom-used transfer scenarios.

Recommendations

Recommendation 3

Regions, subregions, pools, and coordinating groups should review their mutual assistance agreements. These groups should consider, for example, implementing voltage reductions as New York Power Pool did to free up generation or transmission capacity to help other areas about to shed firm load, or reduce the amount of load they had to shed.

Recommendation 4

Systems should review their backup fuel inventory policies.

Recommendation 5

The experiences of the week of January 16 reinforce the importance for the electric utilities and gas pipelines to continue working together individually and through the joint efforts of NERC and the Interstate Natural Gas Association of America to improve operational coordination during emergencies.

Appendix A

Sequence of Events

All times are Eastern Standard. MW values in parentheses are the demand reductions resulting from these actions. Unless noted, all customer loads curtailed were interruptible.

January 18

0615 — Allegheny Power System — Implemented interruptible customer curtailment (restored at 1300 on January 20)

1740 — Allegheny Power System — 5% voltage reduction, public appeal, and appeal to industrial or large commercial customers (withdrawn at 1127 on January 20)

January 19

0500 — Indianapolis Power & Light — Appeal to industrial or large commercial customers (withdrawn at 1800)

0506 — PJM — Manual Load Dump Warning issued

0515 — APS-PJM-Virginia Power Reliability Coordination Plan (RCP) Level I declared (No additional transfers should be scheduled without prior consent of the initiating control area.)
Carolina Power & Light — Large load curtailment program implemented (143 MW)

0530 — Virginia Power — Public appeal issued
Duquesne Light — Public appeal issued

0600 — Indianapolis Power & Light — Public appeal issued (withdrawn at 1800)
PJM — Load management curtailment ordered (withdrawn at 2232)

0608 — Carolina Power & Light — Water heater control began (107 MW)

0615 — Carolina Power & Light — Called NERC Hotline for emergency assistance
Began 5% voltage reduction (240 MW)
Virginia Power — canceled 200 MW diversity schedule to APS

0620 — Virginia Power — Began 5% voltage reduction

0628 — American Electric Power — Implemented interruptible customer curtailment (restored at 1915)

0631 — TVA — Economy Surplus Power Customers Option B curtailed (425 MW)

0645 — TVA — Economy Surplus Power Customers Option A curtailed (550 MW)
PJM — Began 5% voltage reduction (canceled at 2028)

APS/PJM/VP — RCP Level II declared (Level II might require, in the following order, generation adjustments, or a freeze on transfers, or reduction in transfers up to 500 MW at a time. However, if such action would prevent a control area from serving load, it is acceptable to continue operation at Level II.)

0700 — Duquesne Light — Appeal to industrial and large commercial customers
PJM — Radio/TV appeal to reduce demand issued

0702 — Southern — Bowen #4 tripped (880 MW generation), and Bowen #2 had a runback of about 500 MW generation that recovered to full output within the next hour.

0705 — PJM — Voluntary Customer Load Curtailment
PJM — Curtailment of non-essential building load
PJM — 500 MW firm customer load shed

Sequence of Events

0713 — Duke Power — Water heater control began (70 MW)

Standby Generator Program began (36 MW)

0733 — TVA — Economy Surplus Power Customers Option E curtailed (9 MW)

0734 — American Electric Power — Appeal to industrial and large commercial customers (withdrawn at 1200 on January 20)

0741 — PJM — 500 MW firm customer load restored

0800 — TVA — Distribution load reduction programs and public appeals requested

East Kentucky Power Cooperative — Public appeal and appeal to industrial or large commercial customers issued (withdrawn at 2300)

Cincinnati Gas & Electric — Appeal to industrial and large commercial customers (withdrawn at 1200 on January 20)

Ohio Edison — Interruptible customers were interrupted on an emergency basis

Ohio Edison — Appeal to other industrial or large commercial customers

0802 — Duke Power — Interruptible Service Program began (155 MW)

0821 — New York Power Pool — Ordered 5% quick response (available within ten minutes) voltage reduction at PJM's request in order to support deliveries to them.

0823 — Virginia Power — 400 MW firm customer load shed

0830 — American Electric Power — Public appeal issued (withdrawn at 1200 on January 20)

0845 — Virginia Power — 400 MW firm customer load shed (800 MW total)

0902 — American Electric Power — Voltage reduction (restored at 1010 on January 20)

0915 — Hoosier Energy — Public appeal and appeal to industrial or large commercial customers issued (both withdrawn at 0915 on January 20)

0922 — PJM — 500 MW firm customer load shed

0934 — Southern — Bowen #2 tripped (700 MW generation)

New York Power Pool — Ordered 5% manual voltage reduction at PJM's request (withdrawn on January 20)

0941 — Southern — Vogtle #2 tripped (1,200 MW generation). Southern had to recall approximately 800 MW of sales to cover the generation loss.

0946 — PJM requests New York Power Pool to restudy its stability limits

0952 — Duke Power — Water heater control ended

1008 — Carolina Power & Light — Water heater control ended

1010 — PJM — 500 MW firm customer load shed (1,000 MW total)

1100 — Duke Power — Standby Generator Program ended

Virginia Power — 200 MW firm customer load restored (600 MW remaining)

TVA — Economy Surplus Power Option A and B ended

TVA — Economy Surplus Power Option C and E ended

1106 — New York Power Pool — Terminated 5% quick response voltage reductions

Sequence of Events

1109 — Duke Power — Interruptible Service Program ended

1112 — New York Power Pool — Completed studies and rerated transfer capabilities to PJM from 3,000 MW to 3,600 MW to allow additional deliveries to PJM

1130 — Virginia Power — 200 MW firm customer load restored (400 MW remaining)

1133 — Carolina Power & Light — 5% voltage reduction ended

1144 — PJM — 500 MW firm customer load shed (1,500 MW total)

1200 — Virginia Power — 200 MW firm customer load restored (200 MW remaining)

**TVA — Economy Surplus Power Option B ended
Northern Indiana Public Service — Appeal to industrial and large commercial customers (withdrawn at 1200 on January 20)**

1215 — Virginia Power — Final 200 MW firm customer load restored

**1247 — Illinois Power — Baldwin #2 and #3 trip (750 MW generation total)
Purchased power from SERC until 2300**

1254 — PJM — Begin firm load restoration (complete at 1307)

1300 — Carolina Power & Light — Large Load Curtailment Program ended

TVA — Distribution load reduction program and public appeal ended

1307 — PJM — All firm load restored

Appendix B

Interconnection Frequency Response

January 19, 1994

Frequency Profile and Response Characteristic —

Figure 1 shows Interconnection frequency for January 19. The lowest frequency was 59.91 Hz, which occurred immediately after Southern Company's Bowen #4 unit (880 MW) tripped, along with the 500 MW runback (generation reduction) of Bowen #2. Figure 2 shows the frequency response characteristic of the Interconnection from the Bowen #4 trip. This plot from the digital frequency recorder at Pine Bluff, Arkansas, shows the Interconnection frequency dropped to 59.93 Hz. (Control area strip charts show the frequency hit 59.91 Hz a short time later, past the capture period of the digital frequency recorder.)

The Interconnection's frequency response characteristic from the Bowen #4 trip was almost 5,900 MW/0.1 Hz (59,000 MW/Hz). The frequency response characteristic is a function of the load and generation characteristics, and varies from hour to hour, and day to day with load and generation mix changes. For the Eastern Interconnection, it is typically about 4,000 MW/0.1 Hz or 40,000 MW/Hz. That is, a 40,000 MW generation loss will cause the Interconnection's frequency to decline by 1 Hz. The higher frequency response characteristic

on January 19 was possibly due to the tremendous amount of both generation and load on the Eastern Interconnection.

The highest underfrequency load shed point in the Eastern Interconnection is at 59.82 Hz (about 60 MW), with much more beginning at 59.7 Hz. Therefore, using the apparent 5,900 MW/0.1 Hz response, and assuming the response is linear, the Interconnection would have needed to lose an additional:

$$(59.91 \text{ Hz} - 59.7 \text{ Hz}) \times 59,000 \text{ MW/Hz} = 12,390 \text{ MW}$$

to trigger the first step of automatic underfrequency load shedding at 59.7 Hz.

Under normal conditions, this would be considered an unlikely event. But, during a severe and widespread icy cold wave, generation failures can be expected to occur more frequently. Therefore, operating at below-normal frequency becomes a greater concern, and maintaining 60 Hz operation is very important to enable the Interconnection to withstand the next contingency.

Interconnection Frequency Response

January 19, 1994

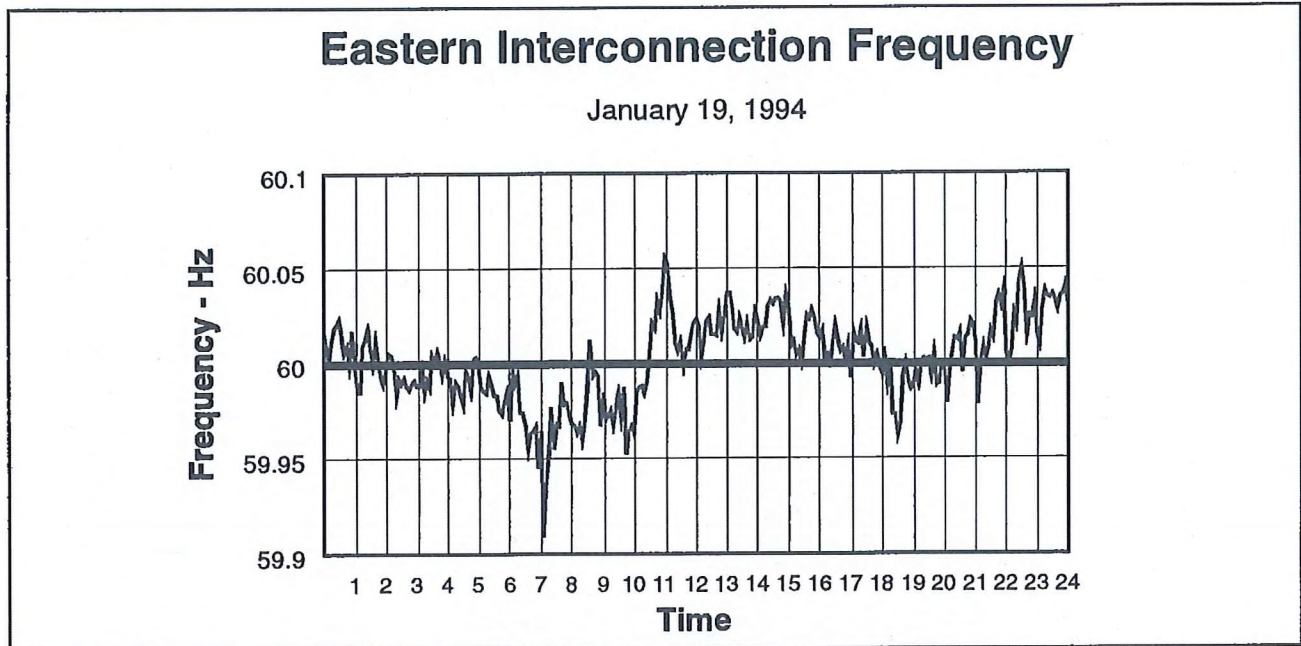


Figure 1 — Eastern Interconnection frequency for January 19, 1994.

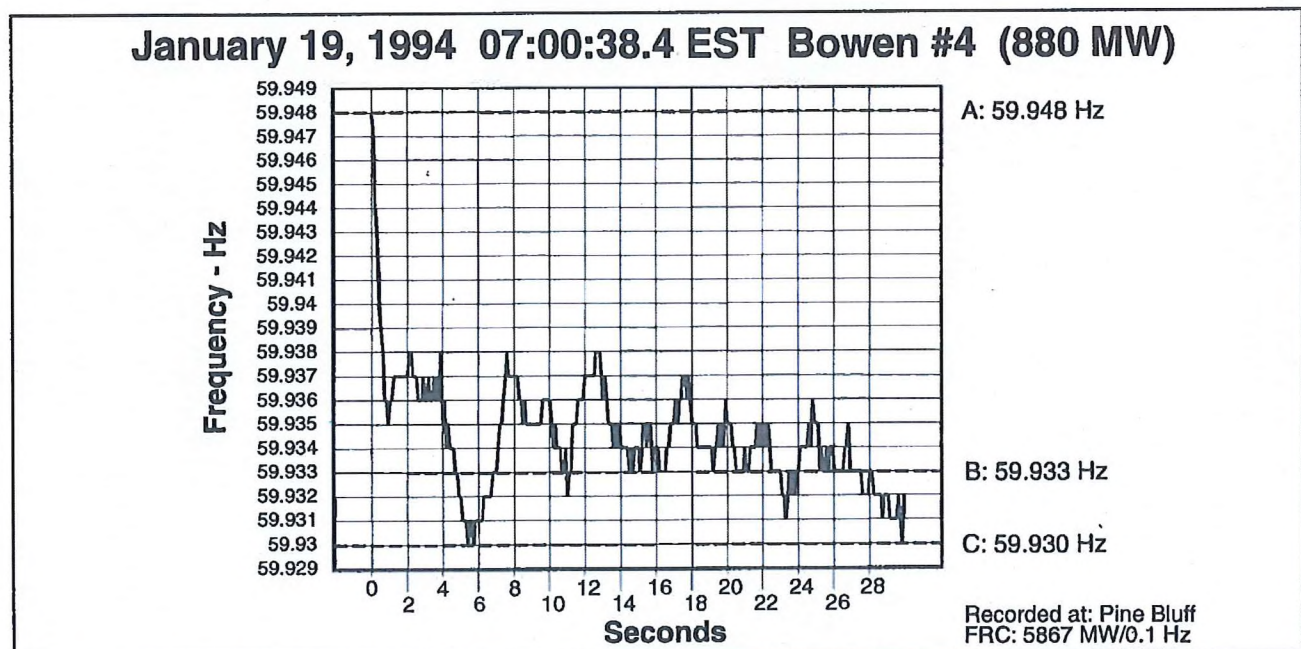


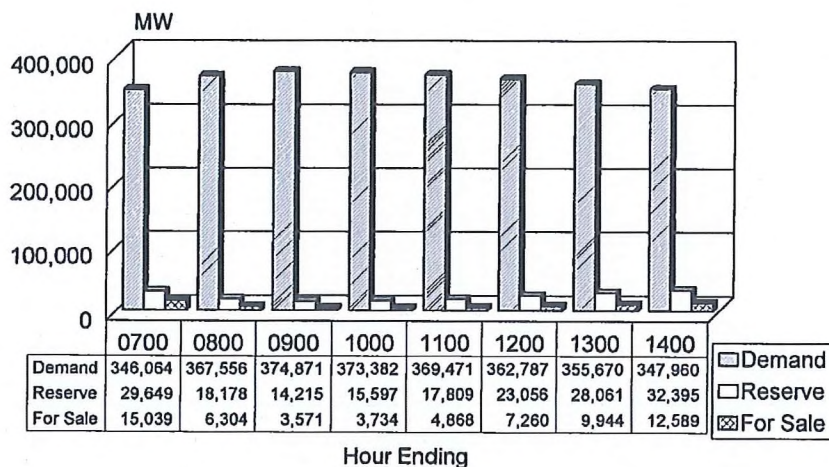
Figure 2 — Eastern Interconnection frequency response from trip of Bowen unit #4 (880 MW).

Appendix C

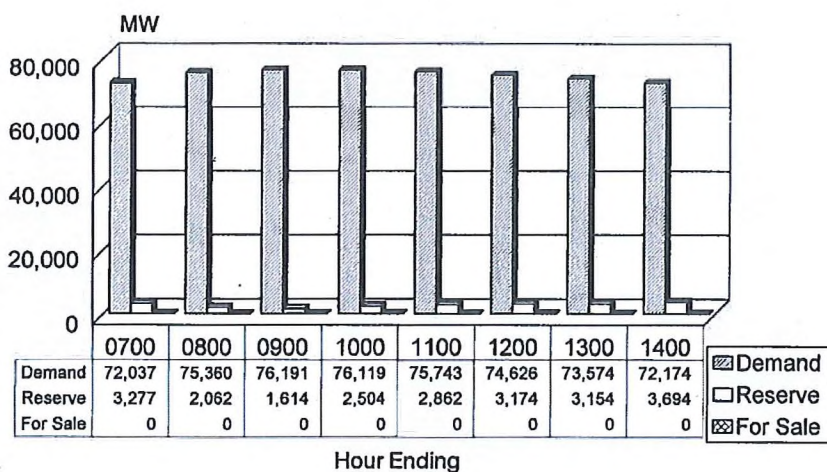
Demand and On-Line Reserves

January 19, 1994

Eastern Interconnection



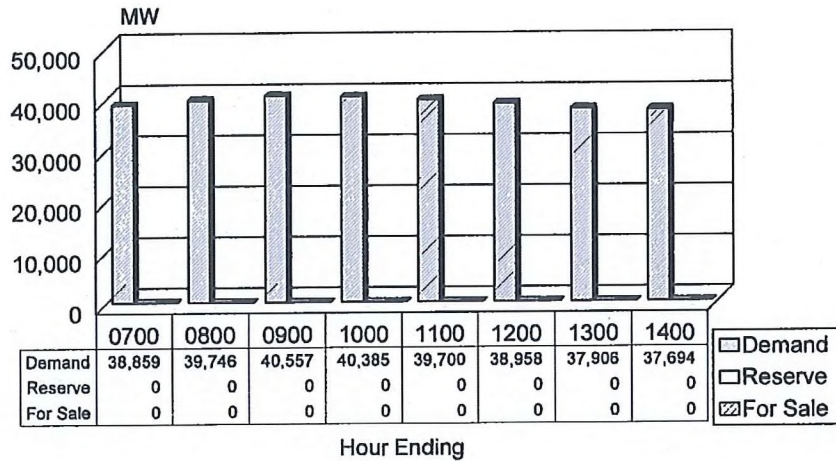
ECAR



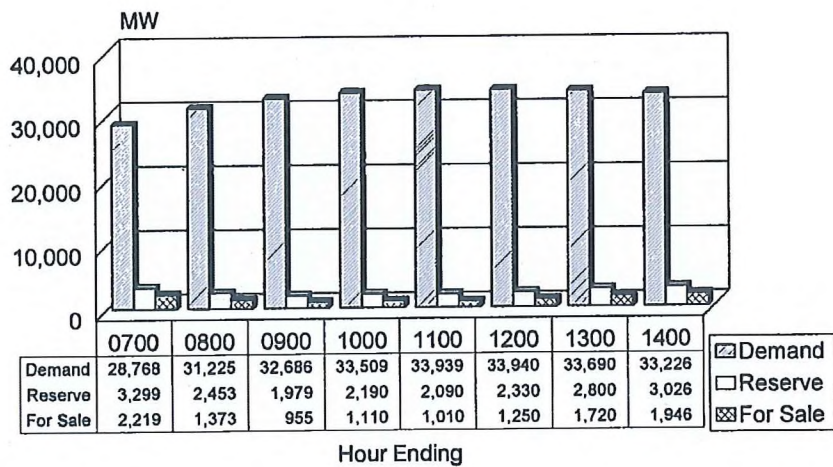
Demand and On-Line Reserves

January 19, 1994

MAAC



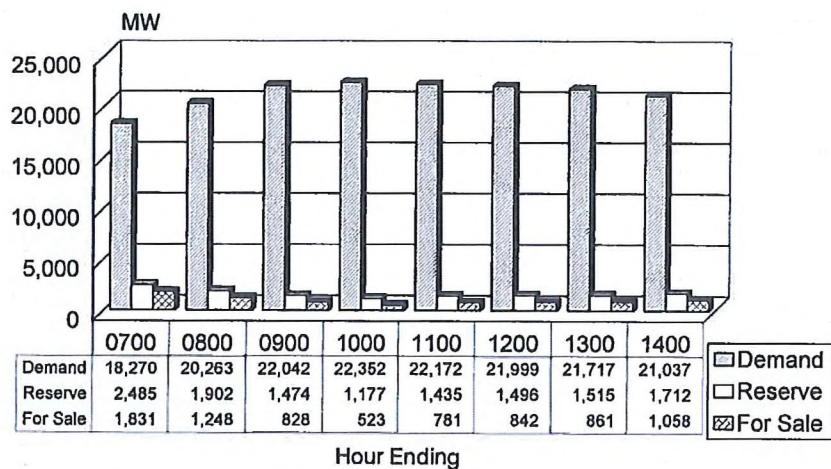
MAIN



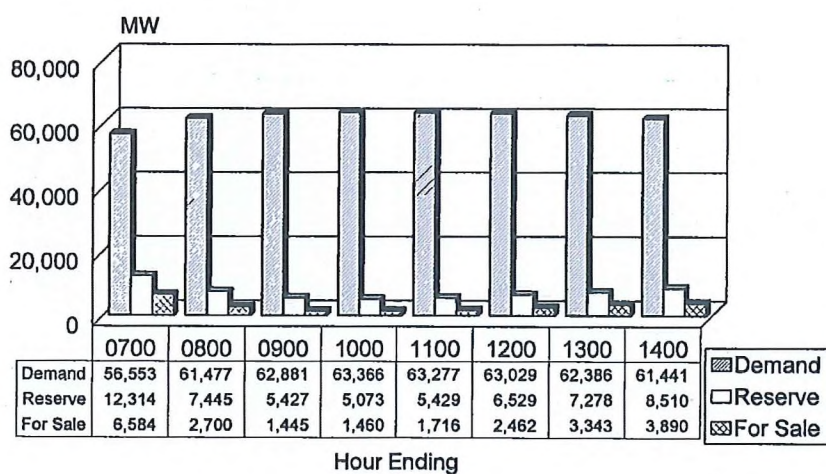
Demand and On-Line Reserves

January 19, 1994

MAPP



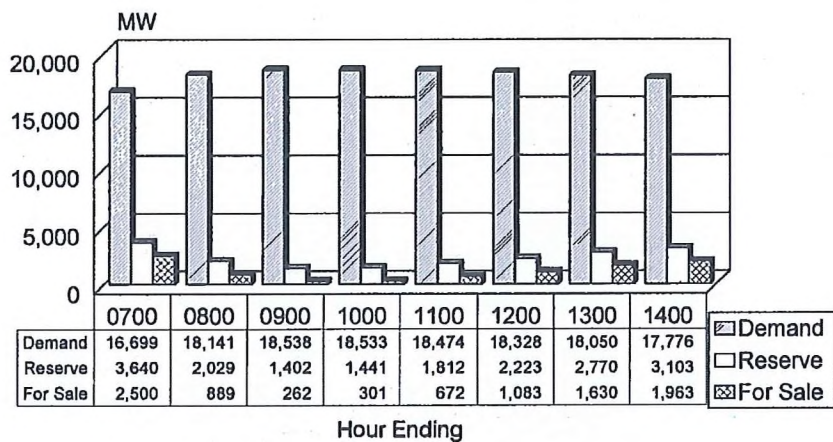
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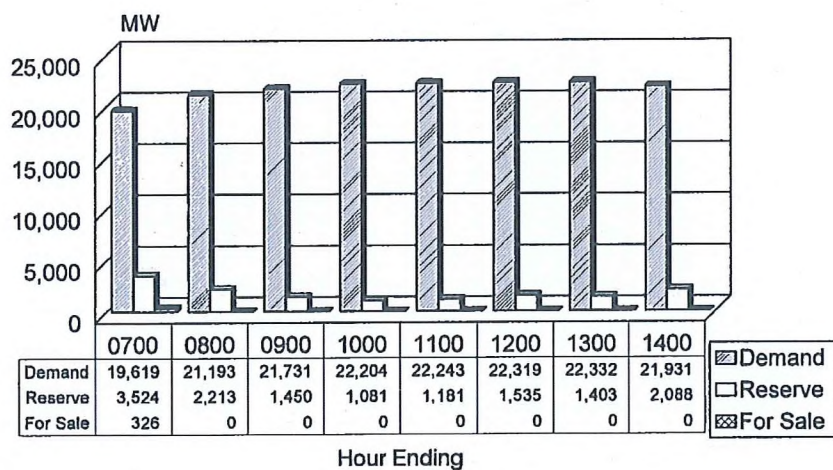
Demand and On-Line Reserves

January 19, 1994

NPCC-NEPOOL



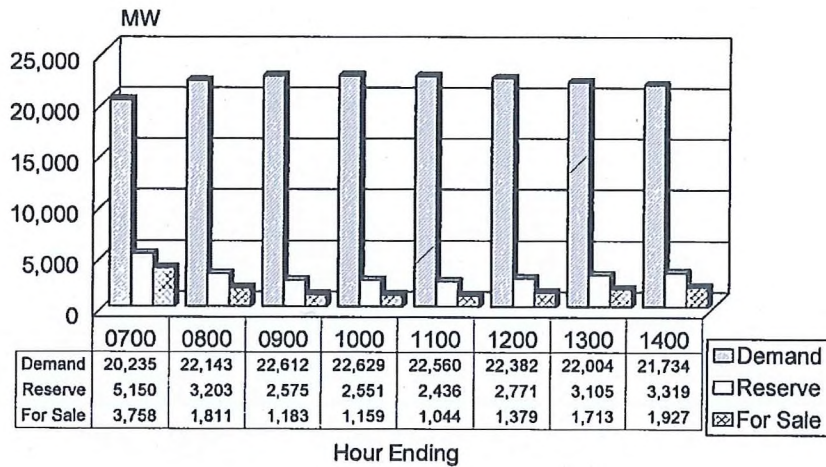
NPCC-New York



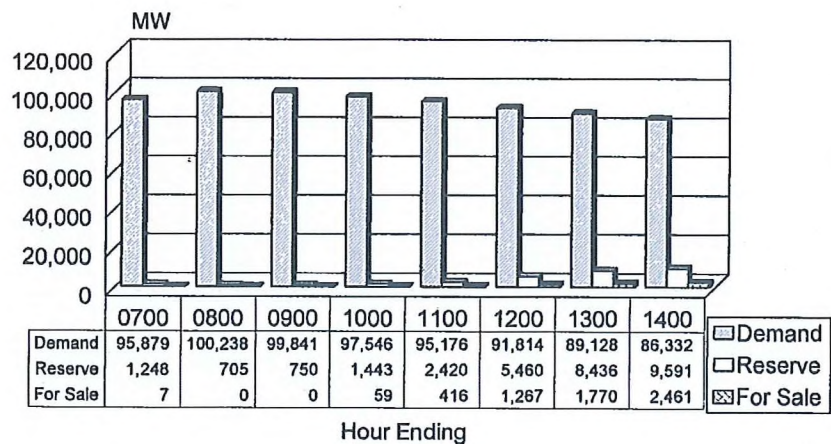
Demand and On-Line Reserves

January 19, 1994

NPCC-Ontario



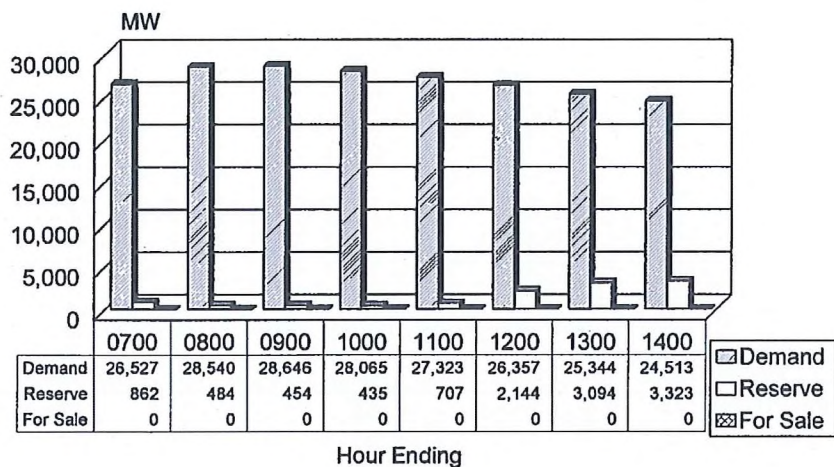
SERC



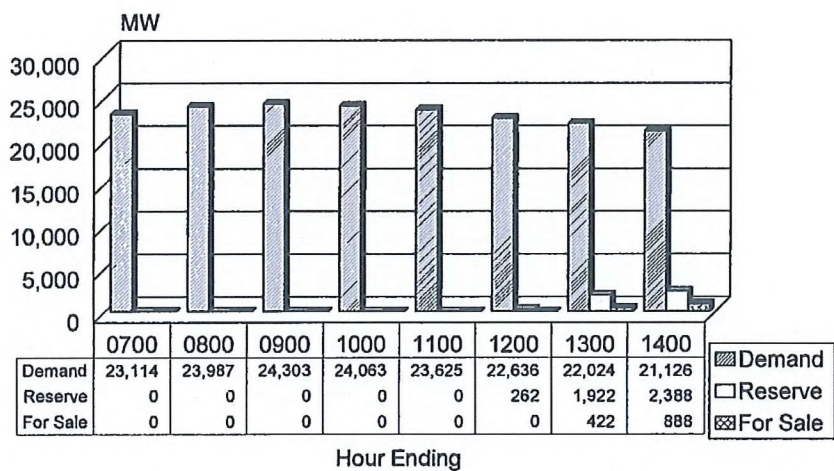
Demand and On-Line Reserves

January 19, 1994

SERC-Southern



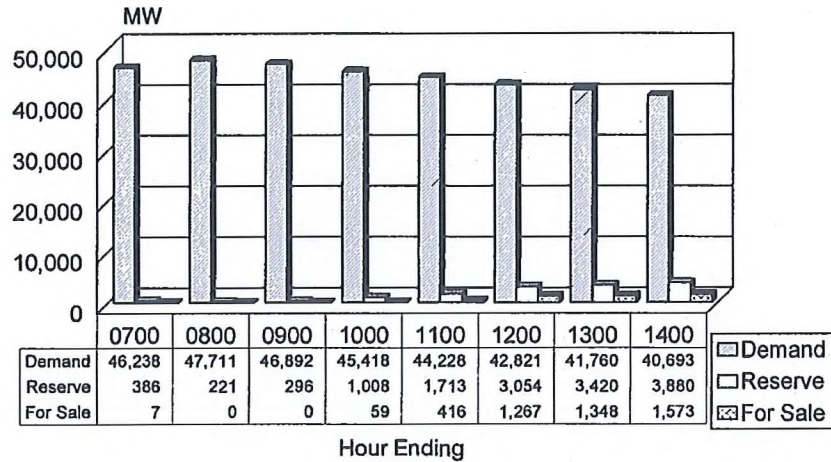
SERC-TVA



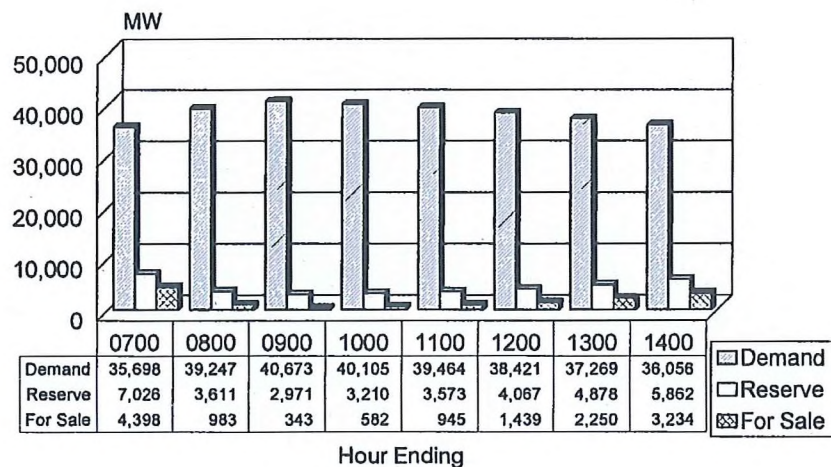
Demand and On-Line Reserves

January 19, 1994

SERC-VACAR



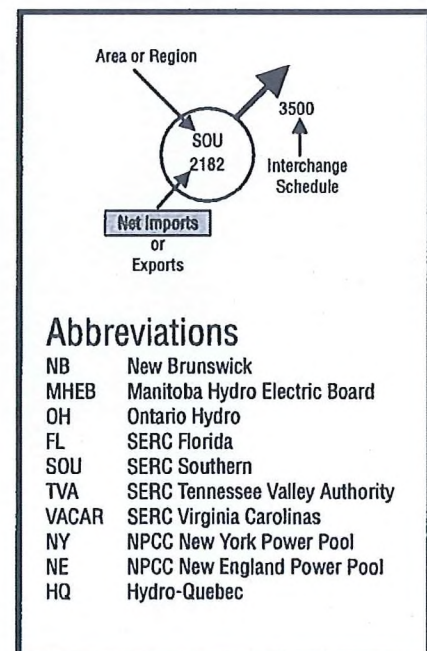
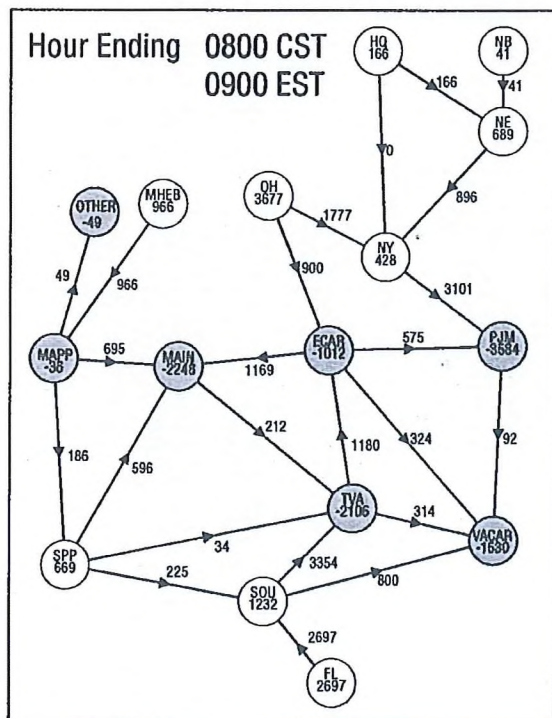
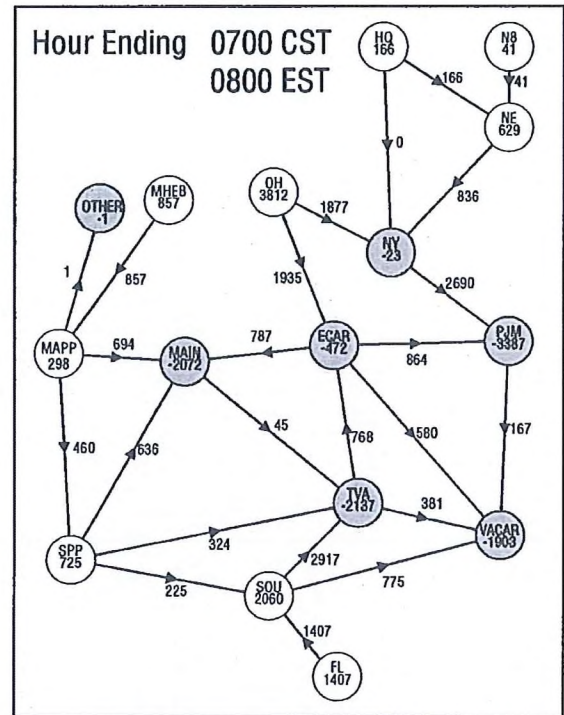
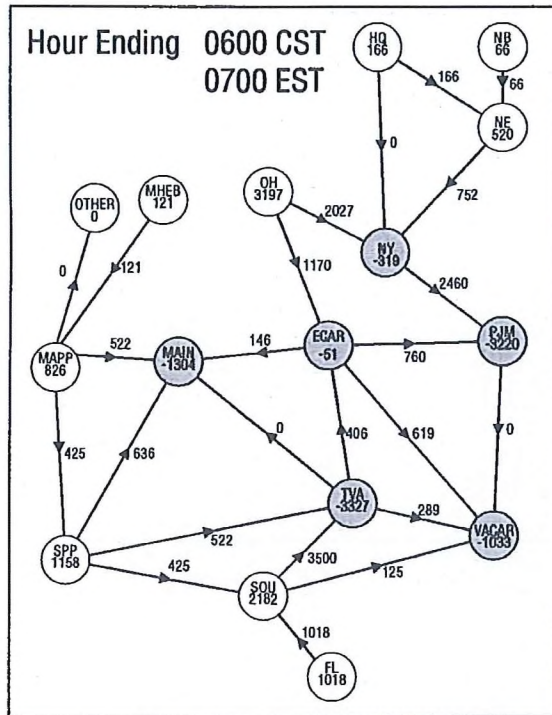
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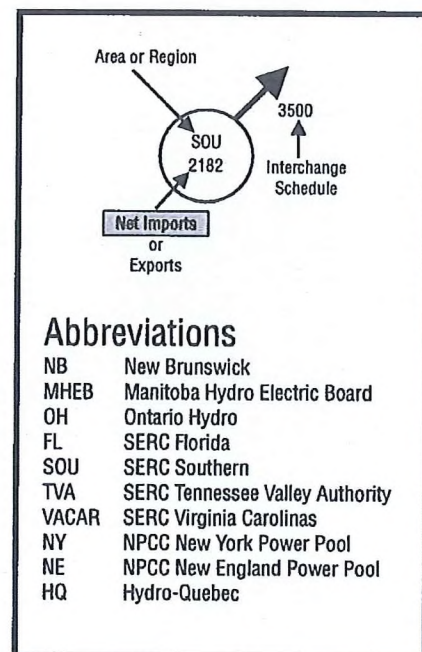
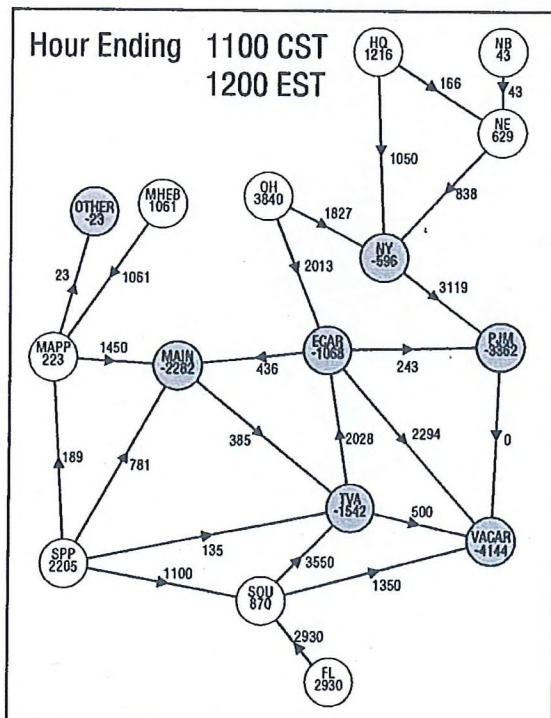
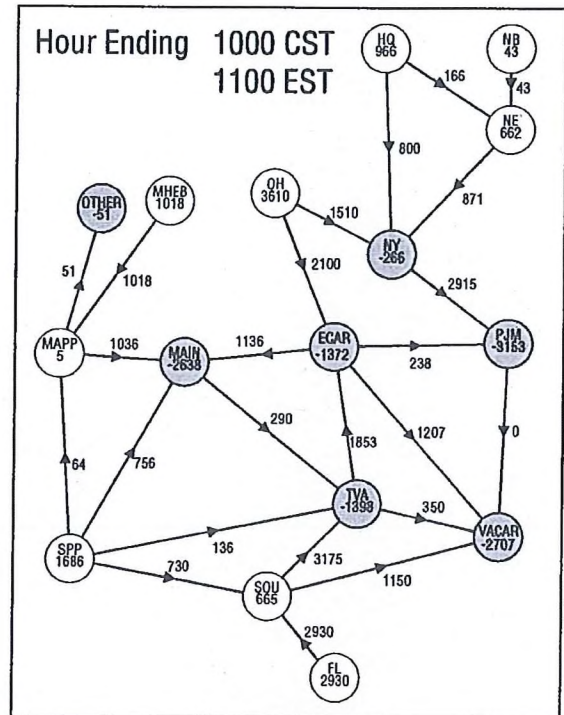
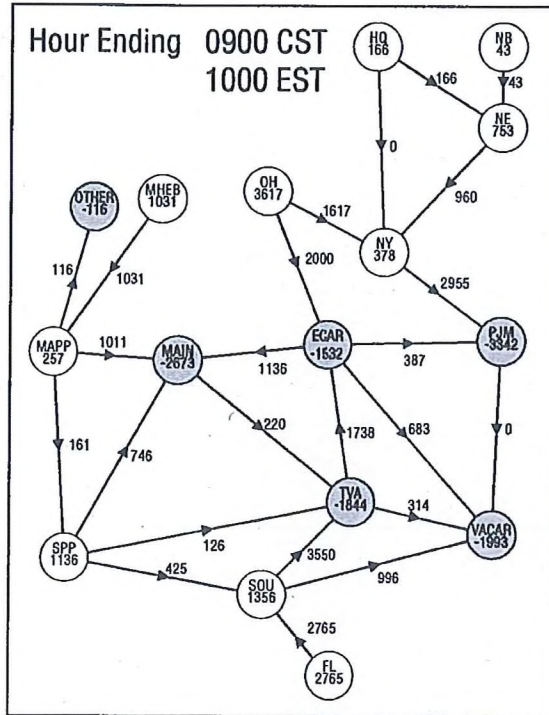
Appendix D

Scheduled Interchange

January 19, 1994

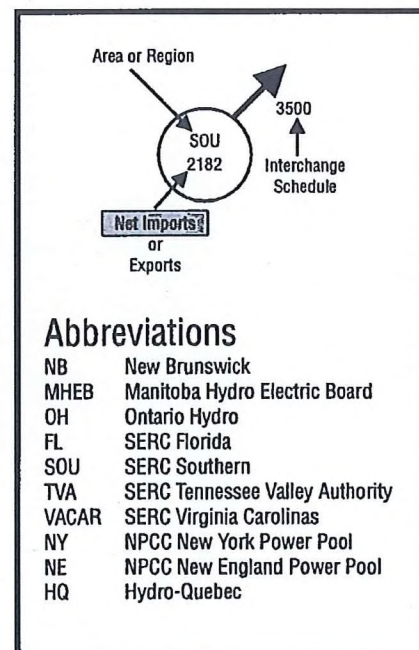
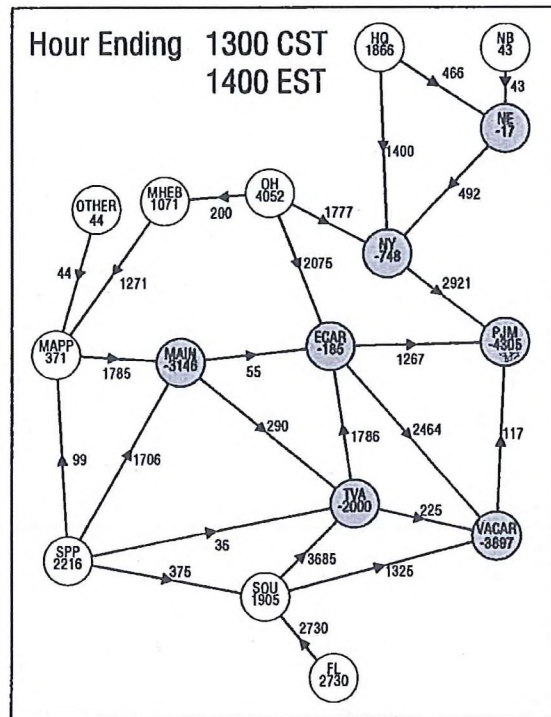
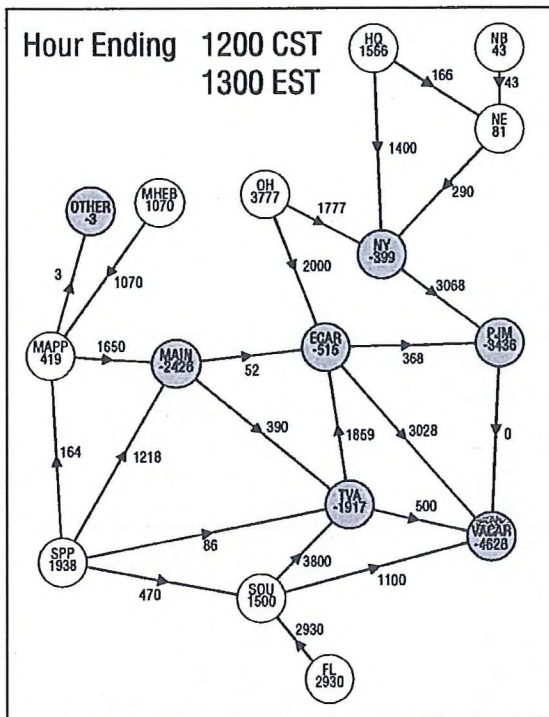


Scheduled Interchange January 19, 1994



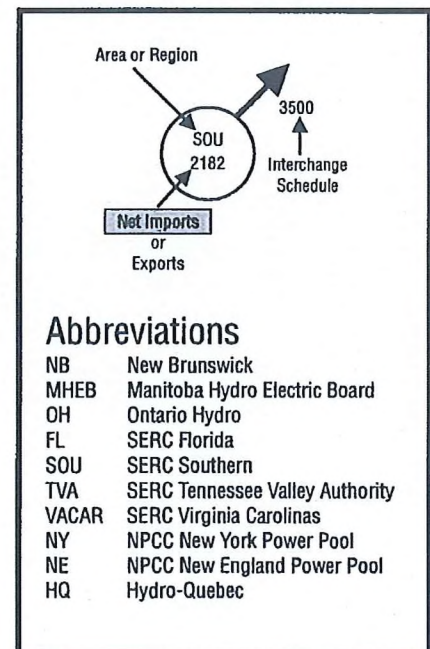
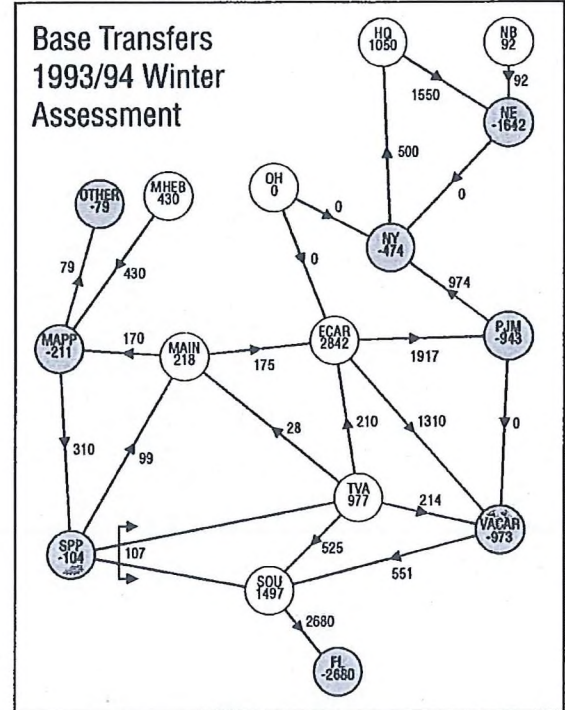
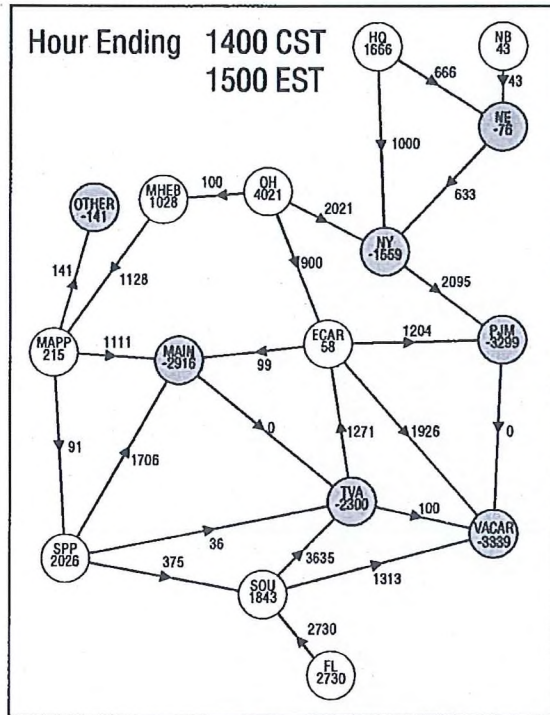
Scheduled Interchange

January 19, 1994

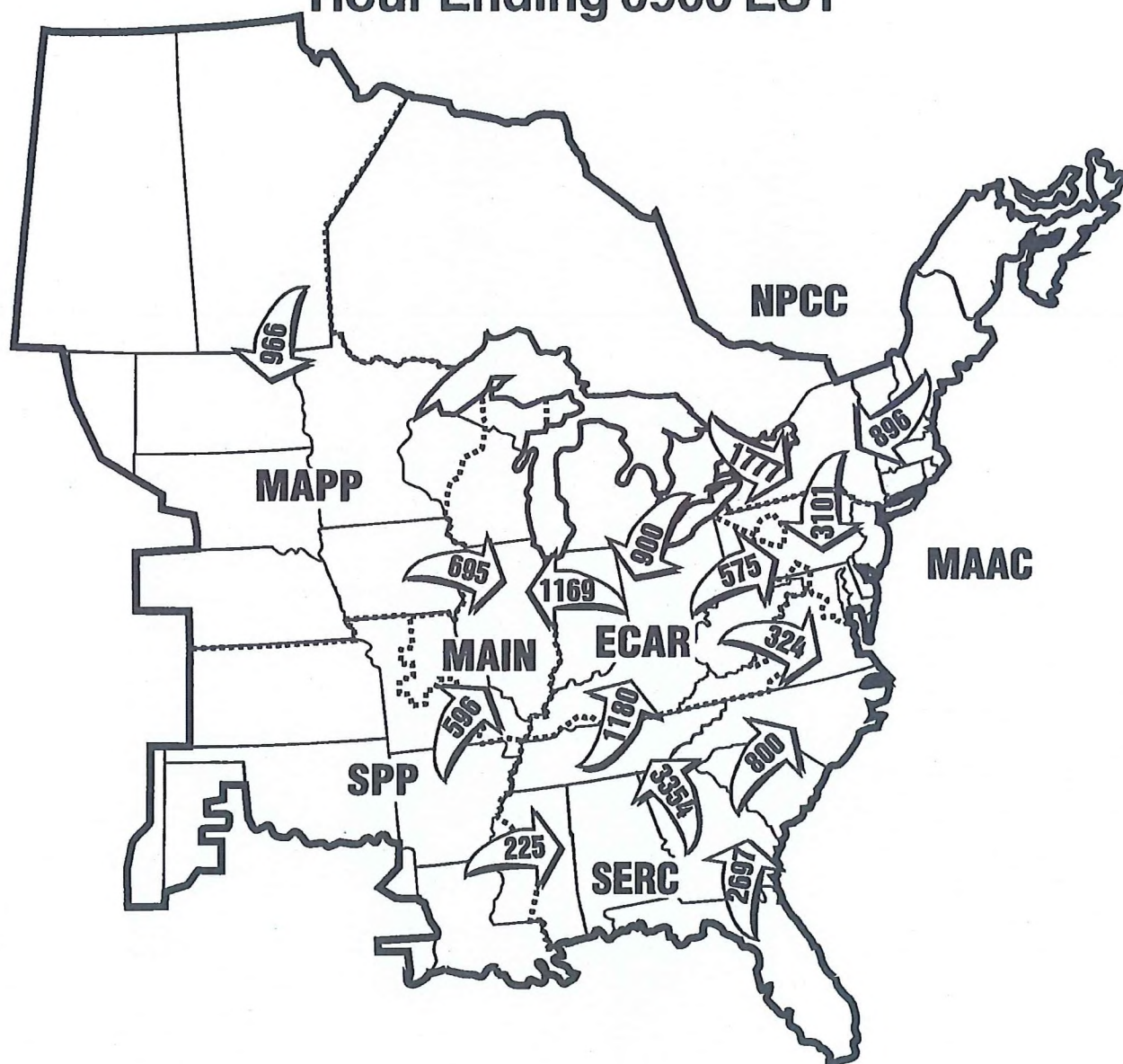


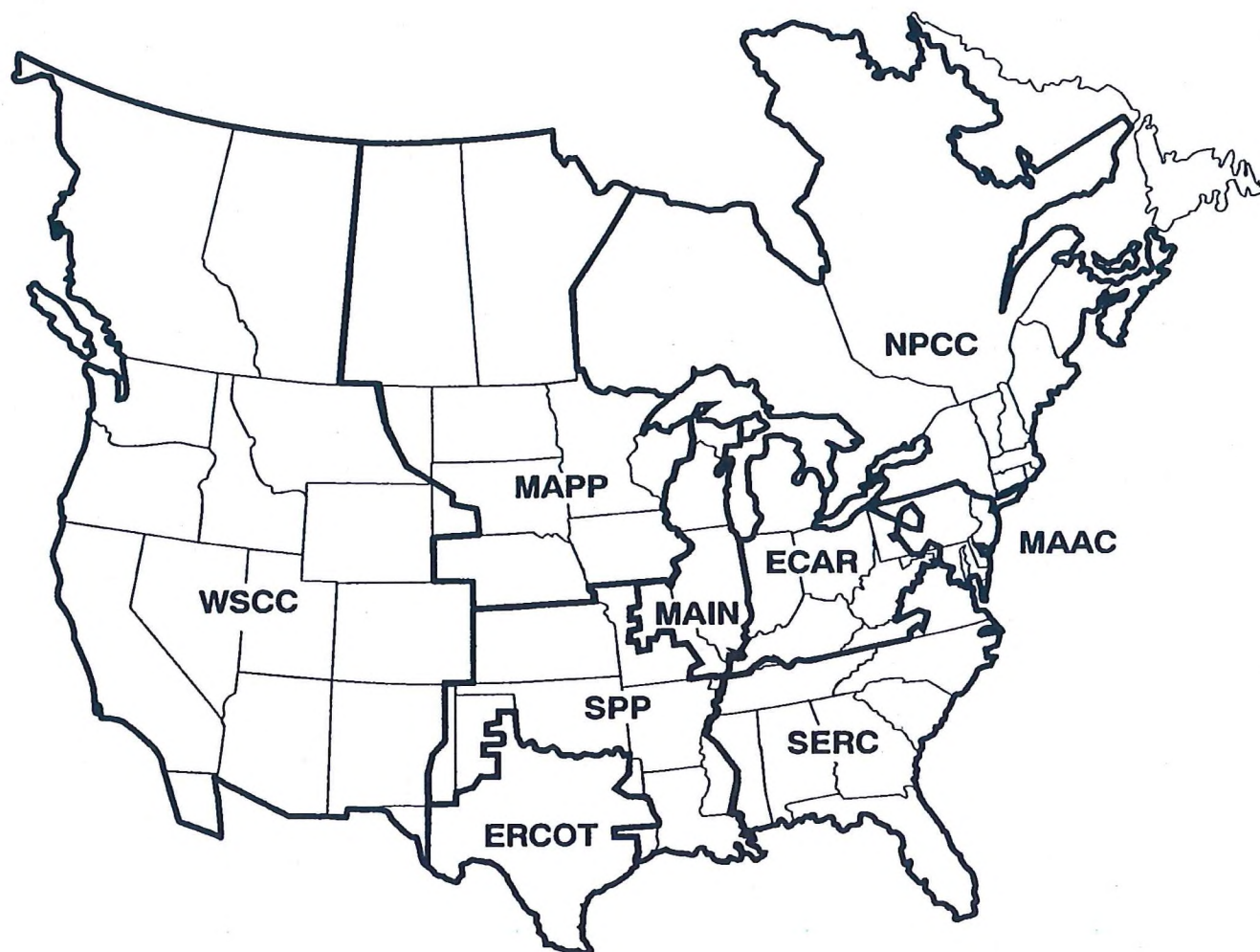
Scheduled Interchange

January 19, 1994



**Eastern Interconnection
January 19, 1994
Hour Ending 0900 EST**





ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

Affiliate

ASCC
Alaska Systems Coordinating Council

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

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in

Case No(s). 14-1297-EL-SSO

Summary: Testimony Direct Testimony of David Scarpignato ATTACHMENT 3 electronically filed by M HOWARD PETRICOFF on behalf of Retail Energy Supply Association