E-235 VOL. 28

500 KV TRANSMISSION SYSTEM PROJECT

FOR

INDEPENDENT POWER PRODUCERS

ELECTRICITY GENERATING AUTHORITY OF THAILAND

REPORT NO. 21200-3901

SYSTEM PLANNING DEPARTMENT

JANUARY 1996

ด่วนมาก
ที่ กฟผ. 21200/11710

การไฟฟ้าฝ่ายผลิตแห่งประเทศไทย
นนทบุรี 11000

28 กุมภาพันธ์ 2539

เรื่อง โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน

เรียน ปลัดสำนักนายกรัฐมนตรี

สิ่งที่ส่งมาด้วย เอกสารโครงการ "500 kV Transmission System Project for Independent Power Producers" รายงานเลขที่ 21200-3901 จำนวน 4 เล่ม

เพื่อสนองนโยบายของรัฐบาลที่ให้เอกชนมีส่วนร่วมในการผลิตไฟฟ้า เพื่อลดภาระการลงทุนของภาครัฐ และให้มีการแข่งขันในการผลิตไฟฟ้า การไฟฟ้าฝ่ายผลิตแห่งประะเทศไทย (กฟผ.) จึงได้จัดทำโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน เพื่อรองรับกำลังไฟฟ้าจากผู้ผลิตไฟฟ้าเอกชนดังกล่าว (Independent Power Producer, IPP) เป็นการสนองความต้องการใช้ไฟฟ้าที่เพิ่มขึ้นในปริมาณที่ยังสูงอย่างต่อเนื่อง นอกจากนี้ยังเป็นการเพิ่มความเชื่อถือได้ของระบบส่งไฟฟ้าให้มีความมั่นคงยิ่งขึ้นด้วย

โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนนี้ เป็นการดำเนินการเสริมระบบส่งไฟฟ้าหลัก (Main Transmission Grid) เพื่อรับซื้อไฟฟ้าจากเอกชนในเขตภาคตะวันตก และภาคตะวันออก ตั้งแต่ปี 2544 โดยได้คำนึงถึงการแก้ไขปัญหาต่าง ๆ เพื่อให้การ ก่อสร้างระบบส่งไฟฟ้าเกิดผลกระทบน้อยที่สุด

สาระสำคัญของโครงการพอสรุปได้ดังนี้

ก. <u>ปริมาณงาน</u>

<u>โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน ภาคตะวันตก</u> ประกอบด้วยงานต่าง ๆ ดังนี้

1. ก่อสร้างสายส่ง 500 เควี วงจรคู่ จำนวน 2 แนว จาก สฟ.บางสะพาน ไปยัง สฟ.จอมบึง (ซึ่งจะก่อสร้างใหม่ตามโครงการโรงไฟฟ้าราชบุรี) ระยะทางประมาณ 275 และ 280 กิโลเมตร ตามลำดับ

2. ก่อสร้างลานไกไฟฟ้า 500 เควี บางสะพาน สำหรับสายส่ง 500 เควี ไปยัง สฟ.จอมบึง จำนวน 4 วงจร พร้อมติดตั้งหม้อแปลง 500/230 เควี ขนาด 1,000 MVA จำนวน 1 ชุด เพื่อเชื่อมโยงกับระบบไฟฟ้า 230 เควี ปัจจุบัน

3. ขยาย สฟ.500 เควี จอมบึง เพื่อรับสายส่ง 500 เควี จาก สฟ.บางสะพาน จำนวน 4 วงจร

4. ก่อสร้างลานไกไฟฟ้า 500 เควี ไทรน้อยใหม่แบบ Gas Insulated Switchyard (GIS) ใกล้กับลานไกไฟฟ้า 500 เควี ไทรน้อยปัจจุบัน โดยการตัดสายส่ง 500 เควี จอมบึง - ไทรน้อย วงจรคู่ทั้ง 2 วงจร และตัดสายส่ง 500 เควี จอมบึง - วังน้อย วงจรคู่เพียง 1 วงจร (แนวสายส่งดังกล่าวผ่านในที่ดิน สฟ.ไทรน้อย อยู่แล้ว) ลงที่ลานไกไฟฟ้า 500 เควีใหม่ดังกล่าว พร้อมติดตั้งอุปกรณ์ไฟฟ้าระบบ 500 เควี สำหรับสายส่งไปยัง สฟ.บางกอกน้อย และ สฟ.แจ้งวัฒนะ แห่งละ 2 วงจรในอนาคต

5. ติดตั้ง Shunt Reactor ขนาด 150 MVAr ที่ปลายสายส่งทั้งสองด้านของสายส่ง 500 เควี บางสะพาน - จอมบึง

6. จัดซื้อที่ดินเพื่อก่อสร้างขยาย สฟ.500 เควี บางสะพาน

7. เพิ่มเติมระบบสื่อสารที่เกี่ยวข้อง

<u>โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน</u>
<u>ภาคตะวันออก</u> ประกอบด้วยงานต่าง ๆ ดังนี้

1. ก่อสร้างสายส่ง 500 เควี วงจรคู่ จำนวน 2 แนว จาก สฟ.ระยอง 4 ไปยังจุดเชื่อม (T Junction) สายส่ง 500 เควี หนองจอก - วังน้อย ระยะทางประมาณ 155 และ 170 กิโลเมตร ตามลำดับ

2. ก่อสร้างสายส่ง 230 เควี แบบวงจรคู่ จาก สฟ.ระยอง 4 ไปยัง สฟ.ระยอง 2 ระยะทางประมาณ 10 กิโลเมตร

3. ก่อสร้างลานไกไฟฟ้า 500 เควี ระยอง 4 สำหรับสายส่ง 500 เควี ไปยัง สฟ.หนองจอก และ สฟ.วังน้อย แห่งละ 2 วงจร พร้อมติดตั้งหม้อแปลง 500/230 เควี ขนาด 1,000 MVA จำนวน 2 ชุด และก่อสร้างลานไกไฟฟ้า 230 เควี เพื่อรับหม้อแปลงจำนวน 2 วงจร และสายส่ง 230 เควี ไปยัง สฟ.ระยอง 2 จำนวน 2 วงจร

4. ขยาย สฟ.230 เควี ระยอง 2 เพื่อรับสายส่ง 230 เควี จาก สฟ.ระยอง 4 จำนวน 2 วงจร

5. ติดตั้ง Shunt Reactor ขนาด 80 และ 100 MVAr ที่ปลายสายส่งทั้งสองด้านของสายส่ง 500 เควี ระยอง 4 - หนองจอก และ 500 เควี ระยอง 4 - วังน้อย ตามลำดับ

6. จัดซื้อที่ดินเพื่อก่อสร้าง สฟ.500 เควี ระยอง 4

7. เพิ่มเติมระบบสื่อสารที่เกี่ยวข้อง

ข. ประมาณราคา ราคาโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก เป็นเงินทั้งสิ้นประมาณ 30,470 ล้านบาท แยกเป็นเงินตราต่างประเทศ 9,735.0 ล้านบาท (เทียบเท่า 389.4 ล้านเหรียญสหรัฐฯ) และเงินบาทอีก 20,735.0 ล้านบาท ดังนี้

	เงินตราต่างประเทศ (ล้านบาท)	(ล้านเหรียญสหรัฐฯ) 1/	เงินบาท (ล้านบาท)	รวม (ล้านบาท)
โครงการระบบส่งไฟฟ้า500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน				
ภาคตะวันตก	6,455.0	(258.2)	12,755.0	19,210.0
ภาคตะวันออก	3,280.0	(131.2)	7,980.0	11,260.0
รวมทั้งสิ้น	9,735.0	(389.4)	20,735.0	30,470.0

ค. ระยะเวลาดำเนินการ ใช้เวลาตั้งแต่เตรียมงานจนก่อสร้างแล้วเสร็จประมาณ 6 ปี ตั้งแต่ปี 2538 จนถึงปี 2543 โดยคาดว่าจะแล้วเสร็จประมาณเดือน กันยายน 2543 ทั้งโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก

หมายเหตุ : 1/ ใช้อัตราแลกเปลี่ยน 1 เหรียญสหรัฐฯ = 25 บาท

ง. ผลประโยชน์ที่ได้รับ

โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก เป็นโครงการที่สนองนโยบายรัฐบาลในการให้เอกชนมีส่วนร่วมในการผลิตไฟฟ้า เพื่อเพิ่มการแข่งขันในการผลิตไฟฟ้า และลดภาระการลงทุนของรัฐบาล ผลประโยชน์ของโครงการนี้สรุปได้ดังนี้

1. สามารถรับซื้อไฟฟ้าจากผู้ผลิตไฟฟ้าเอกชนขนาดใหญ่ (IPP) จ่ายไฟฟ้าผ่านระบบสายส่งของ กฟผ. ไปยังแหล่งผู้ใช้ไฟฟ้าที่มีความต้องการไฟฟ้าที่เพิ่มขึ้นได้อย่างเพียงพอ

2. เพิ่มระดับความเชื่อถือได้ของการจ่ายไฟฟ้าของประเทศ

3. สนับสนุนให้เศรษฐกิจของประเทศมีการเจริญเติบโตอย่างต่อเนื่อง

จ. การวิเคราะห์อัตราผลตอบแทนการลงทุนของโครงการ ได้ดำเนินการวิเคราะห์ทั้งผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) และผลตอบแทนทางด้านการเงินของโครงการ (FIRR) ได้ผลดังนี้

ผลตอบแทนทางด้านเศรษฐศาสตร์ของโครงการ (EIRR) ทำการศึกษาเป็น 2 แนวทาง คือ

แนวทางที่ 1 เปรียบเทียบค่าใช้จ่ายทางด้านเศรษฐศาสตร์ของโครงการกับผลประโยชน์ที่จะได้รับจากการลดความสูญเสียที่คาดว่าจะเกิดขึ้นเนื่องจากไม่สามารถจ่ายไฟฟ้าได้ (outages)

ผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) = 107.01 %

แนวทางที่ 2 เปรียบเทียบค่าใช้จ่ายทางด้านเศรษฐศาสตร์ของโครงการกับผลประโยชน์ที่คาดว่าจะได้รับจากการที่สามารถขายไฟฟ้าได้เพิ่มขึ้นเมื่อก่อสร้างโครงการแล้วเสร็จ

ผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) = 22.63 %

ผลตอบแทนทางด้านการเงินของโครงการ (FIRR) ทำการศึกษาโดยเปรียบเทียบค่าใช้จ่ายทางด้านการเงินของโครงการกับผลประโยชน์ที่คาดว่าจะได้รับจากการที่สามารถขายไฟฟ้าได้เพิ่มขึ้น

ผลตอบแทนทางด้านการเงิน (FIRR) = 22.23 %

ฝ่ายบริหารฯ กฟผ.ได้นำเสนอโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน ต่อคณะกรรมการการไฟฟ้าฝ่ายผลิตแห่งประเทศไทย พิจารณาในการประชุมครั้งที่ 2/2539 เมื่อวันพุธที่ 7 กุมภาพันธ์ 2539 คณะกรรมการการไฟฟ้าฝ่ายผลิตแห่งประเทศไทย มีมติอนุมัติโครงการตามที่เสนอ และให้ฝ่ายบริหารฯ ดำเนินการต่อไป

อนึ่ง โครงการนี้เป็นโครงการลงทุนในแผนพัฒนาฯ ฉบับที่ 7 ตามแผนพัฒนากำลังผลิตไฟฟ้าของ กฟผ.ที่ได้รับความเห็นชอบแล้ว

กฟผ.จึงขอเสนอโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน โดยมีรายละเอียดปรากฏตามเอกสารรายงานที่ได้นำเสนอมาพร้อมนี้ เพื่อโปรดพิจารณาและนำเสนอสำนักงานคณะกรรมการพัฒนาการเศรษฐกิจและสังคมแห่งชาติพิจารณาต่อไปด้วย จักขอบคุณยิ่ง

ขอแสดงความนับถือ

(นายพิเชฐ อมันตสานต์)
รองผู้ว่าการฝ่ายปฏิบัติการระบบส่ง
ผู้ทำการแทน ผู้ว่าการการไฟฟ้าฝ่ายผลิตแห่งประเทศไทย

ฝ่ายวางแผนระบบไฟฟ้า
โทร. 4363500
โทรสาร 4336317
สำเนา : สำนักงานคณะกรรมการพัฒนาการเศรษฐกิจและสังคมแห่งชาติ

ปกปิด

รายงานการประชุม

คณะกรรมการการไฟฟ้าฝ่ายผลิตแห่งประเทศไทย

ครั้งที่ 2/2539

วันพุธที่ 7 กุมภาพันธ์ พ.ศ. 2539

ณ ห้องประชุมคณะกรรมการการไฟฟ้าฝ่ายผลิตแห่งประเทศไทย

(เฉพาะเรื่อง)

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17. <u>โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน</u>

(เอกสาร พ.2.39.17)

คณะกรรมการ ฯ มีมติอนุมัติโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน(IPP) ตามที่เสนอ และให้ฝ่ายบริหาร ฯ ดำเนินการต่อไป.

ปกปิด

ปกปิด

บันทึกย่อเรื่อง

ประกอบระเบียบวาระการประชุมคณะกรรมการการไฟฟ้าฝ่ายผลิตแห่งประเทศไทย

ครั้งที่ 2/2539

วันพุธที่ 7 กุมภาพันธ์ พ.ศ. 2539

เพื่อพิจารณา (พ.)

ปกปิด

พ.2.39.17

โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน

ฝ่ายบริหารใคร่ขอเสนอโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน ซึ่งเป็นการดำเนินการเสริมระบบส่งไฟฟ้าหลัก (Main Transmission Grid) เพื่อรองรับการผลิตไฟฟ้าจากโรงไฟฟ้าเอกชน (IPP) ตามนโยบายของรัฐบาลที่กำหนดให้เอกชนมีส่วนร่วมในการผลิตไฟฟ้า เพื่อแบ่งเบาภาระการลงทุนของภาครัฐ และให้มีการแข่งขันในภาคอุตสาหกรรมไฟฟ้า การเสริมระบบสายส่งหลักตามที่เสนอ ได้ดำเนินการในแนวทางตามผลการศึกษาของบริษัทที่ปรึกษาที่ได้ดำเนินการไว้เมื่อปี 2536-2537 ซึ่งได้คำนึงถึงการแก้ไขปัญหาต่าง ๆ เพื่อให้การก่อสร้างระบบส่งไฟฟ้าเกิดผลกระทบน้อยที่สุด

สาระสำคัญของโครงการพอสรุปได้ดังนี้

ปริมาณงาน

โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตก ประกอบด้วยงานต่าง ๆ ดังนี้

1. ก่อสร้างสายส่ง 500 เควี วงจรคู่ จำนวน 2 แนว จาก สฟ.บางสะพาน ไปยัง สฟ.จอมบึง (ซึ่งจะก่อสร้างใหม่ตามโครงการโรงไฟฟ้าราชบุรี) ใช้สายไฟฟ้าขนาด 4x1272 MCM ACSR ต่อเฟส ระยะทางประมาณ 275 และ 280 กิโลเมตร ตามลำดับ พร้อมติดตั้ง Fibre Optic จำนวน 1 เส้น ในสาย Overhead Ground Wire

2. ก่อสร้างลานไกไฟฟ้า 500 เควี บางสะพาน สำหรับสายส่ง 500 เควี ไปยัง สฟ.จอมบึง จำนวน 4 วงจร พร้อมติดตั้งหม้อแปลง 500/230 เควี ขนาด 1,000 MVA จำนวน 1 ชุด (หม้อแปลง Single Phase ขนาด 200/267/333 MVA จำนวน 3 ชุด และ spare ไว้อีก 1 ชุด รวมเป็น 4 ชุด) และขยายลานไกไฟฟ้า 230 เควี รับหม้อแปลงจำนวน 1 วงจร

3. ขยาย สฟ.500 เควี จอมบึง เพื่อรับสายส่ง 500 เควี จาก สฟ.บางสะพาน จำนวน 4 วงจร

4. ก่อสร้างลานไกไฟฟ้า 500 เควี ไทรน้อยใหม่แบบ Gas Insulated Switchyard (GIS) ใกล้กับลานไกไฟฟ้า 500 เควี ไทรน้อยปัจจุบัน โดยการตัดสายส่ง 500 เควี จอมบึง - ไทรน้อย วงจรคู่ทั้ง 2 วงจร และตัดสายส่ง 500 เควี จอมบึง - วังน้อย วงจรคู่เพียง 1 วงจร (แนวสายส่งดังกล่าวผ่านในที่ดิน สฟ.ไทรน้อย อยู่แล้ว) ลงที่ลานไกไฟฟ้า 500 เควีใหม่ดังกล่าว พร้อมติด

ตั้งอุปกรณ์ไฟฟ้าระบบ 500 เควี สำหรับสายส่งไปยัง สฟ.บางกอกน้อย และ สฟ.แจ้งวัฒนะ แห่งละ 2 วงจรในอนาคต

5. ติดตั้ง Shunt Reactor ขนาด 150 MVAr ที่ปลายสายส่งทั้งสองด้านของสายส่ง 500 เควี บางสะพาน - จอมบึง

6. จัดซื้อที่ดินเพื่อก่อสร้างขยาย สฟ.500 เควี บางสะพาน

7. เพิ่มเติมระบบสื่อสารที่เกี่ยวข้อง

<u>โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันออก</u>
ประกอบด้วยงานต่าง ๆ ดังนี้

1. ก่อสร้างสายส่ง 500 เควี วงจรคู่ จำนวน 2 แนว จาก สฟ.ระยอง 4 ไปยังจุดเชื่อม (T Junction) สายส่ง 500 เควี หนองจอก - วังน้อย ใช้สายไฟฟ้าขนาด 4x1272 MCM ACSR ต่อเฟส ระยะทางประมาณ 155 และ 170 กิโลเมตร ตามลำดับ พร้อมติดตั้ง Fibre Optic จำนวน 1 เส้น ในสาย Overhead Ground Wire

2. ก่อสร้างสายส่ง 230 เควี แบบวงจรคู่ จาก สฟ.ระยอง 4 ไปยัง สฟ.ระยอง 2 ใช้สายไฟฟ้าขนาด 4x1272 MCM ACSR ต่อเฟส ระยะทางประมาณ 10 กิโลเมตร พร้อมติดตั้ง Fibre Optic จำนวน 1 เส้นในสาย Overhead Ground Wire

3. ก่อสร้างลานไกไฟฟ้า 500 เควี ระยอง 4 สำหรับสายส่ง 500 เควี ไปยัง สฟ.หนองจอก และ สฟ.วังน้อย แห่งละ 2 วงจร พร้อมติดตั้งหม้อแปลง 500/230 เควี ขนาด 1,000 MVA จำนวน 2 ชุด (หม้อแปลง Single Phase ขนาด 200/267/333 MVA จำนวน 6 ชุด และ spare ไว้อีก 1 ชุด รวมเป็น 7 ชุด) และก่อสร้างลานไกไฟฟ้า 230 เควี เพื่อรับหม้อแปลงจำนวน 2 วงจร และสายส่ง 230 เควี ไปยัง สฟ.ระยอง 2 จำนวน 2 วงจร

4. ขยาย สฟ.230 เควี ระยอง 2 เพื่อรับสายส่ง 230 เควี จาก สฟ.ระยอง 4 จำนวน 2 วงจร

5. ติดตั้ง Shunt Reactor ขนาด 80 และ 100 MVAr ที่ปลายสายส่งทั้งสองด้านของสายส่ง 500 เควี ระยอง 4 - หนองจอก และ 500 เควี ระยอง 4 - วังน้อย ตามลำดับ

6. จัดซื้อที่ดินเพื่อก่อสร้าง สฟ.500 เควี ระยอง 4

7. เพิ่มเติมระบบสื่อสารที่เกี่ยวข้อง

ประมาณราคา ราคาโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก เป็นเงินทั้งสิ้นประมาณ 30,470 ล้านบาท แยกเป็นเงินตราต่างประเทศ 9,735.0 ล้านบาท (เทียบเท่า 389.4 ล้านเหรียญสหรัฐฯ) และเงินบาทอีก 20,735.0 ล้านบาท ดังนี้

	เงินตราต่างประเทศ (ล้านบาท)	เงินตราต่างประเทศ (ล้านเหรียญสหรัฐฯ)	เงินบาท (ล้านบาท)	รวม (ล้านบาท)
โครงการระบบส่งไฟฟ้า500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน				
ภาคตะวันตก	6,455.0	(258.2)	12,755.0	19,210.0
ภาคตะวันออก	3,280.0	(131.2)	7,980.0	11,260.0
รวมทั้งสิ้น	9,735.0	(389.4)	20,735.0	30,470.0

ค่าใช้จ่ายรายปี ค่าใช้จ่ายรายปีของโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออกเป็นดังนี้

ภาคตะวันตก

ปีงบประมาณ	เงินตราต่างประเทศ (ล้านบาท)	เงินตราต่างประเทศ (ล้านเหรียญสหรัฐฯ) 1/	เงินบาท (ล้านบาท)	รวม (ล้านบาท)
2539	-	-	157.7	157.7
2540	-	-	288.3	288.3
2541	106.0	(4.3)	3,008.8	3,114.8
2542	3,928.6	(157.1)	4,817.2	8,745.8
2543	1,977.8	(79.1)	3,863.5	5,841.3
2544	442.6	(17.7)	619.5	1,062.1
รวม	6,455.0	(258.2)	12,755.0	19,210.0

หมายเหตุ : 1/ ใช้อัตราแลกเปลี่ยน 1 เหรียญสหรัฐฯ = 25 บาท

ภาคตะวันออก

ปีงบประมาณ	เงินตราต่างประเทศ (ล้านบาท)	เงินตราต่างประเทศ (ล้านเหรียญสหรัฐฯ) 1/	เงินบาท (ล้านบาท)	รวม (ล้านบาท)
2539	-	-	253.0	253.0
2540	-	-	175.2	175.2
2541	62.5	(2.5)	1,795.1	1,857.6
2542	2,077.5	(83.1)	2,974.1	5,051.6
2543	934.4	(37.4)	2,390.7	3,325.1
2544	205.6	(8.2)	391.9	597.5
รวม	3,280.0	(131.2)	7,980.0	11,260.0

ระยะเวลาดำเนินการ ใช้เวลาตั้งแต่เตรียมงานจนก่อสร้างแล้วเสร็จประมาณ 6 ปี ตั้งแต่ปี 2538 จนถึงปี 2543 โดยคาดว่าจะแล้วเสร็จประมาณเดือน กันยายน 2543 ทั้งโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก

ผลประโยชน์ที่ได้รับ

โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก เป็นโครงการที่สนองนโยบายรัฐบาลในการให้เอกชนมีส่วนร่วมในการผลิตไฟฟ้า เพื่อเพิ่มการแข่งขันในการผลิตไฟฟ้า และลดภาระการลงทุนของรัฐบาล ผลประโยชน์ของโครงการนี้สรุปได้ดังนี้

1. สามารถรับซื้อไฟฟ้าจากผู้ผลิตไฟฟ้าเอกชนขนาดใหญ่ (IPP) จ่ายไฟฟ้าผ่านระบบสายส่งของ กฟผ. ไปยังแหล่งผู้ใช้ไฟฟ้าที่มีความต้องการไฟฟ้าที่เพิ่มขึ้นได้อย่างเพียงพอ

2. เพิ่มระดับความเชื่อถือได้ของการจ่ายไฟฟ้าของประเทศ

3. สนับสนุนให้เศรษฐกิจของประเทศมีการเจริญเติบโตอย่างต่อเนื่อง

หมายเหตุ : 1/ ใช้อัตราแลกเปลี่ยน 1 เหรียญสหรัฐฯ = 25 บาท

4. การวิเคราะห์อัตราผลตอบแทนการลงทุนของโครงการ ได้ดำเนินการวิเคราะห์ทั้งผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) และผลตอบแทนทางด้านการเงินของโครงการ (FIRR) ได้ผลดังนี้

<u>ผลตอบแทนทางด้านเศรษฐศาสตร์ของโครงการ (EIRR)</u> ทำการศึกษาเป็น 2 แนวทาง คือ

<u>แนวทางที่ 1</u> เปรียบเทียบค่าใช้จ่ายทางด้านเศรษฐศาสตร์ของโครงการกับผลประโยชน์ที่จะได้รับจากการลดความสูญเสียที่คาดว่าจะเกิดขึ้นเนื่องจากไม่สามารถจ่ายไฟฟ้าได้ (outages)

ผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) = 107.01 %

<u>แนวทางที่ 2</u> เปรียบเทียบค่าใช้จ่ายทางด้านเศรษฐศาสตร์ของโครงการกับผลประโยชน์ที่คาดว่าจะได้รับจากการที่สามารถขายไฟฟ้าได้เพิ่มขึ้นเมื่อก่อสร้างโครงการแล้วเสร็จ

ผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) = 22.63 %

<u>ผลตอบแทนทางด้านการเงินของโครงการ (FIRR)</u> ทำการศึกษาโดยเปรียบเทียบค่าใช้จ่ายทางด้านการเงินของโครงการกับผลประโยชน์ที่คาดว่าจะได้รับจากการที่สามารถขายไฟฟ้าได้เพิ่มขึ้น

ผลตอบแทนทางด้านการเงิน (FIRR) = 22.23 %

สำหรับรายละเอียดโครงการได้เสนอไว้ในรายงาน "500 kV Transmission System Project for Independent Power Producers" รายงานเลขที่ 21200-3901 ที่ได้แนบมาพร้อมนี้แล้ว

64
6 ก.พ.39 16.15
2/39 7 ก.พ. 39

ฝ่ายวางแผนระบบไฟฟ้า

การไฟฟ้าฝ่ายผลิตแห่งประเทศไทย ④

บันทึก ③

ที่ 21203/ปิ๊ก

จาก กวส-ผ.

เรื่อง โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน

วันที่ 25 มกราคม 2539

① เรียน ผผฟ. ผ่าน ช.ฝผฟ

② เรียน ผวก.
เพื่อโปรดพิจารณา/สั่งการ
ตามเสนอ

[illegible]
/ 1 กพ 39.

เนื่องจากการเจริญเติบโตทางเศรษฐกิจอุตสาหกรรมของประเทศไทยเพิ่มขึ้นอย่างรวดเร็ว เป็นผลให้ความต้องการใช้ไฟฟ้าของประเทศในช่วง 5 ปี ที่ผ่านมาเพิ่มขึ้นสูงมาก เฉลี่ยร้อยละ 11 ต่อปี และยังมีแนวโน้มเพิ่มขึ้นอย่างต่อเนื่อง ดังนั้นเพื่อให้สามารถผลิตพลังงานไฟฟ้าเพียงพอกับความต้องการใช้ไฟฟ้าที่เพิ่มขึ้น กฟผ.จะต้องก่อสร้างโรงไฟฟ้าแห่งใหม่และระบบส่งไฟฟ้าเพิ่มเติม ซึ่งจะต้องใช้เงินลงทุนเป็นจำนวนมาก เป็นผลให้ต้องมีการก่อหนี้ต่างประเทศส่งผลกระทบต่อเพดานเงินกู้ต่างประเทศที่รัฐบาลได้กำหนดไว้ ด้วยเหตุนี้รัฐบาลจึงได้มีนโยบายให้เอกชนมีส่วนร่วมในการผลิตไฟฟ้า เพื่อก่อให้เกิดการแข่งขันและจะเป็นการเพิ่มประสิทธิภาพการผลิตไฟฟ้า นอกจากนี้ยังสามารถช่วยรัฐบาลลดภาระการลงทุนได้ส่วนหนึ่ง ทั้งนี้ตามนโยบายของรัฐบาลได้กำหนดให้ กฟผ.รับซื้อไฟฟ้าจากผู้ผลิตไฟฟ้าเอกชน (Independent Power Producer, IPP) โดยตรง

ตามแผนพัฒนากำลังผลิตไฟฟ้าของ กฟผ.ฉบับล่าสุด (PDP 95-01) กำหนดให้ กฟผ. รับซื้อไฟฟ้าจากเอกชนรวม 13,100 เมกะวัตต์ ภายในปี 2554 คิดเป็นประมาณ 30 % ของกำลังผลิตติดตั้งทั้งหมด ทั้งนี้กำหนดให้ในช่วงแผนพัฒนาฯ ฉบับที่ 7 ให้เอกชนลงทุนในโครงการโรงไฟฟ้าในรูปแบบ IPP แล้วขายไฟฟ้าให้ กฟผ.เป็นสองระยะรวม 4,100 เมกะวัตต์ โดยระยะแรกเป็นการรับซื้อไฟฟ้าประมาณ 1,300 เมกะวัตต์ โดย กฟผ.ไม่ต้องมีการเพิ่มระบบส่งไฟฟ้า กำหนดแล้วเสร็จภายในปี 2541-2543 และระยะที่สองอีก 2,800 เมกะวัตต์ ให้แล้วเสร็จภายในปี 2544-2545 ในการนี้ กฟผ.ได้ประกาศรับซื้อไฟฟ้าจากเอกชนทั้ง 2 ระยะ จำนวน 4,100 เมกะวัตต์ เมื่อวันที่ 15 ธันวาคม 2537 และมีผู้ผลิตไฟฟ้าเอกชนมากกว่า 30 กลุ่ม ได้ยื่นข้อเสนอการขายไฟฟ้ารวม 50 ข้อเสนอ เมื่อวันที่ 30 มิถุนายน 2538

สำหรับโครงการรับซื้อไฟฟ้าจากเอกชนระยะที่ 2 ในปี 2544-2545 กฟผ.ได้ประกาศรับซื้อไฟฟ้าจากเอกชนในบริเวณรอบอ่าวไทย โดยฝั่งตะวันตกตั้งแต่บริเวณภาคกลางจนถึง

จังหวัดประจวบคีรีขันธ์ และฝั่งตะวันออกตั้งแต่บริเวณภาคกลางไปจนถึงจังหวัดระยอง ดังนั้นในการรับซื้อไฟฟ้าจำนวนมากโดยยังไม่รู้สถานที่ตั้งที่แน่นอนนี้ กฟผ.จึงต้องดำเนินการก่อสร้างระบบส่งไฟฟ้าไว้ล่วงหน้าเพื่อรับไฟฟ้าจากโรงไฟฟ้าเหล่านี้ ในการนี้กองวางแผนระบบส่งไฟฟ้าจึงได้ทบทวนการศึกษาแผนการขยายระบบส่งไฟฟ้าจากโรงไฟฟ้าภาคตะวันตก ซึ่ง กฟผ.เคยว่าจ้างบริษัท Black & Veatch International Company (BVI) ร่วมกับบริษัท Power Technologies, Inc. (PTI) ศึกษาไว้เมื่อเดือนมิถุนายน 2536 พร้อมทั้งศึกษาเพิ่มเติมสำหรับการรับซื้อไฟฟ้าจากโรงไฟฟ้าทางภาคตะวันออกด้วย ซึ่งสามารถสรุปโครงการระบบส่งไฟฟ้า 500 เควี เพื่อรับไฟฟ้าจากโรงไฟฟ้าเอกชนได้ดังนี้

<u>ปริมาณงาน</u>

<u>โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตก</u>
ประกอบด้วยงานต่าง ๆ ดังนี้

1. ก่อสร้างสายส่ง 500 เควี วงจรคู่จำนวน 2 แนว จาก สฟ.บางสะพาน ไปยัง สฟ.จอมบึง ใช้สายไฟฟ้าขนาด 4x1272 MCM ACSR ต่อเฟส ระยะทางประมาณ 275 และ 280 กิโลเมตร ตามลำดับ พร้อมติดตั้ง Fibre Optic จำนวน 1 เส้น ในสาย Overhead Ground Wire

2. ก่อสร้างลานไกไฟฟ้า 500 เควี บางสะพาน สำหรับสายส่ง 500 เควี ไปยัง สฟ.จอมบึง จำนวน 4 วงจร พร้อมติดตั้งหม้อแปลง 500/230 เควี ขนาด 1,000 MVA จำนวน 1 ชุด (หม้อแปลง Single Phase ขนาด 200/267/333 MVA จำนวน 3 ชุด และ spare ไว้อีก 1 ชุด รวมเป็น 4 ชุด) และขยายลานไกไฟฟ้า 230 เควี รับหม้อแปลงจำนวน 1 วงจร

3. ขยาย สฟ.500 เควี จอมบึง เพื่อรับสายส่ง 500 เควี จาก สฟ.บางสะพาน จำนวน 4 วงจร

4. ก่อสร้างลานไกไฟฟ้า 500 เควี ไทรน้อยใหม่แบบ Gas Insulated Switchyard (GIS) ใกล้กับลานไกไฟฟ้า 500 เควี ไทรน้อยปัจจุบัน โดยการตัดสายส่ง 500 เควี จอมบึง - ไทรน้อย วงจรคู่ทั้ง 2 วงจร และตัดสายส่ง 500 เควี จอมบึง - วังน้อย วงจรคู่เพียง 1 วงจร (แนวสายส่งดังกล่าวผ่านในที่ดิน สฟ.ไทรน้อย อยู่แล้ว) ลงที่ลานไกไฟฟ้า 500 เควีใหม่ดังกล่าว พร้อมติดตั้งอุปกรณ์ไฟฟ้าระบบ 500 เควี สำหรับสายส่งในอนาคตไปยัง สฟ.บางกอกน้อย และ สฟ.แจ้งวัฒนะ แห่งละ 2 วงจร

5. ติดตั้ง Shunt Reactor ขนาด 150 MVAr ที่ปลายสายส่งทั้งสองด้านของสายส่ง 500 เควี บางสะพาน - จอมบึง

6. จัดซื้อที่ดินเพื่อก่อสร้างขยาย สฟ.500 เควี บางสะพาน

7. เพิ่มเติมระบบสื่อสารที่เกี่ยวข้อง

<u>โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันออก</u>
ประกอบด้วยงานต่าง ๆ ดังนี้

1. ก่อสร้างสายส่ง 500 เควี วงจรคู่ จำนวน 2 แนว จาก สฟ.ระยอง 4 ไปยัง Nong Chok/Wang Noi T Junction ใช้สายไฟฟ้าขนาด 4x1272 MCM ACSR ต่อเฟส ระยะทางประมาณ 155 และ 170 กิโลเมตร ตามลำดับ พร้อมติดตั้ง Fibre Optic จำนวน 1 เส้นในสาย Overhead Ground Wire

2. ก่อสร้างสายส่ง 230 เควี แบบวงจรคู่ จาก สฟ.ระยอง 4 ไปยัง สฟ.ระยอง 2 ใช้สายไฟฟ้าขนาด 4x1272 MCM ACSR ต่อเฟส ระยะทางประมาณ 10 กิโลเมตร พร้อมติดตั้ง Fibre Optic จำนวน 1 เส้นในสาย Overhead Ground Wire

3. ก่อสร้างลานไกไฟฟ้า 500 เควี ระยอง 4 สำหรับสายส่ง 500 เควี ไปยัง สฟ.หนองจอก และ สฟ.วังน้อย แห่งละ 2 วงจร พร้อมติดตั้งหม้อแปลง 500/230 เควี ขนาด 1,000 MVA จำนวน 2 ชุด (หม้อแปลง Single Phase ขนาด 200/267/333 MVA จำนวน 6 ชุด และ spare ไว้อีก 1 ชุด รวมเป็น 7 ชุด) และก่อสร้างลานไกไฟฟ้า 230 เควี เพื่อรับหม้อแปลงจำนวน 2 วงจร และสายส่ง 230 เควี ไปยัง สฟ.ระยอง 2 จำนวน 2 วงจร

4. ขยาย สฟ.230 เควี ระยอง 2 เพื่อรับสายส่ง 230 เควี จาก สฟ.ระยอง 4 จำนวน 2 วงจร

5. ติดตั้ง Shunt Reactor ขนาด 80 และ 100 MVAr ที่ปลายสายส่งทั้งสองด้านของสายส่ง 500 เควี ระยอง 4 - หนองจอก และ 500 เควี ระยอง 4 - วังน้อย ตามลำดับ

6. จัดซื้อที่ดินเพื่อก่อสร้าง สฟ.500 เควี ระยอง 4

7. เพิ่มเติมระบบสื่อสารที่เกี่ยวข้อง

ประมาณราคา ราคาโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก เป็นเงินทั้งสิ้นประมาณ 30,470 ล้านบาท แยกเป็นเงินตราต่างประเทศ 9,735.0 ล้านบาท (เทียบเท่า 389.4 ล้านเหรียญสหรัฐฯ) และเงินบาทอีก 20,735.0 ล้านบาท ดังนี้

	เงินตราต่างประเทศ		เงินบาท	รวม
	(ล้านบาท)	(ล้านเหรียญสหรัฐฯ)	(ล้านบาท)	(ล้านบาท)
โครงการระบบส่งไฟฟ้า500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชน				
ภาคตะวันตก	6,455.0	(258.2)	12,755.0	19,210.0
ภาคตะวันออก	3,280.0	(131.2)	7,980.0	11,260.0
รวมทั้งสิ้น	9,735.0	(389.4)	20,735.0	30,470.0

ค่าใช้จ่ายรายปี ค่าใช้จ่ายรายปีของโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออกเป็นดังนี้

ภาคตะวันตก

	เงินตราต่างประเทศ		เงินบาท	รวม
ปีงบประมาณ	(ล้านบาท)	(ล้านเหรียญสหรัฐฯ) 1/	(ล้านบาท)	(ล้านบาท)
2539	-	-	157.7	157.7
2540	-	-	288.3	288.3
2541	106.0	(4.3)	3,008.8	3,114.8
2542	3,928.6	(157.1)	4,817.2	8,745.8
2543	1,977.8	(79.1)	3,863.5	5,841.3
2544	442.6	(17.7)	619.5	1,062.1
รวม	6,455.0	(258.2)	12,755.0	19,210.0

หมายเหตุ 1/ ใช้อัตราแลกเปลี่ยน 1 เหรียญสหรัฐฯ = 25 บาท

ภาคตะวันออก

ปีงบประมาณ	เงินตราต่างประเทศ (ล้านบาท)	(ล้านเหรียญสหรัฐฯ) 1/	เงินบาท (ล้านบาท)	รวม (ล้านบาท)
2539	-	-	253.0	253.0
2540	-	-	175.2	175.2
2541	62.5	(2.5)	1,795.1	1,857.6
2542	2,077.5	(83.1)	2,974.1	5,051.6
2543	934.4	(37.4)	2,390.7	3,325.1
2544	205.6	(8.2)	391.9	597.5
รวม	3,280.0	(131.2)	7,980.0	11,260.0

ระยะเวลาดำเนินการ ใช้เวลาตั้งแต่เตรียมงานจนก่อสร้างแล้วเสร็จประมาณ 6 ปี ตั้งแต่ปี 2538 จนถึงปี 2543 โดยคาดว่าจะแล้วเสร็จประมาณเดือน กันยายน 2543 ทั้งโครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก

ผลประโยชน์ที่ได้รับ

โครงการระบบส่งไฟฟ้า 500 เควี สำหรับรับไฟฟ้าจากโรงไฟฟ้าเอกชนภาคตะวันตกและภาคตะวันออก เป็นโครงการที่สนองนโยบายรัฐบาลในการให้เอกชนมีส่วนร่วมในการผลิตไฟฟ้า เพื่อเพิ่มประสิทธิภาพในการผลิตไฟฟ้า และเป็นการช่วยลดภาระการลงทุนของรัฐบาล ตลอดจนช่วยเสริมความมั่นคงและเพิ่มความเชื่อถือได้ของระบบไฟฟ้า เพื่อสนับสนุนให้เศรษฐกิจของประเทศมีการเจริญเติบโตอย่างต่อเนื่อง ผลประโยชน์ของโครงการนี้สรุปได้ดังนี้

1. สนองความต้องการไฟฟ้าที่เพิ่มขึ้นอย่างรวดเร็ว และสามารถเพิ่มความมั่นคง และความเชื่อถือได้

2. ลดภาระการลงทุนในภาครัฐบาล

หมายเหตุ 1/ ใช้อัตราแลกเปลี่ยน 1 เหรียญสหรัฐฯ = 25 บาท

3. เพิ่มการแข่งขันด้านการผลิตไฟฟ้า ซึ่งจะเป็นการเพิ่มประสิทธิภาพ

4. การวิเคราะห์อัตราผลตอบแทนการลงทุนของโครงการ ได้ดำเนินการวิเคราะห์ทั้งผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) และผลตอบแทนทางด้านการเงินของโครงการ (FIRR) ได้ผลดังนี้

<u>ผลตอบแทนทางด้านเศรษฐศาสตร์ของโครงการ (EIRR)</u> ทำการศึกษาเป็น 2 แนวทาง คือ

<u>แนวทางที่ 1</u> เปรียบเทียบค่าใช้จ่ายทางด้านเศรษฐศาสตร์ของโครงการกับผลประโยชน์ที่จะได้รับจากการลดความสูญเสียที่คาดว่าจะเกิดขึ้นเนื่องจากไม่สามารถจ่ายไฟฟ้าได้ (outages)

ผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) = 107.01 %

<u>แนวทางที่ 2</u> เปรียบเทียบค่าใช้จ่ายทางด้านเศรษฐศาสตร์ของโครงการกับผลประโยชน์ที่คาดว่าจะได้รับจากการที่สามารถขายไฟฟ้าได้เพิ่มขึ้นเมื่อก่อสร้างโครงการแล้วเสร็จ

ผลตอบแทนทางด้านเศรษฐศาสตร์ (EIRR) = 22.63 %

<u>ผลตอบแทนทางด้านการเงินของโครงการ (FIRR)</u> ทำการศึกษาโดยเปรียบเทียบค่าใช้จ่ายทางด้านการเงินของโครงการกับผลประโยชน์ที่คาดว่าจะได้รับจากการที่สามารถขายไฟฟ้าได้เพิ่มขึ้น

ผลตอบแทนทางด้านการเงิน (FIRR) = 22.23 %

สำหรับรายละเอียดของโครงการได้เสนอไว้ในรายงาน "500 kV Transmission System Project for Independent Power Producers" ที่ได้แนบมาพร้อมนี้แล้ว

จึงเรียนมาเพื่อโปรดพิจารณาเสนอขออนุมัติดำเนินการต่อไป

(5) เลขานุการคณะกรรมการ กฟผ.
เสนอคณะกรรมการ กฟผ.
พิจารณาอนุมัติ

6-2-39

(นายพฤฒิชัย จงเลิศวณิชกุล)
หัวหน้ากองวางแผนระบบส่งไฟฟ้า

(6) [illegible] กฟผ 64
6 กพ.39 16.15
[illegible] 6 กพ39

500 KV TRANSMISSION SYSTEM PROJECT
FOR
INDEPENDENT POWER PRODUCERS

REPORT NO. 21200-3901

JANUARY 1996

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ABBREVIATIONS

ACSR	-	Aluminum Conductor Steel Reinforced
ADB	-	Asian Development Bank
BVI	-	Black & Veatch International Company
B/C	-	Benefit/Cost Ratio
cct-km	-	Circuit-Kilometer
DC/ST	-	Double Circuit/Steel Tower
DR	-	Discount Rate
EDR	-	Equalized Discount Rate
EGAT	-	Electricity Generating Authority of Thailand
EHV	-	Extra High Voltage
F.C.	-	Foreign Currency
GIS	-	Gas Insulated Switchgear
HVAC	-	High Voltage Alternating Current
HVDC	-	High Voltage Direct Current
IBRD	-	International Bank for Reconstruction and Development
IDC	-	Interest During Construction
IPP	-	Independent Power Producer
L.C.	-	Local Currency
MTHB	-	Million Baht
MEA	-	Metropolitan Electricity Authority
MCM	-	Thousand Circular Mils
MVA	-	Megavolt-ampare
MVAr	-	Megavolt-ampere Reactive
MW	-	Megawatt
NEPC	-	National Energy Policy Council
NEPO	-	National Energy Policy Office
NESDB	-	National Economic and Social Development Board
NESDP	-	National Economic and Social Development Plan
NPV	-	Net Present Value
OECF	-	The Overseas Economic Coorporation Fund
PDP	-	Power Development Plan
PEA	-	Provincial Electricity Authority
SPP	-	Small Power Producer
TDRI	-	Thailand Development Research Institute
THB	-	Thai Baht
TLFS	-	Thailand Load Forecast Subcommittee
USD	-	US Dollar
VAT	-	Value Added Tax
W/O	-	Without

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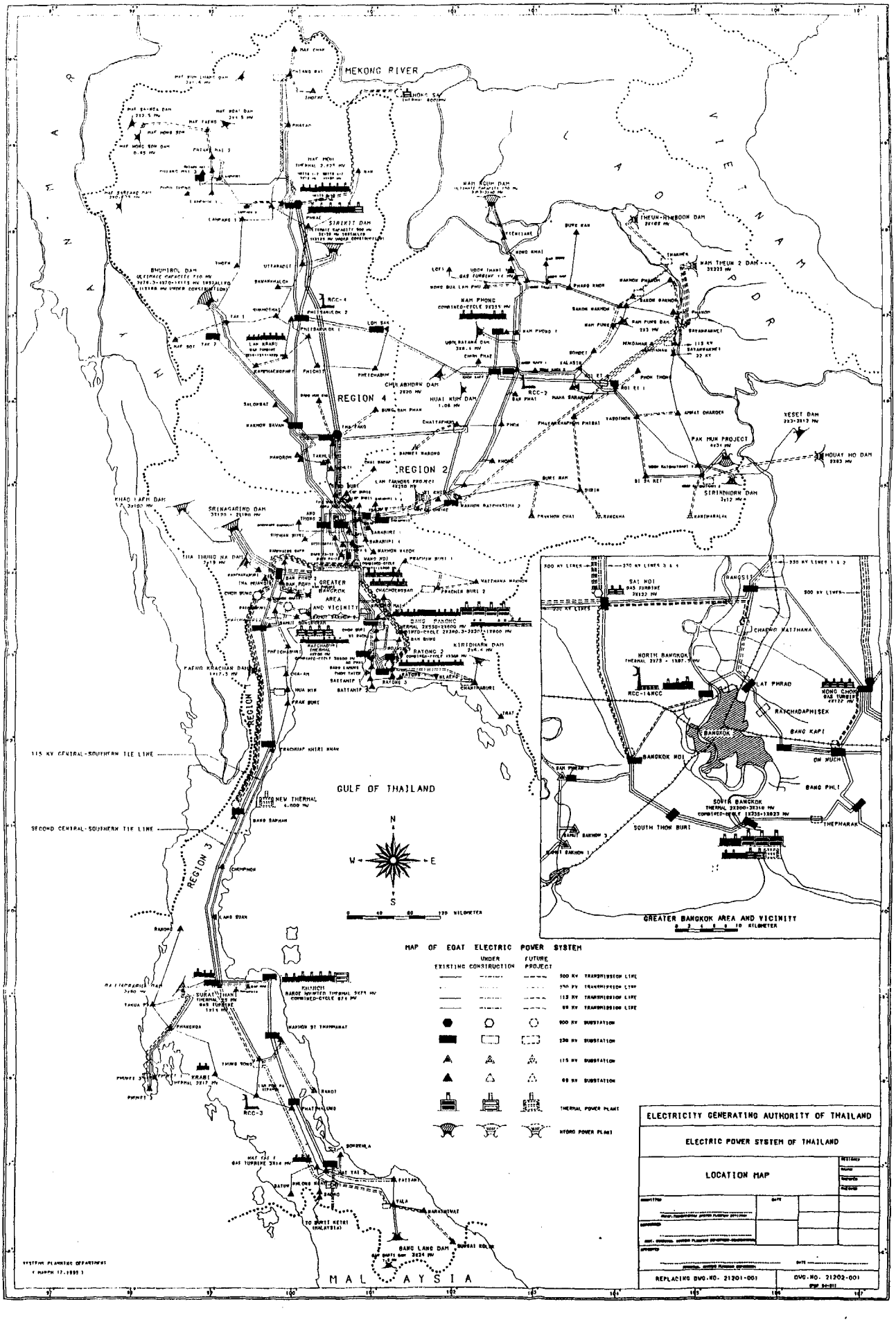
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1. INTRODUCTION

The electric power consumption in Thailand has increased very rapidly. The average growth rates of peak demand recorded in the last five years were at two digits, and the continuously rapid increase is foreseen in the latest load forecast. A huge investment program is required for EGAT, who is responsible for the provision of the sufficient and reliable electricity generation, and also to build the necessary new power plants and transmission system facilities to meet the growing demand.

EGAT so far has successfully managed in the financing programme, mainly on the international capital market and from official sources, such as export credits, IBRD, ADB and OECF. The rapidly increasing volume of capital investment and loans from the international market for EGAT alone has exceeded the national foreign borrowing ceiling imposed by the Government.

The Government also has the policy on the privatization of power supply industry to increase the competitiveness in electricity business, as well as to increase the efficiency and to reduce the investment in the public sector. In September 1992, the cabinet approved a directive, the Four-Step Plan, for the Thai Power Utilities to perform and restructure their organizations in response to the privatization policy. The Four-Step Plan has included three forms of private participation in the power sector : (i) Subsidiary companies, (ii) Small Power Producers (SPPs), and (3) Independent Power Producers (IPPs).

In the third step of the Four-Step Plan, the activities involving EGAT for the implementation in Fiscal Year 1995 includes the invitation announcement to the private sector to participate in the build-own-operate (BOO) scheme of the power plants which are scheduled for the commission during 1996-2002 as IPPs.

The current EGAT long term Power Development Plan (PDP 95-01) has included a total power purchase from IPP up to the year 2011 of about 13,100 MW, representing 30 % of the total installed capacity. In the 7th NESDP, the power purchase from IPP totalling 4,100 MW has been proposed, of which the first stage of 1,300 MW is scheduled for commissioning during 1998-2000 and the second stage of 2,800 MW will be commissioned during 2001-2002. The first solicitation to purchase electricity from IPPs of

4,100 MW was announced on 15 December 1994, and there were more than 30 investor groups submitting their 50 proposals on the bid openning day, 30 June 1995.

To facilitate the private sector investment in IPP projects, EGAT will construct two 500 kV transmission lines along the Gulf of Thailand from Bang Saphan (Prachuap Khiri Khan Province) to Sai Noi and Wang Noi on the western coast and from Rayong to Nong Chok and Wang Noi on the eastern coast. These 500 kV lines will receive the power from IPPs' power plants and transmit most of the generated power to the load centers which are at Greater Bangkok and the surrounding areas.

This report presents the scope of work, tentative construction schedule, cost estimate and expenditure schedule of the proposed 500 kV Transmission System Project for Independent Power Producers. The results of the power system study to ensure the satisfactory system operation are also included.

2. SUMMARY AND RECOMMENDATIONS

2.1 Resulting from the Government's privatization policy, Four-Step Plan has been issued under the Cabinet's resolution on 12 September 1992 to direct the Thai power utilities to restructure their organization to be as the business-like operation organizations, and eventually convert themselves, parts or whole, from the state power utilities into public limited companies. The Four-Step Plan has also included the promotion of private sector participation in the investment of power generation in the form of Independent Power Producers (IPPs).

2.2 According to EGAT's Power Development Plan (PDP 95-01), during the 7th Nation Plan, EGAT has given a total capacity of 4,100 MW power plant projects to the private sector as the IPPs through the competitive bidding process. The first solicitation was announced on 15 December 1995 to purchase electricity from IPPs for the first stage of 1,300 MW which will be completed within 1998-2000, and the second stage of 2,800 MW to be in operation in 2001 and 2002. Another capacity of 4,000 MW IPPs are expected to be solicited during the 8th National Plan.

2.3 The preferable sites of the large IPP projects will be in the areas of Western and Eastern Seaboard. To facilitate the connection of IPPs with the national network, the EHV transmission trunk lines along the Gulf of Thailand are required.

2.4 The study on the long-term transmission development in the western area had been previously carried out by the engineering services of Black & Veatch International (BVI) in association with Power Technologies Inc. (PTI). The main objective of the study was to determine the transmission system for interconnection of 10,000 MW thermal power plants near Bang Saphan in Upper Southern Thailand with Greater Bangkok through year 2008. The study report titled "Feasibility Study for Transmission System Development for Southern Power Plant Project" was completed in March 1994. The study has examined the feasibility of using three basic systems, they are 500 kV HVAC, 765 kV HVAC and $\pm$500 kV HVDC, and the 500 kV HVAC is recommended.

2.5 Based on the BVI/PTI studies, 500 kV transmission lines along the Gulf of Thailand from Bang Saphan to Sai Noi/Wang Noi on the west coast and the others from Rayong to Nong Chok/Wang Noi on the east coast are planned to accommodate the power plant projects for the total capacity of about 10,000 MW in each area.

2.6 Part of the new 500 kV transmission system in the western area will be implemented for the Ratchaburi Power Plant Project which has been planned for a combined capacity of 4,600 MW (1,800 MW combined cycle and 2,800 MW oil/gas fired thermal power plants) to utilize the natural gas from Myanmar. Therefore the additional 500 kV transmission system to accommodate the planned IPP projects will consist of two double-circuit 500 kV lines from Bang Saphan to Chom Bung or Ratchaburi 3 Substation, which will be a new 500 kV substation to be constructed for Ratchaburi power plant, and the maximum transfer capability to accommodate the new IPP power plants will be about 5,800 MW.

2.7 The development of the eastern 500 kV transmission lines consists of a double circuit 500 kV line from Rayong 4 to Nong Chok and a double circuit 500 kV line from Rayong 4 to Wang Noi. The lines can accommodate the maximum power transfer of about 8,800 MW.

2.8 The total estimated cost for the 500 kV Transmission System Project for IPPs based on 1995 price level is THB 30,470.0 million, comprising the foreign currency requirement of THB 9,735.0 million (USD equivalent 389.4 million)[1/] and local currency portion of THB 20,735.0 million. The estimated cost of the project which consists of two parts : (i) the western 500 kV transmission lines, and (ii) the eastern 500 kV transmission lines, can be summarized as follows :

	Foreign Currency (MTHB)	Local Currency (MTHB)	Total (MTHB)
The western 500 kV lines	6,455.0	12,755.0	19,210.0
The eastern 500 kV lines	3,280.0	7,980.0	11,260.0
Total	9,735.0	20,735.0	30,470.0

Note : 1/ 1 USD = 25 THB

2.9 The proposed in-service date of this 500 kV transmission system for IPP Project is September 2000.

2.10 The 500 kV transmission systems for IPPs on the west and east coast are proved to be the least cost alternative to transmit bulk power from those IPPs to EGAT's load centers. The net present value at 10 % real discount rate when compared to the 765 kV transmission system alternatives are THB 1,719.3 million and THB 3,754.8 million for west and east coast respectively.

2.11 The economic internal rate of return (EIRR) of the project was conducted by comparing the project cost with its benefit which was calculated by using two approaches, they were the outage cost reduction and the revenue made available from the incremental energy sale. The EIRR of the two approaches are as follows :

- For Approach 1 = 107.01%
- For Approach 2 = 22.63%

2.12 The financial internal rate of return (FIRR) calculated based on the revenue from the incremental energy sale is 22.23 %.

3. LOAD FORECAST AND POWER DEVELOPMENT PLAN

3.1 Load Forecast

The peak generation of EGAT system was recorded at 12,267.90 MW on May 26, 1995. The latest load forecast prepared by the Thailand Load Forecast Subcommittee (TLFS)[1/] issued in June 1994 (Revision of June 1993 Forecast) has indicated that the peak generation requirement would increase to 13,009 MW by the end of 1996. The peak generation would be 19,029 MW in 2001; 25,371 MW in 2006; and 33,532 MW in 2011. This forecast represents an average annual growth rate of 10.09 % during the 7th NESDP (1992-1996). The growth rates are expected to decline to 7.90 %, 5.92 % and 5.74 % in the periods of 8th NESDP (1997-2001), 9th NESDP (2002-2006) and 10th NESDP (2007-2011) respectively. The 1994 TLFS Load Forecast for the total EGAT generation requirement is shown in Table 3.1.

3.2 Power Development Plan

The latest PDP (PDP 95-01) has been prepared under the rapid changing situations due to the uncontrollable incidents and the Government Policy on the power supply industry in Thailand. The uncontrollable incidents were such as: (i) the shortage of water inflow in the existing dam reservoirs; (ii) the obstacles to implement several projects previously proposed due to lack of the public acceptance on hydroelectric projects, and the environmental problems on the new proposed coal/lignite-fired power plant sites at Ao Phai and Lampang; and (iii) the changes in natural gas supply situations due to the unconfirmed status on gas supply from Malaysia, while the imported gas from Myanmar

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Note : 1/ The Thailand Load Forecast Subcommittee is a subcommittee of the National Energy Policy Formulation Committee. The group is made up of representatives from NEPO, EGAT, PEA and MEA. Outside consultants from TDRI, Monenco Consultants Ltd. of Canada, Bugach Associated Ltd. of Canada, and Dr.Tienchai Chongpeerapien of BERA Ltd. Thailand, had assisted the Subcommittee to prepared the 1993 Load Forecast.

was under negotiations[1/]. The Government policy on the power supply industry in Thailand has been set forth to cover : (i) the purchase of electricity from Independent Power Producers (IPPs) under the aggressive program on the private sector participation in power generation, as well as the purchase of electricity from neighboring Lao PDR; and (ii) the improvement of power supply reliability to cope with the growing economy of the country.

The new Power Development Plan (PDP 95-01) has been formulated based on the following updated information: (i) reducing the dependable capacity of the five existing hydro power plants by a total of 600 MW., (ii) indefinitely postponing Kaeng Krung and Mae Lama Luang hydroelectric, Lampang lignite-fired and Ao Phai coal-fired power plant projects; (iii) increasing the power generation reserve margin from the current 15 % to 25 % from the year 2001 onwards; and (iv) delaying the retirement dates of some existing power plants.

The PDP 95-01 comprises power generation and transmission projects which have been approved and committed for construction; and it is also supplemented with several projects including the purchased power from IPPs which is planned to provide sufficient, and reliable power supply at reasonable prices.

Table 3.2 shows the list of projects in PDP 95-01 (Recommended Plan).

Note : 1/ Negotiation on the purchasing of natural gas from Myanmar's Yadana field has been concluded on 9 September 1994.

Table 3.1 Total EGAT Generation Requirement
(1994 TLFS Forecast)

Fiscal Year	Peak Generation			Energy Generation			Load Factor %
	MW	Increase		GWh	Increase		
		MW	%		GWh	%	
				Actual			
1984	3,547.30	343.00	10.70	21,066.44	2,000.14	10.49	67.79
1985	3,878.40	331.10	9.33	23,356.57	2,290.13	10.87	68.75
1986	4,180.90	302.50	7.80	24,779.53	1,422.96	6.09	67.66
1987	4,733.90	553.00	13.23	28,193.16	3,413.63	13.78	67.99
1988	5,444.00	710.10	15.00	31,996.94	3,803.78	13.49	67.09
1989	6,232.70	788.70	14.49	36,457.09	4,460.16	13.94	66.77
1990	7,093.70	861.00	13.81	43,188.79	6,731.69	18.46	69.50
1991	8,045.00	951.30	13.41	49,225.03	6,036.25	13.98	69.85
1992	8,876.90	831.90	10.34	56,006.44	6,781.41	13.78	72.02
1993	9,730.00	853.10	9.61	62,179.73	6,173.29	11.02	72.95
1994	10,708.80	978.80	10.06	69,651.14	7,471.41	12.02	74.25
Average Growth 1985-1994	-	716.15	11.68	-	4,858.47	12.70	-
				Forecast			
1995	11,880.00	1,171.20	10.94	78,023.00	8,371.86	12.02	74.97
1996	13,009.00	1,129.00	9.50	85,571.00	7,548.00	9.67	75.09
1997	14,193.00	1,184.00	9.10	92,879.00	7,308.00	8.54	74.70
1998	15,315.00	1,122.00	7.91	100,383.00	7,504.00	8.08	74.82
1999	16,446.00	1,131.00	7.38	108,160.00	7,777.00	7.75	75.08
2000	17,685.00	1,239.00	7.53	116,795.00	8,635.00	7.98	75.39
2001	19,029.00	1,344.00	7.60	126,025.00	9,230.00	7.90	75.60
2002	20,237.00	1,208.00	6.35	134,041.00	8,016.00	6.36	75.61
2003	21,440.00	1,203.00	5.94	142,849.00	8,808.00	6.57	76.06
2004	22,690.00	1,250.00	5.83	152,529.00	9,680.00	6.78	76.74
2005	23,997.00	1,307.00	5.76	162,187.00	9,658.00	6.33	77.15
2006	25,371.00	1,374.00	5.73	171,745.00	9,558.00	5.89	77.28
2007	26,835.00	1,464.00	5.77	181,745.00	10,000.00	5.82	77.31
2008	28,409.00	1,574.00	5.87	193,505.00	11,760.00	6.47	77.76
2009	30,044.00	1,635.00	5.76	204,956.00	11,451.00	5.92	77.88
2010	31,749.00	1,705.00	5.68	216,428.00	11,472.00	5.60	77.82
2011	33,532.00	1,783.00	5.62	228,445.00	12,017.00	5.55	77.77
Average Growth 1982-1986	-	318.44	10.06	-	1,763.91	9.20	-
1987-1991	-	772.82	13.99	-	4,689.10	14.71	-
1992-1996	-	992.80	10.09	-	7,269.19	11.69	-
1997-2001	-	1,204.00	7.90	-	8,090.80	8.05	-
2002-2006	-	1,268.40	5.92	-	9,144.00	6.39	-
2007-2011	-	1,632.20	5.74	-	11,340.00	5.87	-

Table 3.2
List of Projects in the Recommended PDP (1995-2011)

Power Plant	Fuel Type	List Number	Rating (MW)	Total (MW)	Commissioning Date	
Khanom CC 1 (ST)	-	1	226	226	February	1995
Sirikit	Hydro	4	125	125	March	1995
Mae Moh	Lignite	12	300	300	May	1995
Nong Chok Gas Turbine	Diesel	1-4	122	488	May 95 - Aug	1995
Sai Noi Gas Turbine	Diesel	1-2	122	244	May 95 - Jun	1995
Mae Moh	Lignite	13	300	300	November	1995
Bhumibol Pumped-Storage	Hydro	8	168	168	December	1995
Wang Noi CC1 (GT)	Gas	1-2	223	446	Mar 96 - May	1996
Wang Noi CC2 (GT)	Gas	1-2	223	446	Jul 96 - Aug	1996
South Bangkok CC2 (GT)	Gas	1-2	202	404	Oct 96 - Nov	1996
EGAT-TNB Stage II Interconnection	-	-	300	300	April	1997
Wang Noi CC1 (ST)	-	1	205	205	April	1997
Wang Noi CC2 (ST)	-	1	205	205	July	1997
South Bangkok CC2 (ST)	-	1	219	219	August	1997
Lam Takhong Pumped-Storage	Hydro	1-2	250	500	February	2000
Wang Noi CC Stage 2 (GT)	Gas	1-2	200	400	Nov 97 - Dec	1997
Purchased Power	-	-	300	300	January	1998
Ratchaburi CC1 (GT)	Gas	1-2	200	400	Jul 98 - Aug	1998
Ratchaburi CC2 (GT)	Gas	1-2	200	400	Sep 98 - Oct	1998
Wang Noi CC Stage 2 (ST)	-	1	200	200	November	1998
Ratchaburi CC3 (GT)	Gas	1-2	200	400	Nov 98 - Dec	1998
Purchased Power	-	-	300	300	January	1999
Ratchaburi Thermal	Oil/Gas	1	700	700	April	1999
Ratchaburi CC1 (ST)	-	1	200	200	July	1999
Ratchaburi Thermal	Oil/Gas	2	700	700	August	1999
Ratchaburi CC2 (ST)	-	1	200	200	September	1999
Purchased Power	-	-	300	300	October	1999
Ratchaburi CC3 (ST)	-	1	200	200	November	1999
Purchased Power	-	-	400	400	January	2000
Krabi/Surat Thani Thermal	Oil/Gas	1	300	300	January	2000
Ratchaburi Thermal	Oil/Gas	3	700	700	October	2000
Ratchaburi Thermal	Oil/Gas	4	700	700	February	2001
Purchased Power	-	-	1400	1400	April	2001
Southern Region Thermal	Oil/Gas	1	300	300	March	2002
Purchased Power	-	-	1400	1400	April	2002
Purchased Power	-	-	1000	1000	January	2003
Lam Takhong Pumped-Storage	Hydro	3-4	250	500	April	2003
Purchased Power	-	-	1000	1000	January	2004
Southern Region Thermal	Oil/Gas	2	300	300	January	2004
Chulabhorn Pumped-Storage	Hydro	1-2	200	400	April	2004
Purchased Power	-	-	1000	1000	January	2005
New Thermal	Coal	1	1000	1000	April	2005
Purchased Power	-	-	1000	1000	January	2006
New Thermal	Coal	2	1000	1000	April	2006
Purchased Power	-	-	1000	1000	January	2007
Southern Region Thermal	Oil/Gas	3	300	300	January	2007
New Thermal	Coal	3	1000	1000	April	2007
Purchased Power	-	-	1000	1000	January	2008
Chulabhorn Pumped-Storage	Hydro	3-4	200	400	January	2008
Khiridharn Pumped-Storage	Hydro	1-2	200	400	March	2008
New Thermal	Coal	4	1000	1000	April	2008
Purchased Power	-	-	1000	1000	January	2009
Southern Region Thermal	Oil/Gas	4	300	300	January	2009
New Thermal	Coal	5	1000	1000	April	2009
Purchased Power	-	-	1000	1000	January	2010
New Thermal	Oil/Gas	1	1000	1000	April	2010
New Peaking GT	Diesel	1-3	100	300	April	2010
Purchased Power	-	-	1000	1000	January	2011
Southern Region Thermal	Oil/Gas	5	300	300	January	2011
New Thermal	Oil/Gas	2	1000	1000	April	2011

Existing Capacity by September 1994	=	12,988.9 MW
Total Added Capacity (Up to 2011)	=	33,676.0 MW
Plants Retirement	=	2,747.1 MW
Total Capacity by Year 2011	=	43,917.8 MW

4. 500 KV TRANSMISSION SYSTEM PROJECT FOR INDEPENDENT POWER PRODUCERS (IPPs)

In June 1993, EGAT entered into a contract with Black & Veatch International Company (BVI) who was engaged in association with Power Technologies, Inc. (PTI), to undertake the feasibility study for Transmission System Development for Southern Power Plant Projects where all power plants were assumed to be located near Bang Saphan in Prachaup Khiri Khan province. The purpose of the study is to determine the most appropriate transmission system requirement to transmit 10,000 MW of power from new power plants to the Greater Bangkok Area. The study which was completed in March 1994, recommended that 500 kV system is the preferred transmission system based on the technical and economical justification. The proposed 500 kV system would be consisting of three double-circuit lines from Bang Saphan to an intermediate substation assumed to be located at Chom Bung district in Ratchaburi province. From this intermediate substation, the 500 kV lines are further extended to link with the 500 kV system in Greater Bangkok Area with one double circuit line terminating at Sai Noi Substation, and another double circuit line terminating at Wang Noi Substation. The study also recommended that in case of the difficulty to obtain the right-of-way for the third 500 kV double circuit line from Bang Saphan to the intermediate substation, the installation of series compensators on the first two 500 kV double circuit lines between Bang Saphan and intermediate substation was considered as an alternative.

The transmission plan recommended in the BVI/PTI Study Report is actually the main power transmission trunk line to facilitate the connection of the IPP projects in western area to the EGAT system. Based on PDP 95-01, the 500 kV transmission plan for the power plant projects in the western area has been reviewed and the transmission system studies have been extended to cover the transmission system requirement for the power plant projects to be developed in the eastern area using the same approach and methodology of BVI/PTI study.

Based on the results of the reviewed study, the 500 kV Transmission System Project for Independent Power Producers which have been divided into two parts, are as follows ;

4.1 500 kV Transmission System in the Western Area

(a) Construction of two routes of the 500 kV double circuit line from Bang Saphan to Chom Bung (a new 500 kV substation to be constructed for Ratchaburi Power Plant Project), using 4x1272 MCM ACSR conductors per phase. The distance of the two line routes are approximately 275 km and 280 km respectively. One overhead ground wire with optical fibre would be provided.

(b) Construction of a 500 kV Bang Saphan Substation to accommodate four 500 kV outgoing lines to Chom Bung and one 500/230 kV interbus transformer rated 600/800/1000 MVA (consisting of four single-phase units, inclusive of one spare unit, each rated 200/267/333 MVA). The existing 230 kV substation will be expanded to provide space for the interbus transformer bank.

(c) Expansion of the 500 kV Chom Bung Substation to accommodate four incoming lines from Bang Saphan Substation.

(d) Since the capacity of the 500 kV equipments of GIS substation at Sai Noi can carry the current up to about 3,000 ampere which is not sufficient to carry the additional power from the West Coast IPP, so that it is necessary to construct a new 500 kV GIS switchyard located next to the existing 500 kV GIS switchyard at Sai Noi Substation. The double circuit 500 kV Chom Bung - Sai Noi line and one circuit of the 500 kV double-circuit Chom Bung - Wang Noi line (to be constructed for Ratchaburi Power Plant Project) will be sectionalized and they will be connected together at the new 500 kV GIS switchyard at Sai Noi. The new switchyard will also provide four line bays for the future lines to Bangkok Noi and Chaeng Watthana Substations.

(e) Installation of line shunt reactors rated 150 MVAr at both ends of the 500 kV Bang Saphan - Chom Bung lines.

(f) Land procurement for the 500 kV Bang Saphan Substation.

(g) Addition of communication system.

4.2 500 kV Transmission System in the Eastern Area

(a) Construction of two routes of 500 kV double circuit transmission line, using 4x1272 MCM ACSR per phase, approximately 155 and 170 km for the the first and second line routes respectively, from the proposed new 500 kV Rayong 4 Substation to interconnect with the 500 kV Sai Noi (Wang Noi) - Nong Chok transmission line (T Junction). At T Junction, one of the two lines of the 500 kV double circuit Wang Noi - Nong Chok transmission line will be sectionalized and reconnected such that one 500 kV double-circuit line from Rayong 4 Substation will be terminated at Wang Noi Substation and the other line will be terminated at Nong Chok Substation. One overhead ground wire with optical fibre will be equipped.

(b) Construction of a 230 kV double circuit Rayong 4 - Rayong 2 line, double circuit on steel tower, using 4x1272 MCM ACSR conductors per phase, for a distance of approximately 10 km.

(c) Construction of a 500/230 kV Rayong 4 Substation. The 500 kV switchyard will be provided for the four 500 kV outgoing lines to Wang Noi and Nong Chok Substations, and two 500/230 kV interbus transformers, each rated 600/800/1,000 MVA (consisting of seven single-phase units inclusive of one spare unit, each rated 200/267/333 MVA). The 230 kV switchyard will be provided for the interbus transformers, and two 230 kV outgoing lines to Rayong 2 Substation.

(d) Expansion of the 230 kV Rayong 2 Substation for two incoming lines from the Rayong 4 Substation.

(e) Installation of line shunt reactors rated 80 and 100 MVAr at both ends of the 500 kV Rayong 4 - Nong Chok and the Rayong 4 - Wang Noi lines respectively.

(f) Land procurement for the 500 kV Rayong 4 Substation.

(g) Addition of communication system.

Figure 4.1-4.2 show the locations and preliminary line routes of the proposed 500 kV transmission systems in the Western and Eastern Areas respectively. Figures 4.3-4.4 illustrate the single-line diagram of the proposed 500 kV transmission systems in the Western and Eastern Areas respectively.

4.3 Cost Estimate

The cost estimate of the 500 kV Transmission System Project for IPPs is based on the EGAT standard design, including engineering and supervision, physical contingencies, escalation, import duties, interest during construction and value added tax (VAT) at the 1995 price.

The escalation factors for the foreign currency portion and local currency portion are as follows :

	Escalation Factor (% Change)[1/]	
Fiscal Year	F.C. Portion [2/]	L.C. Portion [3/]
1996	1.79	4.00
1997	2.59	4.00
1998	2.52	4.00
1999	2.46	4.00
2000	2.48	4.00

The cost estimate of the 500 kV Transmission System Project for IPPs is shown in Table 4.1. The estimated cost of the project which consists of two parts : (i) 500 kV system in the Western Area, and (ii) 500 kV system in the Eastern Area, are summarized below:

Notes : 1/ Per annum growth rate from previous year.

2/ G-5 MUV index from the World Bank Quarterly Report on Commodity Markets and the Developing Countries, January 1995.

3/ Local Consumer Price Index estimated by NESDB and Bank of Thailand, 1994.

Description	Foreign Currency (MTHB)	Foreign Currency (USD.Million)[1/]	Local Currency (MTHB)	Total (MTHB)
(i) 500 kV system in the Western area	6,455.0	(258.2)	12,755.0	19,210.0
(ii) 500 kV system in the Eastern area	3,280.0	(131.2)	7,980.0	11,260.0
Total	9,735.0	(389.4)	20,735.0	30,470.0

4.4 Expenditure Schedule

The expenditure schedule of the 500 kV Transmission System Project for IPP is shown in Table 4.2. The annual disbursements are summarized as follows :

EXPENDITURE SCHEDULE OF 500 KV TRANSMISSION SYSTEM PROJECT
FOR INDEPENDENT POWER PRODUCERS
IN WESTERN AREA

Fiscal Year	Foreign Currency (MTHB)	Foreign Currency (USD.Million)[1/]	Local Currency (MTHB)	Total (MTHB)
1996	-	-	157.7	157.7
1997	-	-	288.3	288.3
1998	106.0	(4.3)	3,008.8	3,114.8
1999	3,928.6	(157.1)	4,817.2	8,745.8
2000	1,977.8	(79.1)	3,863.5	5,841.3
2001	442.6	(17.7)	619.5	1,062.1
Total	6,455.0	(258.2)	12,755.0	19,210.0

Note : 1/ Rate of exchange 1 USD = 25.0 THB.

EXPENDITURE SCHEDULE OF 500 KV TRANSMISSION SYSTEM PROJECT
FOR INDEPENDENT POWER PRODUCERS
IN EASTERN AREA

Fiscal Year	Foreign Currency		Local Currency	Total
	(MTHB)	(USD.Million)[1/]	(MTHB)	(MTHB)
1996	-	-	253.0	253.0
1997	-	-	175.2	175.2
1998	62.5	(2.5)	1,795.1	1,857.6
1999	2,077.5	(83.1)	2,974.1	5,051.6
2000	934.4	(37.4)	2,390.7	3,325.1
2001	205.6	(8.2)	391.9	597.5
Total	3,280.0	(131.2)	7,980.0	11,260.0

4.5 Implementation Schedule

The proposed implementation schedule of the transmission system expansion for the Western and Eastern Areas are shown in Tables 4.3 and 4.4. The expected commissioning date is September 2000.

Note : 1/ Rate of exchange 1 USD = 25.0 THB.

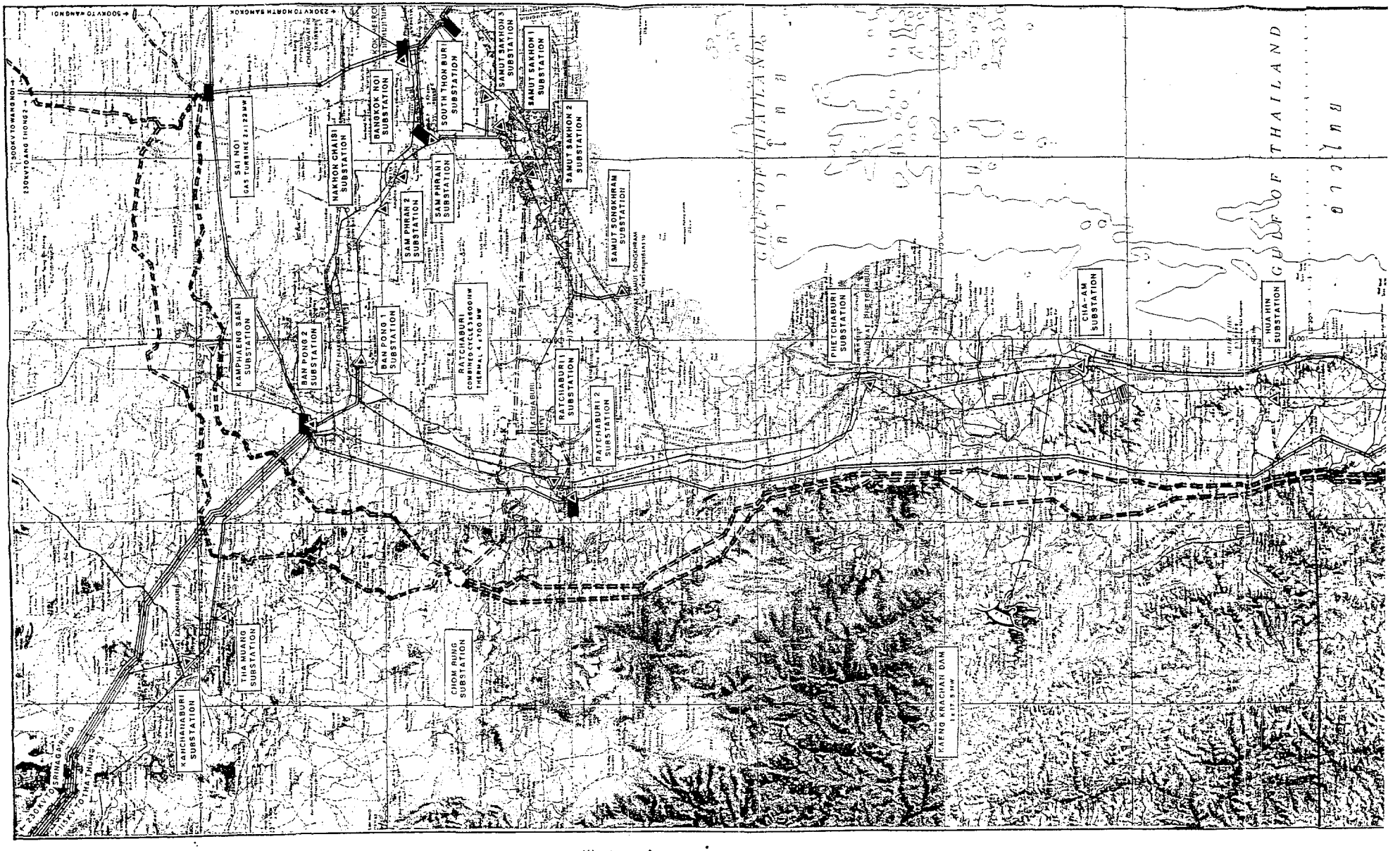
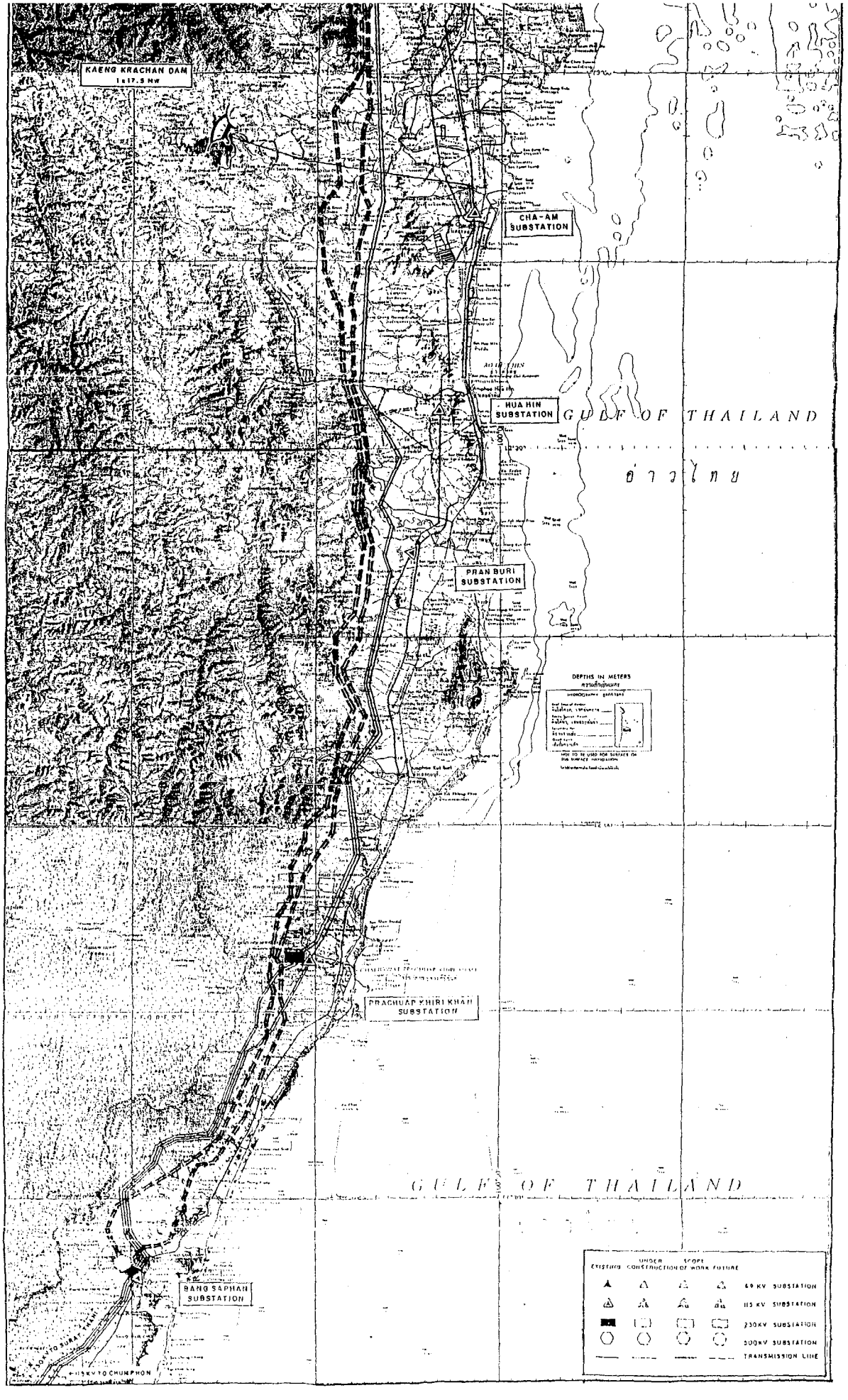


Figure 4.1 Preliminary Line Route of 500 kV Transmission System in the Western Area


KAENG KRACHAN DAM
1 x 17.5 MW
CHA-AM SUBSTATION
HUA HIN SUBSTATION
PRAN BURI SUBSTATION
PRACHUAP KHIRI KHAN SUBSTATION
BANG SAPHAN SUBSTATION
GULF OF THAILAND
ประเทศไทย
DEPTHS IN METERS
115KV TO CHUMPHON
UNDER CONSTRUCTION
SCOPE OF WORK FUTURE
EXISTING
69 KV SUBSTATION
115 KV SUBSTATION
230KV SUBSTATION
500KV SUBSTATION
TRANSMISSION LINE

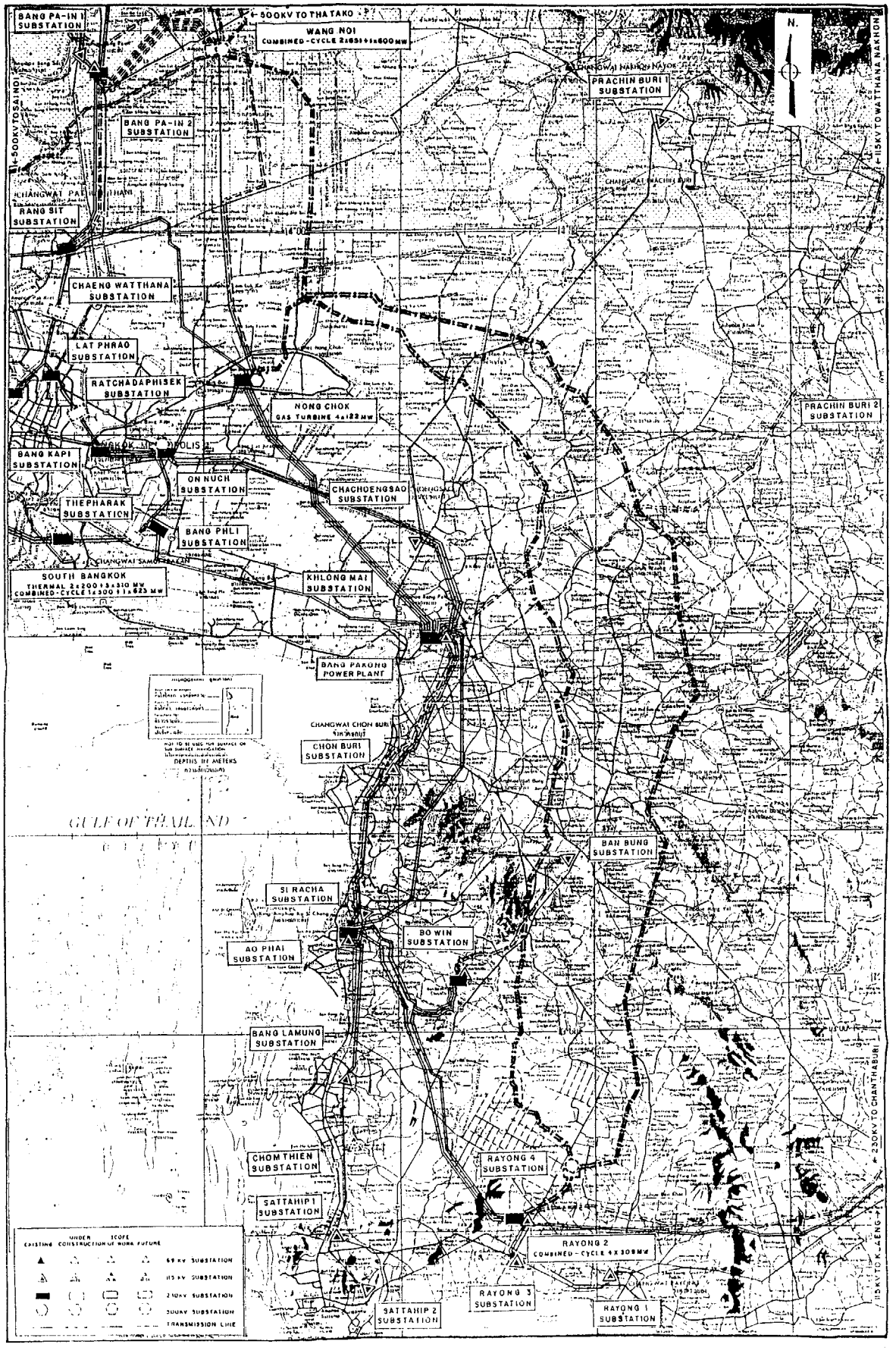


Figure 4.2 Preliminary Line Route of 500 kV Transmission System in the Eastern Area

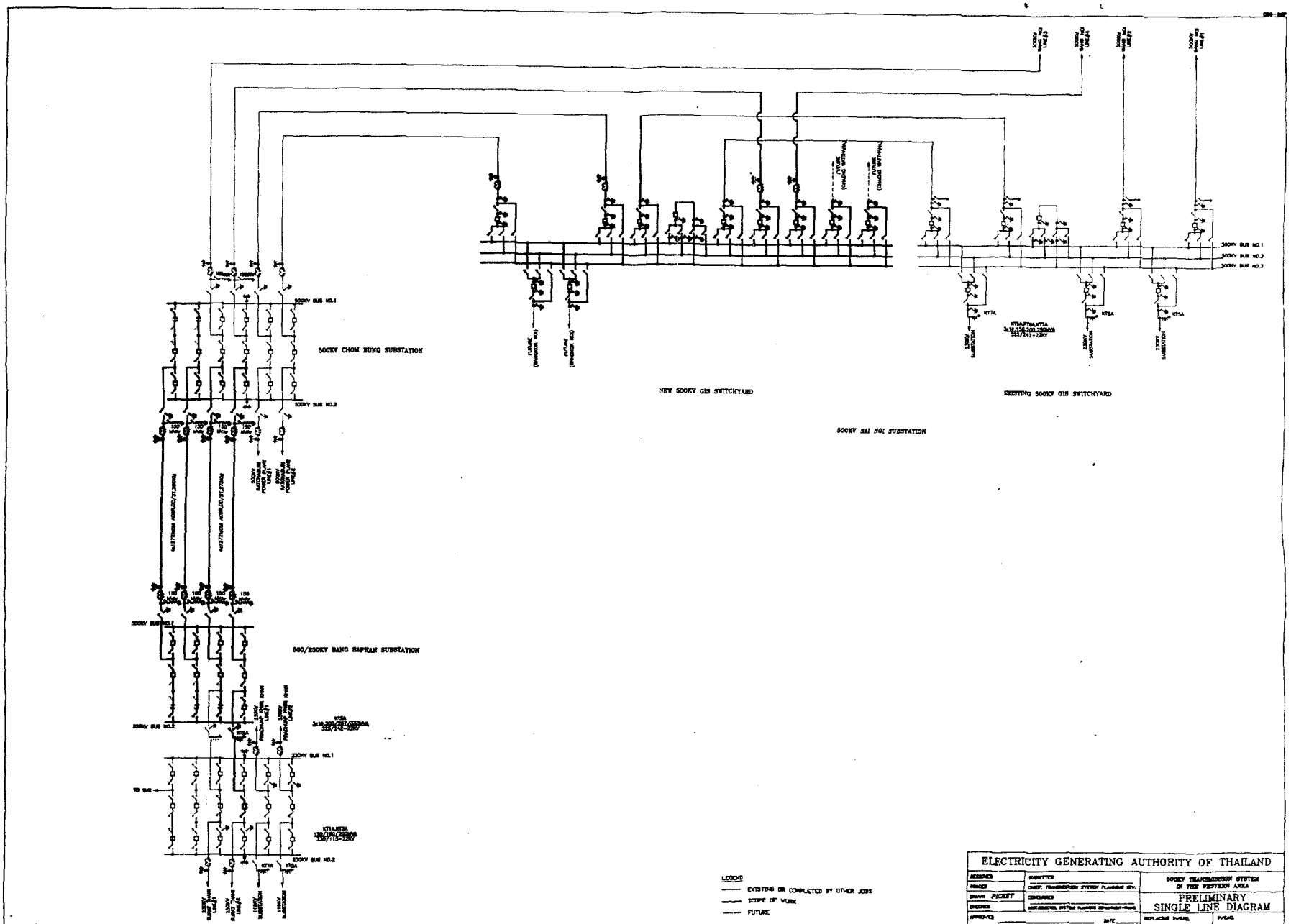
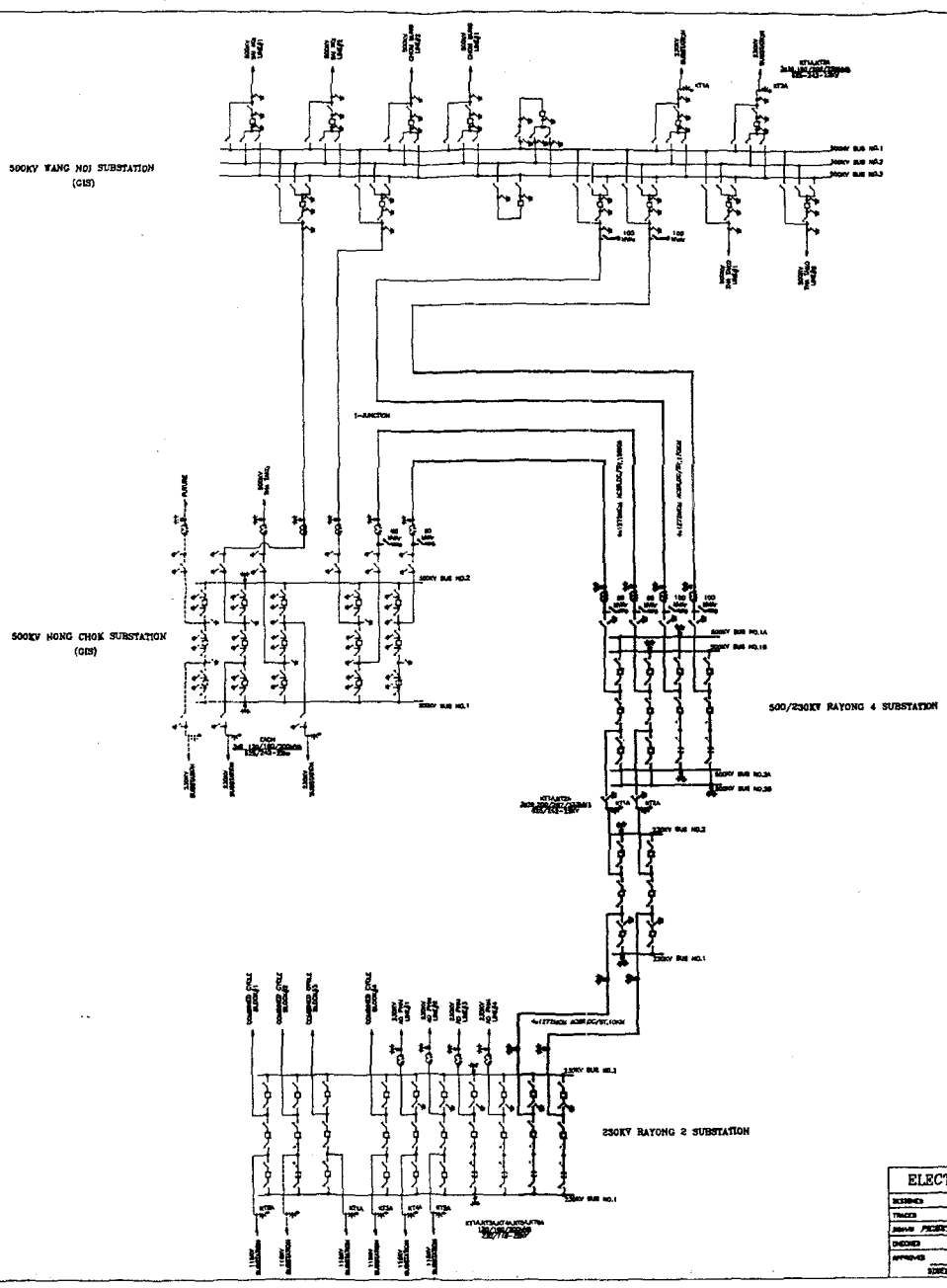


Figure 4.3 Single Line Diagram



ELECTRICITY GENERATING AUTHORITY OF THAILAND		
DESIGNED	SUBMITTED	500KV TRANSMISSION SYSTEM IN THE EASTERN AREA
TRACED	CHIEF, TRANSMISSION SYSTEM PLANNING SEC.	
JOB NO. PROJECT	CONCURRED	PRELIMINARY SINGLE LINE DIAGRAM
CHECKED	ASSISTANT TO THE SYSTEM PLANNING DEPARTMENT MANAGER	
APPROVED	DATE	REPLACING DRAWING
DIRECTOR, SYSTEM PLANNING DEPT.		DRAWING

Table 4.1 Cost Estimate of 500 kV Transmission System Project for IPPs

		F.C. (MTHB)	L.C. (MTHB)	Total (MTHB)
IN WESTERN AREA				
	TRANSMISSION LINE			
1.	500 kV Bang Saphan - Chom Bung 1st Line Route (4x1272 MCM ACSR, DC/ST, 275 km, Including Optical Fibre with Overhead Ground Wire)	1,361.1	3,250.5	4,611.6
2.	500 kV Bang Saphan - Chom Bung 2nd Line Route (4x1272 MCM ACSR, DC/ST, 280 km)	1,293.4	3,294.0	4,587.4
	Subtotal	2,654.5	6,544.5	9,199.0
	SUBSTATION			
3.	500/230 kV Bang Saphan Substation Expansion	632.0	298.1	930.1
4.	500 kV Chom Bung Substation Expansion	289.5	87.3	376.8
5.	500 kV Sai Noi Substation Expansion	1,592.0	106.1	1,698.1
6.	Installation of Line Shunt Reactor at 500 kV Bang Saphan - Chom Bung Lines	352.8	21.2	374.0
7.	Communication System Addition	27.7	3.3	31.0
	Subtotal	2,894.0	516.0	3,410.0
	Total Direct Cost a/	5,548.5	7,060.5	12,609.0
	INDIRECT COST			
8.	Engineering & Supervision	-	630.5	630.5
9.	Physical Contingencies	555.0	769.0	1,324.0
	Total Cost (w/o Escalation, Import Duties, IDC & VAT)	6,103.5	8,460.0	14,563.5
10.	Escalation	351.5	1,236.5	1,588.0
	Total Cost (w/o Import Duties, IDC & VAT)	6,455.0	9,696.5	16,151.5
11.	Import Duties	-	742.5	742.5
	Total Cost (w/o IDC VAT)	6,455.0	10,439.0	16,894.0
12.	Interest During Construction	-	1,454.0	1,454.0
	Total Cost (w/o VAT)	6,455.0	11,893.0	18,348.0
13.	Value Added Tax	-	862.0	862.0
	Total Cost	6,455.0	12,755.0	19,210.0

Note : a/ Price Level 1995.

Table 4.1 Cost Estimate of 500 kV Transmission System Project for IPPs (Continued)

		F.C. (MTHB)	L.C. (MTHB)	Total (MTHB)
IN EASTERN AREA				
	TRANSMISSION LINE			
1.	500 kV Rayong 4 - T Junction 1st Line Route (4x1272 MCM ACSR, DC/ST, 155 km, Including Optical Fibre with Overhead Ground Wire)	773.2	1,903.3	2,676.5
2.	500 kV Rayong 4 - T Junction 2nd Line Route (4x1272 MCM ACSR, DC/ST, 170 km)	785.3	2,069.7	2,855.0
3.	230 kV Rayong 4 - Rayong 2 (4x1272 MCM ACSR, DC/ST, 10 km, Including Optical Fibre with Overhead Ground Wire)	43.5	106.0	149.5
	Subtotal	1,602.0	4,079.0	5,681.0
	SUBSTATION			
4.	500/230 kV Rayong 4 Substation	872.6	449.8	1,322.4
5.	230 kV Rayong 2 Substation Expansion	40.7	9.6	50.3
6.	Installation of Line Shunt Reactor at 500 kV Rayong 4 - Nong Chok and Rayong 4 - Wang Noi Lines	286.6	23.5	310.1
7.	Communication System Addition	18.6	2.6	21.2
	Subtotal	1,218.5	485.5	1,704.0
	Total Direct Cost a/	2,820.5	4,564.5	7,385.0
	INDIRECT COST			
8.	Engineering & Supervision	-	369.5	369.5
9.	Physical Contingencies	282.0	493.5	775.5
	Total Cost (w/o Escalation, Import Duties, IDC & VAT)	3,102.5	5,427.5	8,530.0
10.	Escalation	177.5	779.5	957.0
	Total Cost (w/o Import Duties, IDC & VAT)	3,280.0	6,207.0	9,487.0
11.	Import Duties	-	416.0	416.0
	Total Cost (w/o IDC VAT)	3,280.0	6,623.0	9,903.0
12.	Interest During Construction	-	866.0	866.0
	Total Cost (w/o VAT)	3,280.0	7,489.0	10,769.0
13.	Value Added Tax	-	491.0	491.0
	Total Cost	3,280.0	7,980.0	11,260.0
	TOTAL PROJECT COST	9,735.0	20,735.0	30,470.0
	(USD Million Equivalent b/	389.4	829.4	1,218.8)

Notes : a/ Price Level 1995.
b/ 1 USD = THB 25.0.

Table 4.2 Expenditure Schedule of 500 kV Transmission System Project for IPPs

(Million Baht)

Item	Description	Total			1996			1997			1998			1999			2000			2001		
		F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total
	IN WESTERN AREA																					
	TRANSMISSION LINE																					
1	500 kV Bang Saphan - Chom Bung 1st Line Route (4x1272 MCM ACSR, DC/ST, 275 km, Including Optical Fibre with Overhead Ground Wire)	1,361.1	3,250.5	4,611.6	-	5.5	5.5	-	103.9	103.9	49.7	1,137.7	1,187.4	1,221.9	1,095.0	2,316.9	39.8	725.1	764.9	49.7	183.3	233.0
2	500 kV Bang Saphan - Chom Bung 2nd Line Route (4x1272 MCM ACSR, DC/ST, 280 km)	1,293.4	3,294.0	4,587.4	-	5.6	5.6	-	105.8	105.8	41.4	1,156.6	1,198.0	1,177.5	1,107.2	2,284.7	33.1	733.7	766.8	41.4	185.1	226.5
	Subtotal	2,654.5	6,544.5	9,199.0	-	11.1	11.1	-	209.7	209.7	91.1	2,294.3	2,385.4	2,399.4	2,202.2	4,601.6	72.9	1,458.8	1,531.7	91.1	368.4	459.5
	SUBSTATION																					
3	500/230 kV Bang Saphan Substation Expansion	632.0	298.1	930.1	-	100.0	100.0	-	-	-	-	25.2	25.2	214.9	71.7	286.6	354.0	83.9	437.9	63.1	17.3	80.4
4	500 kV Chom Bung Substation Expansion	289.5	87.3	376.8	-	-	-	-	-	-	-	-	-	98.4	36.2	134.6	162.2	42.4	204.6	28.9	8.7	37.6
5	500 kV Sai Noi Substation Expansion	1,592.0	106.1	1,698.1	-	-	-	-	-	-	-	-	-	541.3	44.0	585.3	891.5	51.5	943.0	159.2	10.6	169.8
6	Installation of Line Shunt Reactor at 500 kV Bang Saphan - Chom Bung Lines	352.8	21.2	374.0	-	-	-	-	-	-	-	-	-	120.0	8.8	128.8	197.5	10.3	207.8	35.3	2.1	37.4
7	Communication System Addition	27.7	3.3	31.0	-	-	-	-	-	-	-	-	-	2.8	0.3	3.1	22.1	2.7	24.8	2.8	0.3	3.1
	Subtotal	2,894.0	516.0	3,410.0	-	100.0	100.0	-	-	-	-	25.2	25.2	977.4	161.0	1,138.4	1,627.3	190.8	1,818.1	289.3	39.0	328.3
	Total Direct Cost a/	5,548.5	7,060.5	12,609.0	-	111.1	111.1	-	209.7	209.7	91.1	2,319.5	2,410.6	3,376.8	2,363.2	5,740.0	1,700.2	1,649.6	3,349.8	380.4	407.4	787.8
	INDIRECT COST																					
8	Engineering & Supervision	-	630.5	630.5	-	-	-	-	1.0	1.0	-	21.4	21.4	-	332.5	332.5	-	275.6	275.6	-	-	-
9	Physical Contigencies	555.0	769.0	1,324.0	-	11.1	11.1	-	21.1	21.1	9.1	234.2	243.3	337.9	269.4	607.3	170.0	192.5	362.5	38.0	40.7	78.7
10	Escalation	351.5	1,236.5	1,588.0	-	2.4	2.4	-	14.0	14.0	5.8	265.9	271.7	213.9	437.1	651.0	107.6	409.2	516.8	24.2	107.9	132.1
11	Import Duties	-	742.5	742.5	-	-	-	-	-	-	-	-	-	-	501.9	501.9	-	240.6	240.6	-	-	-
	Subtotal	906.5	3,378.5	4,285.0	-	13.5	13.5	-	36.1	36.1	14.9	521.5	536.4	551.8	1,540.9	2,092.7	277.6	1,117.9	1,395.5	62.2	148.6	210.8
	Total Cost (w/o IDC & VAT)	6,455.0	10,439.0	16,894.0	-	124.6	124.6	-	245.8	245.8	106.0	2,841.0	2,947.0	3,928.6	3,904.1	7,832.7	1,977.8	2,767.5	4,745.3	442.6	556.0	998.6
12	Interest During Construction	-	1,454.0	1,454.0	-	33.1	33.1	-	42.5	42.5	-	124.6	124.6	-	438.2	438.2	-	815.6	815.6	-	-	-
	Total Cost (w/o VAT)	6,455.0	11,893.0	18,348.0	-	157.7	157.7	-	288.3	288.3	106.0	2,965.6	3,071.6	3,928.6	4,342.3	8,270.9	1,977.8	3,583.1	5,560.9	442.6	556.0	998.6
13	Value Added Tax	-	862.0	862.0	-	-	-	-	-	-	-	43.2	43.2	-	474.9	474.9	-	280.4	280.4	-	63.5	63.5
	Total Cost	6,455.0	12,755.0	19,210.0	-	157.7	157.7	-	288.3	288.3	106.0	3,008.8	3,114.8	3,928.6	4,817.2	8,745.8	1,977.8	3,863.5	5,841.3	442.6	619.5	1,062.1

Notes : a/ Price Level 1995

Table 4.2 Expenditure Schedule of 500 kV Transmission System Project for IPPs (Continued)

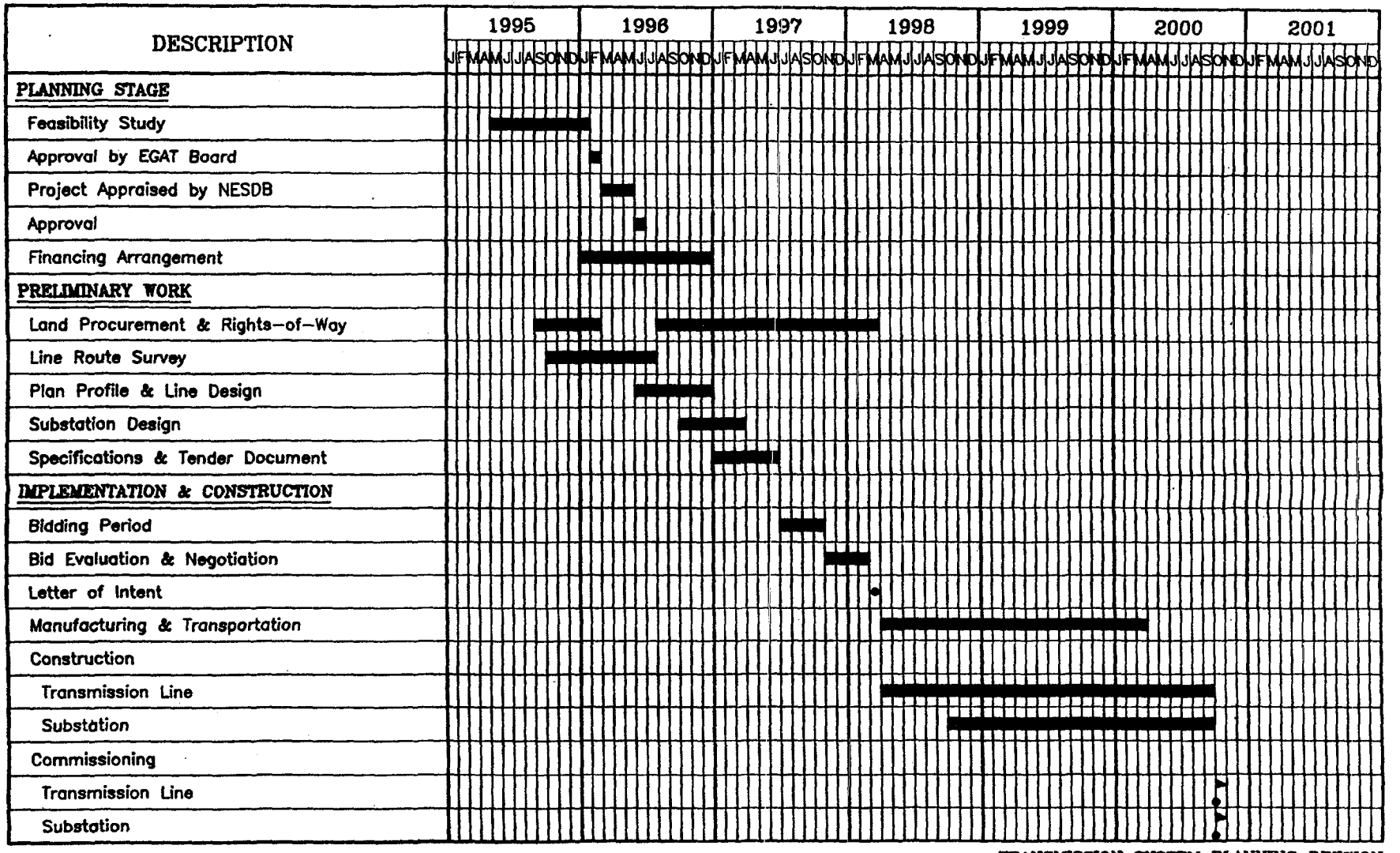
(Million Baht)

Item	Description	Total			1996			1997			1998			1999			2000			2001		
		F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total
	IN EASTERN AREA																					
	TRANSMISSION LINE																					
1	500 kV Rayong 4 - T Junction 1st Line Route (4x1272 MCM ACSR, DC/ST, 155 km, Including Optical Fibre with Overhead Ground Wire)	773.2	1,903.3	2,676.5	-	3.1	3.1	-	58.6	58.6	28.6	649.9	678.5	693.1	651.8	1,344.9	22.9	429.4	452.3	28.6	110.5	139.1
2	500 kV Rayong 4 - T Junction 2nd Line Route (4x1272 MCM ACSR, DC/ST, 170 km)	785.3	2,069.7	2,855.0	-	3.4	3.4	-	64.2	64.2	25.1	710.7	735.8	715.0	706.2	1,421.2	20.1	465.8	485.9	25.1	119.4	144.5
3	230 kV Rayong 4 - Rayong 2 (4x1272 MCM ACSR, DC/ST, 10 km, Including Optical Fibre with Overhead Ground Wire)	43.5	106.0	149.5	-	-	-	-	-	-	-	0.2	0.2	32.7	56.5	89.2	9.6	45.1	54.7	1.2	4.2	5.4
	Subtotal	1,602.0	4,079.0	5,681.0	0.0	6.5	6.5	0.0	122.8	122.8	53.7	1,360.8	1,414.5	1,440.8	1,414.5	2,855.3	52.6	940.3	992.9	54.9	234.1	289.0
	SUBSTATION																					
4	500/230 kV Rayong 4 Substation	872.6	449.8	1,322.4	-	200.0	200.0	-	-	-	-	18.9	18.9	296.7	95.7	392.4	488.6	112.1	600.7	87.3	23.1	110.4
5	230 kV Rayong 2 Substation Expansion	40.7	9.6	50.3	-	-	-	-	-	-	-	-	-	13.9	2.5	16.4	22.8	6.1	28.9	4.0	1.0	5.0
6	Installation of Line Shunt Reactor at 500 kV Rayong 4 - Nong Chok and Rayong 4 - Wang Noi Lines	286.6	23.5	310.1	-	-	-	-	-	-	-	-	-	28.7	2.4	31.1	229.2	18.7	247.9	28.7	2.4	31.1
7	Communication System Addition	18.6	2.6	21.2	-	-	-	-	-	-	-	-	-	1.9	0.3	2.2	14.8	2.0	16.8	1.9	0.3	2.2
	Subtotal	1,218.5	485.5	1,704.0	-	200.0	200.0	-	-	-	-	18.9	18.9	341.2	100.9	442.1	755.4	138.9	894.3	121.9	26.8	148.7
	Total Direct Cost a/	2,820.5	4,564.5	7,385.0	-	206.5	206.5	0.0	122.8	122.8	53.7	1,379.7	1,433.4	1,782.0	1,515.4	3,297.4	808.0	1,079.2	1,887.2	176.8	260.9	437.7
	INDIRECT COST																					
8	Engineering & Supervision	-	369.5	369.5	-	-	-	-	1.0	1.0	-	11.8	11.8	-	192.8	192.8	-	163.9	163.9	-	-	-
9	Physical Contigencies	282.0	493.5	775.5	-	20.7	20.7	-	12.4	12.4	5.4	139.3	144.7	181.3	171.0	352.3	77.6	124.0	201.6	17.7	26.1	43.8
10	Escalation	177.5	779.5	957.0	-	4.5	4.5	-	8.2	8.2	3.4	157.8	161.2	114.2	276.7	390.9	48.8	263.2	312.0	11.1	69.1	80.2
11	Import Duties	-	416.0	416.0	-	-	-	-	-	-	-	-	-	-	285.4	285.4	-	130.6	130.6	-	-	-
	Subtotal	459.5	2,058.5	2,518.0	-	25.2	25.2	-	21.6	21.6	8.8	308.9	317.7	295.5	925.9	1,221.4	126.4	681.7	808.1	28.8	95.2	124.0
	Total Cost (w/o IDC & VAT)	3,280.0	6,623.0	9,903.0	-	231.7	231.7	-	144.4	144.4	62.5	1,688.6	1,751.1	2,077.5	2,441.3	4,518.8	934.4	1,760.9	2,695.3	205.6	356.1	561.7
12	Interest During Construction	-	866.0	866.0	-	21.3	21.3	-	30.8	30.8	-	79.5	79.5	-	260.8	260.8	-	473.6	473.6	-	-	-
	Total Cost (w/o VAT)	3,280.0	7,489.0	10,769.0	-	253.0	253.0	-	175.2	175.2	62.5	1,768.1	1,830.6	2,077.5	2,702.1	4,779.6	934.4	2,234.5	3,168.9	205.6	356.1	561.7
13	Value Added Tax	-	491.0	491.0	-	-	-	-	-	-	-	27.0	27.0	-	272.0	272.0	-	156.2	156.2	-	35.8	35.8
	Total Cost	3,280.0	7,980.0	11,260.0	-	253.0	253.0	-	175.2	175.2	62.5	1,795.1	1,857.6	2,077.5	2,974.1	5,051.6	934.4	2,390.7	3,325.1	205.6	391.9	597.5
	TOTAL PROJECT COST	9,735.0	20,735.0	30,470.0	-	410.7	410.7	-	463.5	463.5	168.5	4,803.9	4,972.4	6,006.1	7,791.3	13,797.4	2,912.2	6,254.2	9,166.4	648.2	1,011.4	1,659.6
	USD Million Equivalent b/	389.4	829.4	1,218.8	-	16.4	16.4	-	18.5	18.5	6.8	192.1	198.9	240.2	311.7	551.9	116.5	250.2	366.7	25.9	40.5	66.4

Notes : a/ Price Level 1995.

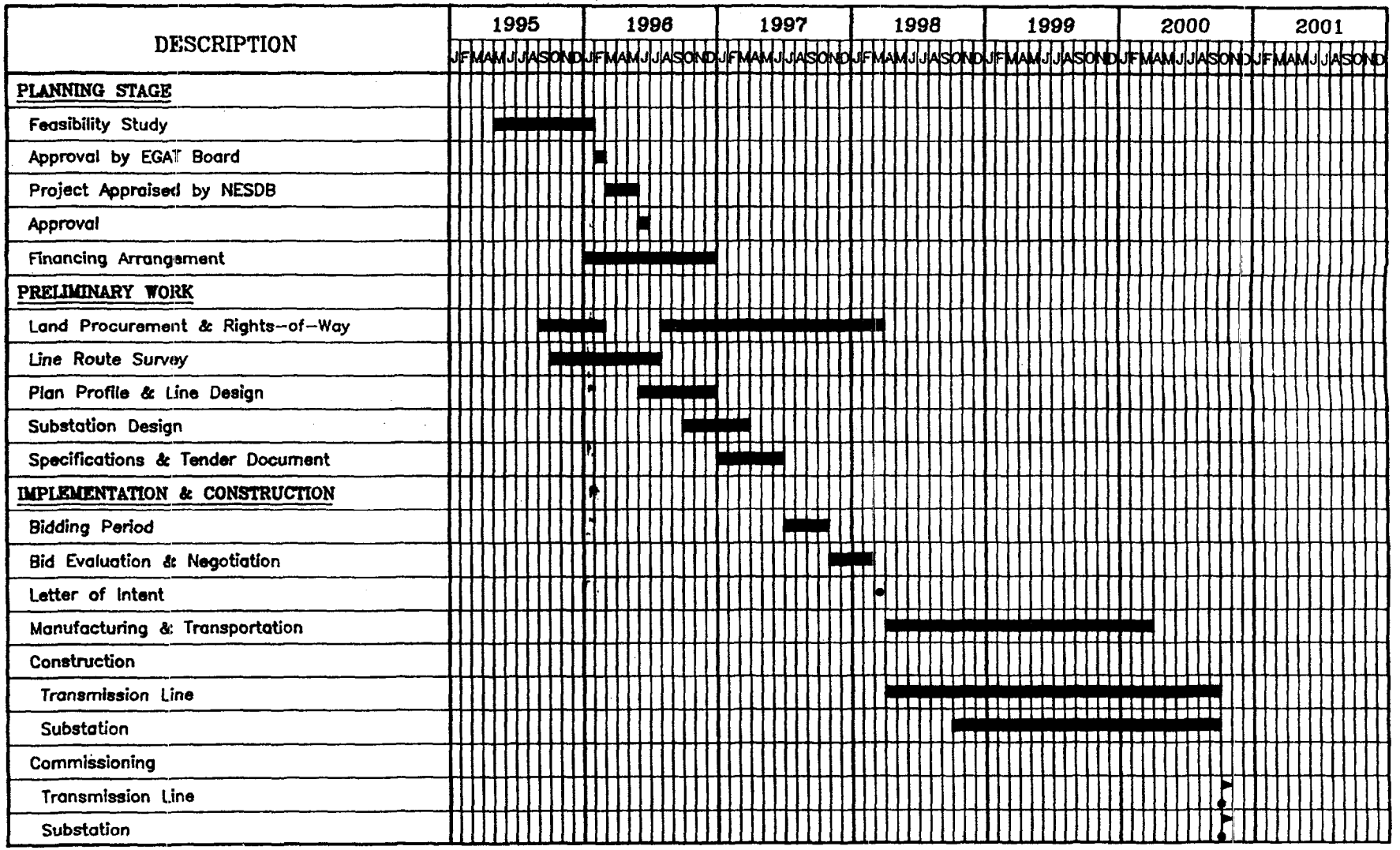
b/ 1.0 USD = THB 25.0.

Table 4.3 Implementation Schedule of 500 kV Transmission System Project for IPPs (Western Area)



TRANSMISSION SYSTEM PLANNING DIVISION

Table 4.4 Implementation Schedule of 500 kV Transmission System Project for IPPs (Eastern Area)



TRANSMISSION SYSTEM PLANNING DIVISION

5. POWER SYSTEM STUDIES

Power system studies have been made to investigate and verify the maximum power transfer capability of the 500 kV transmission plan as recommended by the BVI/PTI study. This revised study has been performed with the changing conditions from the previous BVI/PTI study; i.e., the adoption of new load forecast and Power Development Plan (PDP 95-01); the generating capacity of the planned Ratchaburi Thermal Power Plant is increased from 3,600 MW to 4,600 MW; and the possibility of 600 MW stage 1 IPP Project to be integrated at Ratchaburi 2 Substation. The 500 kV transmission plan is also adopted for the connection of 10,000 MW power plant projects in the eastern area.

In the 1994 solicitation for power of 4,100 MW from IPPs, has included the first 1,000-1,300 MW (First Stage IPPs) for completion during 1996-2000. With the limitation of the existing transmission capability, many substations have the capacities enough to receive the power from the first stage IPPs with the maximum of :

either 600 MW at Ratchaburi or 800 MW at Sam Phran for the western area,

and either 700 MW at Ao Phai or 700 MW at Pranchin Buri or 300 MW at Khlong Mai and 200 MW at Rayong for the eastern area.

For the next 2,800 MW of capacity, preference will be given to a division of approximately 1,400 MW located in the western area and 1,400 MW located in the eastern area in order to stabilize the power system.

According to the recommended plan in the PDP 95-01, the power development program during 1998-2011 includes many new large base-load power plants and the power purchases from the IPPs as follows :

IPP 1,300 MW (without system reinforcement)	1998-2000
Ratchaburi Combined Cycle (3x600 MW)	1998-1999
Ratchaburi Thermal Plant (4x700 MW)	1999-2001

IPP (2x700 MW)	2001
IPP (2x700 MW)	2002
IPP (1,000 MW)	2003
IPP (1,000 MW)	2004
IPP & EGAT new thermal plant (2x1000 MW)	2005
IPP & EGAT new thermal plant (2x1000 MW)	2006
IPP & EGAT new thermal plant (2x1000 MW)	2007
IPP & EGAT new thermal plant (2x1000 MW)	2008
IPP & EGAT new thermal plant (2x1000 MW)	2009
IPP & EGAT new thermal plant (2x1000 MW)	2010
IPP & EGAT new thermal plant (2x1000 MW)	2011

As shown above, up to 2011, the large base load power plant projects of about 13,100 MW will be given to IPPs and the other new power plants for a total capacity of 11,600 MW will be developed by EGAT.

For the studies, all of the first stage IPPs (1,300 MW) of the 1994 solicitation are assumed to be located in the Western and Eastern Areas at the limited capacity of each substation. However, for the next and future IPPs, including the new EGAT thermal power plant projects as indicated in the PDP 95-01, two basic plans are used for the studies : (1) All future power plants are assumed to be located in the west coast for the studies of the transmission system in the Western Area; and (ii) All future power plants are assumed to be located in the east coast for the studies of the transmission system in the Eastern Area.

Steady state power flow and stability studies are simulated at both peak load and light load conditions to determine the maximum power transfer capability of the proposed 4 circuits of the 500 kV transmission lines. Fault level study is also carried out.

The following machine parameters are used in the study.

Inertia constant of each generator (H)	=	3.8 kW-s/kVA
Transient reactance (X'_d)	=	0.28 p.u.
Subtransient reactance (X''_d)	=	0.22 p.u.

Auto transformer impedance (500/230 kV)	= 22	%
Short-circuit impedance of generator transformer	= 18	%
Power factor	= 0.85	

All exciters are equipped with power system stabilizers (PSSs)

5.1 The 500 kV Transmission System in the Western Area

Two double-circuit 500 kV transmission lines, using 4x1272 MCM ACSR conductors per phase, from Bang Saphan to Chom Bung switching station and from Chom Bung to Wang Noi and Sai Noi in the Bangkok vicinity have been planned. The latter line sections will be constructed under Ratchaburi Power Plant Project.

The generated power, totalling 4,600 MW, from the Ratchaburi combined cycle power plant and the Ratchaburi thermal power plants, as well as 600 MW of the first stage of IPP installed at Ratchaburi 2 Substation, are assumed to be included in Year 2000.

With the completion of the proposed 500 kV lines by the end of Year 2000, the results of the studies can be concluded as follows :

a) System of Year 2001 with additional 2x700 MW IPP Power Plants (total 1,400 MW)

From the power system analyses, it is shown that the system works technically satisfactorily.

b) System of Year 2002 with additional 2x700 MW IPP Power Plants (total accumulative new capacities from Year 2001 is 2,800 MW)

With the same configuration, the system is technically satisfactory.

c) System of Year 2003 with additional 1,000 MW IPP Power Plant (total accumulative new capacities from Year 2001 is 3,800 MW)

The system is technically satisfactory without any reinforcement.

d) System of Year 2004 with additional 1,000 MW IPP Power Plant (total accumulative new capacities from Year 2001 is 4,800 MW)

The system studies based on the N-1 criterion confirm that the system is technically viable. If, however, the N-2 is applied on the 500 kV Chom Bung - Sai Noi line during the light load period, the system is oscillated (Figure Case TS-L04W). To solve such problem, the sectionalization of one circuit of the 500 kV Chom Bung - Wang Noi line and the reconnection of the two line sections at the 500 kV Sai Noi Substation is proposed.

e) System of Year 2005 with additional 1,000 MW IPP and 1,000 MW new thermal Power Plant (total accumulative new capacities from Year 2001 is 6,800 MW)

Transient stability studies based on the N-1 criterion show that the system is unstable if a three phase fault occurs on the 500 kV Bang Saphan - Chom Bung line during light load period (Figure Case TS-L05W). However, if only 1,000 MW Power Plant is included this year, the system is technically satisfactory with both N-1 and N-2 contingencies..

Based on the results of the study, it can be concluded that the maximum power transfer capability of two double-circuit 500 kV lines from Bang Saphan to Chom Bung can be 5,800 MW. To increase the power transfer capability, the addition of more parallel lines or the installation of the appropriate series compensators are required. Further studies will be carried out for the next stage of transmission system reinforcement or expansion program.

Power flow diagrams and stability curves are shown in Appendix 2 and 3.

5.2 The 500 kV Transmission System in the Eastern Area

Two double-circuit 500 kV lines consisting of one double-circuit from Rayong 4 to Wang Noi and another double-circuit from Rayong 4 to Nong Chok, using 4x1272 MCM ACSR conductors per phase, are assumed in the studies. The integration with the existing system is made at Rayong 4 by the installation of two 500/230 kV tie

transformers, each rated 1,000 MW, connecting to Rayong 2 Substation via a 230 kV double-circuit line, using 4x1272 MCM ACSR conductors per phase.

Since it is possible to add 700 MW out of the first IPP into the Eastern Area, the injection of 300 MW in Khlong Mai and 400 MW in Ao Pha is assumed in this study. This case is considered as the worst scenario to the network conditions.

The results of the studies can be concluded as follows :

a) System of Year 2001 with additional 2x700 MW IPP Power Plants (total accumulative new capacities from Year 2001 is 1,400 MW)

With the proposed 500 kV transmission system, the system is technically satisfactory.

b) System of Year 2002 with additional 2x700 MW IPP Power Plants (total accumulative new capacities from Year 2001 is 2,800 MW)

With the same system configuration above, the system is technically satisfactory.

c) System of Year 2003 with additional 1,000 MW IPP Power Plants (total accumulative new capacities from Year 2001 is 3,800 MW)

The system is technically satisfactory without any further reinforcement.

d) System of Year 2004 with additional 1,000 MW IPP Power Plants (total accumulative new capacities from Year 2001 is 4,800 MW)

From the power system analyses, it is shown that the system is still technically satisfactory.

e) System of Year 2005 with additional 1,000 MW IPP and 1,000 MW new thermal Power Plants (total accumulative new capacities from Year 2001 is 6,800 MW)

The results of the studies show that the system is technically satisfactory without further reinforcement.

f) System of Year 2006 with additional 1,000 MW IPP and 1,000 MW new thermal Power Plants (total accumulative new capacities from Year 2001 is 8,800 MW)

The high fault current (exceed 50 kA) at 500 kV Rayong 4 was observed. The measure to limit the fault current was the splitting of the 500 kV bus into two buses, with equal capacity at each bus was used. But the power flow studies shew that, in case of N-1 contingency, if a fault occured on the 500 kV Rayong 4 - Nong Chok line, the 500/230 kV tie transformer at Bus #1 of Rayong 4 would be 8 % overloaded during peak load period, and if a fault occured on the 500 kV Rayong 4 - Wang Noi line, the 500/230 kV tie transformer at Bus #2 of Rayong 4 would be overloaded about 18 % and 5 % during peak and light load periods respectively. So that the installation of two additional 500/230 kV tie transformers at Rayong 4 Substation will be recommended. No transient instability is shown, when a disturbance occurs in the system.

g) System of Year 2007 with additional 1,000 MW IPP and 1,000 MW new thermal Power Plants (total accumulative new capacities from Year 2001 is 10,800 MW)

The power flow studies based on the single contingency criterion show that the 230 kV Rayong 2 - Ao Phai line will be overloaded by 7.6 %, if a fault is applied on each line.

The transient stability studies have been also investigated. The results indicate that the system is unstable if a three-phase fault occurs on the 500 kV Rayong 4 - Nong Chok line.

If only 1,000 MW Power Plant is connected to the system in this year, the results of the studies show that the system is still unstable, if a three-phase fault is applied on one circuit of the 500 kV Rayong 4 - Wang Noi line during the light load period.

As the results of the study, the maximum power transfer capability of the Eastern Area is 8,800 MW. Further studies are required to determine the additional transfer capability. The installation of more parallel lines or series compensators would be recommended in the next stage of transmission system expansion program.

Power flow diagrams and stability curves are shown in Appendix 2 and 3.

Conclusion

For the 500 kV transmission system in the Western Area, the maximum power transfer capability of the two 500 kV double-circuit line is 5,800 MW by the stability limit.

For the 500 kV transmission system in the Eastern Area, the maximum power transfer capability of the two 500 kV double-circuit transmission line is 8,800 MW by the stability limit.

To increase more power transfer capability of the two areas, further studies will be required. According to the BVI study, the installation of more 500 kV lines or the installation of series capacitor with appropriate compensation would be the options to be considered .

5.3 Fault Level Studies

The fault level studies have been conducted for the development of the Western 500 kV transmission system and the Eastern 500 kV transmission system in Year 2005 and 2006 respectively.

The three-phase fault and the single-line-to-ground fault at the concerned power plants and substations have been investigated. The high fault current is observed at 500 kV Rayong 4 Busbar in 2006. This is due to the fact that many generating units will be installed. To limit the fault current at this power plant, splitting the bus at the switchyard into two sections would be therefore recommended in 2006. The expected high fault current at significant power plants and substations (with the measures to limit fault currents) are shown below :

5.3.1 The Development of the Western 500 kV Transmission Lines

	3-Ø (kA)	1-Ø (kA)
230 kV South Thon Buri Substation	40.5	28.0
230 kV Bangkok Noi Substation	44.0	26.7
230 kV Wang Noi Substation	38.8	41.8
500 kV Bang Saphan Substation	34.0	30.5
500 kV Wang Noi Substation	34.1	23.9

5.3.2 The Development of the Eastern 500 kV Transmission Lines

	3-Ø (kA)	1-Ø (kA)
230 kV On Nuch Substation	41.6	25.0
230 kV Wang Noi Substation	39.7	42.6
230 kV Rayong 2 Substation	42.0	39.0
230 kV Bang Pakong Substation (Bus #1)	39.9	45.1
230 kV Bang Pakong Substation (Bus #2)	47.1	48.0
230 kV Rayong 4 Substation	46.9	42.1
500 kV Rayong 4 Substation (Bus #1)	29.9	33.0
500 kV Rayong 4 Substation (Bus #2)	29.6	33.0
500 kV Wang Noi Substation	41.5	27.0

Fault current flow diagrams are shown in Appendix 4.

Notes : 3-Ø = three-phase fault.
1-Ø = single-line-to-ground fault.

6. ECONOMIC ANALYSIS

The economic analysis is made to justify the economic viability of the proposed 500 kV transmission system. The proposed 500 kV transmission system project is compared with the other transmission project which can transmit the bulk power from the IPP plants to the load center. Referring to BVI/PTI study, two out of three basic systems have been reviewed : the 500 kV transmission system (the preferred plan) and the 765 kV transmission system (The second best alternative).

The requirement of transmission system for the 765 kV alternative are determined to meet the same maximum transfer capability of the 500 kV alternative.

The cost streams of the two alternatives which comprise the capital investment cost, operation and maintenance cost (O&M) and the cost of system losses are compared by using discount cash flow technique. The benefit/cost ratio (B/C ratio), net present value (NPV) with reference to 10 % discount rate and the equalized discount rate (EDR) are calculated to indicate the least cost alternative. The study is conducted separately for western and eastern coast IPP.

6.1 Transmission System Alternative

The transmission system alternatives for the west and east coast power plant projects (IPPs as well as EGAT's future base load power plant projects) can be summarized as follows :

The West Coast

500 kV Alternative

- Construction of 500 kV Bang Saphan Substation.

- Construction of two routes of the 500 kV double circuit line from Bang Saphan to Chom Bung, using 4x1272 MCM ACSR conductors. The distance of the two line routes are approximately 275 and 280 km respectively.

- Expansion and improvement of the related substations.

765 kV Alternative

- Construction of 765 kV Bang Saphan and Chom Bung Substations.

- Construction of three circuits of 765 kV Bang Saphan - Chom Bung, consisting of one double circuit steel tower line and one single circuit steel tower line. The three circuits are strung with 4x1590 MCM ACSR conductors, a distance of approximately 285 km.

- Installation of 765/500 kV tie transformers at Chom Bung Substation, rated 1,000 MVA, in the stages as required by the demand of the power system.

- Expansion and improvement of the related substation.

The East Coast

500 kV Alternative

- Construction of 500 kV Rayong 4 Substation.

- Construction of two routes of the 500 kV double circuit line from the proposed new 500 kV Rayong 4 Substation to interconnect with Sai Noi (Wang Noi) - Nong Chok transmission line, using 4x1272 MCM ACSR conductors with the distance of approximately 155 and 170 km for the first and second line routes respectively.

- Construction of 230 kV double circuit line Rayong 4 - Rayong 2 using 4x1272 MCM ACSR conductors with the distance of approximately 10 km.

- Expansion and improvement of the related substations.

765 kV Alternative

- Construction of new 765 kV Rayong 4 Substation.

- Sectionalization and extension of two circuit of 500 kV Wang Noi - Nong Chok to be terminated at the junction located 17 km away from 500 kV Nong Chok Substation and construction of the new 765/500 kV substation at the junction.

- Construction of three circuits of 765 kV Rayong 4 - New Substation, consisting of one double circuit steel tower line and one single circuit steel tower line. The three circuits are strung with 4x1590 MCM ACSR conductors, a distance of approximately 155 km.

- Construction of 230 kV double circuit line Rayong 4 - Rayong 2 using 4x1272 MCM ACSR conductors with the distance of approximately 10 km.

- Installation of $\pm$ 1,800 MVAr. Static Var Compensator (SVC) at new substation.

- Installation of 765/500 kV tie transformers at new substation, rated 1,000 MVA, in the stages as required by the demand of the power system.

6.2 Capital Cost of Alternatives All capital cost are estimated based on 1995 price level. The cost without import duties and taxes, interest during construction (IDC) and escalation are used in the analysis. The economic capital cost of two alternatives can be summarized as follows :

Unit : MTHB

	Transmission Line	Substation	Total
Western Transmission System			
500 kV Alternative	10,625.0	3,938.5	14,563.5
765 kV Alternative	11,428.1	7,682.8	19,110.9
Eastern Transmission System			
500 kV Alternative	6,562.1	1,968.0	8,530.1
765 kV Alternative	6,198.1	12,059.4	18,257.5

6.3 Operation and Maintenance Cost (O&M) The O&M cost of the transmission line portion is assumed to be 1 % of the capital investment cost while the O&M cost of substation is assumed to be 2 % of the capital cost.

6.4 Losses in the Transmission System Since two alternatives produce different losses to the power system, the difference in EGAT's power system losses is also taken into account in the least cost analysis. The capacity loss (MW) is adopted from the power flow study of the respective alternative. The energy loss (GWh) is calculated from the capacity loss and loss factor using the equations as follows :

$$\text{Energy Loss} = \text{Capacity Loss (MW)} \times 8.76 \times \text{Loss Factor}$$

$$\text{Loss Factor} = 0.1 \times (\text{Load Factor}) + 0.9\ (\text{Load Factor})^2$$

The cost of losses used in the study are adopted from EGAT's Long Run Marginal Cost (LRMC) which is based on 1994 price level and is escalated to be 1995 price as follows:

Cost of Capacity Loss	=	3,117.3	THB/kW-yr
Cost of Energy Loss	=	0.7402	THB/kWh

6.5 Economic Life The economic life of the transmission line and substation are assumed to be 40 and 25 years respectively.

6.6 Results of the Least Cost Solution Study

a) Comparison of Present Value

	P.V at 10 % DR. (MTHB)
Western System	
500 kV	32,518.3
765 kV	34,237.6
Eastern System	
500 kV	28,919.7
765 kV	32,674.5

b) Net Present Value, B/C Ratio and EDR.

	Net P.V. (MTHB)	B/C Ratio	EDR. (%)
Western System			
500 kV VS. 765 kV	1,719.3	1.0529	> 150.0
Eastern System			
500 kV VS. 765 kV	3,754.8	1.1298	> 150.0

The results of the study have led to the conclusion that the construction of 500 kV transmission system to transmit bulk power from the IPP power plants and EGAT base load power plants is the least cost alternative for both west coast and east coast transmission systems.

The summary of the results of the least cost solution study and the cost stream of each alternative are shown in Tables 6.1 to 6.6.

Table 6.1
Summary of Results of Economic Analysis

Project : **Transmission System Project for IPP**

Cost Stream : **500 kV Transmission System for Western IPP**

Benefit Stream : **765 kV Transmission System for Western IPP**

Discount Rate (%)	Present Value of Benefit	Present Value of Cost	B/C Ratio	Present Value of Net Benefit
4.00	66045.18	65119.70	1.0142	925.49
6.00	51853.61	50471.44	1.0274	1382.18
8.00	41694.44	40077.11	1.0404	1617.33
10.00	**34237.61**	**32518.32**	**1.0529**	**1719.28**
12.00	28633.47	26892.21	1.0647	1741.26
14.00	24328.12	22612.40	1.0759	1715.72
16.00	20953.07	19290.41	1.0862	1662.66
18.00	18258.27	16663.80	1.0957	1594.47
20.00	16070.71	14551.83	1.1044	1518.88
22.00	14268.41	12827.72	1.1123	1440.69
24.00	12763.77	11400.93	1.1195	1362.84
26.00	11492.79	10205.68	1.1261	1287.11

Equalized Discount Rate is Greater Than 150%

Table 6.2

Cost Stream of 500 kV Transmission System for Western IPP

Unit : MTHB

Fiscal Year	Capital Cost		O&M Cost		System Losses		Cost of Losses		Total Cost
	Line	Sub.	Line	Sub.	Peak (MW)	Energy (GWh)	Peak	Energy	
1995									–
1996	12.2	110.0							122.2
1997	231.8	–							231.8
1998	2633.6	41.7							2675.3
1999	5359.7	1320.1							6679.8
2000	1882.3	2105.6							3987.9
2001	505.4	361.1	106.3	78.8	376.05	1889.99	1172.3	1399.0	3622.8
2002			106.3	78.8	427.63	2158.42	1333.1	1597.7	3115.8
2003			106.3	78.8	481.37	2456.52	1500.6	1818.3	3504.0
2004			106.3	78.8	585.91	3052.17	1826.5	2259.2	4270.8
2005			106.3	78.8	602.40	3162.88	1877.9	2341.2	4404.1
2006			106.3	78.8	602.40	3187.79	1877.9	2359.6	4422.6
2007			106.3	78.8	602.40	3207.32	1877.9	2374.1	4437.0
2008			106.3	78.8	602.40	3215.15	1877.9	2379.9	4442.8
2009			106.3	78.8	602.40	3222.99	1877.9	2385.7	4448.6
2010			106.3	78.8	602.40	3230.05	1877.9	2390.9	4453.8
2011			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2012			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2013			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2014			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2015			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2016			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2017			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2018			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2019			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2020			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2021			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2022			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2023			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2024			106.3	78.8	602.40	3237.12	1877.9	2396.1	4459.1
2025	-3984.4	–	106.3	78.8	602.40	3237.12	1877.9	2396.1	474.7
Total	6640.6	3938.5	2657.5	1970.0	–	–	45267.4	57247.1	117721.2
P.V. 10% DR.	7067.8	2544.2	599.1	444.1	–	–	9708.2	12154.9	32518.3

Table 6.3

Cost Stream of 765 kV Transmission System for Western IPP

Unit : MTHB

Fiscal Year	Capital Cost		O&M Cost		System Losses		Cost of Losses		Total Cost
	Line	Sub.	Line	Sub.	Peak (MW)	Energy (GWh)	Peak	Energy	
1995									–
1996	12.2	110.0							122.2
1997	345.8	–							345.8
1998	3626.7	56.5							3683.2
1999	5144.3	1984.1							7128.4
2000	1817.4	3097.8							4915.2
2001	481.7	974.1	114.3	124.5	374.55	1882.46	1167.6	1393.4	4255.6
2002		511.9	114.3	134.7	418.65	2113.09	1305.1	1564.1	3630.1
2003		453.9	114.3	143.8	463.16	2363.59	1443.8	1749.5	3905.3
2004		445.7	114.3	152.7	552.14	2876.25	1721.2	2129.0	4562.9
2005		48.8	114.3	153.7	554.13	2909.44	1727.4	2153.6	4197.8
2006			114.3	153.7	554.13	2932.36	1727.4	2170.5	4165.9
2007			114.3	153.7	554.13	2950.32	1727.4	2183.8	4179.2
2008			114.3	153.7	554.13	2957.52	1727.4	2189.2	4184.5
2009			114.3	153.7	554.13	2964.73	1727.4	2194.5	4189.9
2010			114.3	153.7	554.13	2971.23	1727.4	2199.3	4194.7
2011			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2012			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2013			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2014			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2015			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2016			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2017			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2018			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2019			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2020			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2021			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2022			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2023			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2024			114.3	153.7	554.13	2977.73	1727.4	2204.1	4199.5
2025	−4285.5	–	114.3	153.7	554.13	2977.73	1727.4	2204.1	−86.0
Total	7142.6	7682.8	2857.5	3783.4	–	–	41912.8	52988.7	116367.7
P.V. 10% DR.	7690.1	4653.2	644.2	835.0	–	–	9068.1	11347.0	34237.6

Table 6.4
Summary of Results of Economic Analysis

Project : **Transmission System Project for IPP**

Cost Stream : **500 kV Transmission System for Eastern IPP**

Benefit Stream : **765 kV Transmission System for Eastern IPP**

Discount Rate (%)	Present Value of Benefit	Present Value of Cost	B/C Ratio	Present Value of Net Benefit
4.00	66339.75	62399.89	1.0631	3939.86
6.00	51200.26	47163.03	1.0856	4037.23
8.00	40469.28	36524.66	1.1080	3944.62
10.00	**32674.46**	**28919.65**	**1.1298**	**3754.81**
12.00	26880.44	23359.48	1.1507	3520.96
14.00	22480.44	19207.23	1.1704	3273.22
16.00	19072.64	16044.36	1.1887	3028.29
18.00	16385.55	13590.54	1.2057	2795.01
20.00	14232.06	11654.45	1.2212	2577.61
22.00	12480.82	10103.13	1.2353	2377.69
24.00	11037.86	8842.53	1.2483	2195.32
26.00	9834.83	7805.05	1.2601	2029.78

Equalized Discount Rate is Greater Than 150%

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Table 6.5

Cost Stream of 500 kV Transmission System for Eastern IPP

Unit : MTHB

Fiscal Year	Capital Cost		O&M Cost		System Losses		Cost of Losses		Total Cost
	Line	Sub.	Line	Sub.	Peak (MW)	Energy (GWh)	Peak	Energy	
1995									–
1996	7.2	220.0							227.2
1997	136.2	–							136.2
1998	1561.5	28.4							1589.9
1999	3321.9	555.7							3877.6
2000	1217.3	1000.3							2217.6
2001	317.9	163.6	65.6	39.4	396.11	1990.81	1234.8	1473.6	3294.9
2002			65.6	39.4	403.34	2035.81	1257.3	1506.9	2869.2
2003			65.6	39.4	426.62	2177.12	1329.9	1611.5	3046.4
2004			65.6	39.4	490.54	2555.36	1529.2	1891.5	3525.6
2005			65.6	39.4	539.60	2833.15	1682.1	2097.1	3884.2
2006			65.6	39.4	663.96	3513.56	2069.8	2600.7	4775.5
2007			65.6	39.4	663.96	3535.08	2069.8	2616.7	4791.4
2008			65.6	39.4	663.96	3543.71	2069.8	2623.1	4797.8
2009			65.6	39.4	663.96	3552.35	2069.8	2629.4	4804.2
2010			65.6	39.4	663.96	3560.13	2069.8	2635.2	4810.0
2011			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2012			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2013			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2014			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2015			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2016			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2017			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2018			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2019			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2020			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2021			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2022			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2023			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2024			65.6	39.4	663.96	3567.93	2069.8	2641.0	4815.7
2025	-2460.8	–	65.6	39.4	663.96	3567.93	2069.8	2641.0	2355.0
Total	4101.3	1968.0	1640.0	985.0	–	–	48428.5	61300.4	118423.2
P.V. 10% DR.	4355.5	1314.3	369.7	222.1	–	–	10053.3	12604.7	28919.7

Table 6.6

Cost Stream of 765 kV Transmission System for Eastern IPP

Unit : MTHB

Fiscal Year	Capital Cost		O&M Cost		System Losses		Cost of Losses		Total Cost
	Line	Sub.	Line	Sub.	Peak (MW)	Energy (GWh)	Peak	Energy	
1995									–
1996	7.2	550.0							557.2
1997	203.0	–							203.0
1998	2071.3	71.2							2142.5
1999	2535.7	1664.7							4200.4
2000	1130.5	3119.0							4249.5
2001	250.4	944.4	62.0	127.0	401.19	2016.35	1250.6	1492.5	4126.9
2002		120.4	62.0	129.4	390.02	1968.58	1215.8	1457.1	2984.8
2003		405.1	62.0	137.5	416.46	2125.27	1298.2	1573.1	3476.0
2004		969.1	62.0	156.9	474.24	2470.45	1478.3	1828.6	4495.0
2005		3768.9	62.0	232.3	505.46	2653.90	1575.7	1964.4	7603.3
2006		446.6	62.0	241.2	582.77	3083.91	1816.7	2282.7	4849.2
2007			62.0	241.2	582.77	3102.81	1816.7	2296.7	4416.6
2008			62.0	241.2	582.77	3110.38	1816.7	2302.3	4422.2
2009			62.0	241.2	582.77	3117.96	1816.7	2307.9	4427.8
2010			62.0	241.2	582.77	3124.79	1816.7	2313.0	4432.8
2011			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2012			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2013			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2014			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2015			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2016			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2017			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2018			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2019			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2020			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2021			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2022			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2023			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2024			62.0	241.2	582.77	3131.63	1816.7	2318.0	4437.9
2025	-2324.3	–	62.0	241.2	582.77	3131.63	1816.7	2318.0	2113.6
Total	3873.8	12059.4	1550.0	5607.1	–	–	43152.1	54589.0	120831.3
P.V. 10% DR.	4172.5	6431.6	349.4	1150.0	–	–	9132.9	11438.0	32674.5

7. FINANCIAL JUSTIFICATION OF THE PROJECT

The financial justification is the economic and financial internal rate of return (EIRR and FIRR) of the 500 kV transmission system projects for the west coast and east coast IPP power plants by comparing their investment costs with the benefit accrued from the project. The study is made separately for EIRR and FIRR study.

7.1 Economic Internal Rate of Return Study (EIRR)

The economic internal rate of return study is conducted by comparing the cost of implementing the 500 kV transmission system of both west coast and east coast systems with the benefit which will be made available from the purchasing of electric energy from the IPP together with the electric energy generated from EGAT's coal-fired power plants which are planned to be connected to the proposed 500 kV transmission system. Details of IPP and EGAT's power project planned to be connected to the proposed project are shown in Table 7.1. The cost and benefit applied for the study will be the combined cost and benefit of the west coast and east coast systems since the projects are proposed to be implemented simultaneously.

The benefit of the project for the EIRR study can be pointed out by two approaches, i.e;

Approach 1 : The benefit of the project is assumed to be the reduction of the country's load losses and outages. The load losses will be presented as the difference in the probabilistic Expected Unserved Energy (EUE) between the EGAT's Power Development Plan (PDP) with and without the project calculated by using Westinghouse Interactive Generation Planning Software (WIGPLAN) computer program. The cost of the reduction of the EUE resulting from the implementation of this project is adopted from the latest "EGAT's Cost of an Outage Study" conducted by EGAT's System Planning Department on October 1992. The cost of an outage according to the mentioned study is 58.87 THB/kWh.

Approach 2 : Since the proposed 500 kV transmission system project is proposed to transmit bulk power from the IPP and EGAT's coal-fired power plants to the load center in the central region, so it is reasonable to assume that the benefit of the project is the incremental energy sale resulting from the implementation of this project.

7.1.1 Basic Assumptions

The economic internal rate of return (EIRR) study of the two approaches are performed based on the following assumptions :

Cost Stream The cost stream of the projects consists of the following :

a) Capital Investment Cost The capital investment cost is the construction cost of the 500 kV transmission system implemented for west coast and east coast systems. The constant 1995 price without import duties and taxes, interest during construction (IDC) are used for the study.

b) Operation and Maintenance Cost (O&M) The O&M of the project are also assumed to be the percentage of the capital cost as used in the economic analysis.

c) Cost of Energy Supply The purchasing price between EGAT and IPP is assumed as a cost of supplying electric energy of both IPP and EGAT's coal-fired power plants. Since the real purchasing price is still unknown at the time of the study, the forecasted purchasing price is adopted from EGAT's financial projection which are conducted based on EGAT's PDP 95-01 for the period of 1995-2001. The levelized nominal purchasing price (current value) at Year 2001 is 1.6040 THB/kWh.

Benefit Stream The assumptions used for the calculation of benefit stream are :

Approach 1 The benefit is assumed to be the incremental economic benefit of the country due to the reduction of expected load losses which may occurred if the proposed project is not implemented. The Expected Unserved Energy (EUE) is used to represent these losses and the cost of an outage of 58.87 THB/kWh is used to calculate the monetary value of these losses.

Approach 2 The benefit is assumed to be the incremental energy sale made available to EGAT by this project. The calculation of the benefit is based on the assumptions as follows :

a) Incremental Energy Sale The value of the incremental energy sale is calculated from the energy produced by the IPP reduced by the losses in transmission system. The losses are represented in term of energy loss occurring between the sending end and the receiving end of the proposed transmission line. The energy loss (GWh) is calculated from the capacity loss (adopted from the power flow study) and IPP's plant factor as follows :

$$\text{Energy Loss (GWh)} = \text{Capacity Loss (MW)} \times 8.76 \times \text{Plant Factor}$$

b) Average Selling Price The EGAT average selling price is adopted from EGAT's financial analysis of the Year 2001 which is adjusted to conform with all of the required financial criteria.

7.1.2 Sensitivity Study

Due to the uncertainty of the purchasing price from IPP, EGAT's average selling price and other economic parameters of the project, the sensitivity studies of EIRR study based on the variation the project's vital economic parameters are also conducted to examine the effect of these variations to the EIRR of the project. The sensitivity study is calculated according to the variation of the economic parameters as follows :

- The purchasing price from IPP.
- The EGAT's average selling price.
- Capital investment cost of the project.
- Expected unserved energy.

7.1.3 Results of the EIRR Study

The results of the base case and sensitivity study can be summarized as follows :

a) Base Case

	EIRR (%)
- Approach 1	107.01
- Approach 2	22.63

b) Sensitivity Study

Approach 1

	EIRR (%)
- Purchasing Price	
- Increased by 10 %	106.95
- Increased by 20 %	106.89
- Increased by 30 %	106.84
- Capital Cost	
- Increased by 10 %	104.62
- Increased by 20 %	102.47
- Increased by 30 %	100.52
- Expected Unserved Energy	
- Decreased by 10 %	104.37
- Decreased by 20 %	101.47
- Decreased by 30 %	98.26

Approach 2

- Purchasing Price	
- Increased by 5 %	16.78
- Increased by 10 %	7.55

	EIRR (%)
- Capital Cost	
- Increased by 10 %	21.42
- Increased by 20 %	20.35
- Increased by 30 %	19.39
- Average Selling Price	
- Decreased by 5 %	15.86
- Decreased by 10 %	3.50

It can be concluded from the results of the base case calculation of EIRR that the project is economically feasible and the sensitivity studies indicate that for Approach 1, the EIRR is not sensitive to the tested variation but for Approach 2, the EIRR is sensitive to the increment of the purchasing price and the decreasing of EGAT's average selling price. Details of the base case calculation of EIRR of the two approaches are shown Table 7.2 and 7.3.

Table 7.1

IPP and EGAT's Power Project Planned to be Transmitted

via the Proposed 500 kV Transmission System

Power Plant	Fuel Type	Unit Number	Rating (MW)	Cumulative Capacity (MW)	Commissioning Date
IPP	-	-	1,400	1,400	April 2001
IPP	-	-	1,400	2,800	April 2002
IPP	-	-	1,000	3,800	January 2003
IPP	-	-	1,000	4,800	January 2004
IPP	-	-	1,000	5,800	January 2005
New Thermal	Coal	1	1,000	6,800	April 2005
IPP	-	-	1,000	7,800	January 2006
New Thermal	Coal	2	1,000	8,800	April 2006
IPP	-	-	1,000	9,800	January 2007
New Thermal	-	3	1,000	10,800	April 2007
IPP	-	-	1,000	11,800	January 2008
New Thermal	Coal	4	1,000	12,800	April 2008
IPP	-	-	1,000	13,800	January 2009
New Thermal	Coal	5	1,000	14,800	April 2009

Table 7.2
Calculation of EIRR of 500 kV Transmission System for IPP (Approach 1)

Unit : MTHB

Fiscal Year	a/ Cost Stream								b/ Benefit Stream					Net Benefit
	Capital Cost		O&M Cost		Supplied Energy (GWh)	Purchasing Price (THB/kWh)		Cost of Supply	Total Cost	Expected Unserved Energy (GWh)			Cost of Outages (THB/kWh) c/	Project Benefit	
	Line	Substation	Line	Substation		Current Price	1995 Price			W/O 500 kV Transmission Project e/	With 500 kV Transmission Project	EUE Reduction			
1995					–			–	–						–
1996	19.4	330.0			–			–	349.4						-349.4
1997	368.0	–			–			–	368.0						-368.0
1998	4195.1	70.1			–			–	4265.2						-4265.2
1999	8681.6	1875.8			–			–	10557.4						-10557.4
2000	3099.6	3105.9			–	d/		–	6205.5						-6205.5
2001	823.3	524.7	171.9	118.2	1.5	1.6040	1.2677	2.0	1640.1	1.55		1.5	58.87	91.1	-1549.0
2002	–	–	171.9	118.2	19.3	1.6040	1.2677	24.5	314.6	19.32		19.3	58.87	1137.3	822.7
2003			171.9	118.2	534.1	1.6040	1.2677	677.1	967.2	534.12		534.1	58.87	31443.4	30476.2
2004			171.9	118.2	1238.9	1.6040	1.2677	1570.5	1860.6	1238.86		1238.9	58.87	72931.7	71071.1
2005			171.9	118.2	7303.3	1.6040	1.2677	9258.1	9548.2	7303.27		7303.3	58.87	429943.6	420395.4
2006			171.9	118.2	17352.8	1.6040	1.2677	21997.5	22287.6	17352.75		17352.8	58.87	1021556.4	999268.8
2007			171.9	118.2	24934.0	1.6040	1.2677	31607.9	31898.0	24933.98		24934.0	58.87	1467863.6	1435965.6
2008			171.9	118.2	40631.0	1.6040	1.2677	51506.4	51796.5	40630.98		40631.0	58.87	2391945.5	2340149.0
2009			171.9	118.2	54067.7	1.6040	1.2677	68539.7	68829.8	54067.72		54067.7	58.87	3182966.9	3114137.1
2010			171.9	118.2	64020.2	1.6040	1.2677	81156.2	81446.3	64020.24		64020.2	58.87	3768871.5	3687425.2
2011			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2012			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2013			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2014			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2015			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2016			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2017			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2018			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2019			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2020			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2021			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2022			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2023			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2024			171.9	118.2	73480.0	1.6040	1.2677	93148.0	93438.1	73480.00		73480.0	58.87	4325767.8	4232329.7
2025	-6445.1	–	171.9	118.2	73480.0	1.6040	1.2677	93148.0	86993.0	73480.00		73480.0	58.87	4325767.8	4238774.8
Total	10741.9	5906.5	4297.5	2955.0	–	–	–	1663559.7	1687460.8	–	–	–	–	77255268.0	75567807.2

Base

Economic Internal Rate of Return = 107.01%

Notes : a/ Capital investment cost of western and eastern 500 kV transmission system for IPP.
b/ Probabilistic unserved energy calculated by using WIGPLAN .
c/ Adopted from "Cost of an Outage Study" by EGAT's System Planning Department (October 1992).
d/ Adopted from EGAT's Financial Projection (1995–2001) and assumed to be constant after 2001.
e/ Incremental EUE.

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Table 7.3
Calculation of EIRR of 500 kV Transmission System for IPP (Approach 2)

Unit :MTHB

Fiscal Year	Cost Stream									Benefit Stream						Net Benefit
	Capital Cost		O&M Cost		Cost of Energy Supply				Total Cost	Power Loss (MW)	Energy Loss (GWh)	Energy Sale (GWh)	Average Selling Price (THB/kWh)		Revenue	
	Line	Substation	Line	Substation	Planned Power Purchase (MW)	Planned Energy Purchase (GWh)	Purchasing Price (THB/kWh) Current Price	Purchasing Price (THB/kWh) 1995 Price	Cost of Supply				Current Price	1995 Price		
1995	–	–							–			–			–	–
1996	19.4	330.0							349.4			–			–	-349.4
1997	368.0	–							368.0			–			–	-368.0
1998	4195.1	70.1							4265.2			–			–	-4265.2
1999	8681.6	1875.8							10557.4			–			–	-10557.4
2000	3099.6	3105.9					a/		6205.5			–			–	-6205.5
2001	823.3	524.7	171.9	118.2	1400	4600.0	1.6040	1.2677	5831.3	7469.4	8.4	58.9	4541.1	1.8478	1.4603	6631.6	-837.8
2002	–	–	171.9	118.2	2800	13800.0	1.6040	1.2677	17493.8	17783.9	32.4	227.1	13572.9	1.8478	1.4603	19821.2	2037.3
2003			171.9	118.2	3800	23330.0	1.6040	1.2677	29574.6	29864.7	58.0	406.5	22923.5	1.8478	1.4603	33476.2	3611.5
2004			171.9	118.2	4800	29900.0	1.6040	1.2677	37903.2	38193.3	95.0	665.8	29234.2	1.8478	1.4603	42692.0	4498.7
2005			171.9	118.2	6800	39755.0	1.6040	1.2677	50398.0	50686.1	134.6	943.3	38811.7	1.8478	1.4603	56678.4	5992.3
2006			171.9	118.2	8800	52895.0	1.6040	1.2677	67053.1	67343.2	242.3	1698.3	51196.7	1.8478	1.4603	74764.8	7421.6
2007			171.9	118.2	10800	66035.0	1.6040	1.2677	83710.2	84000.3	242.3	1698.3	64336.7	1.8478	1.4603	93953.7	9953.4
2008			171.9	118.2	12800	79175.0	1.6040	1.2677	100367.3	100657.4	242.3	1698.3	77476.7	1.8478	1.4603	113142.6	12485.2
2009			171.9	118.2	14800	92315.0	1.6040	1.2677	117024.4	117314.5	242.3	1698.3	90616.7	1.8478	1.4603	132331.5	15017.0
2010			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2011			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2012			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2013			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2014			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2015			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2016			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2017			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2018			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2019			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2020			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2021			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2022			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2023			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2024			171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	123557.8	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	15965.9
2025	-6445.1	–	171.9	118.2	14800	97240.0	1.6040	1.2677	123267.7	117112.7	242.3	1698.3	95541.7	1.8478	1.4603	139523.7	22411.0
Total	10741.9	5906.5	4297.5	2955.0	–	–	–	–	2481637.1	2505538.0	–	–	–	–	–	2805871.2	300333.2

Economic Internal Rate of Return = 22.63%

Note : a/ Adopted from EGAT's Financial Projection (1995-2001) and assumed to be constant after 2001.

Transmission System Planning Division
30-Jan-96

7.2 Financial Internal Rate of Return Study (FIRR)

Apart from the internal rate of return study based on the country's point of view, the internal rate of return of the project based on EGAT's point of view is also conducted to evaluate the financial viability of this project. According to the purpose of the project as previously mentioned, the 500 kV transmission system project is proposed to transmit the bulk power to EGAT's load center which is resulting in the increment of EGAT's energy sale. So the financial internal rate of return (FIRR) which is EGAT's rate of return from this project is made by comparing the total cost of the project with the benefit from the incremental revenue.

7.2.1 Basic Assumptions

The financial internal rate of return study is performed based on the assumptions similar to the Approach 2 of the EIRR study. But all costs are based on their current values including import duties and taxes, interest during construction (IDC).

7.2.2 Sensitivity Study

The sensitivity study of the FIRR study is also conducted as done for the EIRR study of which the assumptions are :

- The purchasing price from IPP is assumed to be increased by 5 and 10 %.

- The EGAT's average selling price is assumed to be decreased by 5 and 10 %.

7.2.3 Results of the FIRR Study

The results of the base case and sensitivity study can be summarized as follows :

	FIRR (%)
a) Base Case	22.23
b) Sensitivity Study	
- Purchasing Price	
- Increased by 5 %	16.41
- Increased by 10 %	7.25
- Capital Cost	
- Increased by 10 %	21.03
- Increased by 20 %	19.96
- Increased by 30 %	19.00
- Average Selling Price	
- Decreased by 5 %	15.50
- Decreased by 10 %	3.24

It can be noticed from the results of the base case calculation of FIRR that the project can generate the internal rate of return to EGAT's acceptable level while the sensitivity study shows that the FIRR is not sensitive to the change of project's investment cost but sensitive to the variation of the purchasing price and average selling price since the 10 % variation of these values can make the FIRR dropped below EGAT's acceptable level. Details of the base case calculation of the FIRR is shown in Table 7.4.

Table 7.4
Calculation of FIRR of 500 kV Transmission System for IPP

Unit :MTHB

Fiscal Year	Cost Stream										Benefit Stream						Net Benefit
	Capital Cost		O&M Cost		Cost of Energy Supply					Total Cost	Power Loss (MW)	Energy Loss (GWh)	Energy Sale (GWh)	Average Selling Price (THB/kWh)		Revenue	
	Line	Substation	Line	Substation	Planned Power Purchase (MW)	Planned Energy Purchase (GWh)	Purchasing Price (THB/kWh) Current Price	Purchasing Price (THB/kWh) 1995 Price	Cost of Supply					Current Price	1995 Price		
1995	–	–								–			–			–	–
1996	44.1	366.6								**410.7**			–			–	-410.7
1997	424.7	38.8								**463.5**			–			–	-463.5
1998	4852.4	120.0								**4972.4**			–			–	-4972.4
1999	11444.7	2352.7								**13797.4**			–			–	-13797.4
2000	4938.2	4228.2					a/			**9166.4**			–			–	-9166.4
2001	1055.4	604.2	227.6	154.2	1400	4600.0	1.6040	1.2677	7378.4	**9419.8**	8.4	58.9	4541.1	1.8478	1.4603	**8391.1**	-1028.7
2002	–	–	227.6	154.2	2800	13800.0	1.6040	1.2677	22135.2	**22517.0**	32.4	227.1	13572.9	1.8478	1.4603	**25080.1**	2563.1
2003			227.6	154.2	3800	23330.0	1.6040	1.2677	37421.3	**37803.1**	58.0	406.5	22923.5	1.8478	1.4603	**42358.1**	4555.0
2004			227.6	154.2	4800	29900.0	1.6040	1.2677	47959.6	**48341.4**	95.0	665.8	29234.2	1.8478	1.4603	**54019.0**	5677.6
2005			227.6	154.2	6800	39755.0	1.6040	1.2677	63767.0	**64148.8**	134.6	943.3	38811.7	1.8478	1.4603	**71716.3**	7567.5
2006			227.6	154.2	8800	52895.0	1.6040	1.2677	84843.6	**85225.4**	242.3	1698.3	51196.7	1.8478	1.4603	**94601.3**	9375.9
2007			227.6	154.2	10800	66035.0	1.6040	1.2677	105920.1	**106301.9**	242.3	1698.3	64336.7	1.8478	1.4603	**118881.4**	12579.4
2008			227.6	154.2	12800	79175.0	1.6040	1.2677	126996.7	**127378.5**	242.3	1698.3	77476.7	1.8478	1.4603	**143161.4**	15782.9
2009			227.6	154.2	14800	92315.0	1.6040	1.2677	148073.3	**148455.1**	242.3	1698.3	90616.7	1.8478	1.4603	**167441.5**	18986.5
2010			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2011			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2012			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2013			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2014			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2015			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2016			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2017			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2018			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2019			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2020			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2021			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2022			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2023			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2024			227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**156354.8**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	20187.2
2025	-8534.8	–	227.6	154.2	14800	97240.0	1.6040	1.2677	155973.0	**147819.9**	242.3	1698.3	95541.7	1.8478	1.4603	**176542.0**	28722.0
Total	14224.7	7710.5	5690.0	3855.0	–	–	–	–	3140062.6	3171542.8	–	–	–	–	–	3550321.5	378778.8

Financial Internal Rate of Return = 22.23%

Note : a/ Adopted from EGAT's Financial Projection (1995-2001) and assumed to be constant after 2001.

Transmission System Planning Division
07-Dec-95

8. SHUNT REACTOR SIZING

8.1 Objective and Method of Study

Two shunt reactors of equal magnitude are installed at each end of an extra high-voltage transmission line to compensate for the Ferranti Effect. Ferranti Effect is a phenomenon that the voltage at the receiving end of a long open-ended uncompensated transmission line is higher than at the sending end for the steady-state condition. The receiving-end voltage, V_{REC}, can be roughly calculated by the following expression :

$$V_{REC} = V_{SEND}/\cos \beta \ell$$

where ℓ is the line length and β is the phase factor, which is equal to approximately 7.2°/100 km. The longer the transmission line is, the higher the Ferranti Effect becomes.

In the study, the size of the shunt reactor to be installed at each end of the transmission line is varied from 0-300 MVAr. The installation of shunt reactors has been considered for the transmission lines which are longer than 150 km since the Ferranti Effect on a shorter line is found to be nonsignificant.

Shunt reactors can also reduce the overvoltage during energization of transmission lines but the amount of surge reduction is small compared to other more practical counter-measures. The study has been conducted with the computer software developed by Manitoba HVDC Research Center. The use of the software is under a trial agreement between Manitoba HVDC Research Center and EGAT.

8.2 Results of Study

The shunt reactor sizing study has been conducted for four 500 kV transmission lines as follows :

1) Bang Saphan - Chom Bung
2) Wang Noi - Chom Bung

3) Rayong 4 - Wang Noi
4) Rayong 4 - Nong Chok

The overvoltage during line energization of the Bang Saphan - Chom Bung has been found to be 1.046 p.u. For the other 3 lines, the overvoltages are less than 3 %. Nontheless, if shunt reactors were to be installed to compensate for the Ferranti Effect, the following are the reactors which would reduce the receiving end voltages to 1.0 p.u.

1) 150 MVAr/phase for Bang Saphan - Chom Bung lines
2) 100 MVAr/phase for Wang Noi - Chom Bung lines
3) 105 MVAr/phase line Rayong 4 - Wang Noi lines
4) 82.5 MVAr/phase line Rayong 4 - Nong Chok lines

The results of the reactor sizing study are shown in Figure 8.1 to Figure 8.4. Samples of the switching transients for the Bang Saphan - Chom Bung lines are also shown in Figure 8.5 to Figure 8.7.

FIGURE 8.1
REACTOR SIZING FOR BANG SAPAN - CHOM BUNG LINES
(280 KM)

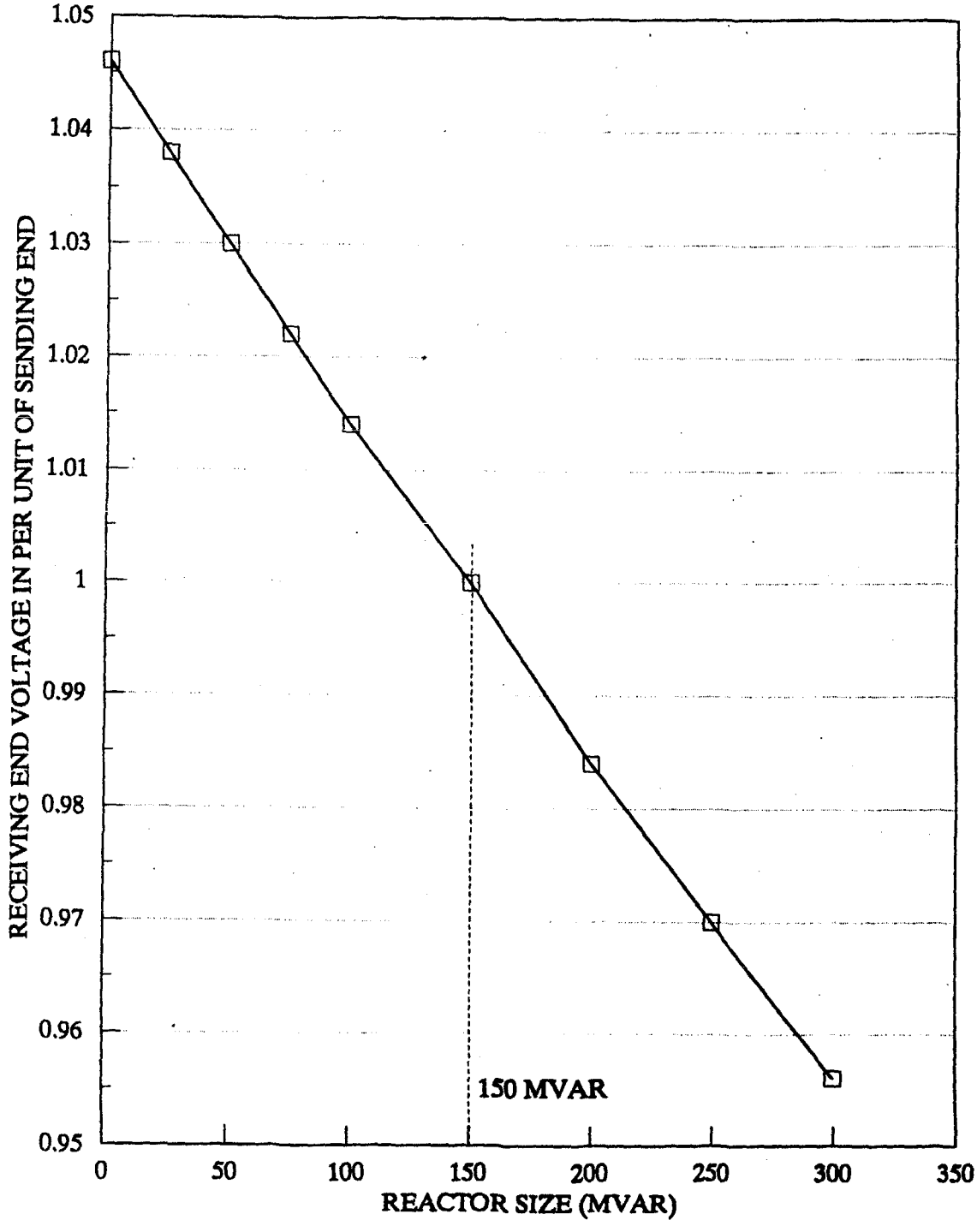


FIGURE 8.2

REACTOR SIZING FOR WANG NOI - CHOM BUNG LINES
(192 KM)

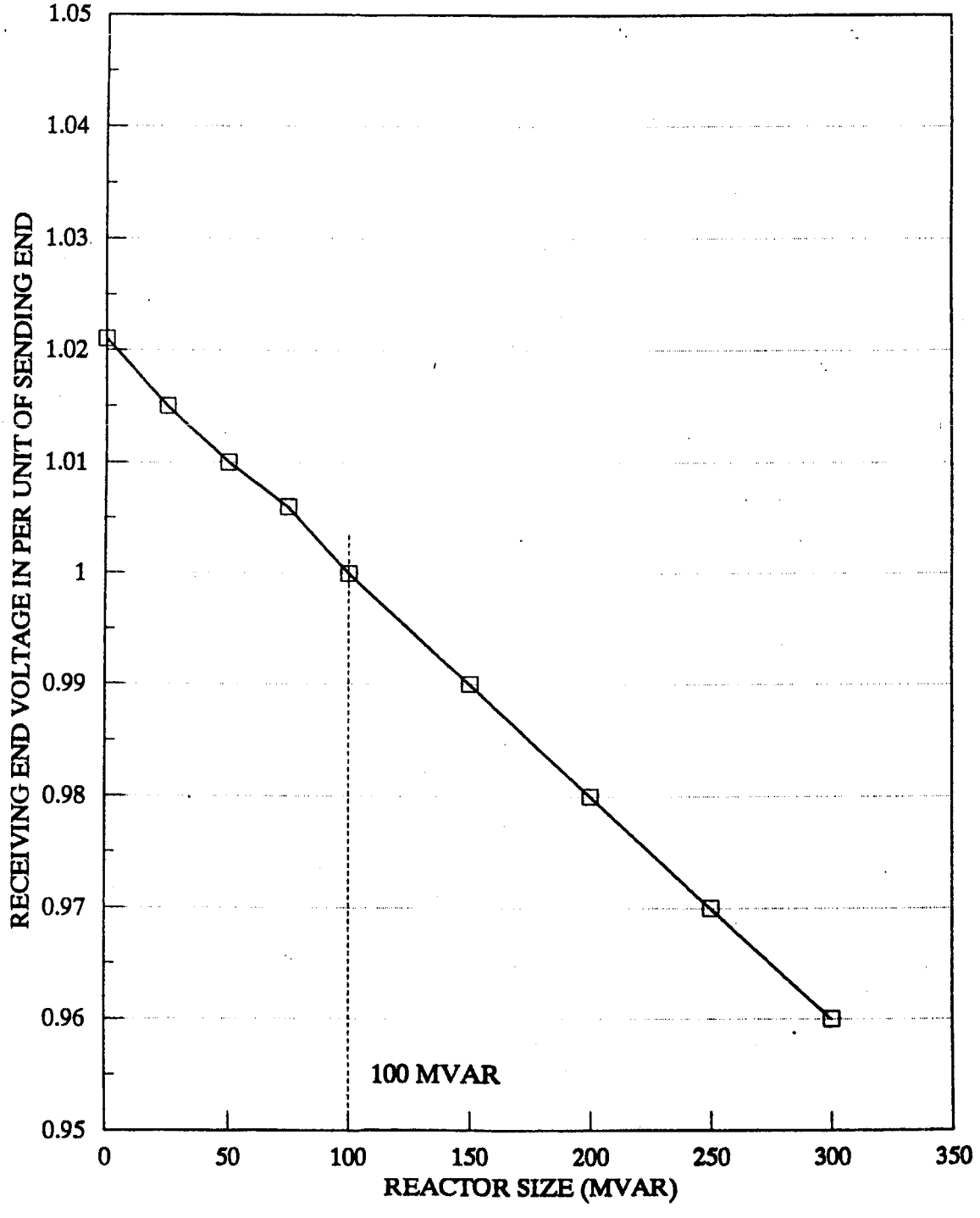


FIGURE 8.3
REACTOR SIZING FOR RAYONG 4 - WANG NOI LINES
(210 KM)

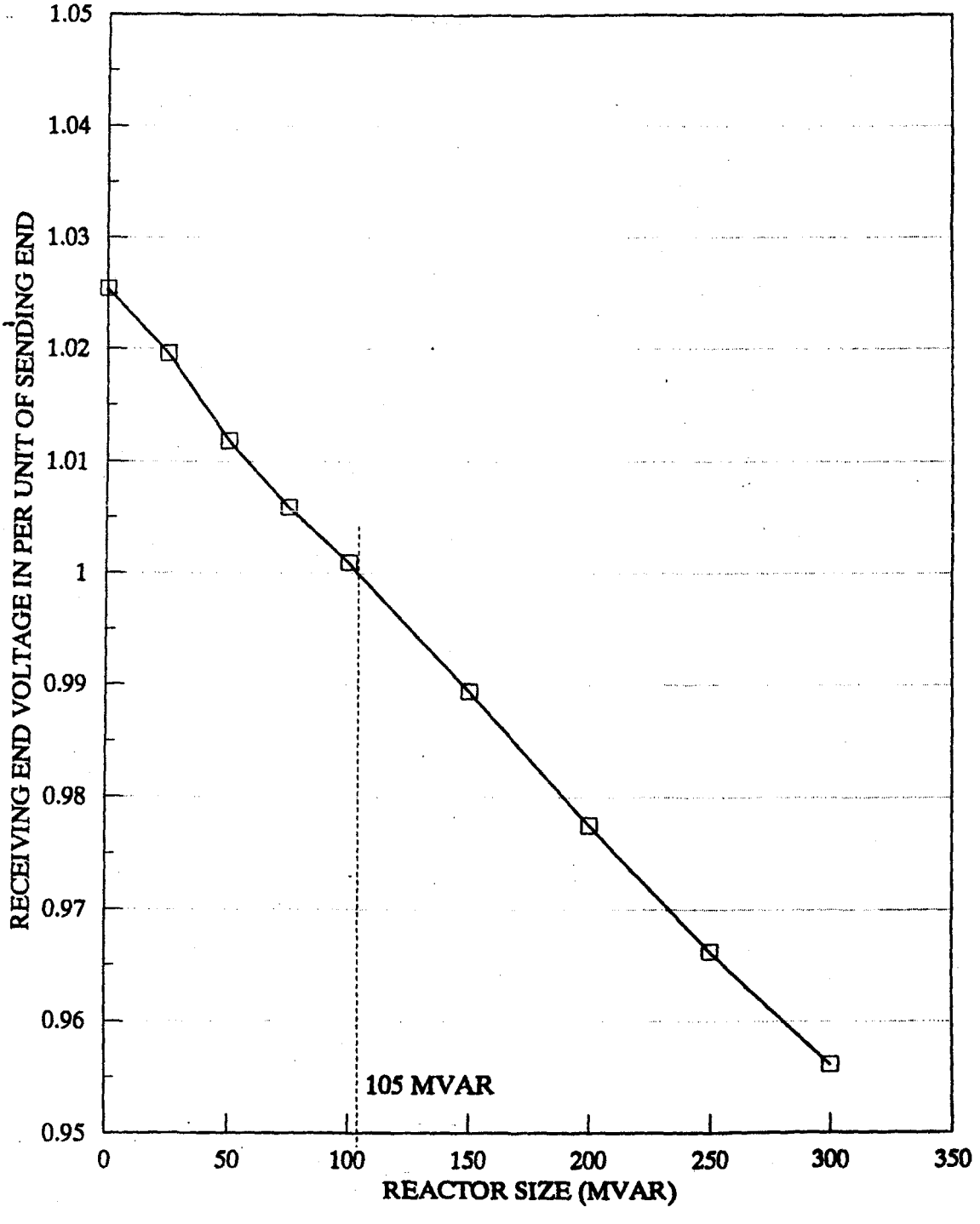
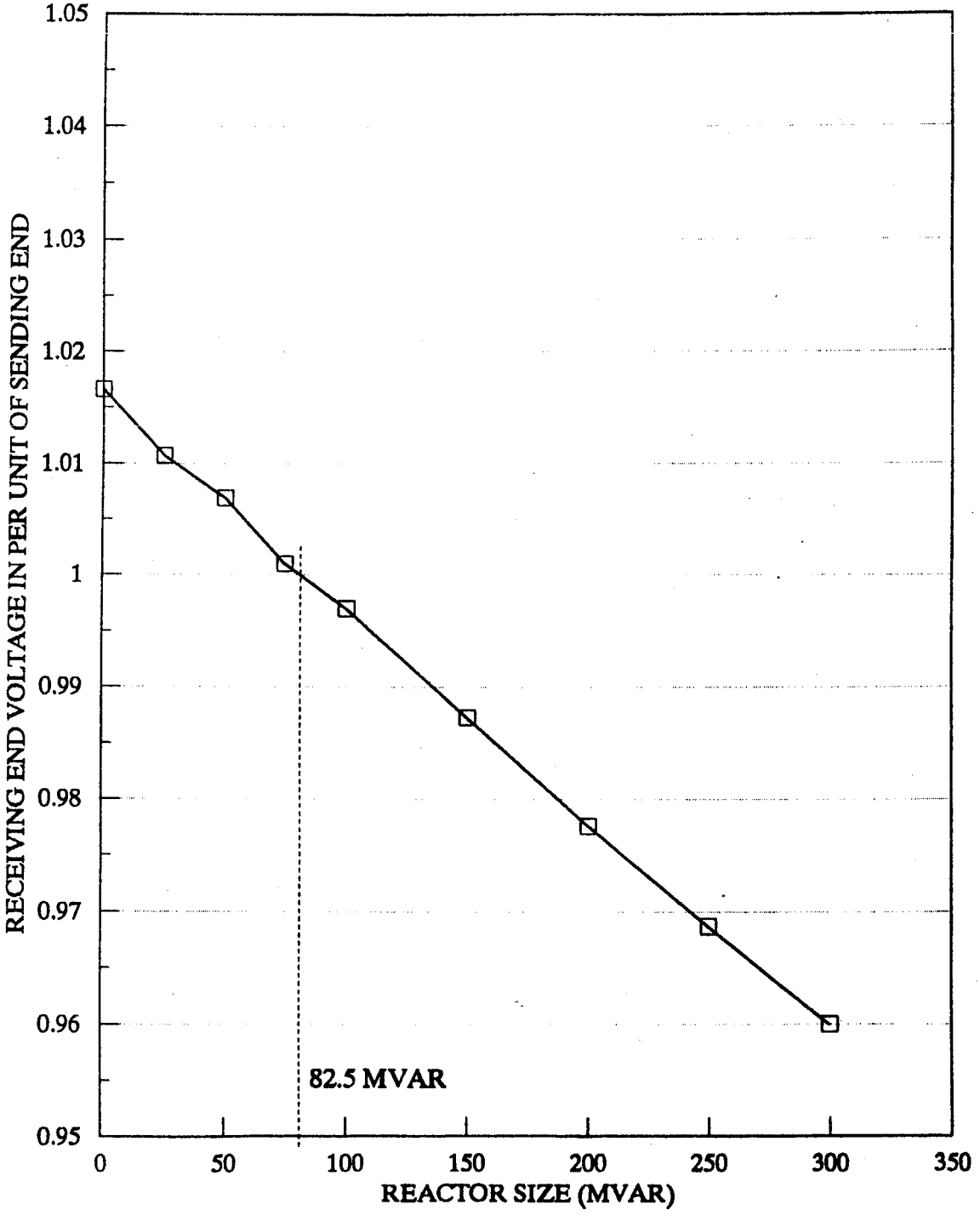


FIGURE 8.4

REACTOR SIZING FOR RAYONG 4 - NONG CHOK LINES

(172 KM)



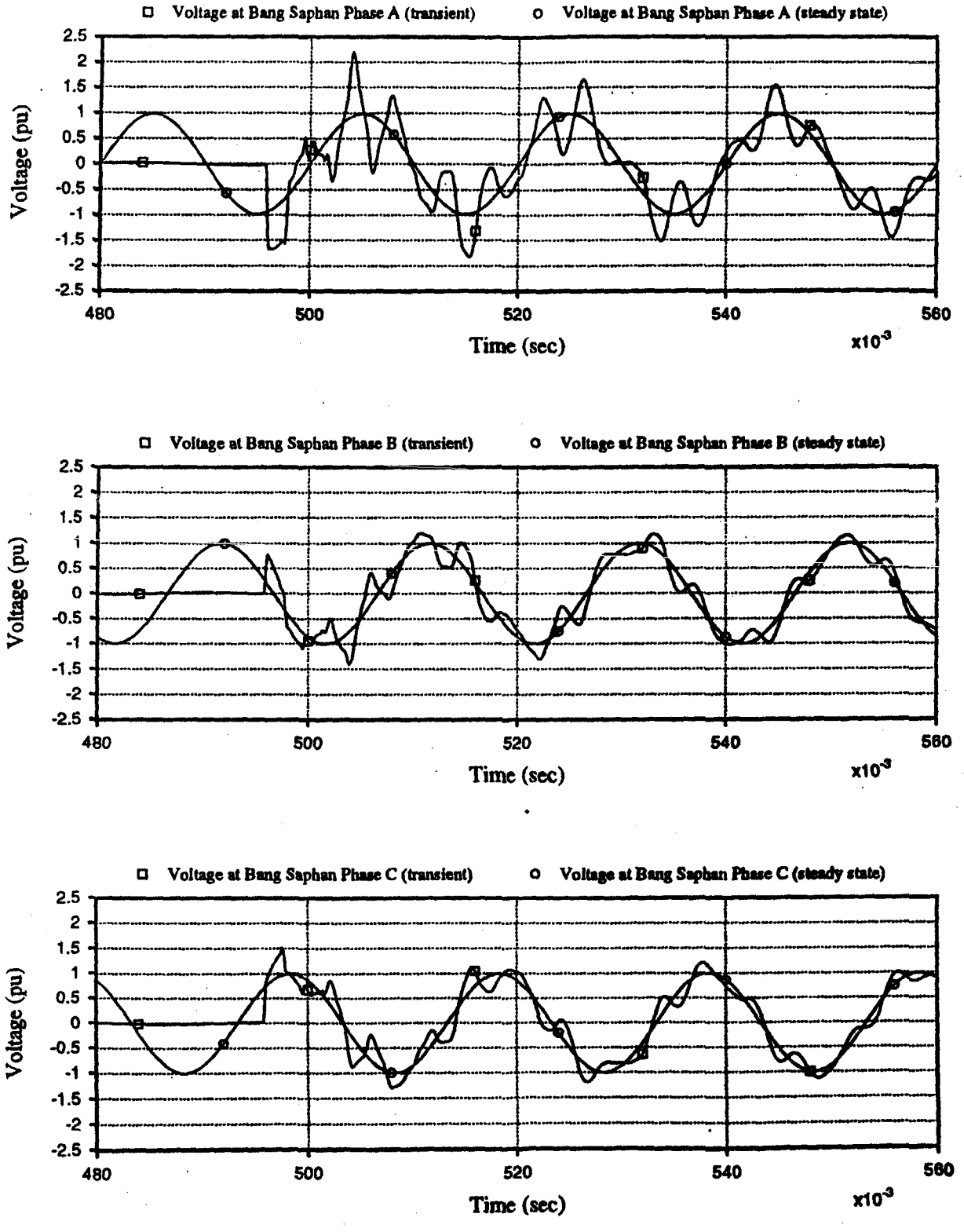
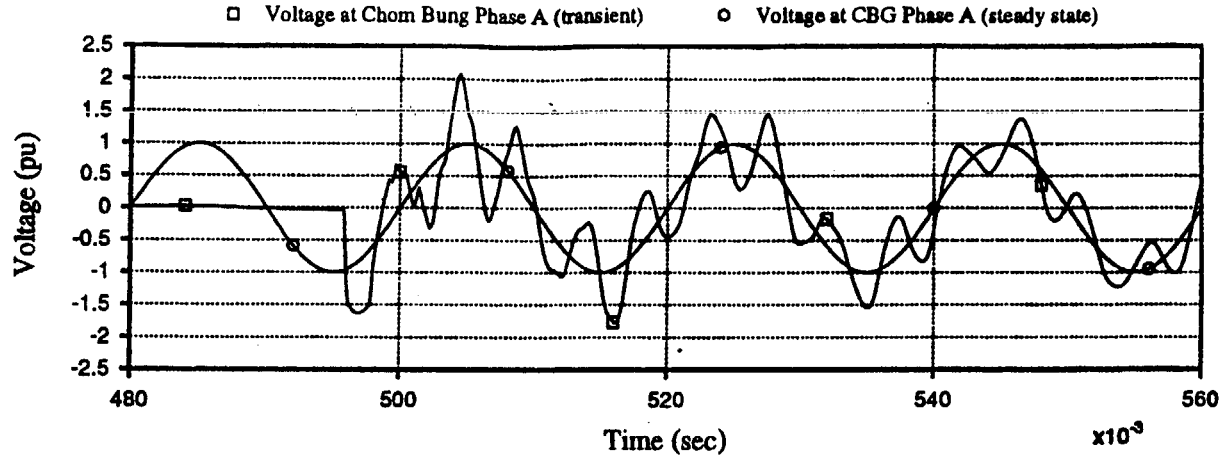
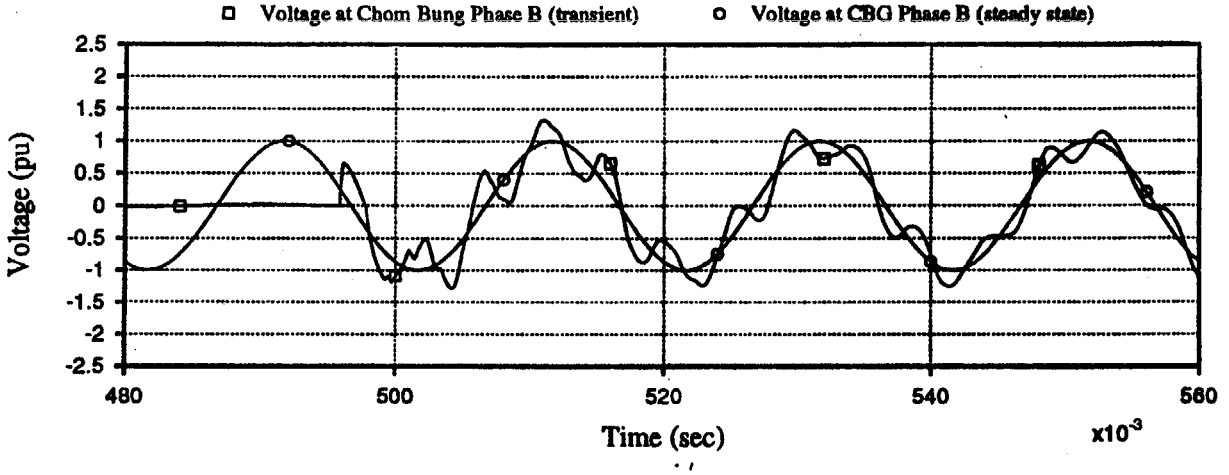


Figure 8.5 Energization of Chom Bung - Bang Saphan Lines (w/ 150 MVAr Reactors)

(Energize from Chom Bung)





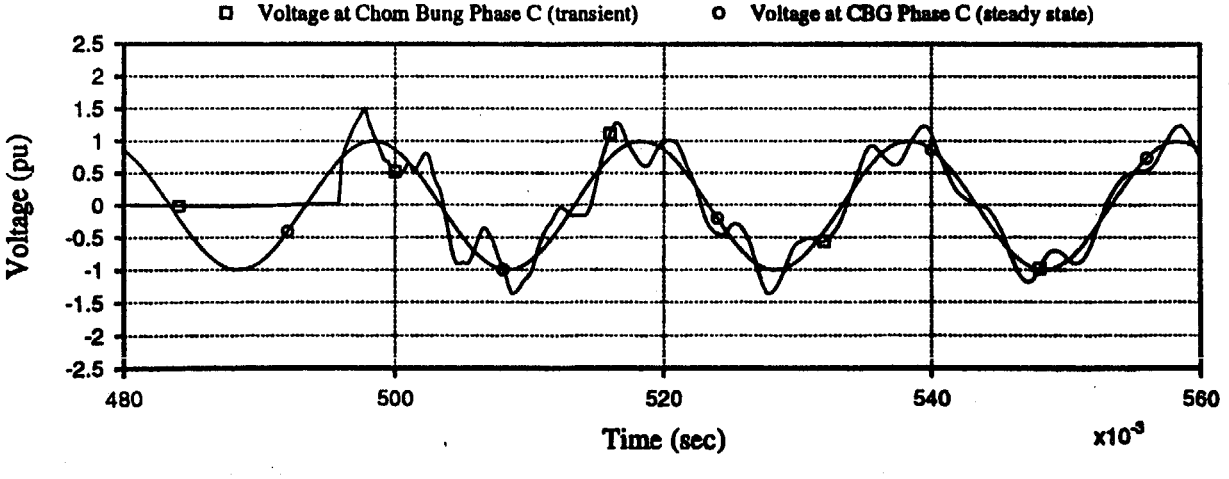
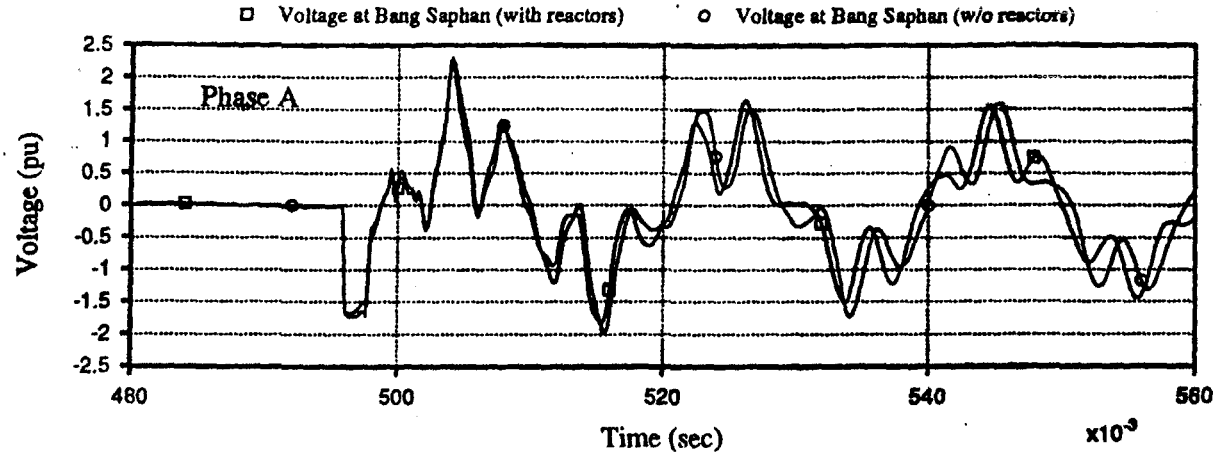
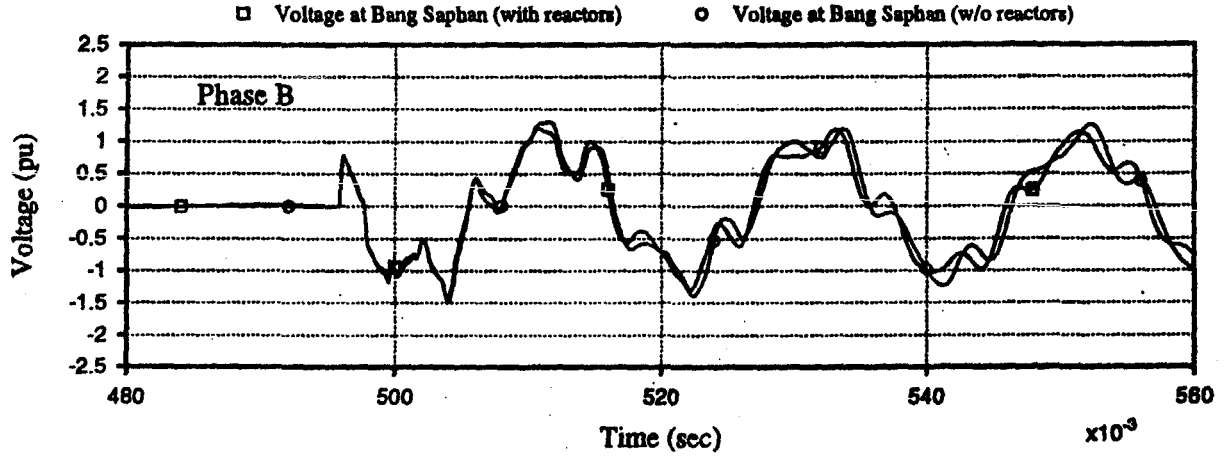


Figure 8.6 Energization of Chom Bung - Bang Saphan Lines (w/ 150 MVAr Reactors)

(Energize from Bang Saphan)





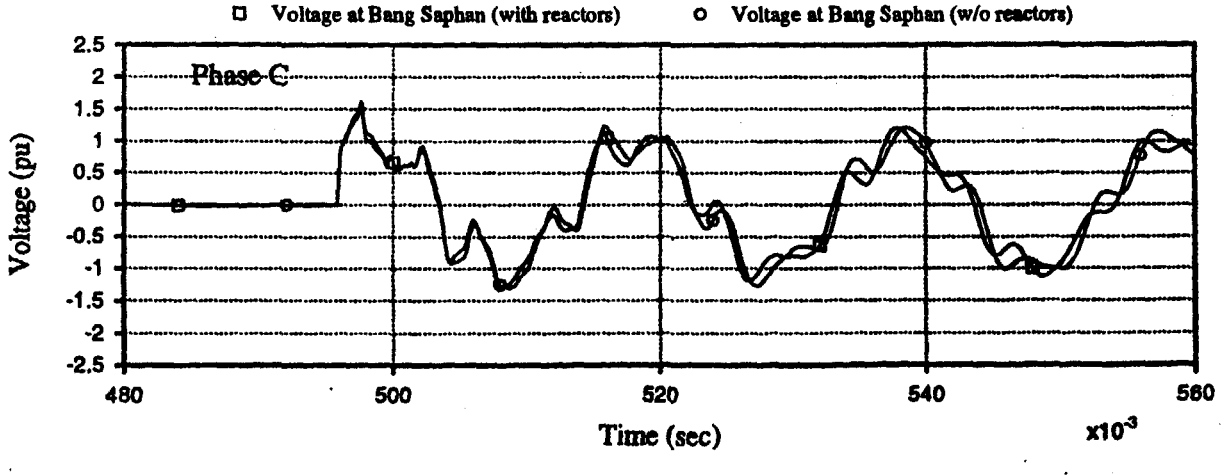


Figure 8.7 Comparison of Overvoltage for Chom Bung - Bang Saphan Lines

(Energize from Chom Bung)

REFERENCES

1. EGAT's System Planning Department. EGAT Power Development Plan (PDP 95-01), Report No.21200-3802, April, 1995.

2. Black & Veatch International Company. Feasibility Study for Transmissiion System Development for Southern Power Plant Project, July, 1994.

APPENDIX 1

SUBSTATION LOAD FORECAST

Substation Load Forecast of Metropolitan Area

COINCIDENT
UNIT : MW

SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
BANG KAPI 69 KV	617.40	565.03	543.34	570.11	599.06	724.31	763.74
BANG KAPI 230 KV (CL)	421.80	348.21	345.25	355.43	387.49	282.51	270.50
BANG KAPI 230 KV (KT)	0.00	0.00	0.00	0.00	377.41	629.52	666.80
BANG PHLI 69 KV	301.00	175.55	197.01	202.83	213.55	321.22	358.09
BANG PHLI 115 KV	331.70	509.31	394.78	368.97	424.06	342.09	359.13
BANGKOK NOI 69 KV	415.60	355.26	417.23	428.96	475.12	395.17	440.52
BANGKOK NOI 115 KV	0.00	50.85	50.93	66.97	97.70	303.08	342.72
CHAENG WATTANA 115 KV	0.00	249.35	340.60	463.98	670.74	656.61	720.73
LAT PHRAO 69 KV	574.00	536.86	605.01	606.01	420.13	714.04	730.80
NONG CHOK 115 KV	177.60	212.58	188.80	208.20	269.72	334.43	450.58
NORTH BANGKOK 69 KV	391.85	494.67	502.39	558.26	548.94	498.65	534.40
NORTH BANGKOK 230 KV	0.00	0.00	0.00	0.00	0.00	510.72	1,025.00
ON-NUCH 230 KV	0.00	0.00	178.84	247.02	296.83	544.74	804.32
ON-NUCH 230 KV (PK)	0.00	0.00	0.00	0.00	0.00	0.00	679.38
RANGSIT 69 KV	205.70	275.45	282.02	264.45	209.87	368.51	367.11
RANGSIT 115 KV	92.90	136.20	137.66	177.44	259.22	275.81	285.26
RATCHADA PHISEK 69 KV	0.00	354.65	365.99	394.85	355.67	346.67	359.80
RATCHADA PHISEK 115 KV	0.00	0.00	0.00	0.00	0.00	115.88	313.06
SAI NOI 115 KV	0.00	25.29	27.53	28.32	131.32	306.77	341.97
SOUTH BANGKOK 69 KV	620.20	495.82	517.92	528.50	607.02	630.86	703.27
SOUTH BANGKOK 115 KV	269.60	262.20	198.49	187.66	244.72	196.98	164.05
SOUTH THONBURI 69 KV	335.40	374.52	372.60	405.07	462.68	463.60	455.63
SOUTH THONBURI 230 KV	0.00	446.66	549.56	608.43	726.32	1,088.94	1,553.44
TEPARAK 69 KV	0.00	180.77	205.33	221.07	207.16	256.28	351.78
TEPARAK 115 KV	0.00	155.86	248.52	281.50	305.32	335.42	373.92
TOTAL	4,754.75	6,205.09	6,669.80	7,174.03	8,290.05	10,642.81	13,416.00

Substation Load Forecast of Central Area

NON-COINCIDENT
UNIT : MW

SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
ANGTHONG 1	14.31	14.63	14.75	14.89	15.19	16.21	17.68
ANGTHONG 1 (69 KV)	0.00	10.20	10.20	10.20	10.20	10.20	10.20
ANGTHONG 2	25.69	38.80	42.72	46.79	55.44	80.22	112.36
AYUTTHAYA 1	53.76	38.80	42.56	46.59	55.46	82.81	118.22
AYUTTHAYA 2	13.38	18.52	20.32	22.24	26.47	39.53	56.42
BANG PA-IN 1	39.12	44.36	48.57	53.03	62.79	92.74	132.04
BANG PA-IN 1 (115 KV)	25.49	36.68	40.50	44.44	52.88	77.81	105.49
BANG PA-IN 2	178.40	327.14	355.60	381.54	435.69	581.82	744.03
CHAIBADAN	24.48	16.10	17.46	18.75	21.19	27.02	33.59
DOEMBANG NANGBUAT	21.58	32.93	35.26	37.69	42.92	58.66	79.50
LOP BURI 1	36.70	29.80	31.93	34.13	38.73	51.86	68.37
LOP BURI 2	19.03	28.44	30.47	32.56	36.96	49.49	65.25
LOP BURI 2 (115 KV)	0.00	12.20	13.75	15.30	15.30	15.30	15.30
NAKHON NAYOK	24.58	19.74	21.49	23.31	27.21	38.77	53.42
PHRAPHUTTHABAT	36.10	50.52	56.07	61.78	73.68	107.39	152.17
RANGSIT (69 KV)	213.46	264.08	286.05	307.95	353.07	491.36	679.59
RANGSIT (115 KV)	219.74	264.08	286.05	307.95	353.07	491.36	679.59
SAI NOI (115 KV)	0.00	55.58	59.97	64.63	74.86	106.99	151.58
SARABURI 1	44.40	52.57	57.15	61.96	72.51	105.86	152.82
SARABURI 2	35.85	25.53	27.93	30.44	35.88	52.58	75.75
SARABURI 2 (115 KV)	179.23	255.29	298.11	331.84	361.74	370.26	382.33
SARABURI 3	96.06	95.00	95.00	95.00	95.00	95.00	95.00
SARABURI 4	35.96	63.62	68.28	73.25	84.23	118.95	168.00
SARABURI 4 (115 KV)	11.82	18.30	18.30	18.30	18.30	18.30	18.30
SINGBURI	33.50	33.95	36.47	39.04	44.26	58.84	77.11
SINGBURI (115 KV)	0.00	16.00	16.00	16.00	16.00	16.00	16.00
SUPHAN BURI	43.88	31.12	33.84	36.72	43.04	62.79	90.17
THALAN 1	26.38	35.79	37.53	39.34	43.18	54.11	67.10
THALAN 1 (115 KV)	95.94	10.10	10.10	10.10	10.10	10.10	10.10
THALAN 3 (115 KV)	0.00	263.03	276.70	289.35	312.96	372.82	436.46
THALAN 1 (CEMENT)	57.82	60.00	60.00	60.00	60.00	60.00	60.00
THALAN 2 (STEEL)	53.36	115.00	115.00	115.00	115.00	115.00	115.00
PHACHI (VOA)	2.45	2.50	2.50	2.50	2.50	2.50	2.50
TOTAL	1,662.47	2,380.40	2,566.63	2,742.61	3,065.81	3,932.65	5,041.44

Substation Load Forecast of Eastern Area

NON-COINCIDENT
UNIT : MW

SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
AO PHAI	29.35	12.40	13.35	14.36	16.67	23.88	33.83
AO PHAI (115 KV)	53.60	173.26	187.85	199.94	226.27	305.79	412.61
BAN BUNG	49.62	58.01	65.07	72.53	88.95	139.99	207.15
BAN BUNG (115 KV)	0.00	21.87	27.98	29.86	29.86	29.86	29.86
BANG LAMUNG	55.69	66.21	71.78	77.68	90.55	130.41	185.27
BANG LAMUNG (115 KV)	28.27	43.69	47.36	51.25	59.75	86.05	122.25
BOWIN (115 KV)	64.20	169.70	181.61	192.22	209.84	256.97	291.77
CHACHOENGSAO	98.84	62.28	68.23	74.41	87.64	127.83	181.74
CHACHOENGSAO (115 KV)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CHANTHABURI	65.08	51.73	56.41	61.30	71.85	104.65	149.95
CHANTHABURI (115 KV)	0.00	49.24	53.57	58.10	67.91	98.36	140.37
CHOM THIEN	23.64	33.48	35.65	37.94	42.96	58.47	79.83
CHON BURI	76.64	31.22	33.90	36.72	42.85	61.62	87.11
KHLONG MAI (115 KV)	120.00	238.45	257.11	276.57	317.17	438.35	605.12
KLAENG	38.84	30.18	32.53	35.01	40.45	57.28	80.36
PRACHIN BURI 1	53.56	28.91	30.96	33.16	38.02	53.47	75.06
PRACHIN BURI 2	0.00	9.47	10.14	10.86	12.45	17.51	24.58
PRACHIN BURI 2 (115 KV)	0.00	115.56	139.12	157.80	199.60	300.45	388.56
RAYONG 1	45.14	44.49	49.07	53.86	64.13	94.98	137.77
RAYONG 1 (115 KV)	44.64	0.00	0.00	0.00	0.00	0.00	0.00
RAYONG 2	23.09	26.59	28.61	30.75	35.43	49.75	68.98
RAYONG 2 (115 KV)	92.01	402.79	463.42	485.62	514.49	572.15	634.51
RAYONG 3	50.60	42.24	46.80	51.38	61.02	90.78	132.27
SI RACHA	28.44	32.44	34.47	36.58	41.16	55.26	74.28
TRAT	26.50	25.91	27.36	28.85	32.00	40.97	51.92
TRAT (115 KV)	0.00	6.16	6.50	6.86	7.60	9.74	12.34
WATTHANA NAKHON	29.66	27.17	29.43	31.80	36.98	52.95	74.74
WATTHANA NAKHON (115 KV)	0.00	13.35	14.46	15.62	18.17	26.01	36.71
AO PHAI (THAI OIL)	42.64	50.00	50.00	50.00	50.00	50.00	50.00
AO PHAI (ESSO CO. PLANT)	7.31	3.80	3.80	3.80	3.80	3.80	3.80
SATTAHIP 1 (DIR)	8.27	10.00	10.00	10.00	10.00	10.00	10.00
SATTAHIP 2 (DIR)	22.69	31.96	34.89	37.86	43.96	57.52	69.77
TOTAL	1,178.32	1,912.56	2,111.43	2,262.69	2,561.53	3,404.85	4,452.51

Substation Load Forecast of Western Area

NON-COINCIDENT

UNIT : MW

SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
BANPONG 1	91.60	50.36	55.32	60.37	70.79	100.62	140.96
BANPONG 2	66.16	34.53	35.53	36.61	38.99	46.65	57.53
BANPONG 2 (115 KV)	0.00	49.26	50.77	52.38	55.96	67.45	83.77
BANG SAPHAN	47.00	17.16	18.60	20.07	23.06	26.17	41.17
BANG SAPHAN (115 KV)	0.00	135.00	135.00	135.00	135.00	135.00	135.00
CHA AM	40.84	35.22	38.07	40.94	46.88	62.84	82.22
HUA HIN	0.00	29.97	32.36	34.78	39.83	54.02	71.57
KAMPHAENG SAEN	30.71	40.44	43.53	46.84	54.17	77.73	111.26
KAMPHAENG SAEN (115 KV)	26.81	0.00	0.00	0.00	0.00	0.00	0.00
KANCHANABURI	43.48	59.03	63.18	67.55	77.06	106.17	145.60
KANGKRACHAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KHAO LAEM	4.83	5.00	5.17	5.35	5.71	6.76	8.06
NAKHON CHAISI	124.74	117.19	126.74	136.91	159.25	229.08	325.83
PHETCHABURI	30.76	42.89	46.34	49.86	57.14	76.26	96.38
PRACHUAP KHIRI KHAN	26.20	20.15	21.84	23.56	27.07	36.64	48.33
PRANBURI	25.66	17.63	19.01	20.43	23.40	32.05	42.90
RATCHABURI 1	21.54	31.90	34.34	36.85	42.13	56.80	73.44
RATCHABURI 2	33.56	26.13	28.64	31.20	36.47	50.35	66.70
RATCHABURI 2 (115 KV)	0.00	60.46	66.16	71.99	84.67	117.84	161.67
SAM PHRAN 1	113.30	82.79	89.31	96.29	111.70	160.88	231.02
SAM PHRAN 1 (115 KV)	0.00	291.22	314.26	338.57	391.44	555.34	784.40
SAM PHRAN 2	87.84	75.68	81.74	88.20	102.50	148.02	212.88
SAMUT SAKHON 1	87.80	53.16	57.75	62.66	73.53	108.09	157.08
SAMUT SAKHON 2	73.76	103.87	112.70	122.09	142.79	208.20	300.07
SAMUT SAKHON 2 (115 KV)	12.92	26.15	29.97	34.08	43.12	70.00	103.54
SAMUT SAKHON 3	82.12	69.48	75.38	81.68	95.59	139.60	201.53
SAMUT SONGKHRAM	36.16	25.65	27.58	29.58	33.85	46.36	62.48
SRINAGARIND	0.60	0.69	0.74	0.79	0.89	1.16	1.49
THA MUANG (PEA)	28.56	31.17	33.22	35.40	40.20	55.21	75.75
TOTAL	1,136.95	1,532.18	1,643.25	1,760.03	2,013.19	2,775.29	3,822.63

Substation Load Forecast of Northeastern Area

NON-COINCIDENT

UNIT: MW

SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
AMNAT CHAROEN	0.00	17.41	18.85	20.32	23.40	32.21	42.25
BAN PHAI	16.88	24.66	26.69	28.80	33.33	46.94	65.35
BAMNET NARONG	0.00	0.00	36.80	38.10	40.80	47.79	55.40
BUNG KAN	15.96	10.96	11.78	12.62	14.39	19.19	24.76
BURI RAM	55.88	20.52	21.92	23.34	26.19	34.08	43.82
CHAIYAPHUM	37.68	40.66	36.80	39.75	44.51	60.29	80.74
CHAIYAPHUM (115 KV)	0.00	5.81	6.22	6.64	7.55	10.20	13.56
CHULABHORN	0.00	0.15	0.16	0.18	0.21	0.31	0.43
CHUM PHAE	37.47	39.34	42.22	45.19	51.44	68.92	89.26
KALASIN	36.80	29.23	31.28	33.39	37.88	50.23	64.80
KANTARALAK	0.00	0.00	19.90	21.70	25.30	35.60	45.45
KHONG	28.20	24.29	26.74	29.26	34.54	49.78	69.40
KHONG (115 KV)	0.00	34.65	39.29	40.70	43.59	51.52	60.92
KHON KAEN 1	48.96	61.84	66.70	71.79	82.61	113.30	148.90
KHON KAEN 2	25.12	32.51	35.07	37.75	43.44	59.57	78.29
LOEI	33.44	23.15	24.93	26.75	30.40	40.69	52.91
LOEI (115 KV)	0.00	8.62	9.29	9.96	11.35	15.16	19.71
MAHA SARAKHAM	37.24	36.33	38.57	40.87	45.69	59.48	76.66
MUKDAHAN (PEA)	18.54	24.03	26.22	28.46	33.07	45.74	60.15
NAKHON PHANOM (PEA)	15.18	19.58	21.10	22.72	26.27	37.37	52.50
NAKHON RATCHASIMA 1	75.95	28.92	43.17	45.58	50.49	61.97	80.43
NAKHON RATCHASIMA 2	44.00	59.40	43.17	45.58	50.49	61.97	80.43
NAKHON RATCHASIMA 2 (115 KV)	3.60	58.91	66.73	73.88	85.63	123.35	165.65
NAM PHONG	25.31	22.71	24.67	26.65	30.72	41.87	55.36
NAM PHONG (115 KV)	19.43	40.30	41.43	42.59	44.98	51.58	59.30
NAM PHUNG	2.64	4.03	4.49	4.96	5.97	9.10	13.43
NONG BUA LAM PHU	0.00	30.43	32.59	34.79	39.30	51.82	66.52
NONG HAN	14.02	17.54	18.67	19.83	22.24	28.64	36.81
NONG HAN (115 KV)	6.45	8.50	8.50	8.50	8.50	8.50	8.50
NONG KHAI	27.10	35.67	38.57	41.64	48.24	68.31	94.83
PAK CHONG	34.48	43.68	46.84	50.13	57.13	77.45	102.92
PHAYAKKHAPHUM PHISAI	0.00	25.41	27.11	28.85	32.40	42.32	54.57
PHAYAKKHAPHUM PHISAI (115 KV)	0.00	12.75	13.60	14.46	16.18	20.89	26.68
PHANG KHON	20.36	22.92	24.53	26.23	29.86	40.51	53.62
PHANG KHON (115 KV)	0.00	7.31	7.85	8.42	9.60	12.79	16.51
PHON	19.88	26.02	27.96	29.99	34.36	47.03	62.04
PHON THONG	0.00	19.82	21.28	22.70	25.86	34.62	45.03
PRAKHON CHAI	0.00	30.78	32.88	35.01	39.29	51.11	65.73
ROI ET	40.76	57.35	61.84	64.67	74.43	101.93	134.20
SAKHON NAKHON	25.30	33.28	35.98	38.86	45.21	65.09	92.64
SANGKHA	0.00	0.00	15.30	16.80	20.00	28.80	39.90
SI SA KET	49.40	54.73	36.25	38.87	44.86	63.11	87.01
SIKHUI	35.20	42.11	43.00	45.56	51.04	67.27	87.96
SIRINDHORN	8.61	10.94	11.85	12.78	14.65	19.72	25.78
SOMDET	20.80	20.82	22.54	24.30	27.95	38.14	50.66
SURIN	52.80	51.01	42.16	44.38	48.70	60.51	74.79
THAT PHANOM	10.52	12.24	13.20	14.19	16.31	22.75	31.43
UBON RATCHATHANI 1	49.80	50.33	53.67	57.14	64.47	85.32	111.33
UBON RATCHATHANI 2	23.68	15.64	16.76	17.93	20.43	27.66	36.58
UBON RATCHATHANI 2 (115 KV)	0.00	22.76	24.38	26.05	29.56	39.45	51.55
UDON THANI 1	51.52	35.84	38.10	40.40	45.14	58.09	73.14
UDON THANI 2	26.88	35.85	38.10	40.40	45.14	58.09	73.14
UDON THANI 2 (115 KV)	0.00	4.91	5.22	5.53	6.18	7.96	10.02
YASOTHON	37.84	29.65	32.09	34.60	39.84	54.84	71.94
MUKDAHAN (SUVANNAKHET)	7.30	7.97	8.35	8.73	9.49	11.25	12.88
NAKHON PHANOM (THAKHEK)	4.20	5.05	5.25	5.45	5.85	6.85	7.85
TOTAL	1,145.18	1,439.32	1,568.61	1,674.72	1,896.45	2,529.03	3,306.42

Substation Load Forecast of Southern Area

NON-COINCIDENT

UNIT : MW

SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
BAN DON	52.36	42.12	45.34	48.61	55.45	74.39	95.20
BANG LANG	5.92	8.66	9.40	10.15	11.66	15.74	20.54
CHUMPHON	43.72	46.73	50.74	55.07	64.33	90.18	120.79
HAT YAI 1	53.04	44.76	48.41	52.16	59.95	81.80	108.40
HAT YAI 2	38.80	36.62	39.61	42.67	49.04	66.93	88.69
HAT YAI 2 (115 KV)	0.00	44.09	57.15	66.61	85.07	112.75	136.58
KAENG KRUNG	0.00	3.95	4.34	4.76	5.63	7.90	10.22
KHANOM	30.24	33.84	36.44	39.10	44.67	60.99	81.37
KHOK KLOI	0.00	5.36	7.05	8.33	9.35	9.84	9.84
KRABI	19.86	15.12	16.30	17.48	19.90	26.62	33.91
KRABI (115 KV)	0.00	12.33	13.42	14.53	16.79	22.90	29.78
LANG SUAN	0.00	11.68	12.69	13.77	16.08	22.55	30.20
LAM POO RA	43.70	25.60	27.63	29.75	34.17	46.01	58.82
LAM POO RA (115 KV)	0.00	31.29	33.77	36.36	41.77	56.23	71.88
NAKHON SI THAMMARAT	66.56	67.82	73.31	78.90	90.35	121.77	160.16
NAKHON SI THAMMARAT (115 KV)	0.00	19.13	20.68	22.26	25.49	34.35	45.17
NARATHIWAT	31.80	17.56	18.89	20.28	23.19	31.38	40.66
PATTANI	36.68	57.52	61.38	65.33	73.60	97.00	125.28
PHANGNGA	15.80	10.65	11.65	12.73	14.77	20.46	27.17
PHANGNGA (115 KV)	0.00	4.56	4.99	5.45	6.33	8.77	11.65
PHATTHALUNG	24.86	32.81	35.53	38.26	43.79	58.59	76.53
PHUKET 1	44.00	40.05	43.37	46.84	54.25	76.53	105.76
PHUKET 2	42.74	39.73	43.02	46.47	53.82	75.92	104.92
PHUKET 2 (115 KV)	0.00	39.29	42.55	45.96	53.23	75.09	103.77
PHUNPHIN	19.60	28.95	31.85	34.87	41.23	57.93	74.98
RANONG	26.30	25.68	28.28	31.00	36.78	53.20	72.60
RANONG (115 KV)	0.00	19.37	21.33	23.38	27.75	40.13	54.77
RANOT	0.00	23.35	25.17	27.03	30.91	41.93	55.44
RAJJAPRABHA	2.75	3.63	4.01	4.39	5.21	7.45	10.12
SADAO	14.31	18.87	20.26	21.68	24.75	34.21	46.89
SATUN	20.66	28.72	31.79	34.97	41.88	60.13	80.52
SONGKHLA	64.08	63.14	68.04	73.09	83.58	113.36	149.88
SUNGAI KOLOK	0.00	26.34	28.34	30.42	34.77	47.07	60.99
TAKUA PA	11.92	13.30	14.23	15.19	17.23	23.27	30.91
YALA	30.34	37.60	40.50	43.55	50.07	69.58	94.62
THUNG SONG (PEA)	27.00	33.91	36.29	38.70	43.65	57.80	74.67
THUNG SONG (PEA 115 KV)	0.00	15.58	16.77	17.98	20.50	27.52	35.21
SADAO TO TNB	0.00	0.00	0.00	0.00	0.00	0.00	0.00
THUNG SONG (CEMENT)	32.04	78.50	78.50	78.50	78.50	78.50	78.50
TOTAL	799.08	1,108.21	1,203.02	1,296.58	1,489.49	2,006.77	2,617.39

Substation Load Forecast of Northern Area

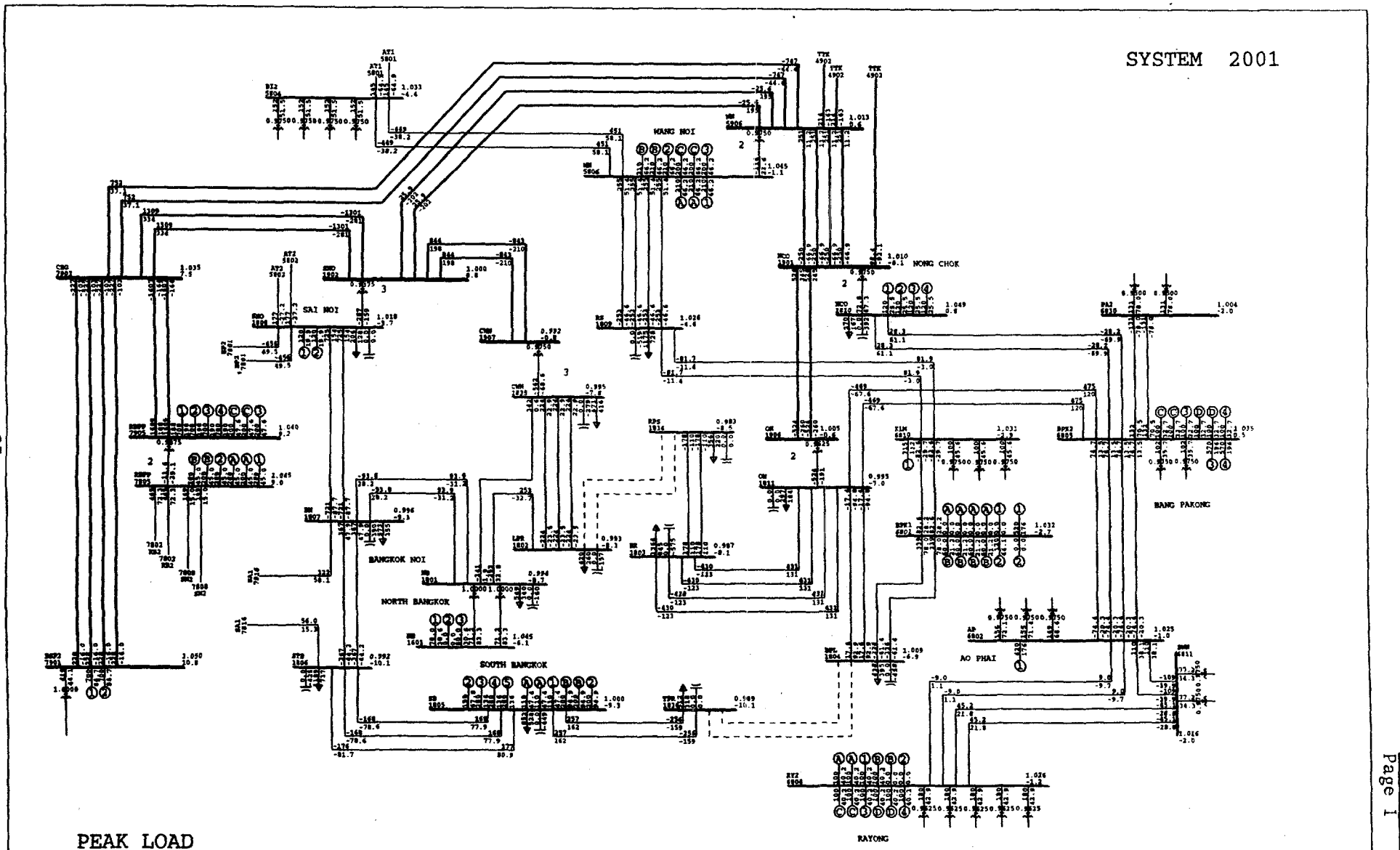
NON-COINCIDENT

UNIT: MW

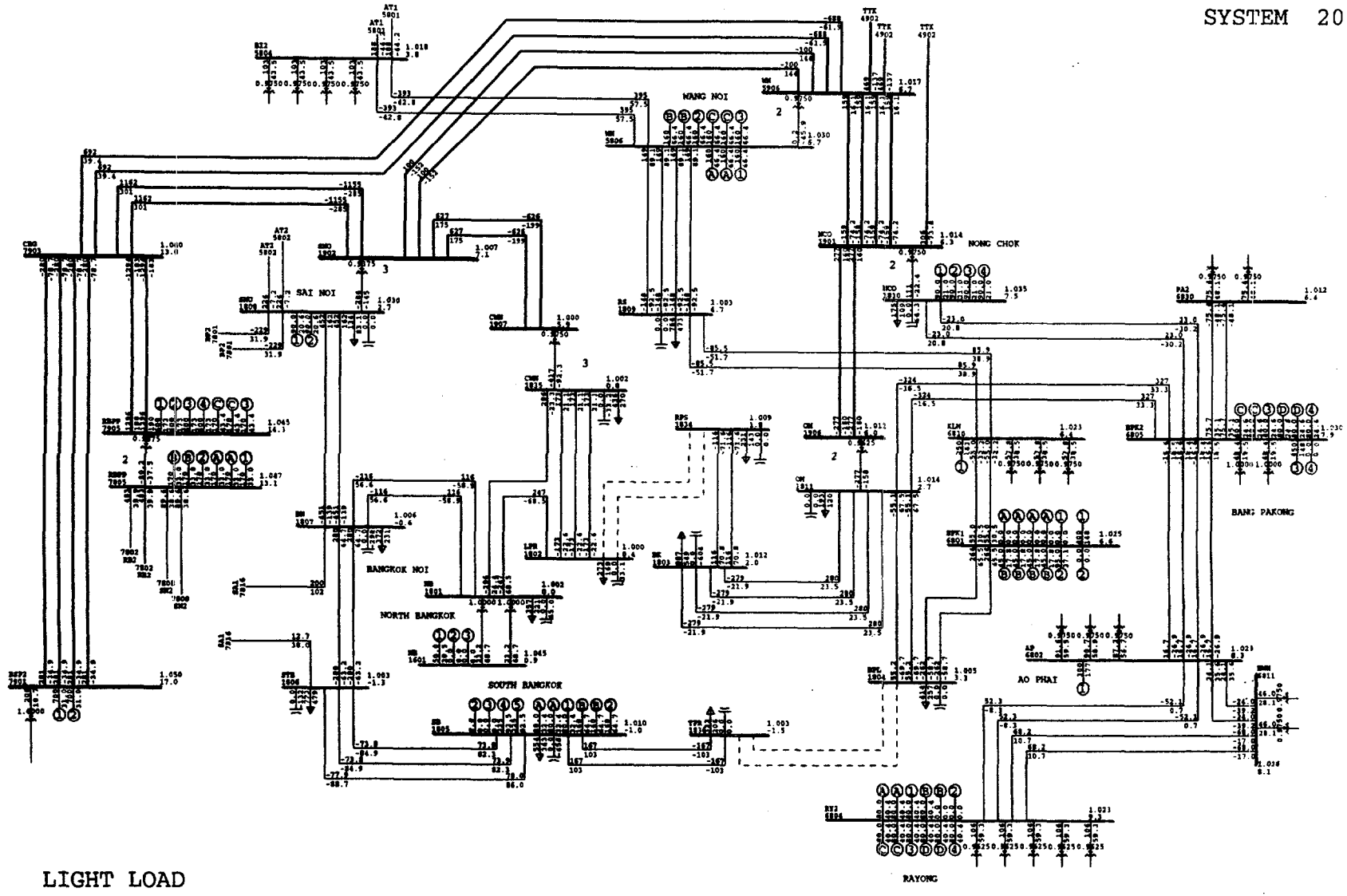
SUBSTATION	ACTUAL 1994 (2537)	FORECAST 1997 (2540)	1998 (2541)	1999 (2542)	2001 (2544)	2006 (2549)	2011 (2554)
BANG MUN NAK	0.00	34.00	36.65	39.34	44.87	60.36	79.64
BUNG SAM PHAN	0.00	22.93	24.69	26.40	29.66	37.51	46.09
CHIANG MAI 1	58.80	47.00	33.91	36.85	43.54	65.58	90.71
CHIANG MAI 2	58.80	47.00	33.91	36.85	43.54	65.58	90.71
CHIANG MAI 3	54.56	47.42	50.90	54.57	62.51	85.73	113.47
CHIANG MAI 3 (115 KV)	0.00	80.80	86.56	92.64	105.80	144.47	190.28
CHIANG RAI	81.78	65.93	70.78	75.84	86.62	117.49	154.01
CHIANG RAI (115 KV)	0.00	16.00	16.92	17.87	19.86	25.45	31.82
CHOM THONG	23.40	27.21	29.26	31.29	35.47	45.94	56.60
CHOM THONG (115 KV)	0.00	8.13	8.74	9.35	10.59	13.72	16.91
KAMPHANGPHET	24.42	36.91	40.51	44.30	52.62	79.30	116.53
LAMPANG 1	34.68	30.23	32.15	34.18	38.57	51.75	68.65
LAMPANG 2	25.30	29.05	30.89	32.84	37.05	49.72	65.96
LAMPANG 2 (115 KV)	0.00	40.00	40.00	40.00	80.00	80.00	80.00
LAMPHUN 1	13.66	21.29	23.80	26.40	31.83	46.84	62.69
LAMPHUN 2	49.04	37.04	41.40	45.92	55.38	81.49	109.06
LAMPHUN 2 (115 KV)	0.00	31.79	35.54	39.41	47.53	69.94	93.60
LAN KRABU	7.31	12.91	14.38	15.89	19.01	27.52	38.04
LOM SAK	15.72	15.05	15.99	16.95	18.96	24.64	31.61
LOM SAK (115 KV)	0.00	4.59	4.93	5.28	5.98	7.96	10.32
MAE CHAN	0.00	23.02	24.72	26.49	30.25	41.03	53.78
MAE SOT	0.00	20.20	21.97	23.78	27.63	39.99	54.01
MAE TAENG	0.00	0.00	34.40	37.20	42.60	55.70	68.82
MANOROM	37.04	30.33	32.76	35.17	39.95	52.19	66.15
MANOROM (115 KV)	0.00	23.83	25.74	27.63	31.39	41.01	51.98
NAKHON SAWAN	58.16	32.01	34.24	36.50	41.01	53.13	67.19
NAKHON SAWAN (115 KV)	0.00	26.05	27.87	29.71	33.40	43.24	54.69
NAN	25.42	21.43	23.13	24.94	28.91	41.31	58.26
NAN (115 KV)	0.00	10.55	11.39	12.28	14.24	20.36	28.70
PHAYAO	48.68	44.13	46.62	49.17	54.53	69.76	88.60
PHETCHABUN	28.08	30.30	32.42	34.49	38.54	48.35	58.72
PHICHIT	42.24	39.22	42.58	46.00	53.15	73.85	100.75
PHITSANULOK 1	53.84	47.00	50.35	53.85	61.34	83.31	111.01
PHITSANULOK 2	8.91	11.19	11.94	12.72	14.38	19.16	25.07
PHITSANULOK 2 (115 KV)	0.00	19.20	20.57	22.00	25.06	34.03	45.34
PHRAE	37.24	33.58	36.11	38.70	43.96	58.69	75.38
PHRAE (115 KV)	0.00	13.06	14.04	15.05	17.10	22.83	29.31
SALOKBAT	17.72	30.45	33.07	35.66	40.84	54.67	71.52
SAM NGAO (BHUMIBOL)	1.94	2.23	2.42	2.62	3.01	4.05	5.30
SAWAN KHALOK	17.46	21.61	23.35	25.11	28.76	39.12	52.77
SIRIKIT	2.67	4.18	4.52	4.87	5.58	7.60	10.21
SUKHOTHAI	19.78	28.34	30.19	32.10	36.15	47.68	61.72
TAK 1	31.43	21.88	23.80	25.77	29.93	42.24	58.51
TAK 2 (PEA)	0.00	0.10	0.10	0.10	0.10	0.10	0.10
TAKHLI 2 (PEA)	12.17	15.89	17.02	18.17	20.59	27.34	34.91
THA TAKO	10.07	16.84	18.28	19.69	22.45	29.09	36.36
THOEN	6.85	6.88	7.28	7.70	8.59	11.14	14.19
THOENG	0.00	18.25	19.46	20.72	23.37	30.96	40.08
UTTARADIT	30.72	42.34	44.95	47.68	53.51	70.83	93.07
TAK 2 (PADAENG CO. PLANT)	38.78	40.00	40.00	40.00	40.00	40.00	40.00
TAKHLI 1 (CEMENT)	11.82	13.00	13.00	13.00	13.00	13.00	13.00
OTHER (CONSTRUCTION PROJECT)	72.60	135.00	176.00	125.00	148.00	165.00	143.00
TOTAL	1,061.09	1,477.37	1,616.20	1,666.04	1,940.71	2,561.75	3,259.20

APPENDIX 2

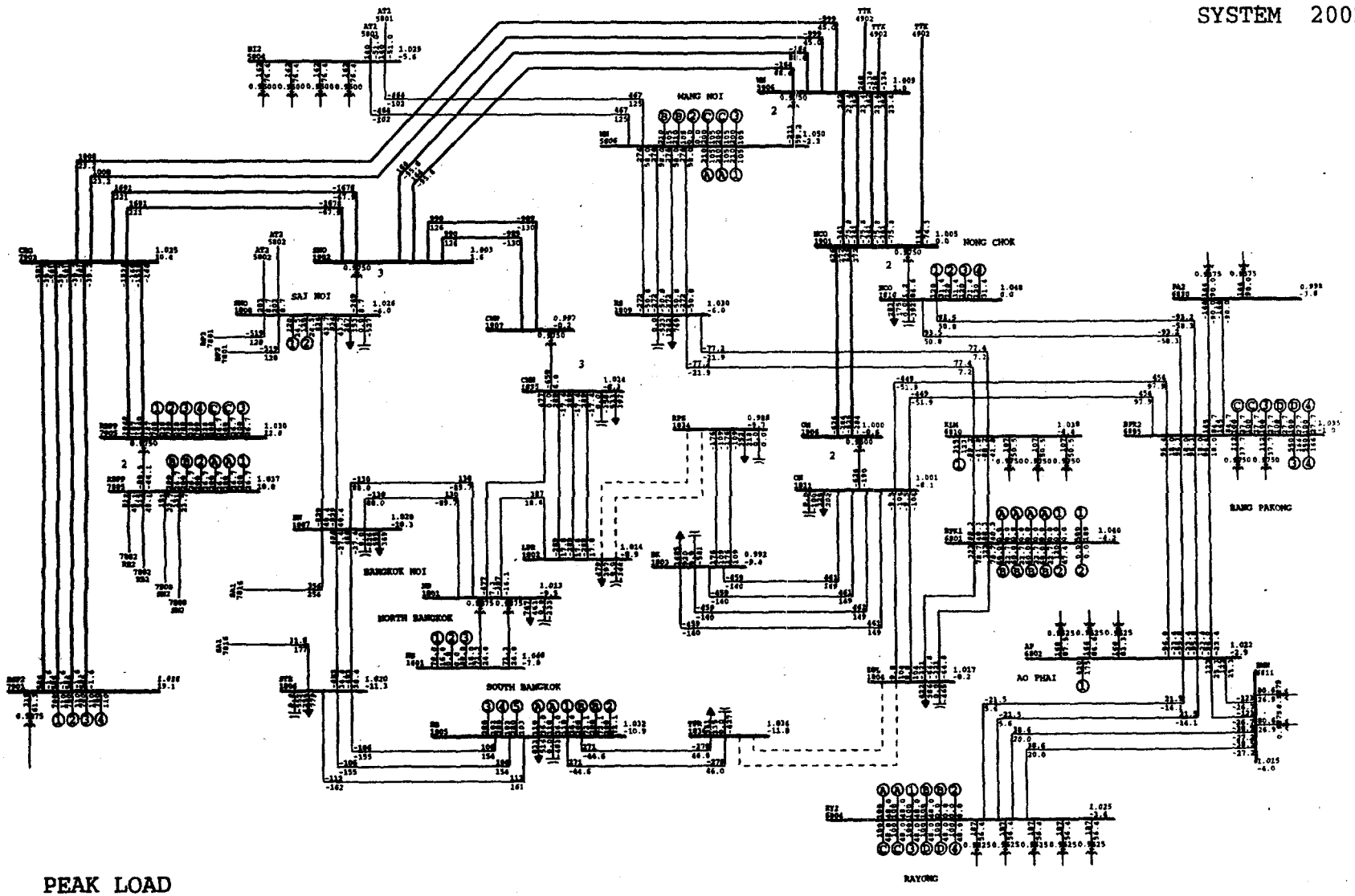
POWER FLOW DIAGRAMS



	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2001	IPPs in the western area (With 2 x 700 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 cct s.)	CASE LF - P01W

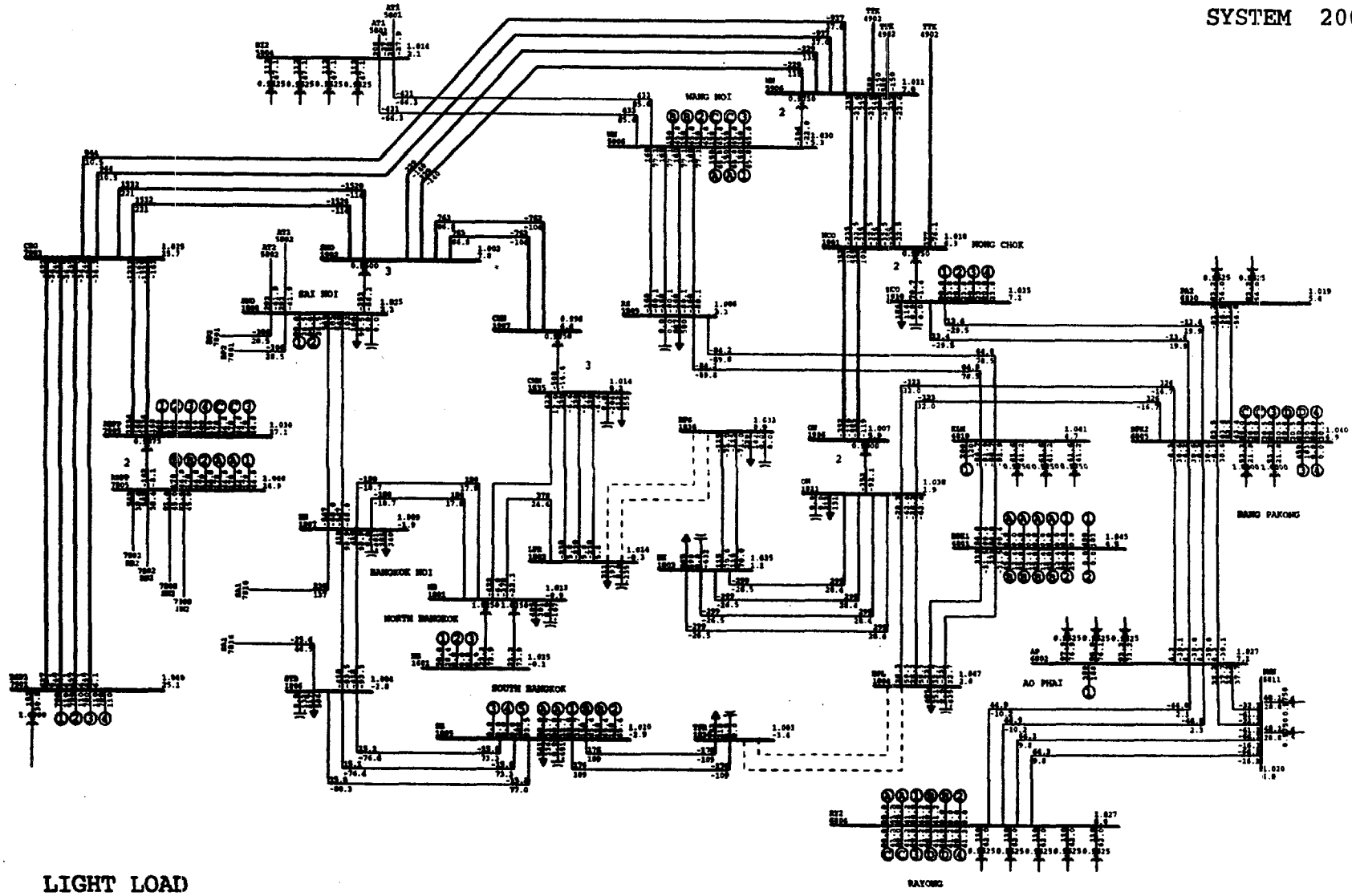


	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2001	IPPs in the western area (With 2 x 700 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 cct.)	CASE LF - L01W

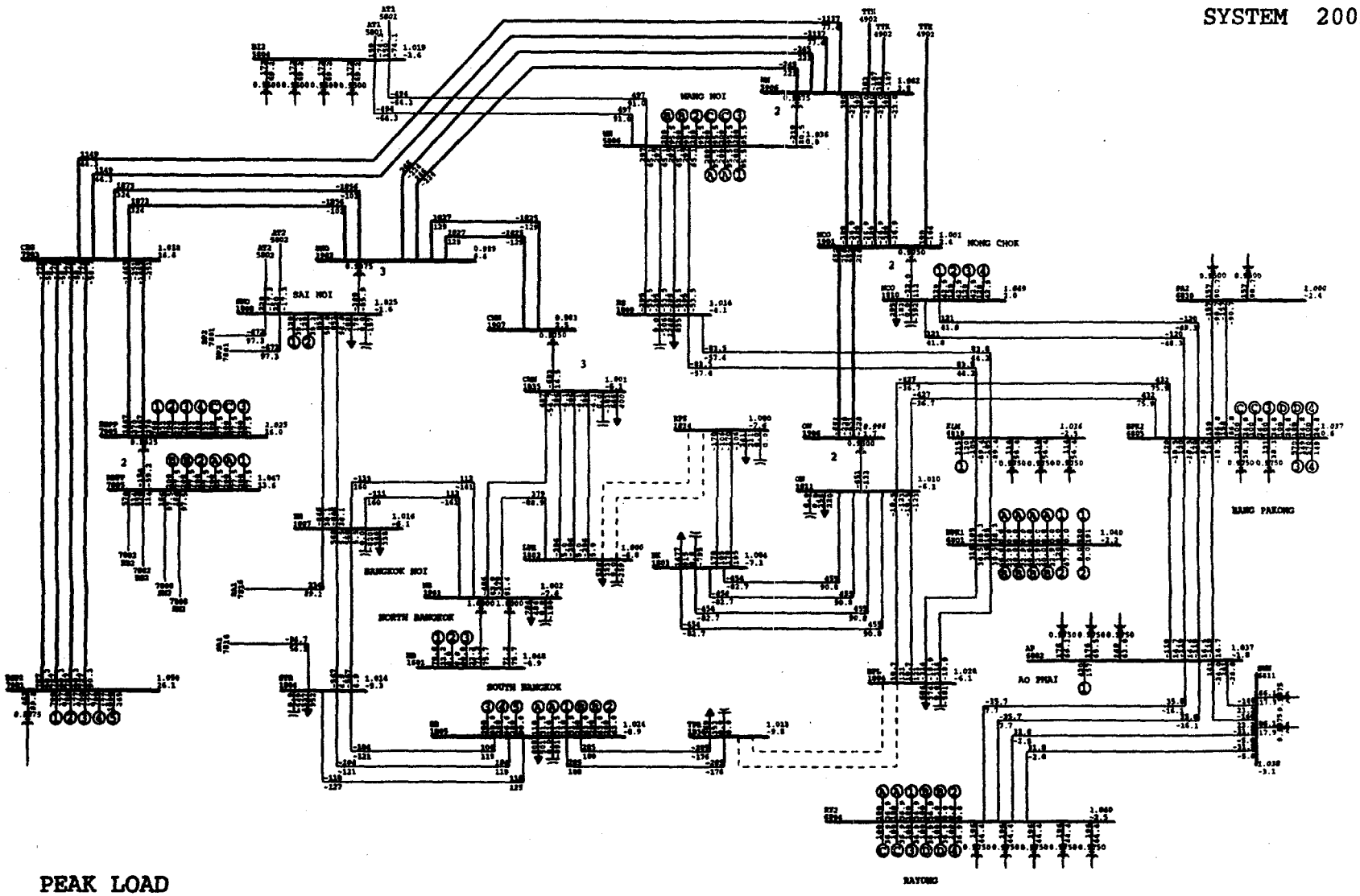


PEAK LOAD

	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2002	IPPs in the western area (With 4 x 700 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 ccts.)	CASE LF - P02W



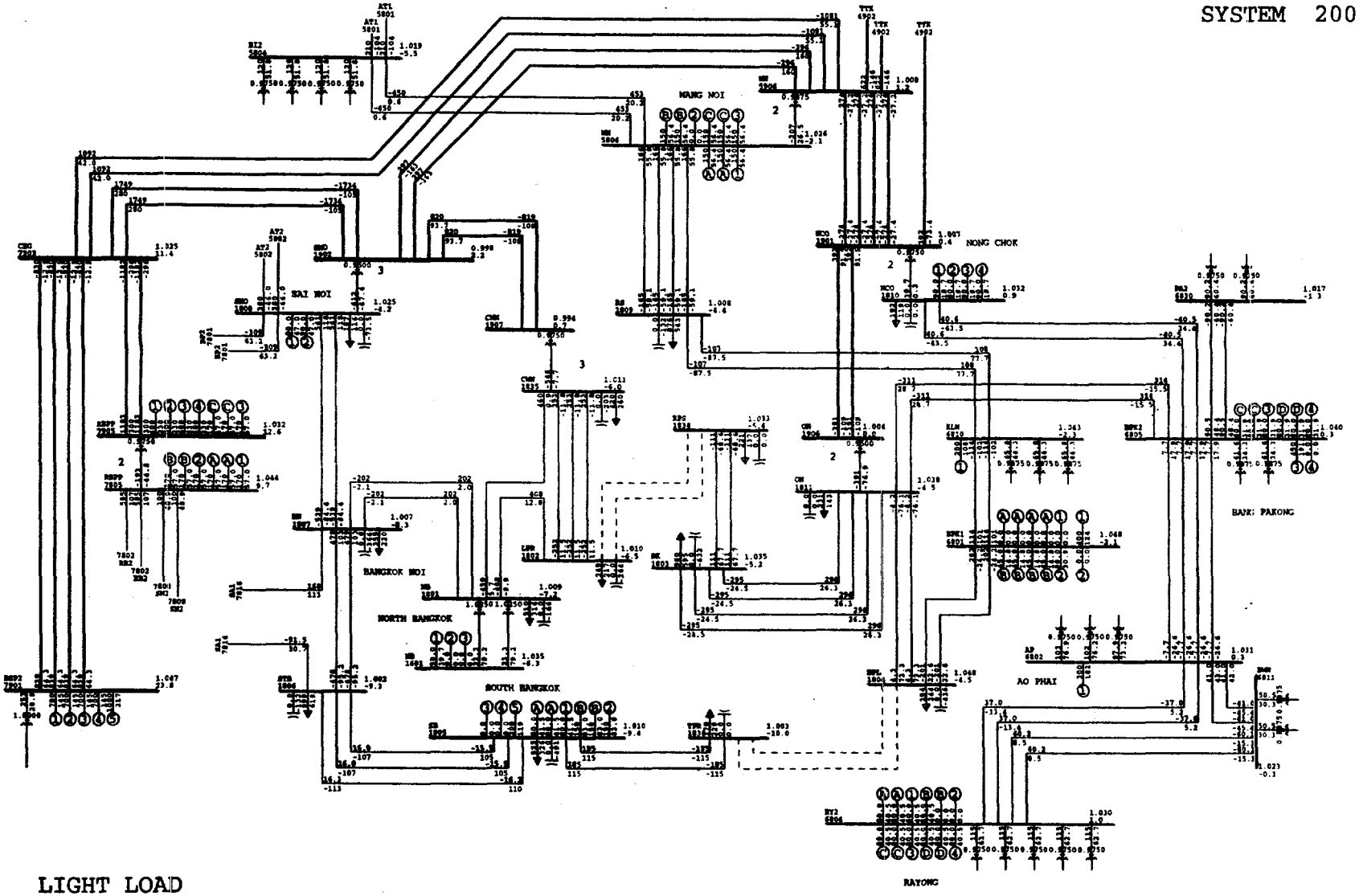
	System Planning Dept., Load Jun 94, PDP 95-01 500 KV Transmission System Project For IPPs	Light Load 2002	IPPs in the western area (With 4 x 700 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 cct's.)	CASE LF - L02W



PEAK LOAD

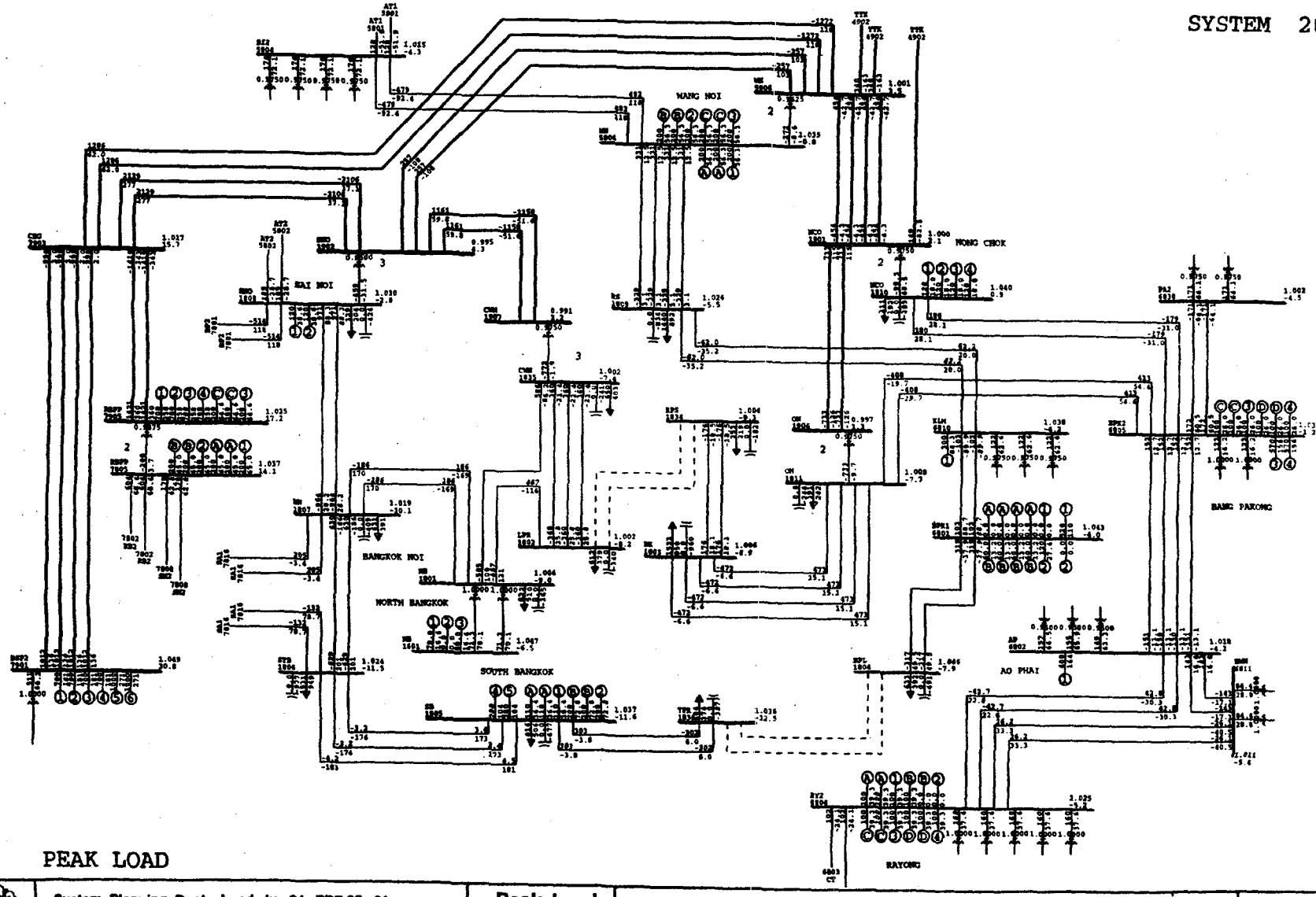
System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2003	IPPs in the western area (With 4 x 700 + 1,000 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 ccts.)	CASE LF - P03W

SYSTEM 2003



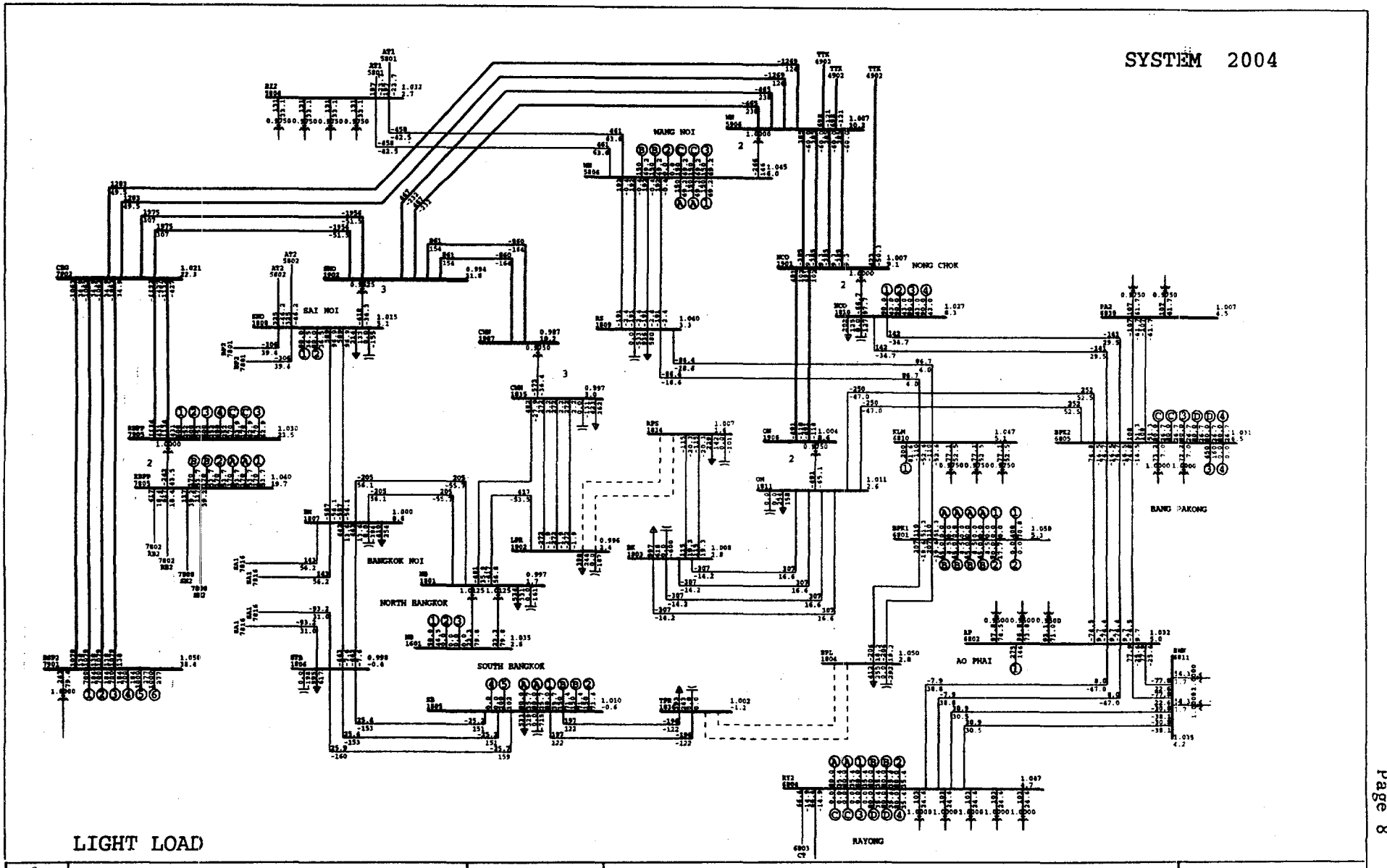
LIGHT LOAD

System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2003	IPPs in the western area (With 4 x 700 + 1,000 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 ccts.)	CASE LF - L03W



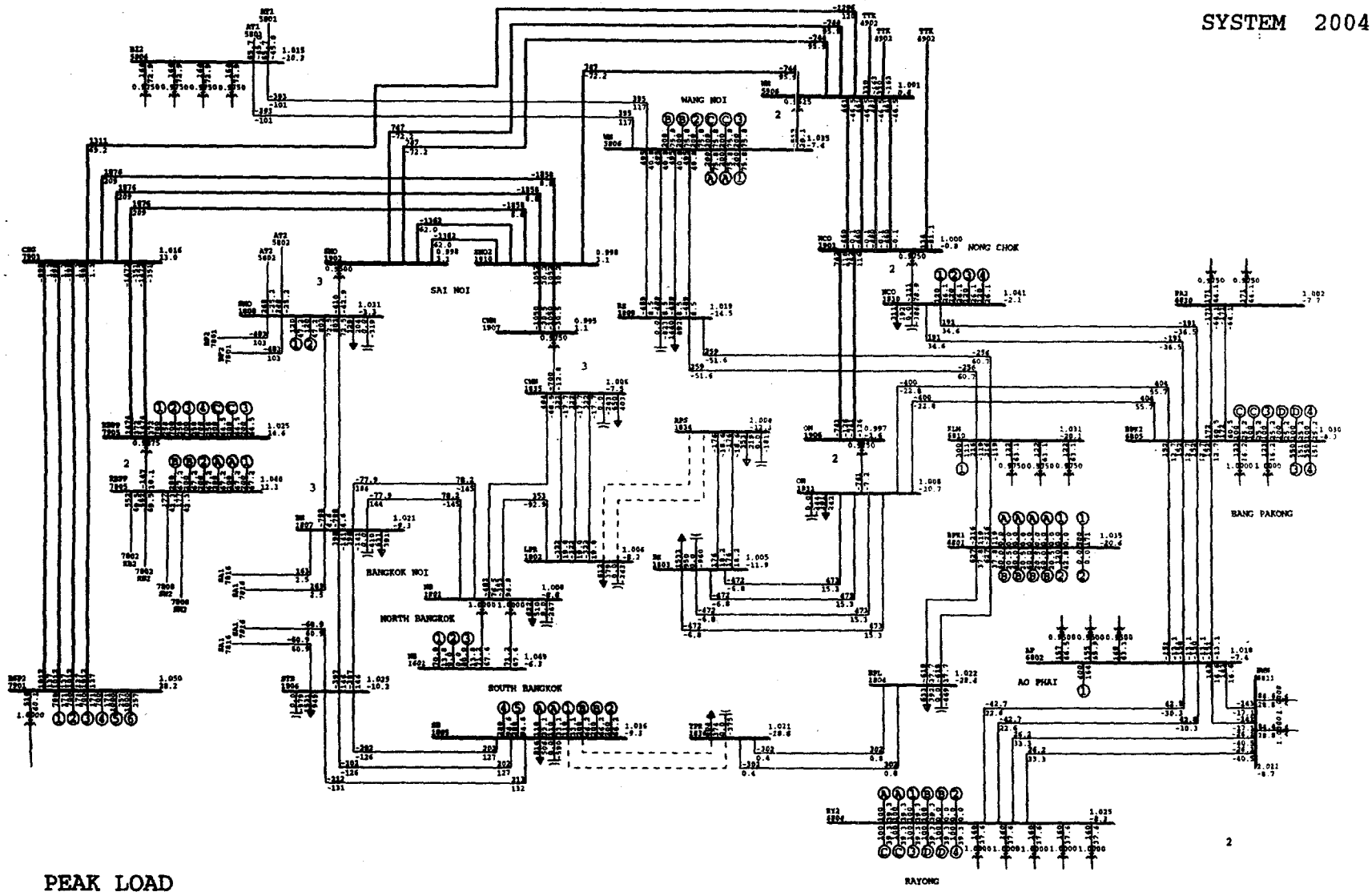
PEAK LOAD

	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2004	IPPs in the western area (With 4 x 700 + 2 x 1,000 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 ccts.)	CASE LF - P04W - 1



	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2004	IPPs in the western area (With 4 x 700 + 2 x 1,000 MW at Bang Saphan 2 and 500 kv Bang Saphan 2 - Chom Bung 4 ccts.)	CASE LF - L04W - 1

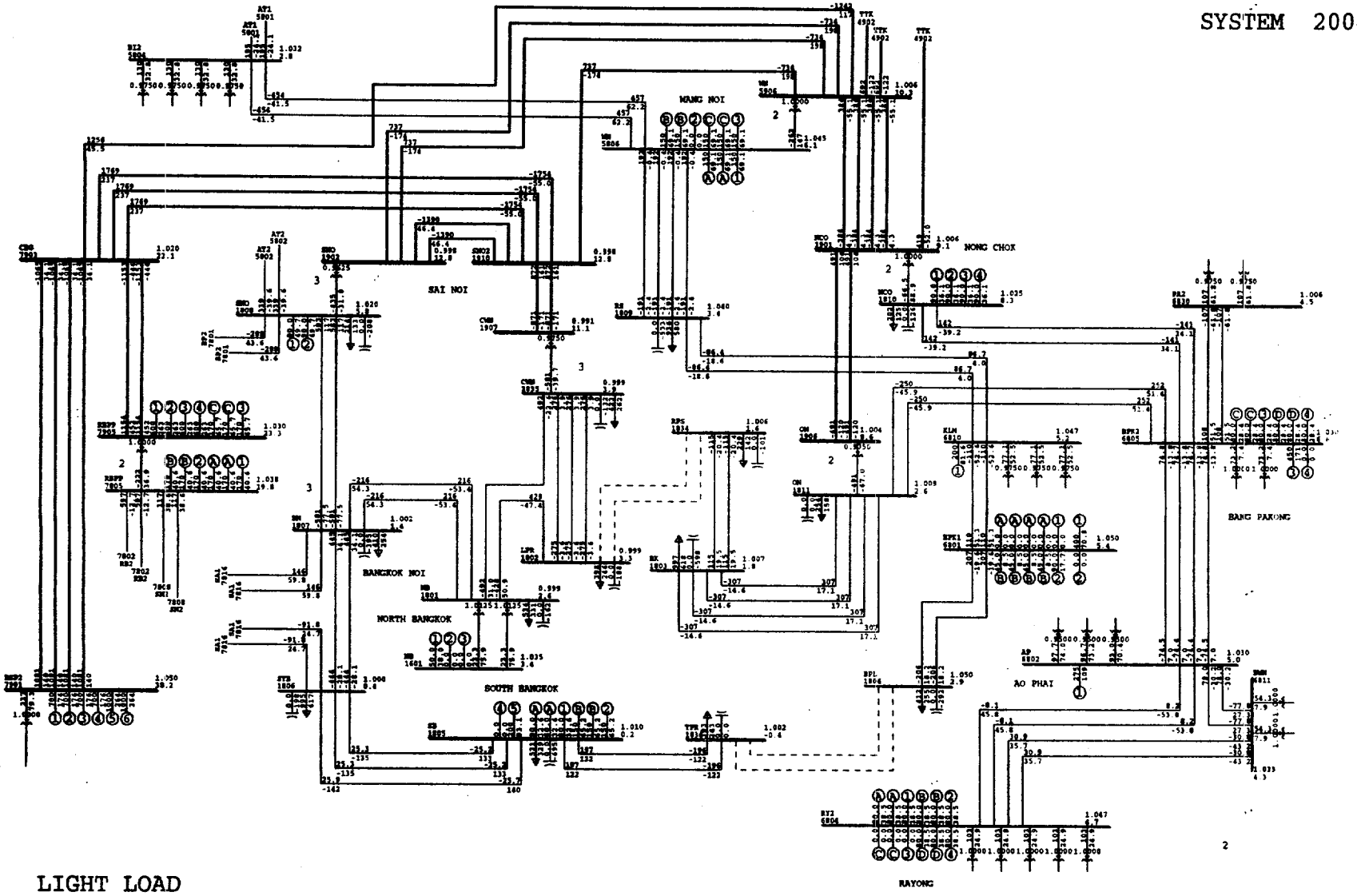
SYSTEM 2004



PEAK LOAD

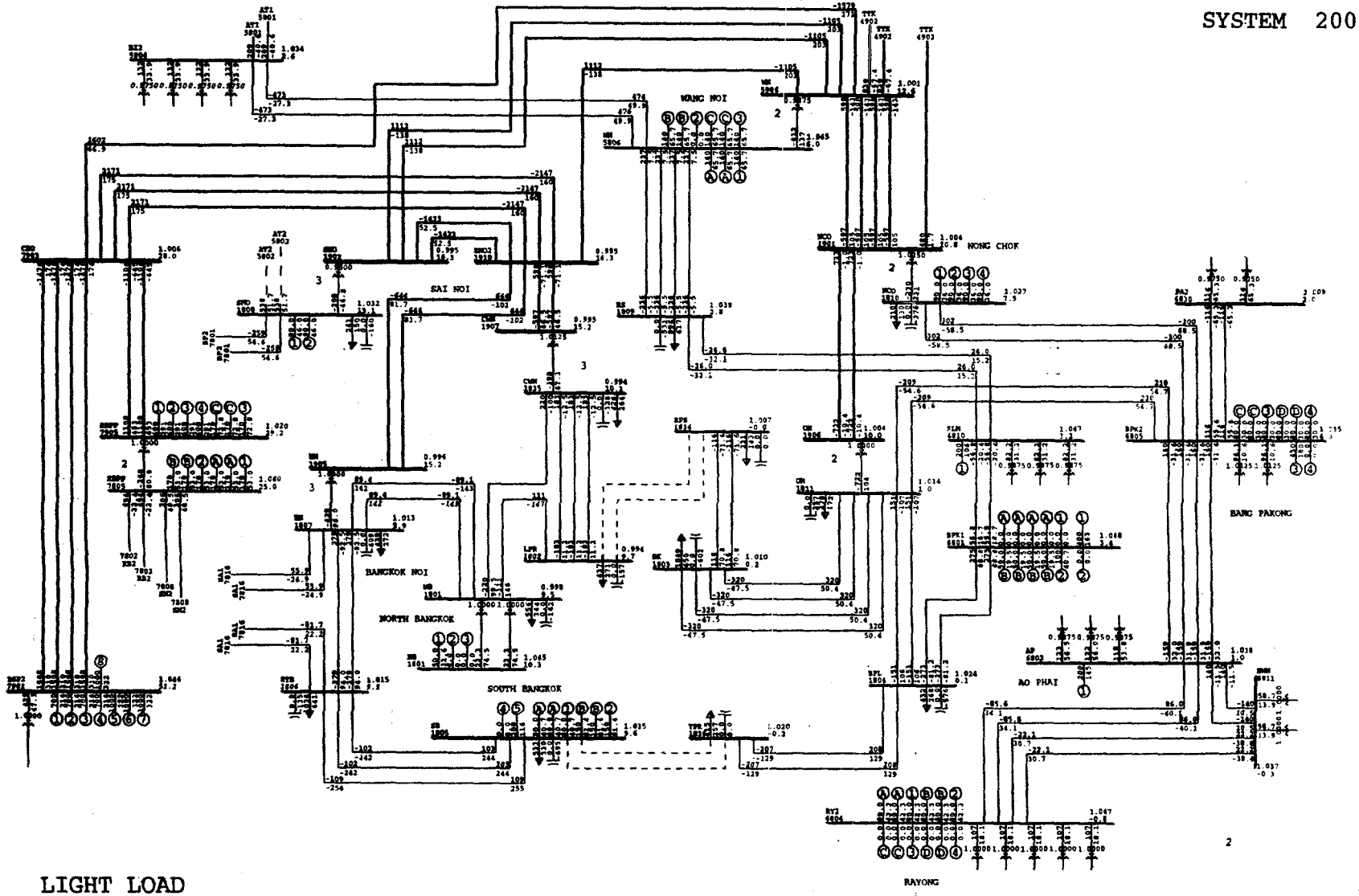
System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2004	IPPs in the western area (With 4 x 700 + 2 x 1,000 MW at Bang Saphan 2, 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE LF - P04W - 2

SYSTEM 2004

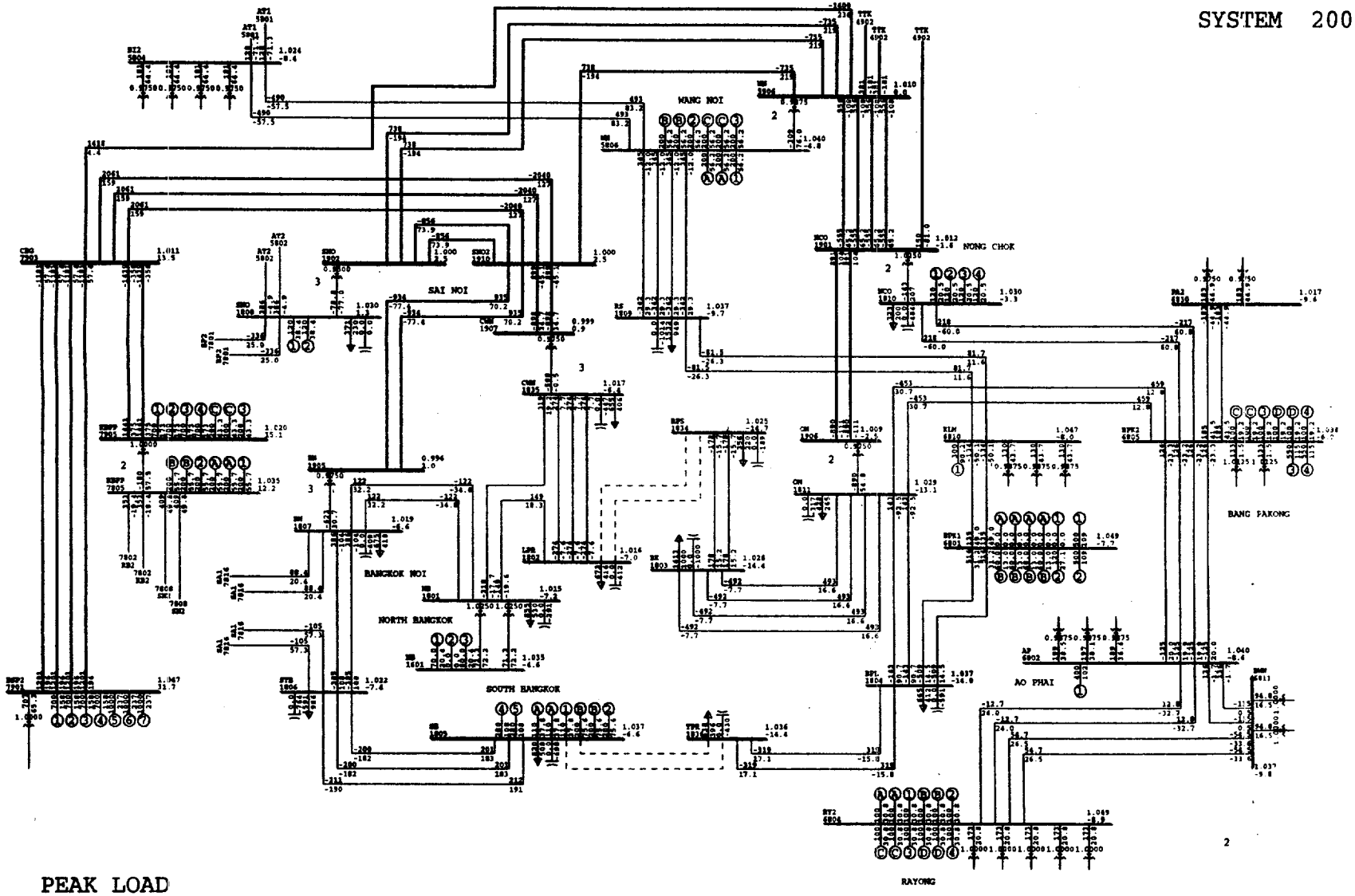


LIGHT LOAD

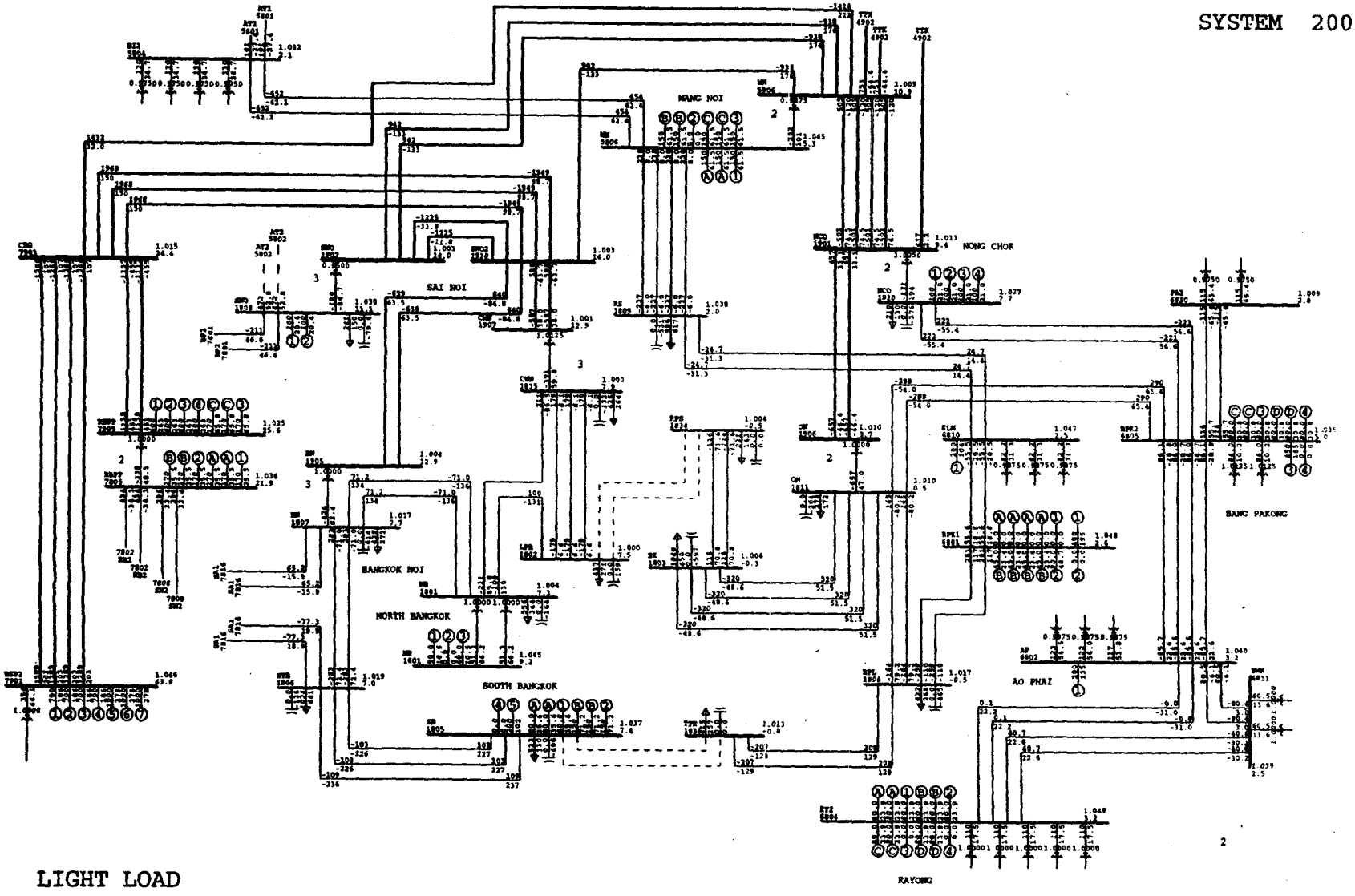
System Planning Dept., Load Jun 94, PDP 95-01 500 KV Transmission System Project For IPPs	**Light Load 2004**	IPPs in the western area (With 4 x 700 + 2 x 1,000 MW at Bang Saphan 2, 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE LF - L04W - 2



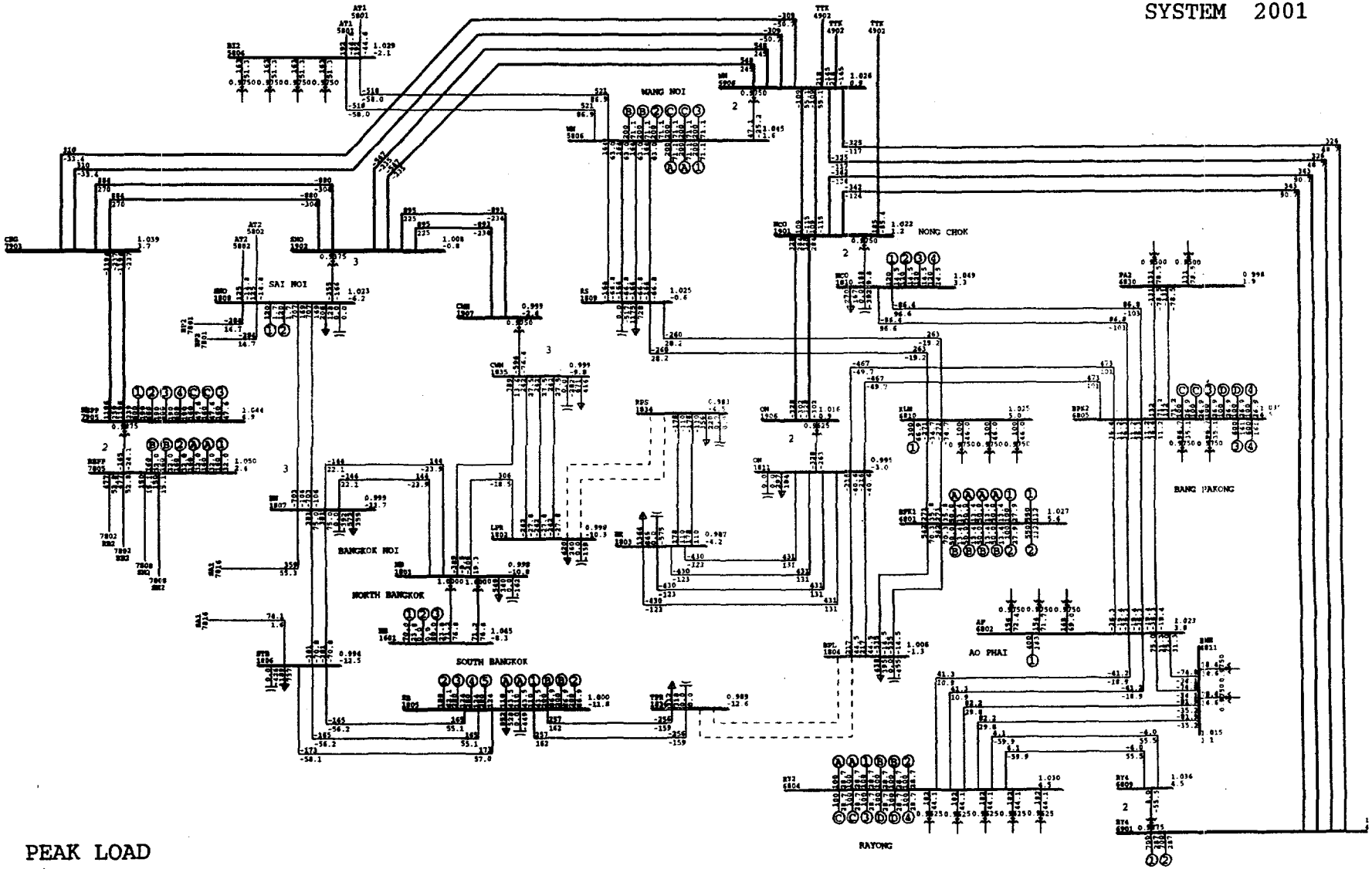
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2005	IPPs in the western area (With 4 x 700 + 4 x 1,000 MW at Bang Saphan 2, 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE LF - L05W - 1



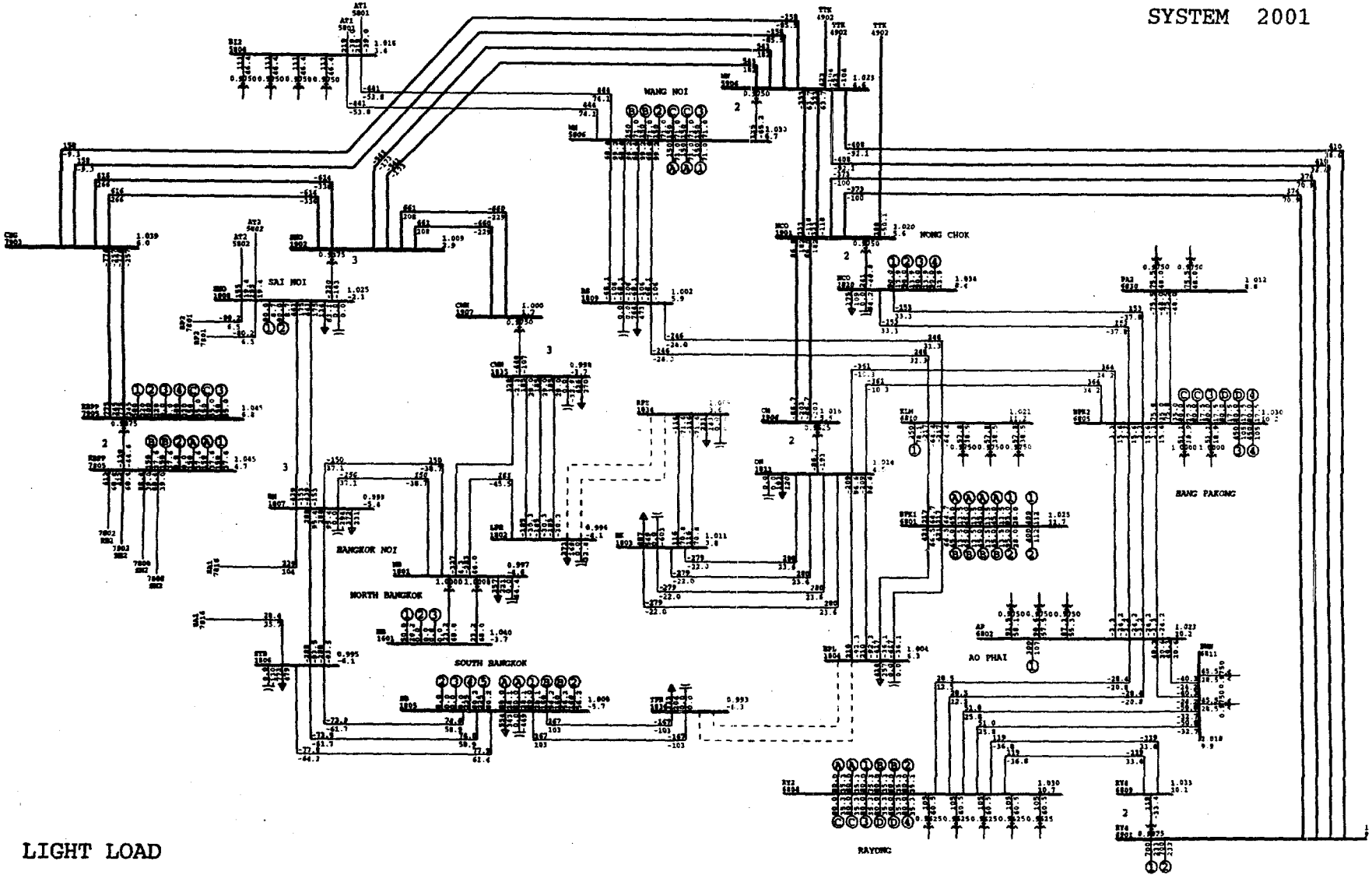
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2005	IPPs in the western area (With 4 x 700 + 3 x 1,000 MW at Bang Saphan 2 , 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE LF - P05W - 2



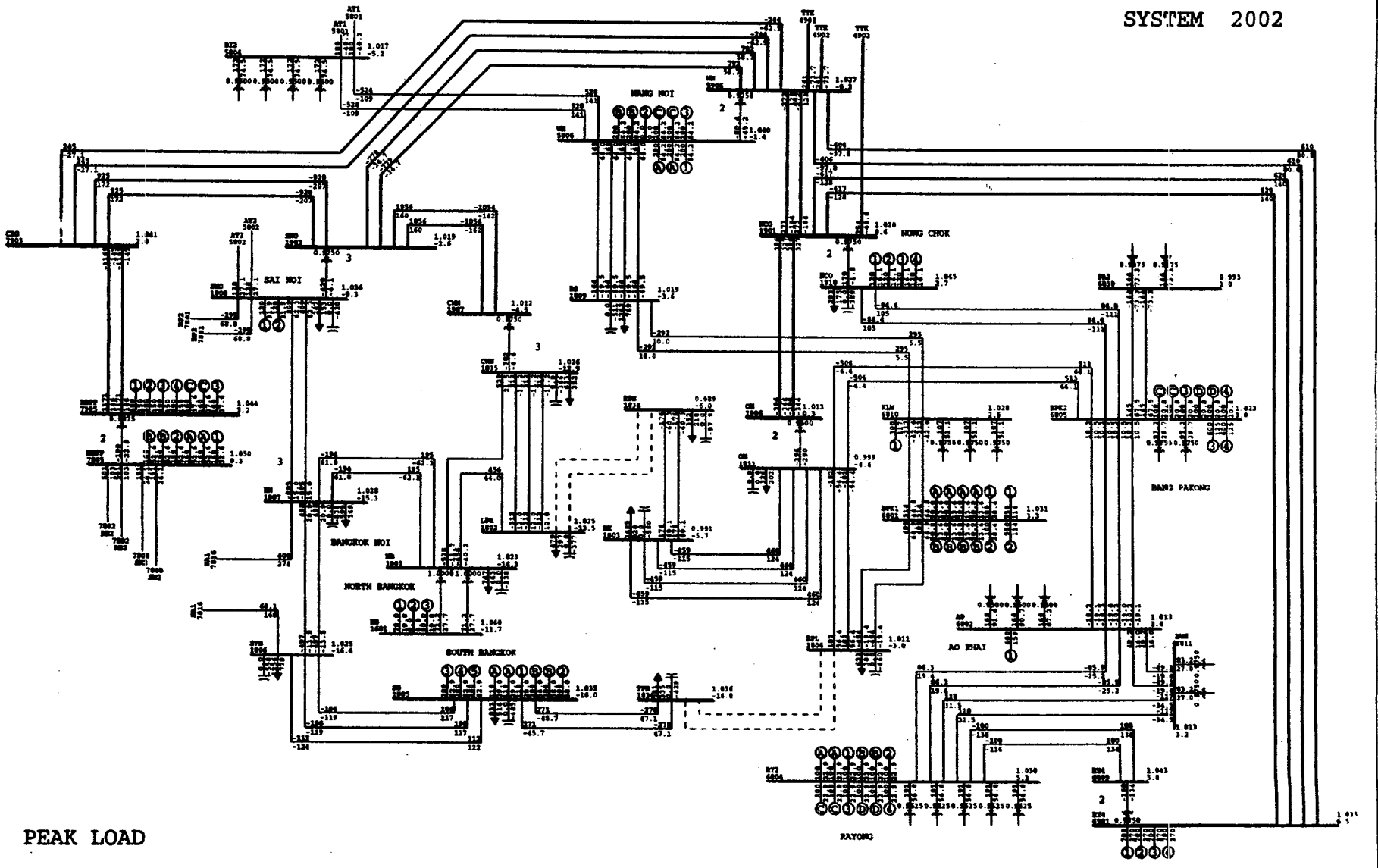
System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2005	IPPs in the western area (With 4 x 700 + 3 x 1,000 MW at Bang Saphan 2 , 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE LF - L05W - 2



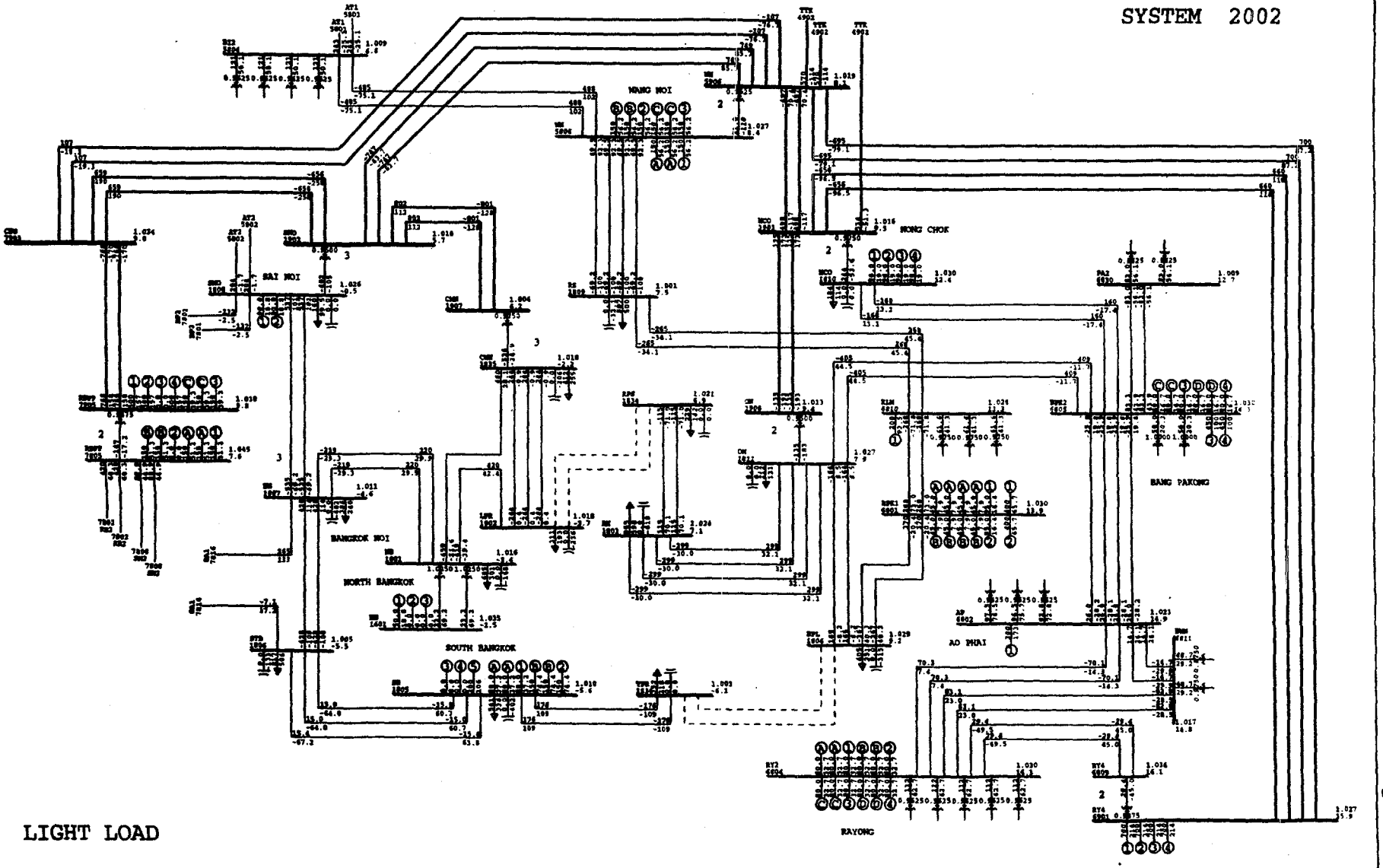
System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2001	IPPs in the eastern area (With 2 x 700 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P01E



System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2001	IPPs in the eastern area (With 2 x 700 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L01E

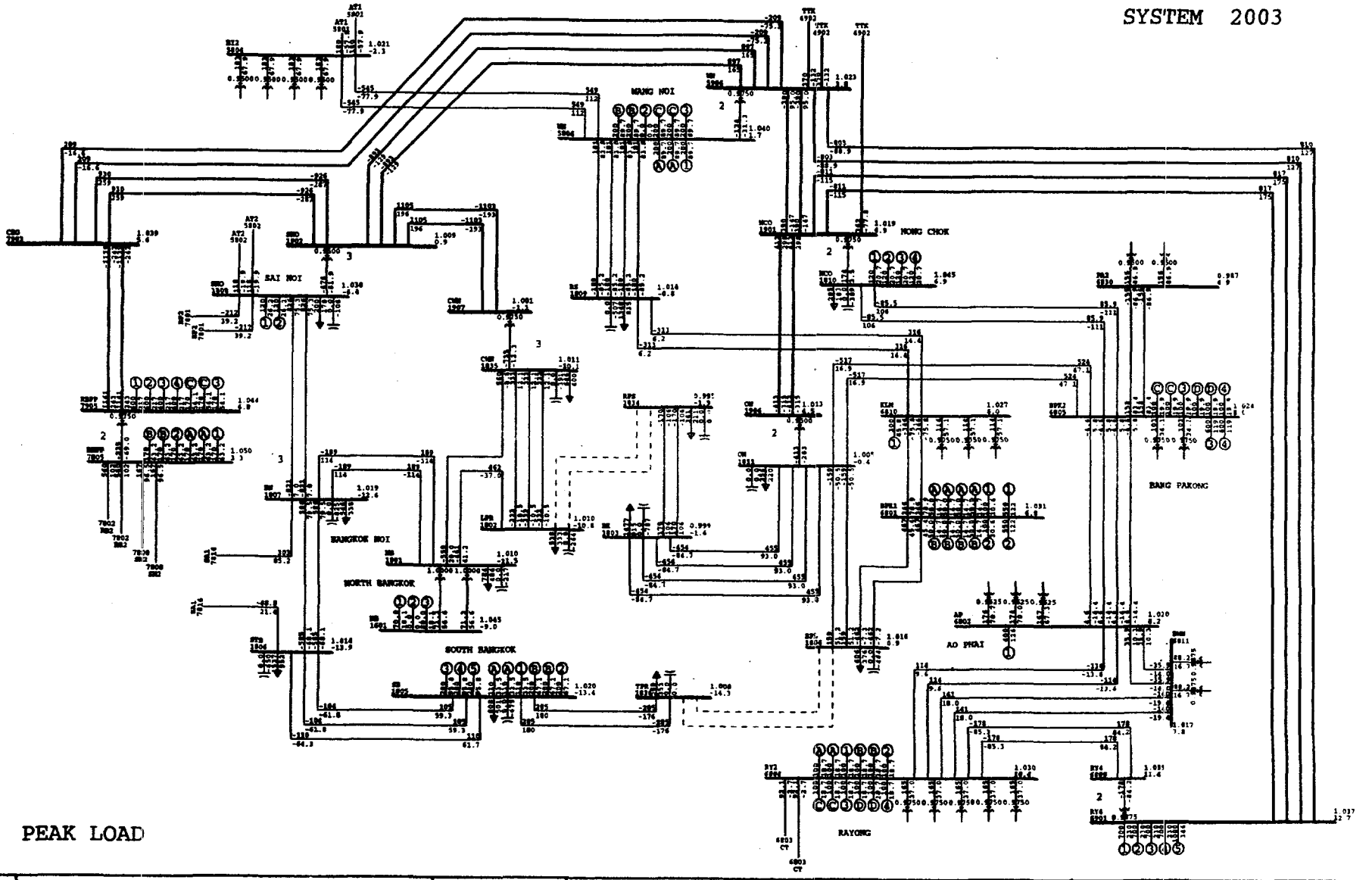


	System Planning Dept., Load Jun 94, PDP 95-01 500 KV Transmission System Project For IPPs	Peak Load 2002	IPPs in the eastern area (With 4 x 700 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P02E



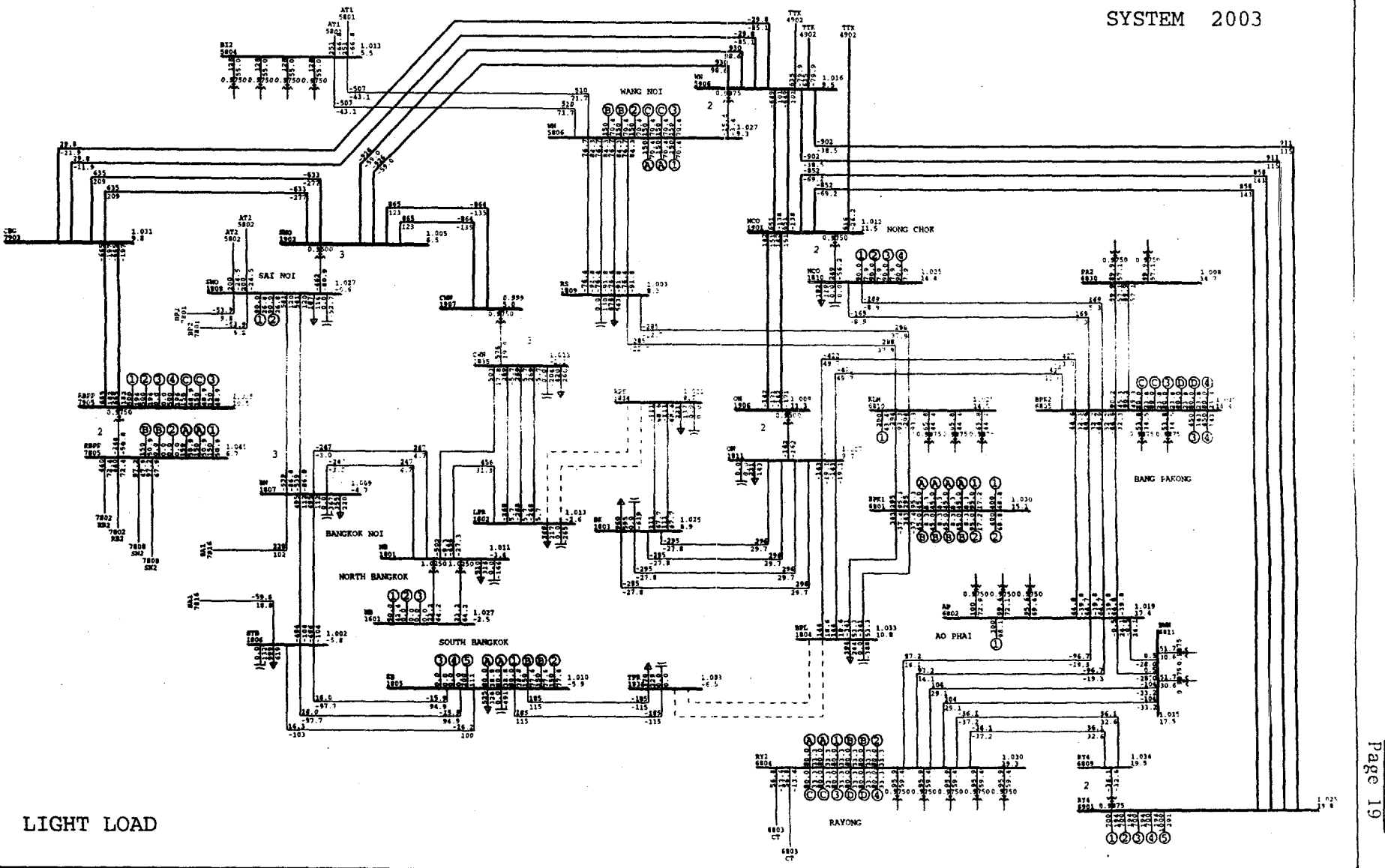
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2002	IPPs in the eastern area (With 4 x 700 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LIF - L02E

SYSTEM 2003

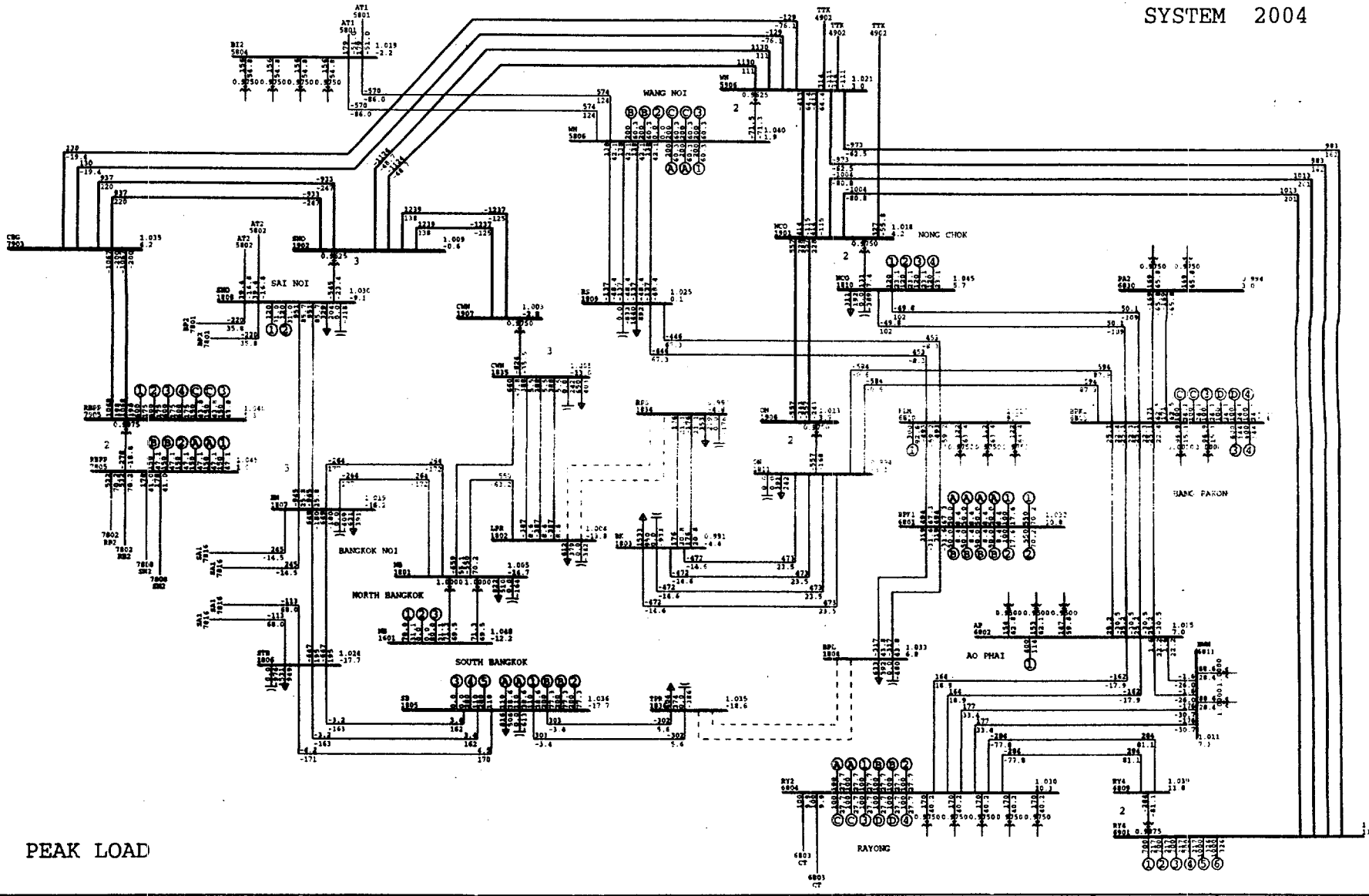


PEAK LOAD

System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2003	IPPs in the eastern area (With 4 x 700 + 1,000 MW at Rayong 4 ; 500 kv Rayong 4 -Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts)	CASE LF - P03E

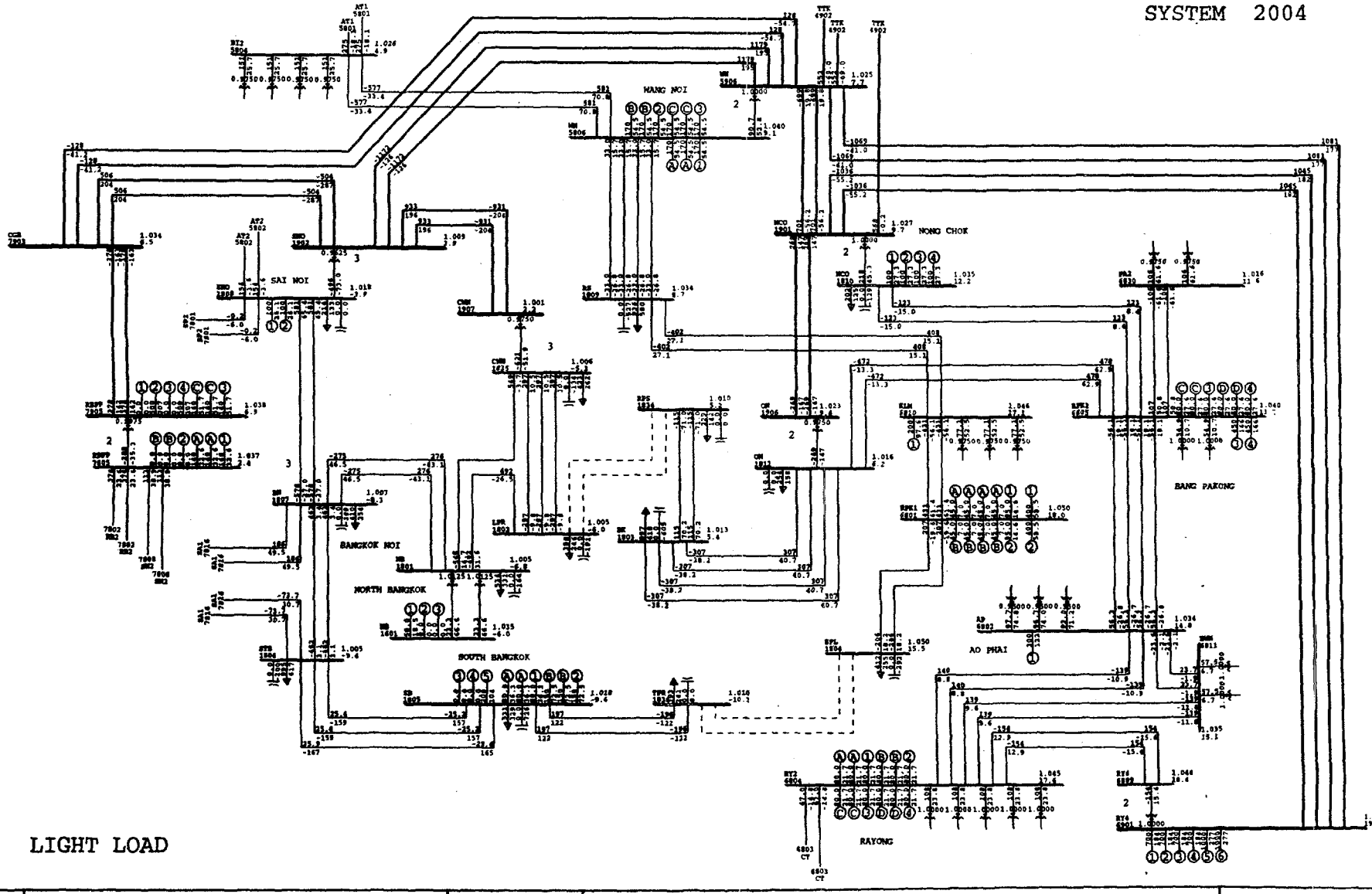


System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2003	IPPs in the eastern area (With 4 x 700 + 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L03E



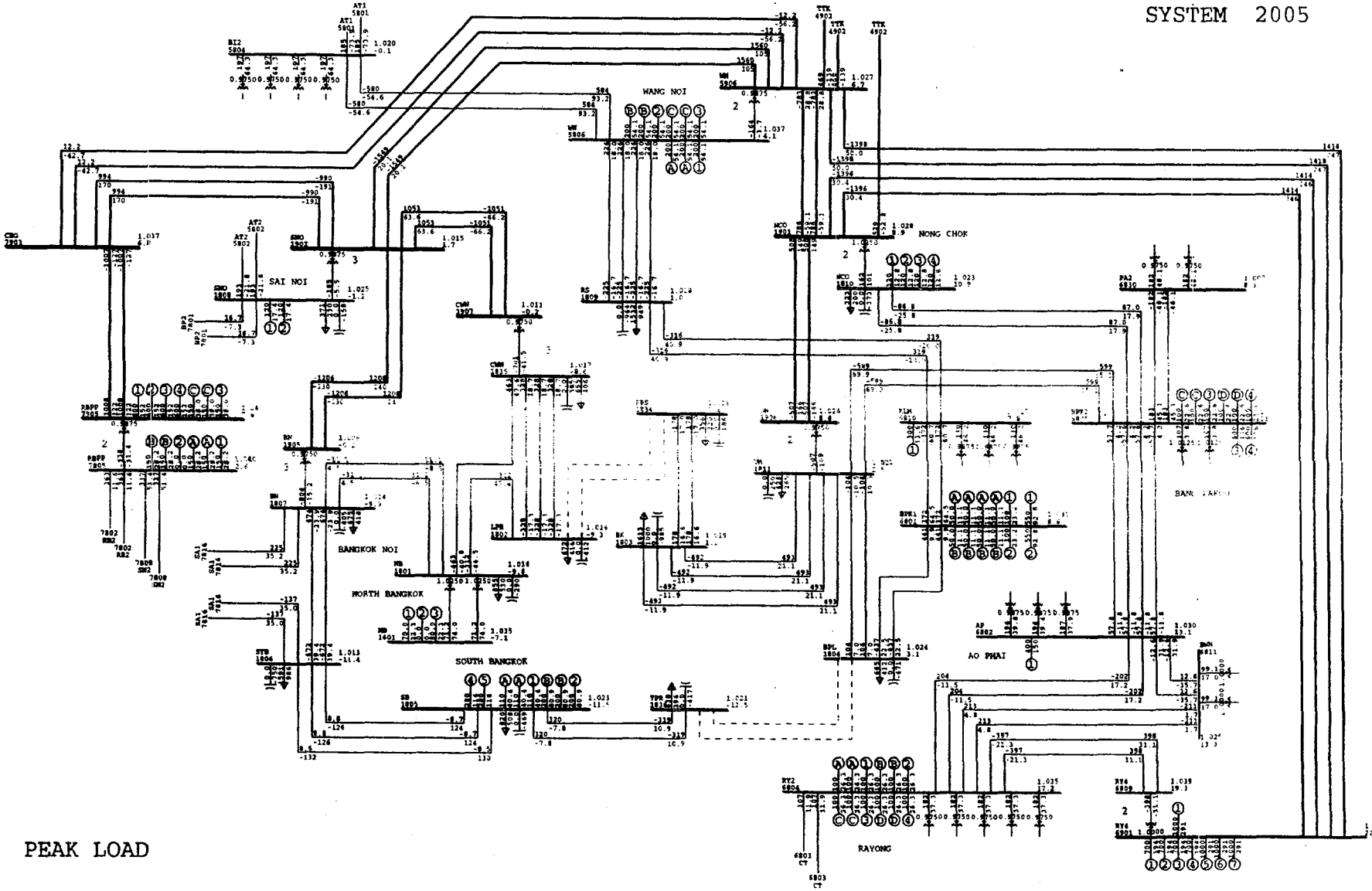
	System Planning Dept. , Load Jun 94 , PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2004	IPPs in the eastern area (With 4 x 700 + 2 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4.- Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts)	CASE LF - P04E

SYSTEM 2004

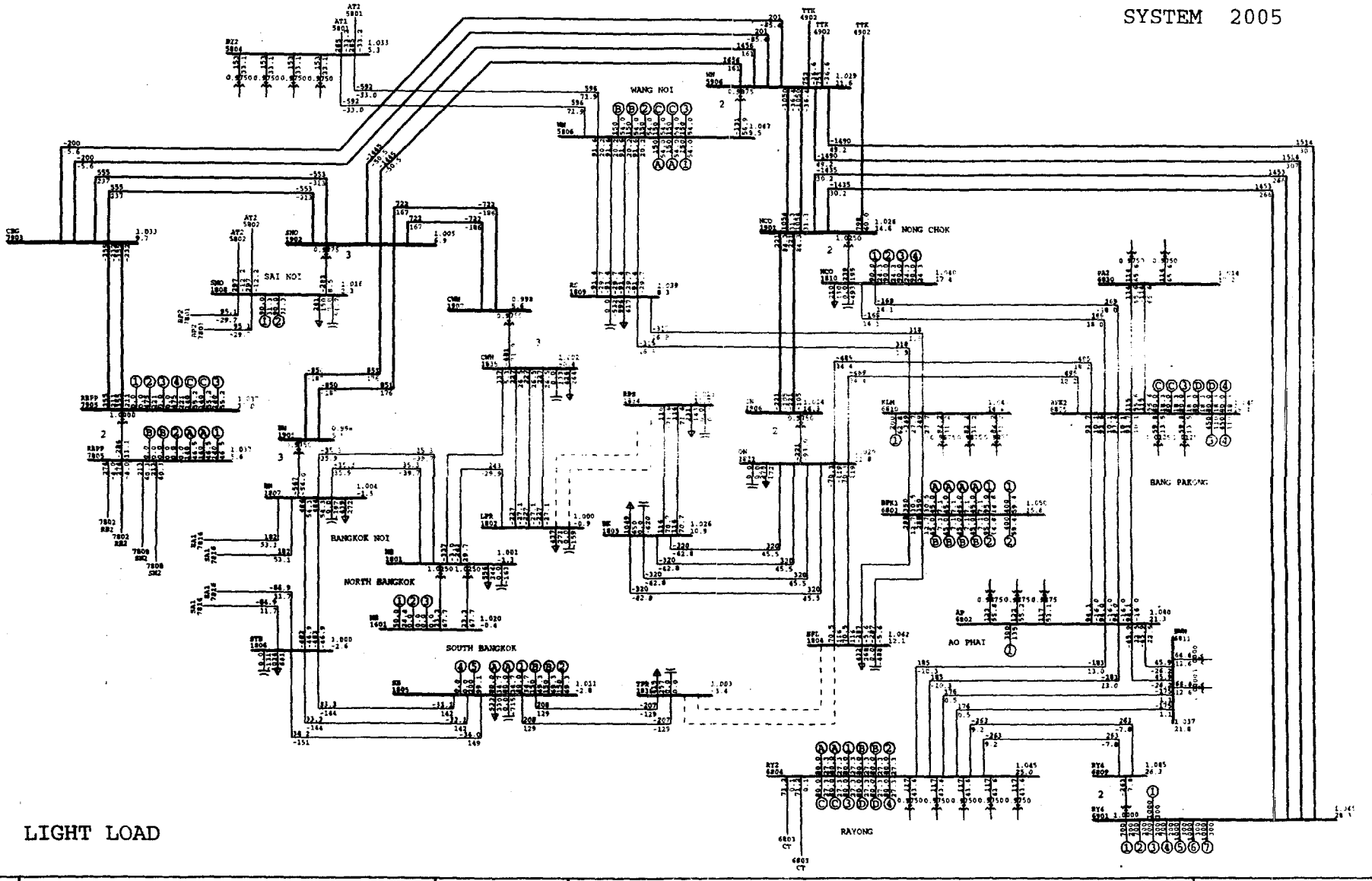


LIGHT LOAD

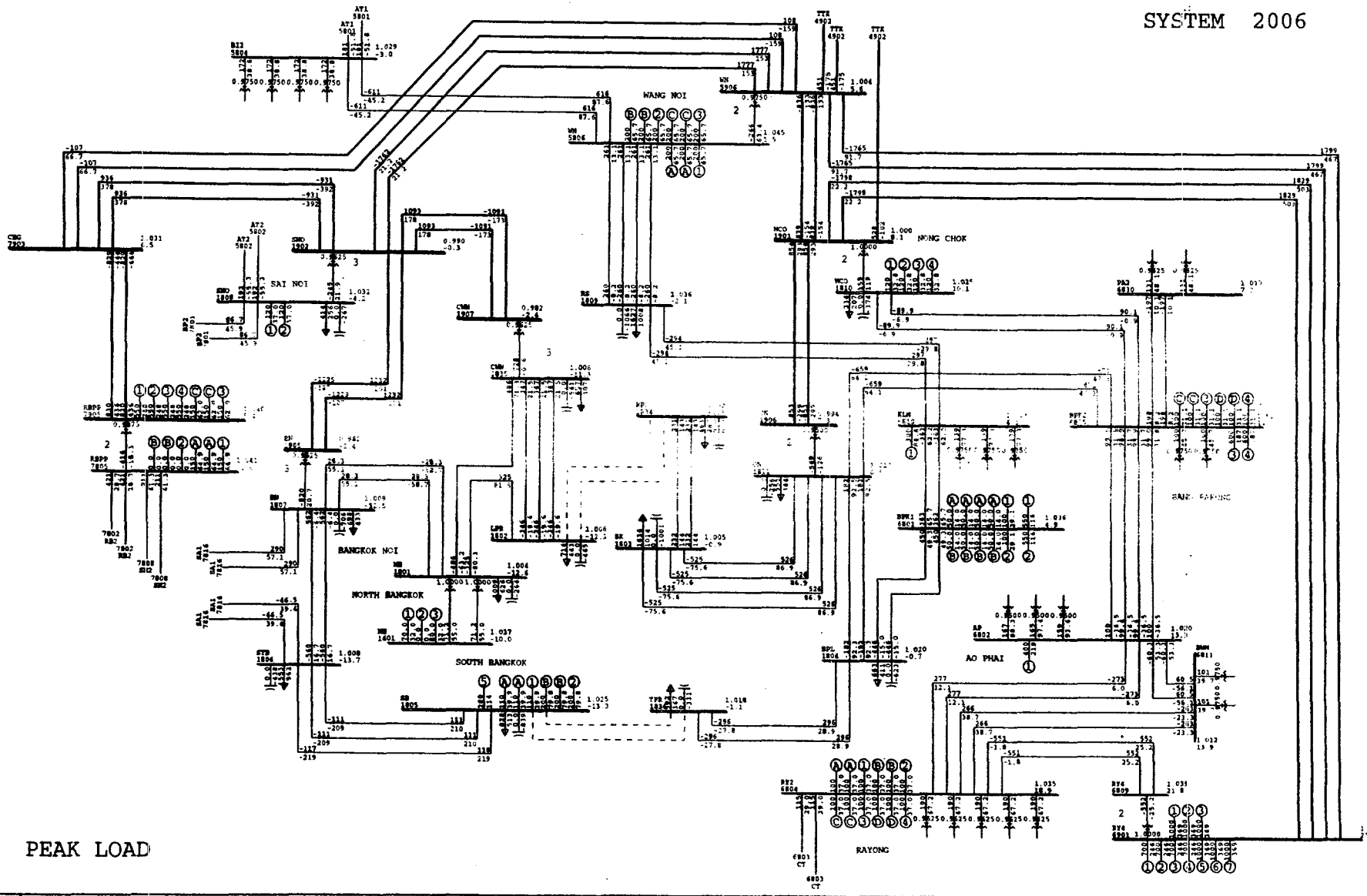
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2004	IPPs in the eastern area (With 4 x 700 + 2 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L04E



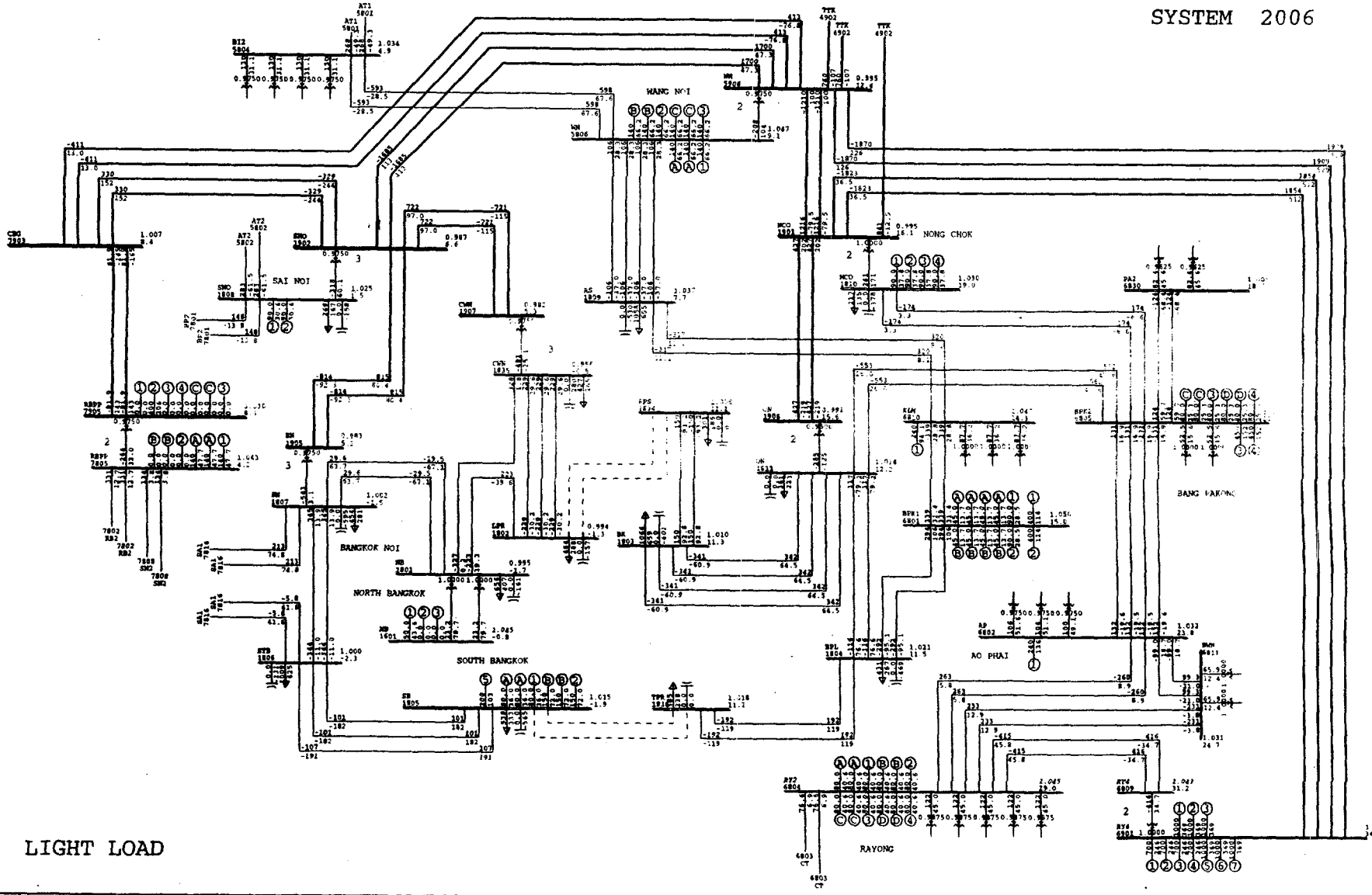
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2005	IPPs in the eastern area (With 4 x 700 + 4 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P05E



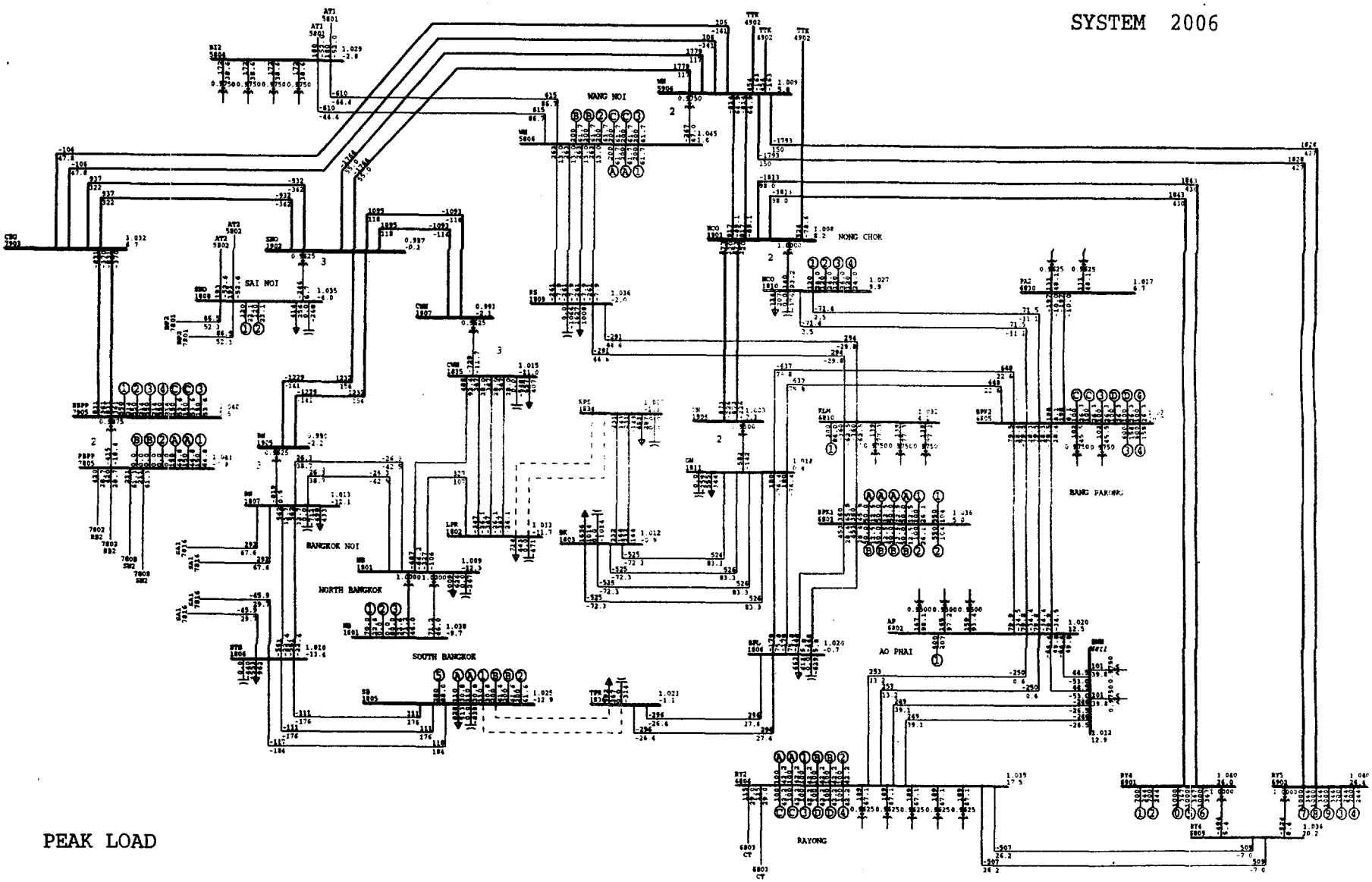
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2005	IPPs in the eastern area (With 4 x 700 + 4 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L05E



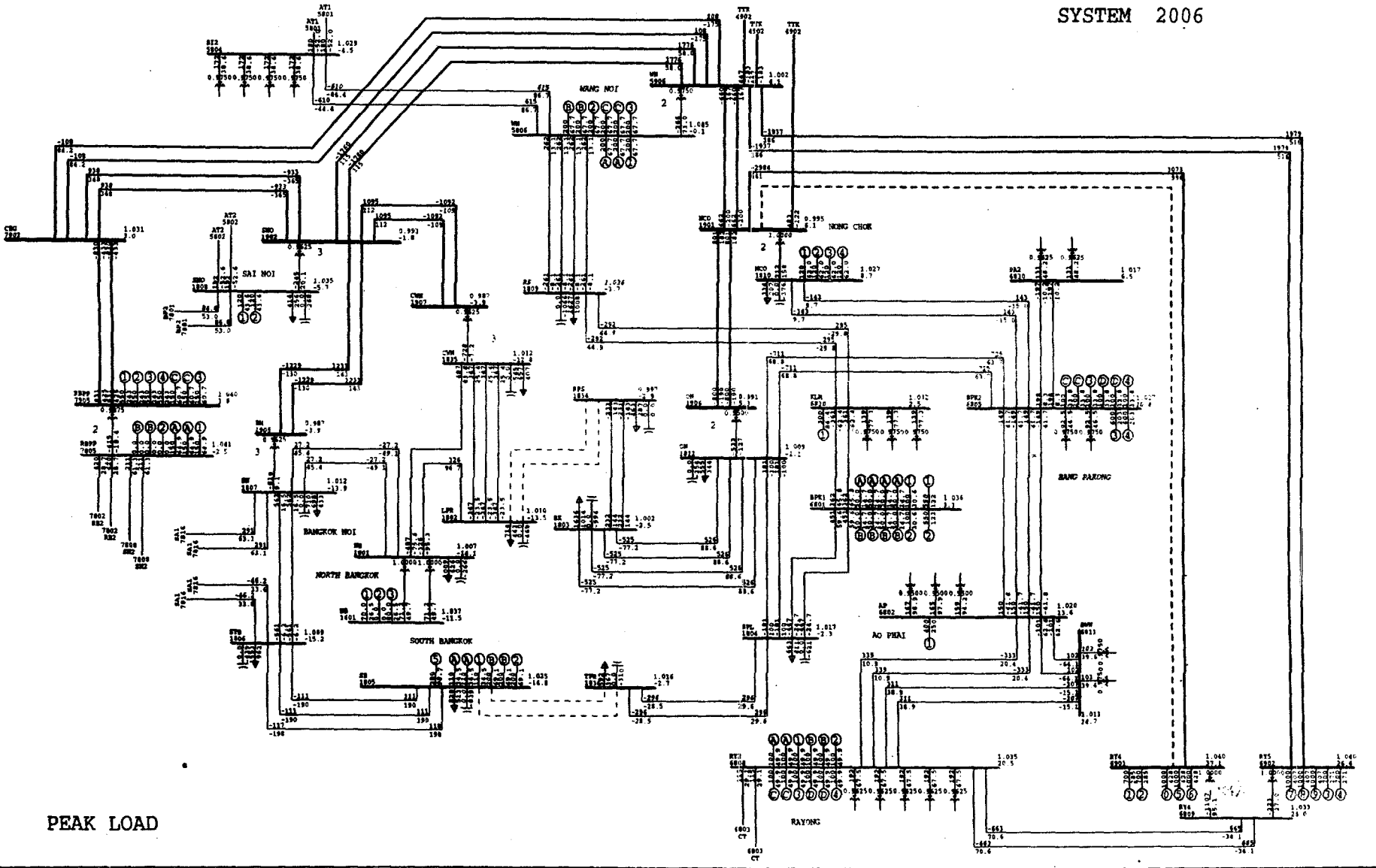
System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P06E 1



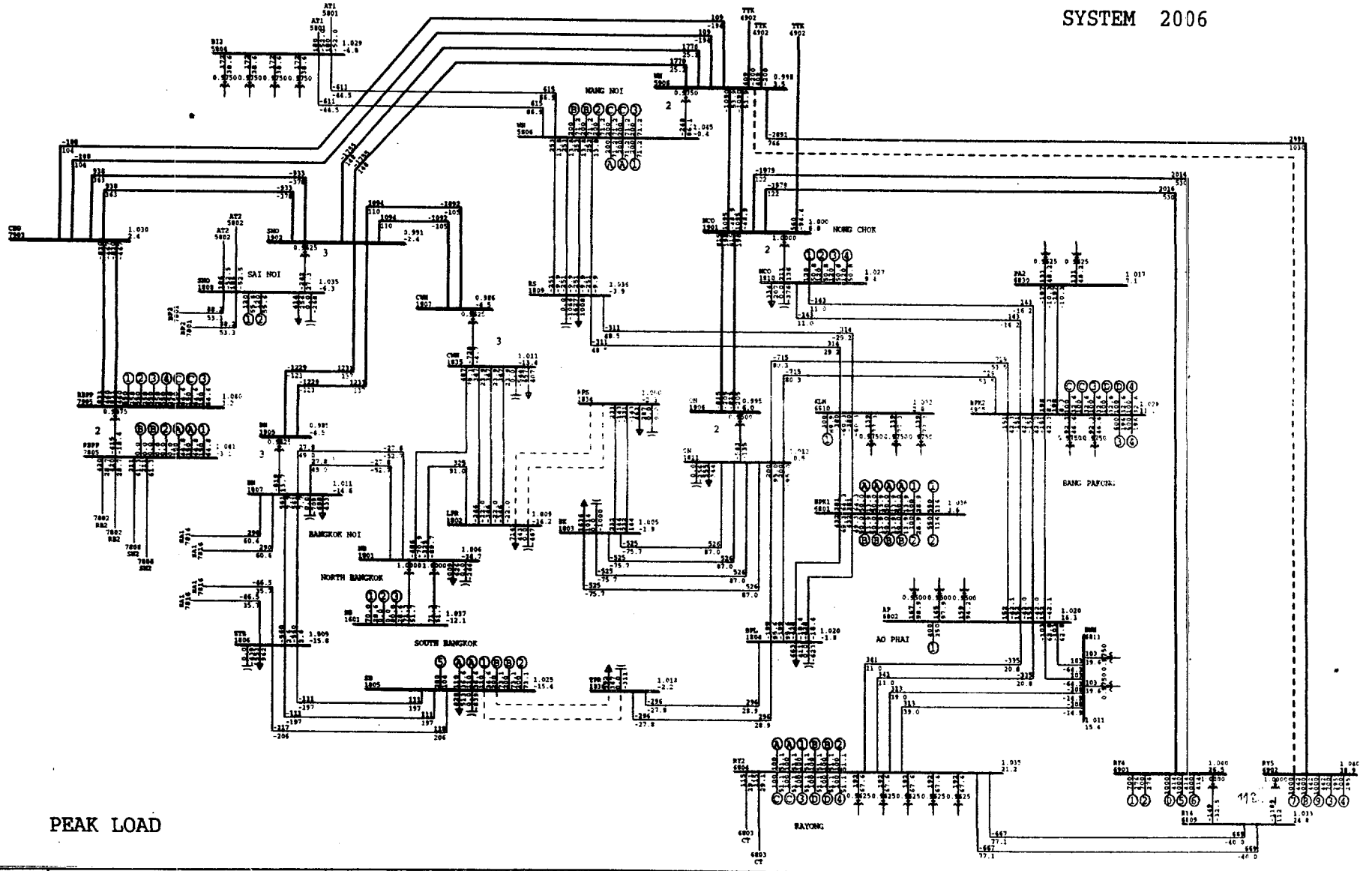
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L06E 1



	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P06E - 2

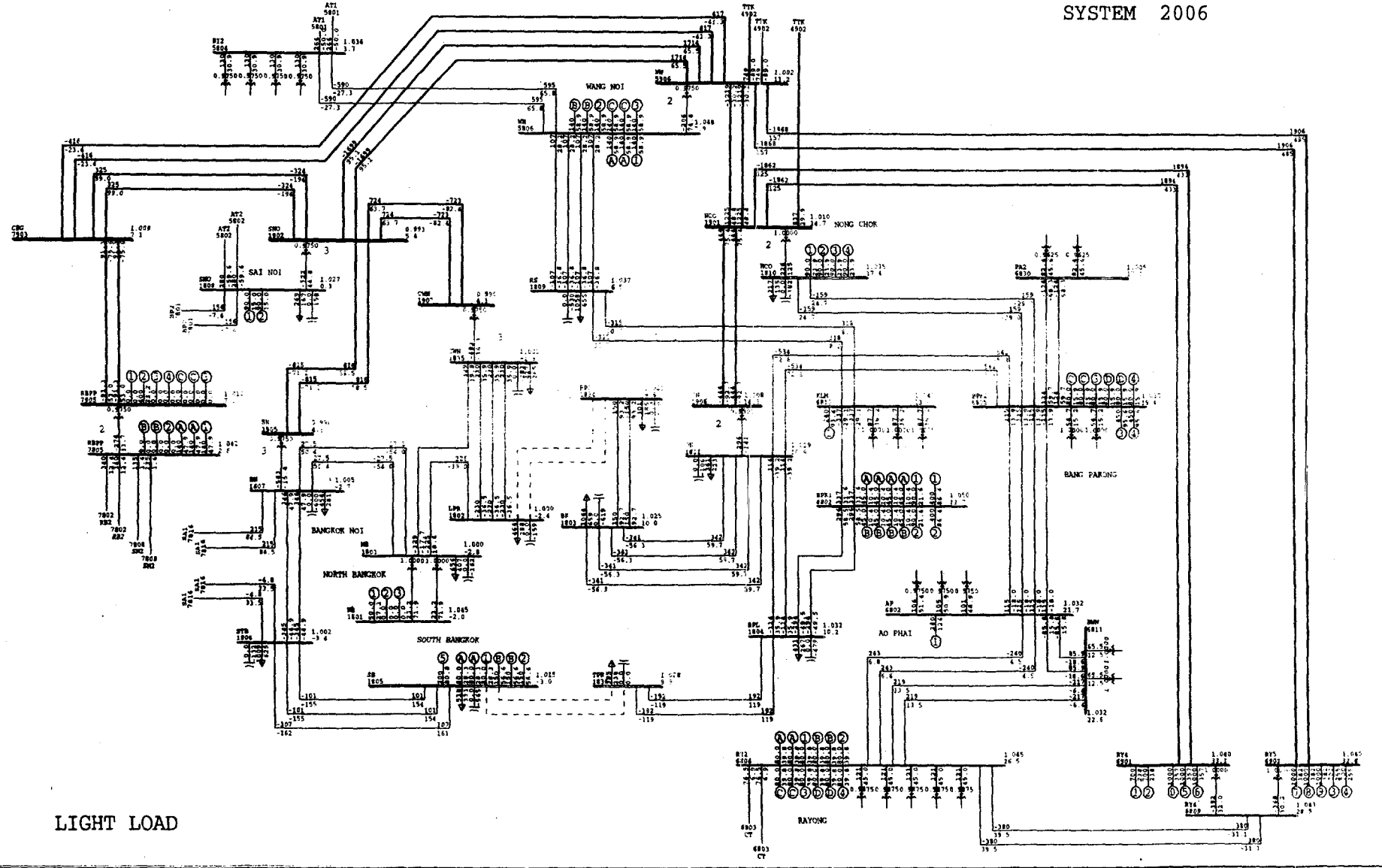


	System Planning Dept., Load Jun 94', PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P06E - 3



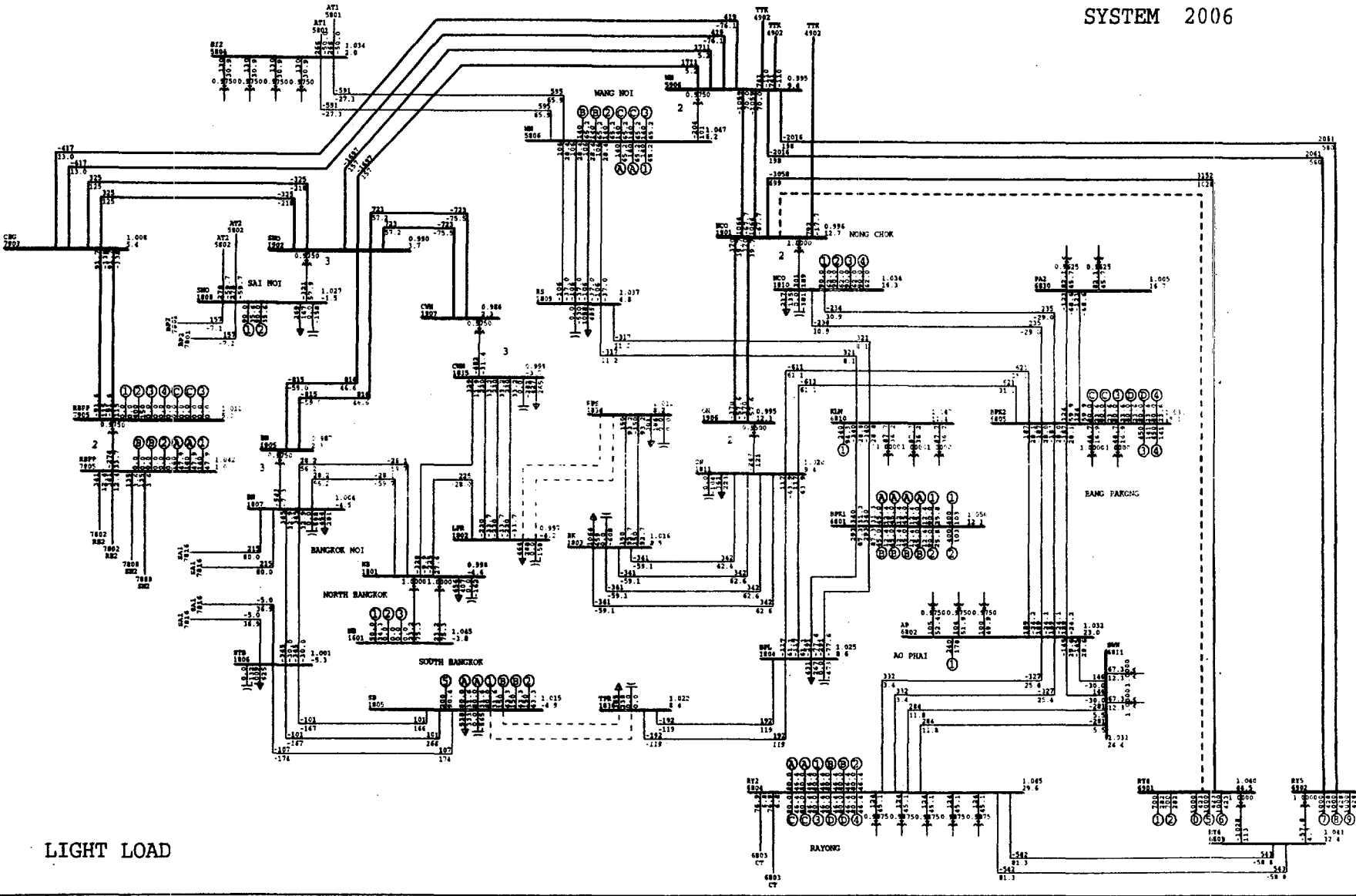
	System Planning Dept., Load Jun 94, PDP 95-01 500 KV Transmission System Project For IPPs	Peak Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P06E - 4

SYSTEM 2006

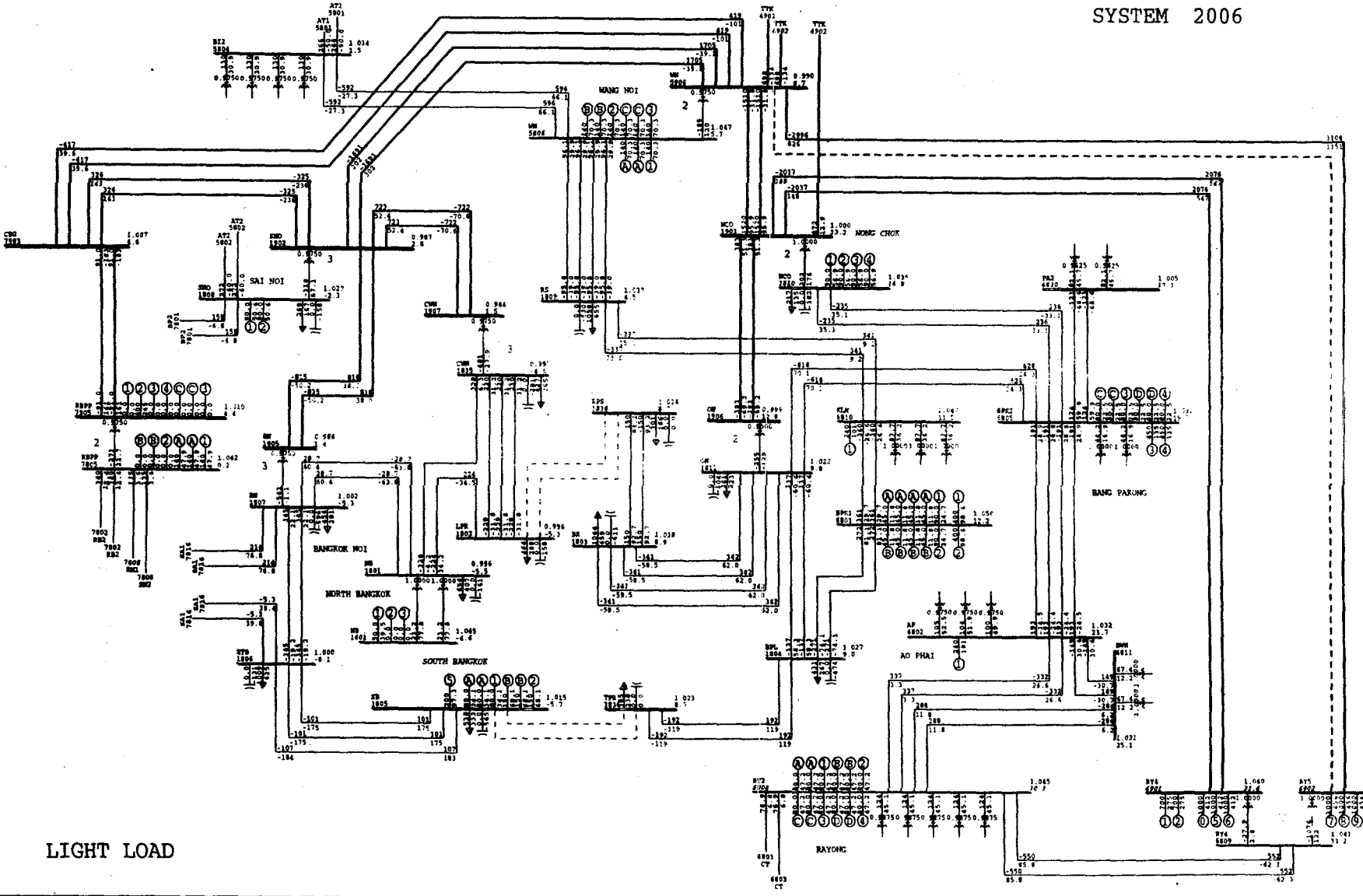


LIGHT LOAD

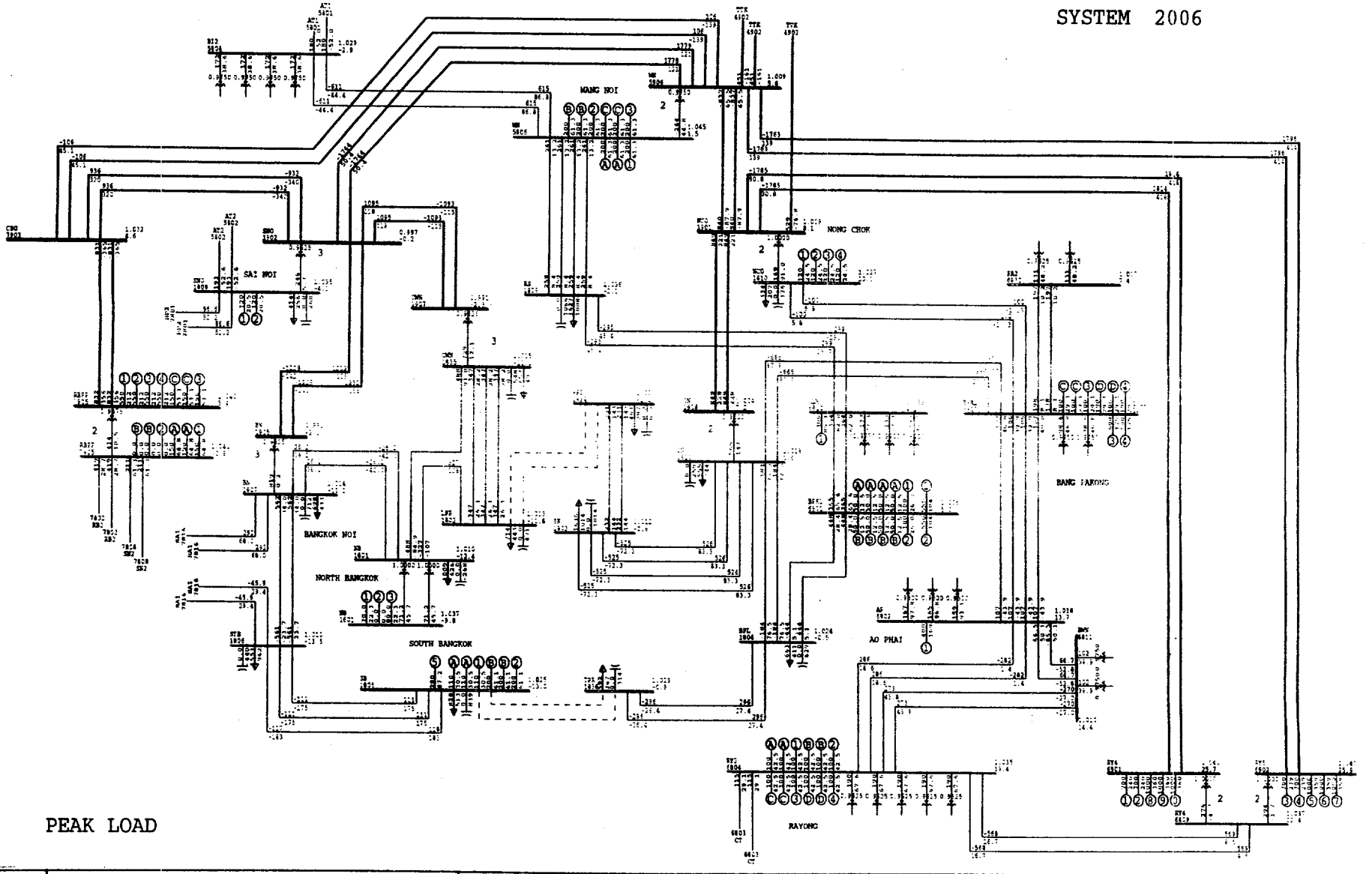
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4.; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L06E - 2



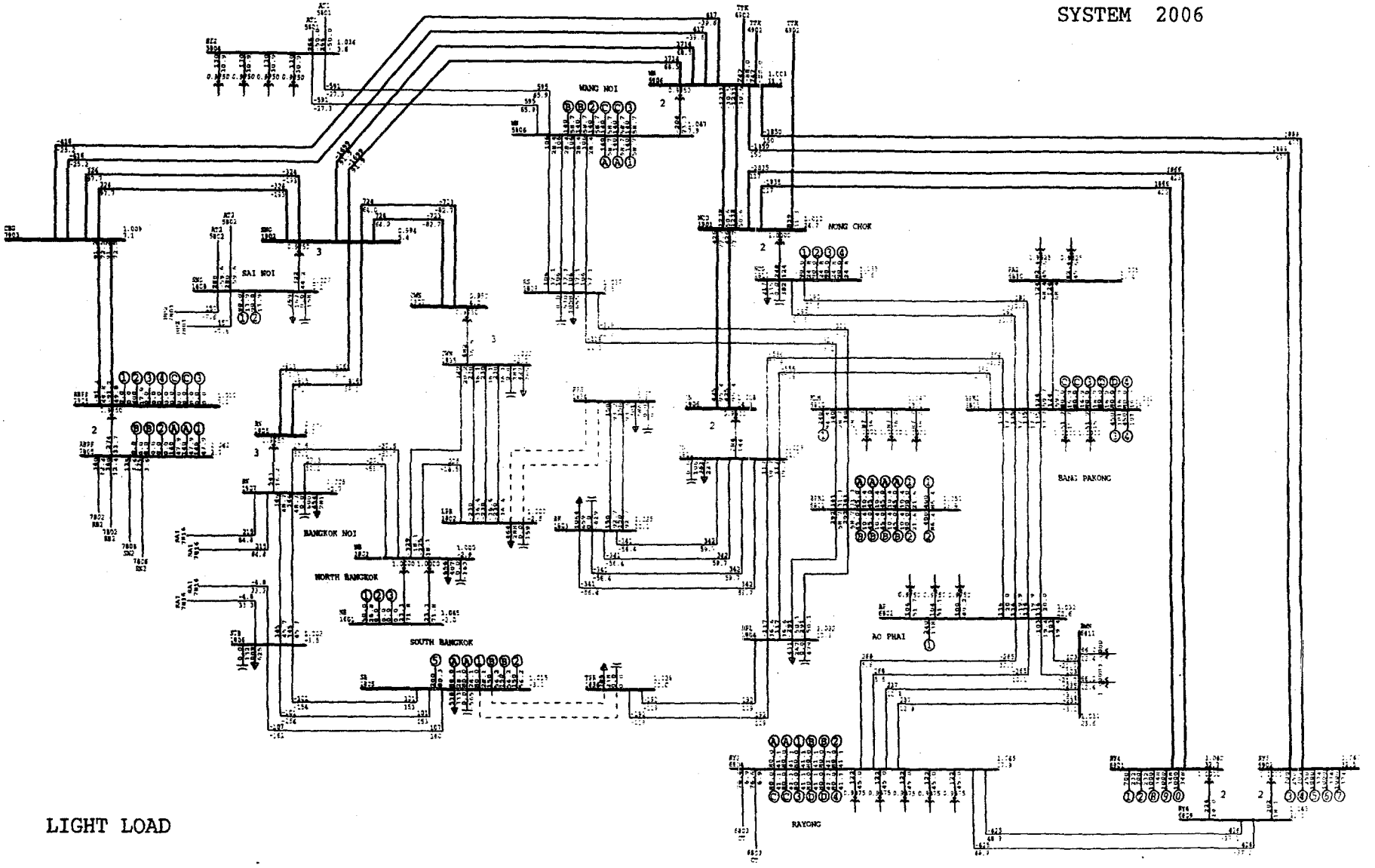
	System Planning Dept. , Load Jun 94 , PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L06E - 3



	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Light Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L06E - 4

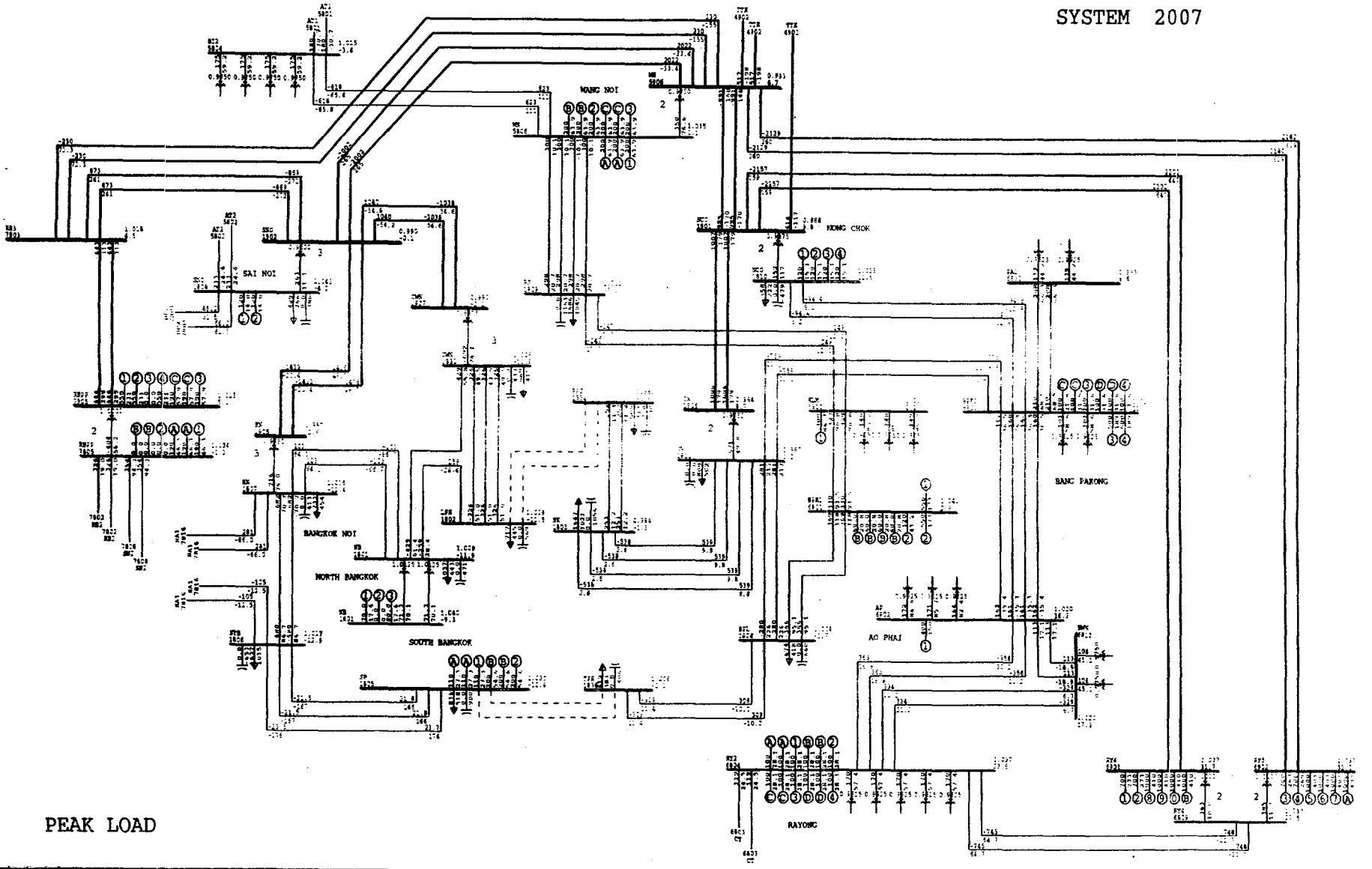


System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P06E



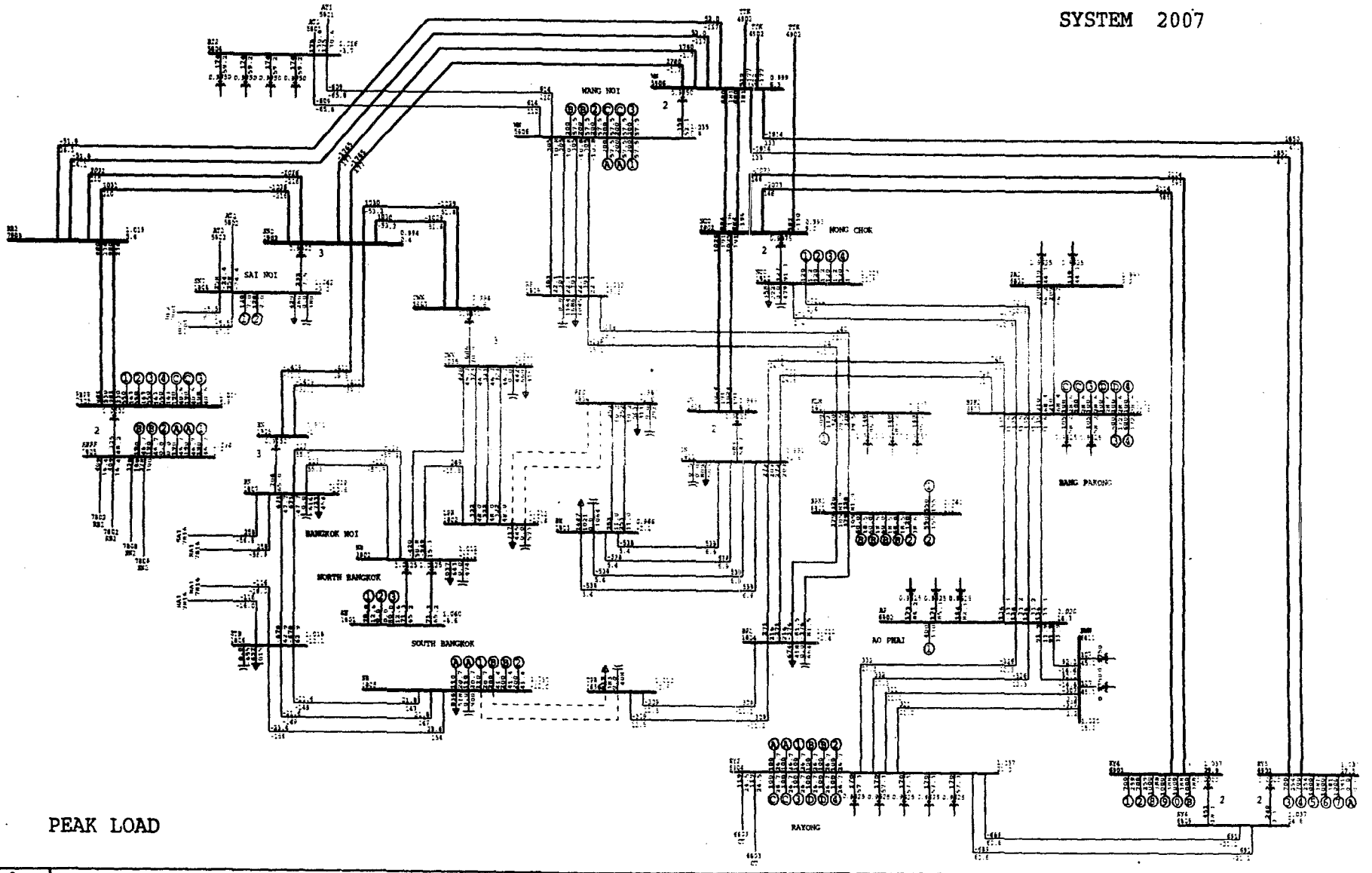
System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	**Light Load 2006**	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - L06E

SYSTEM 2007



PEAK LOAD

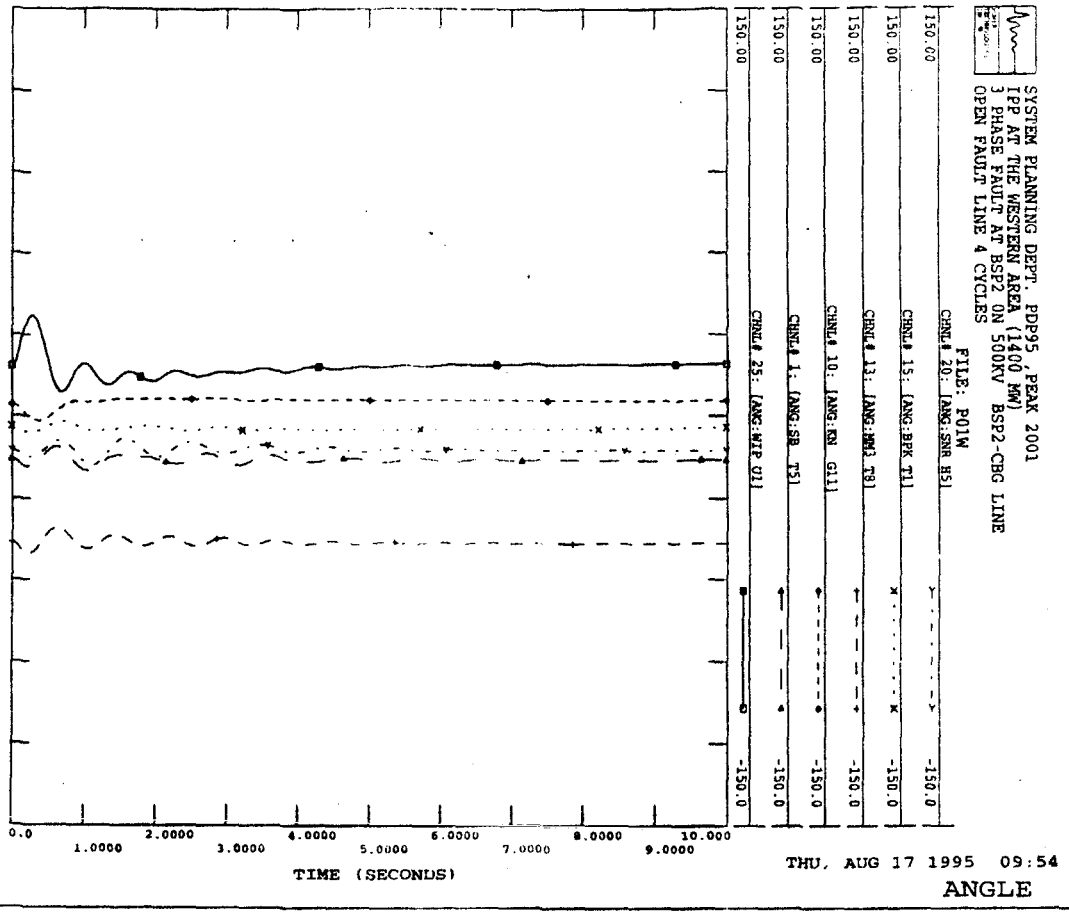
	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	Peak Load 2007	IPPs in the eastern area (With 4 x 700 + 8 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P07E - 1

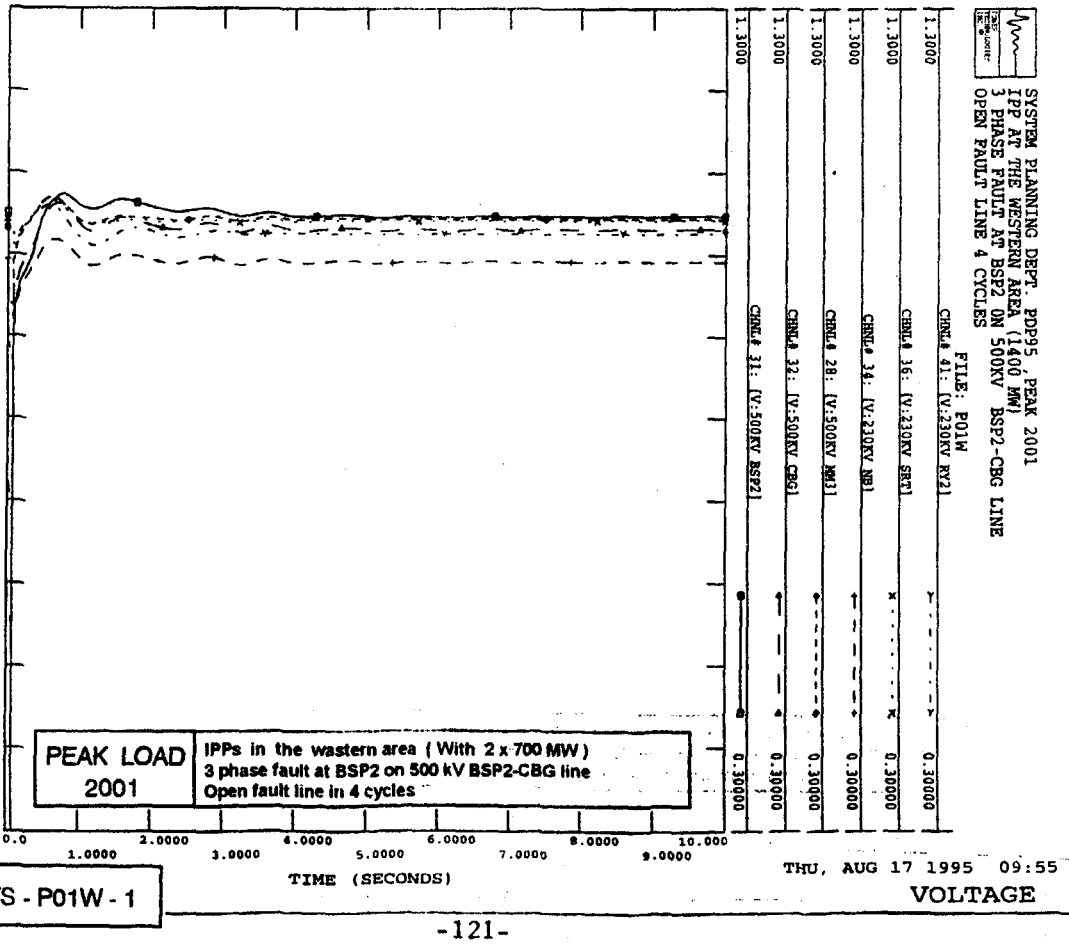


	System Planning Dept., Load Jun 94, PDP 95 - 01 *500 KV Transmission System Project For IPPs*	**Peak Load 2007**	IPPs in the eastern area (With 4 x 700 + 7 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE LF - P07E - 2

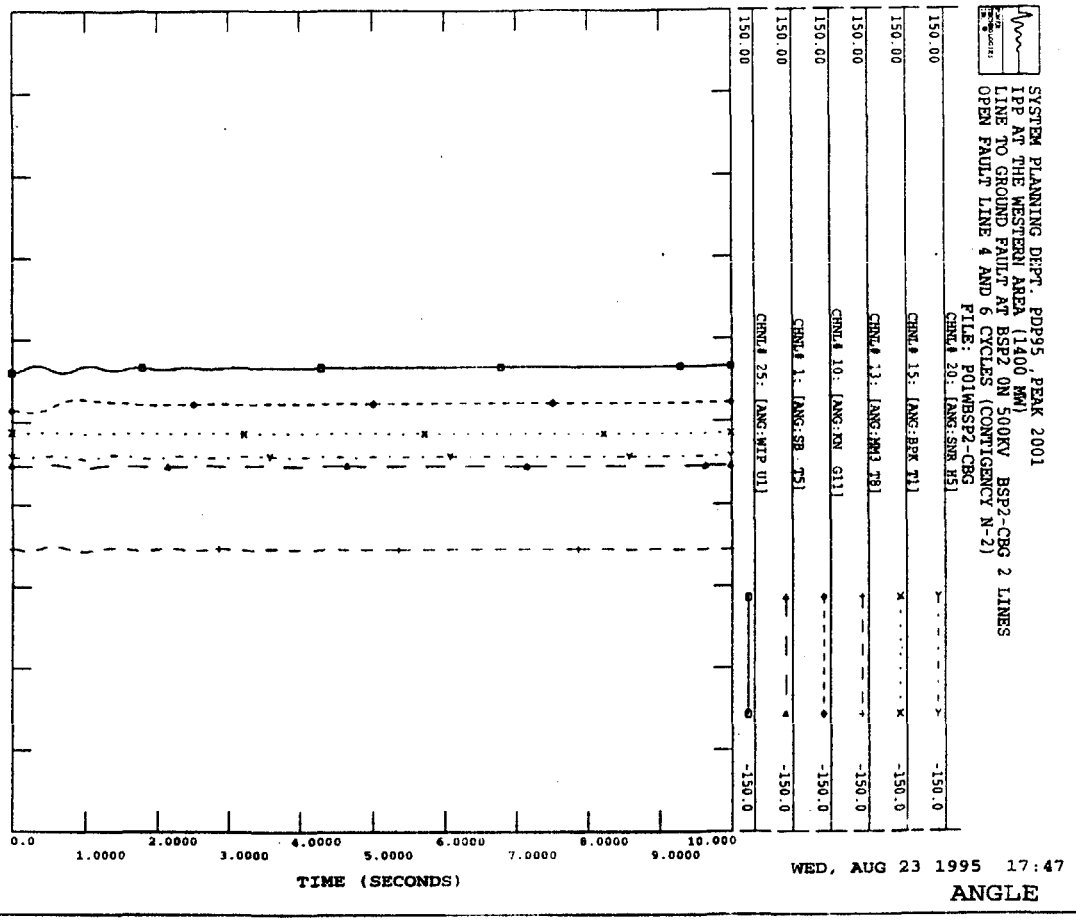
APPENDIX 3

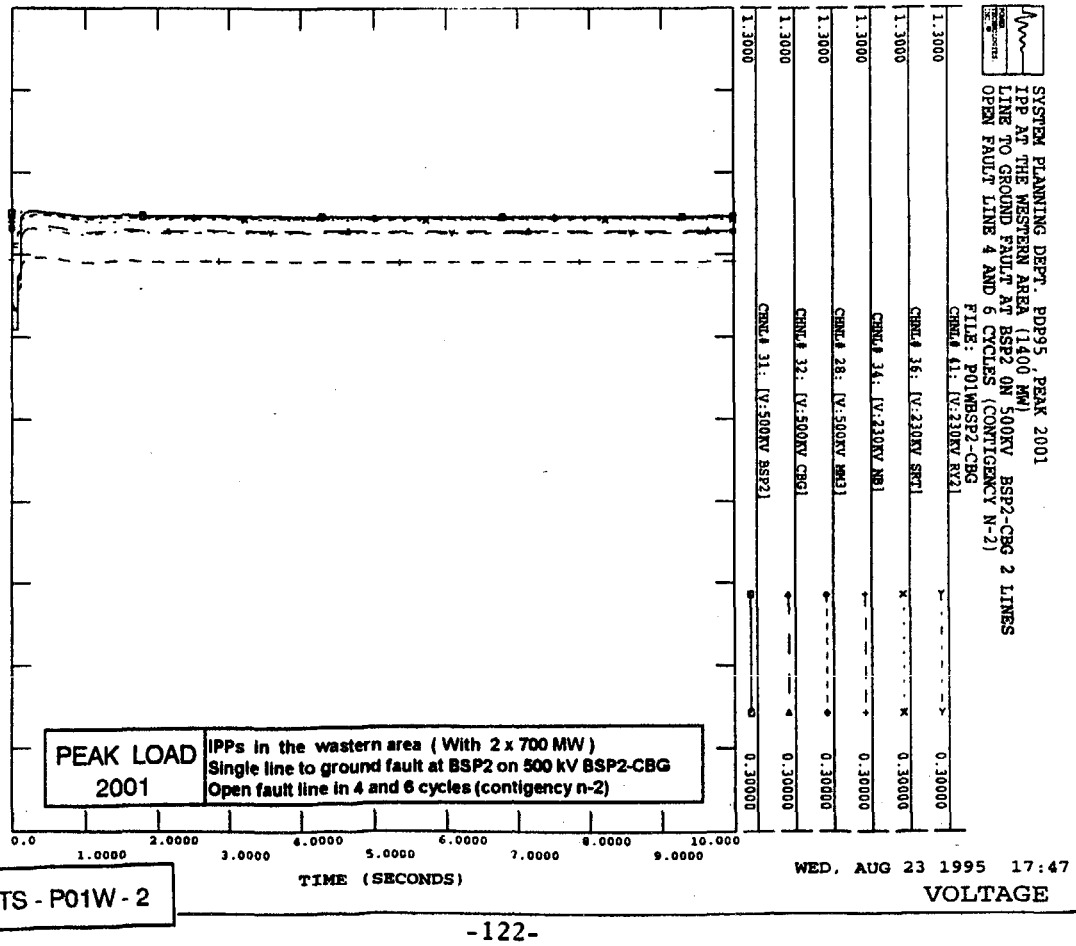
DYNAMIC STABILITY CURVES



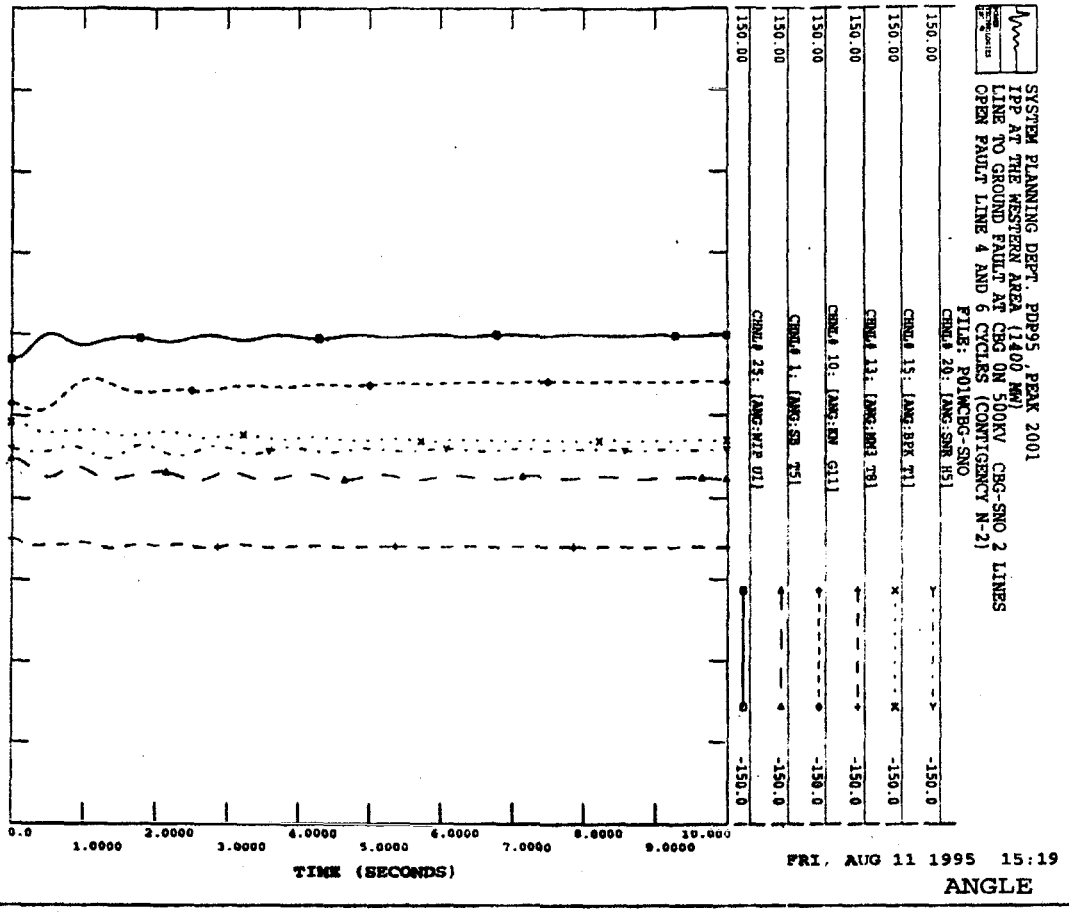


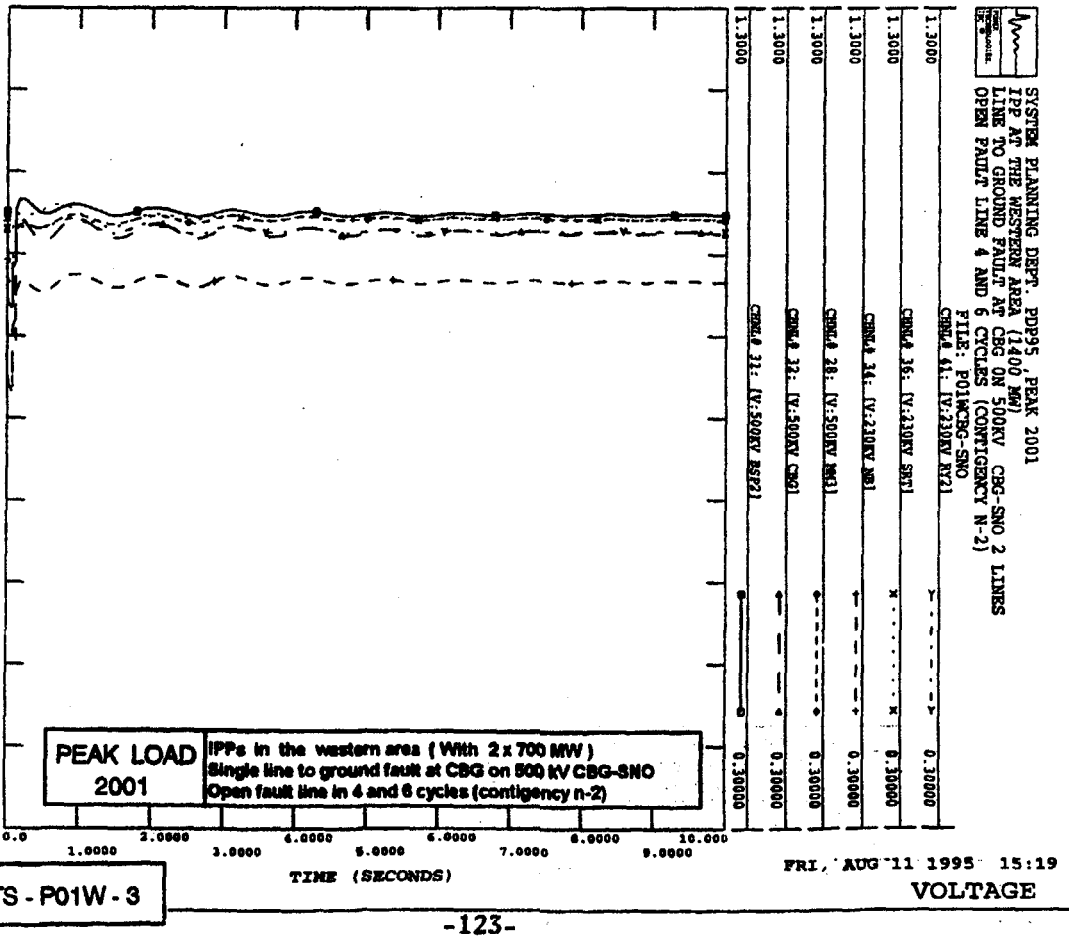
CASE TS - P01W - 1



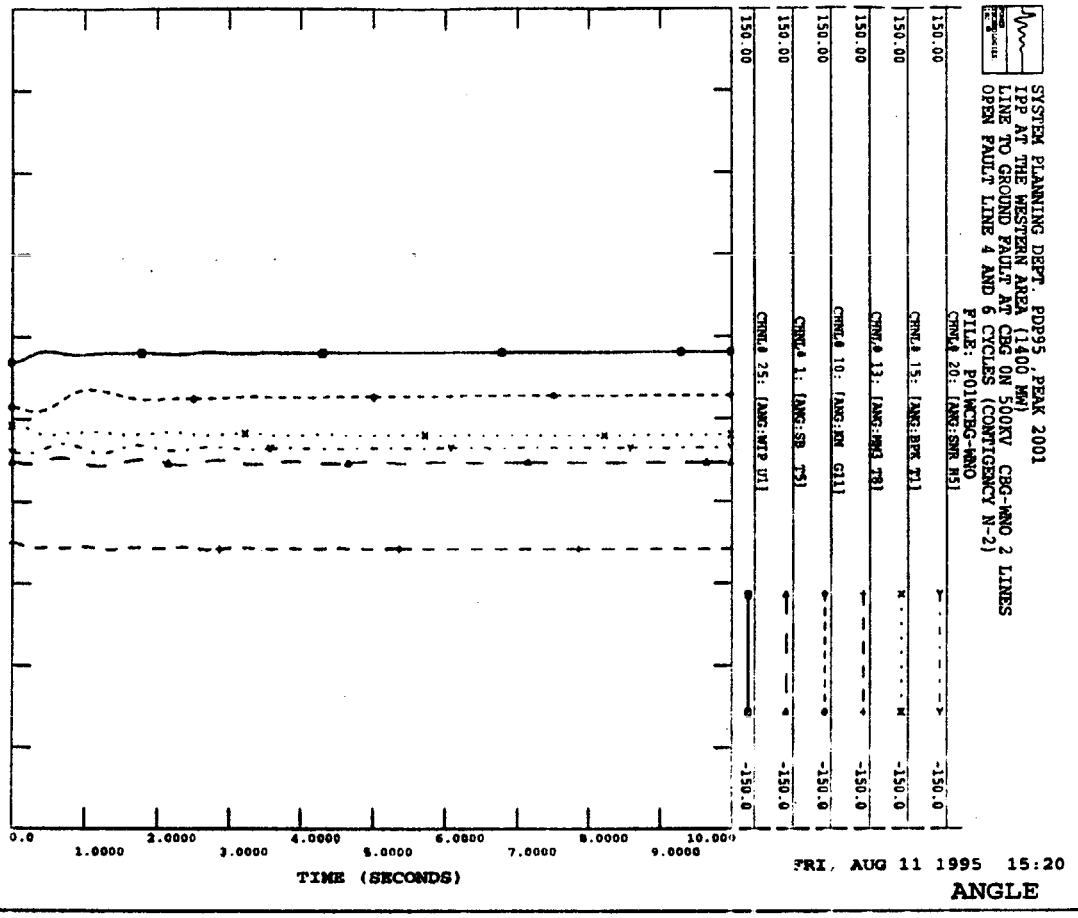


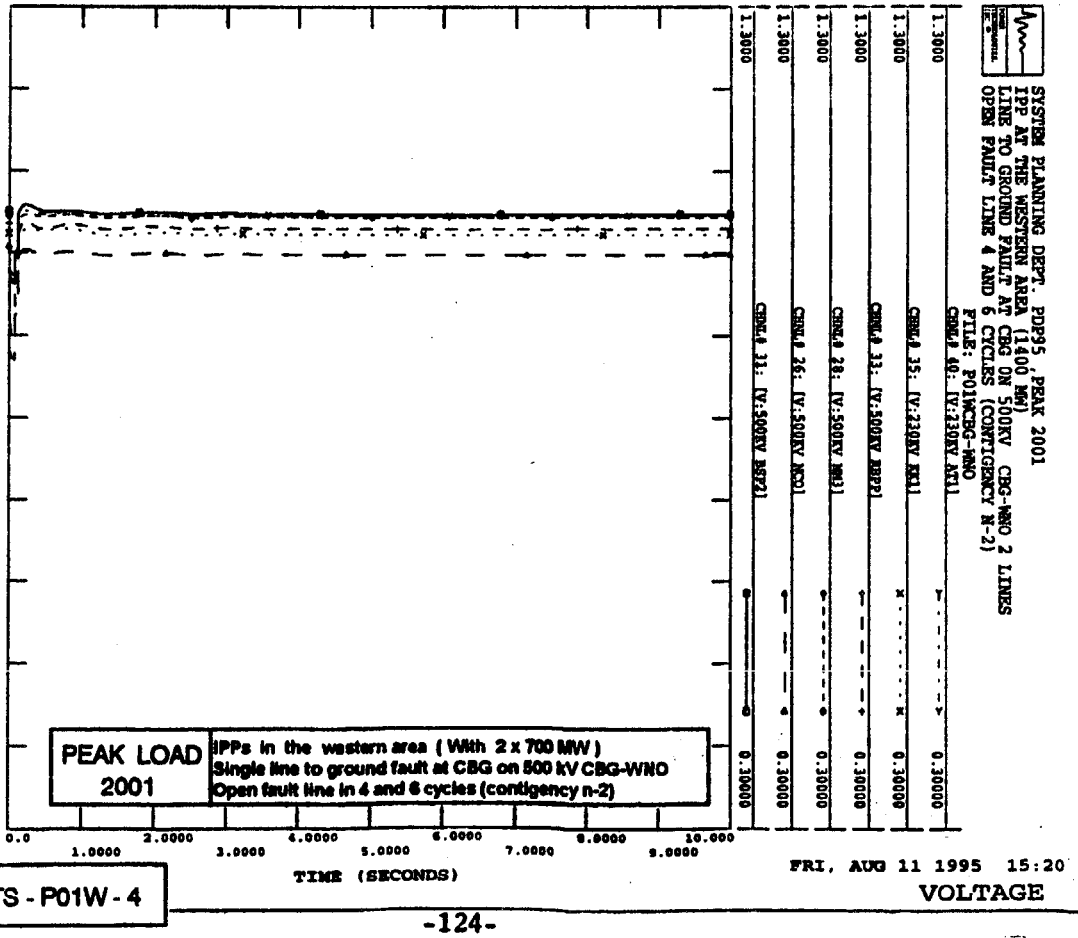
CASE TS - P01W - 2



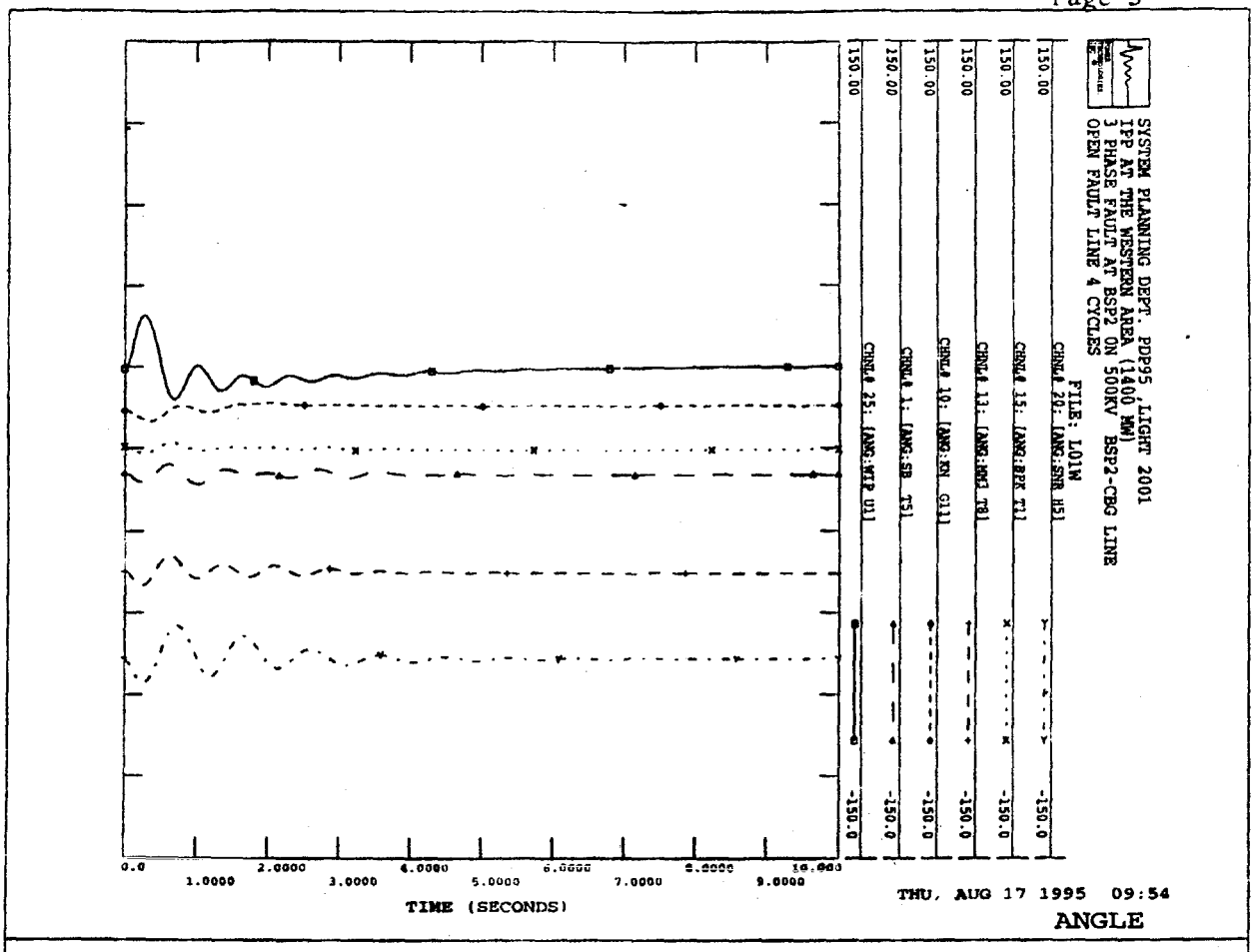


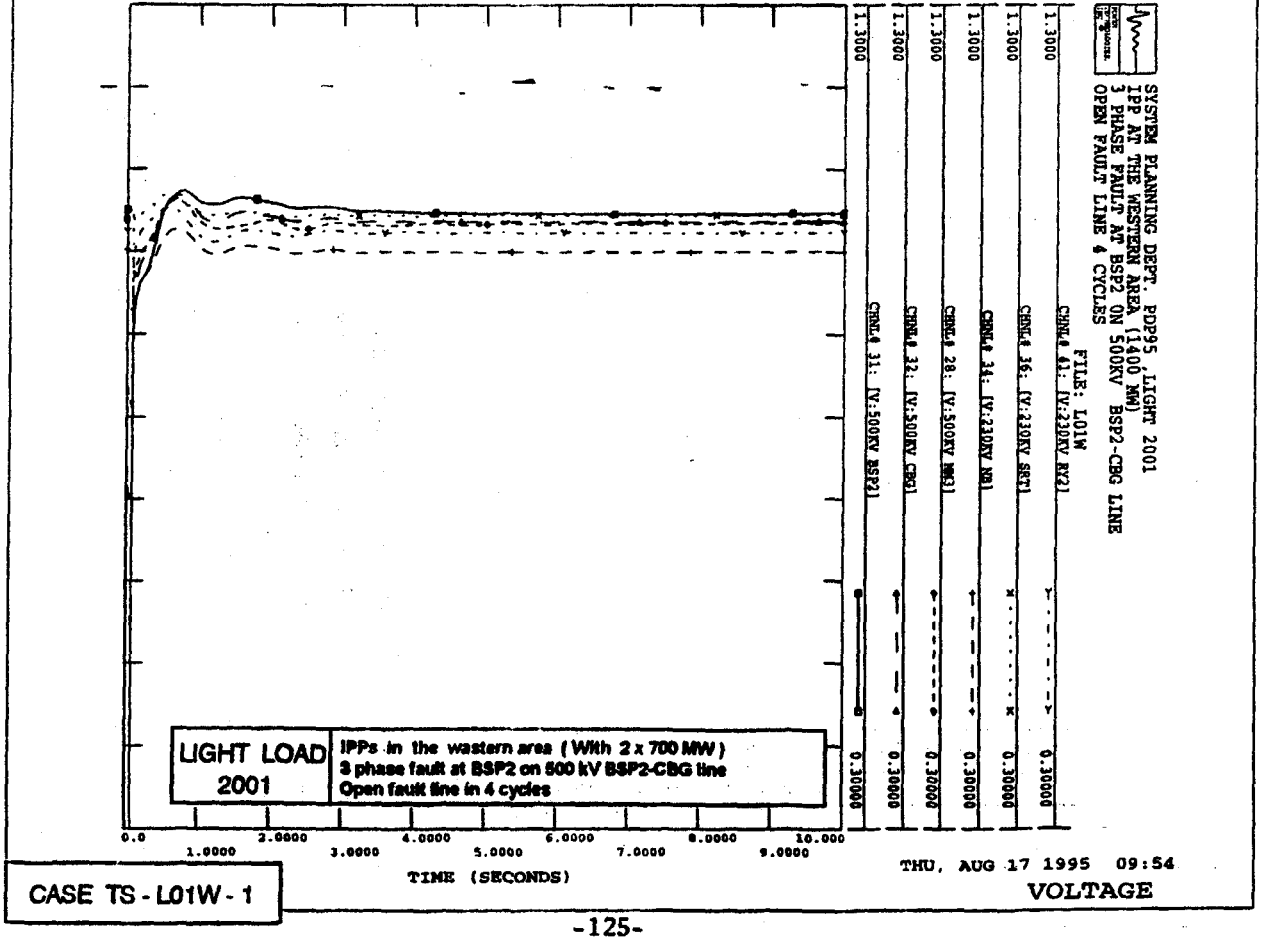
CASE TS - P01W - 3

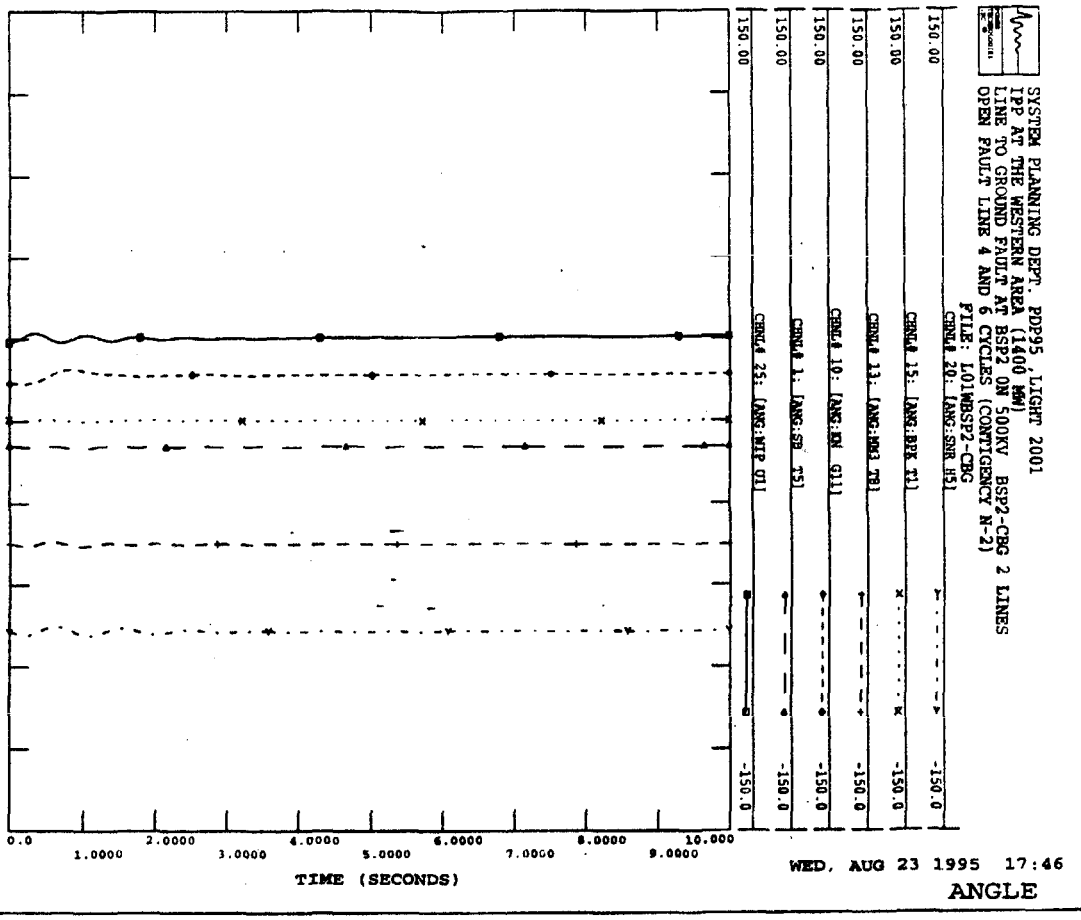


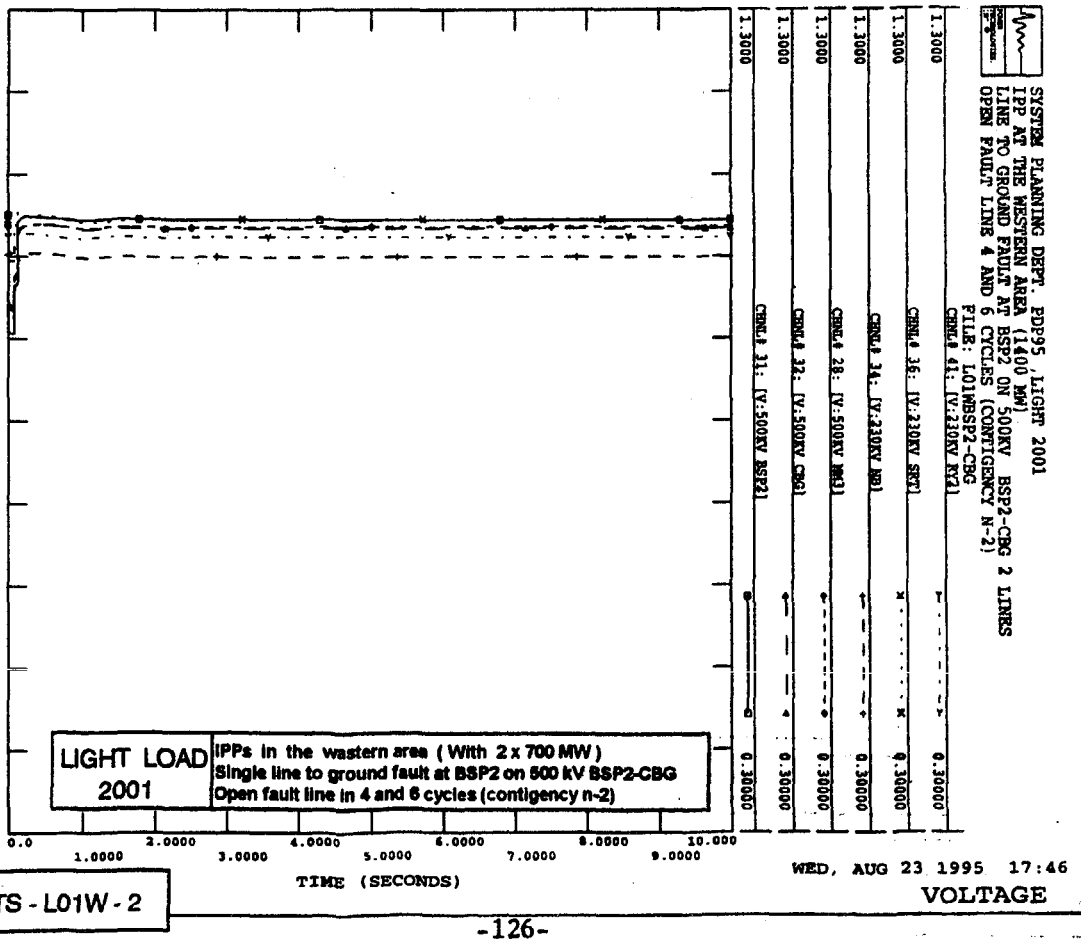


CASE TS - P01W - 4

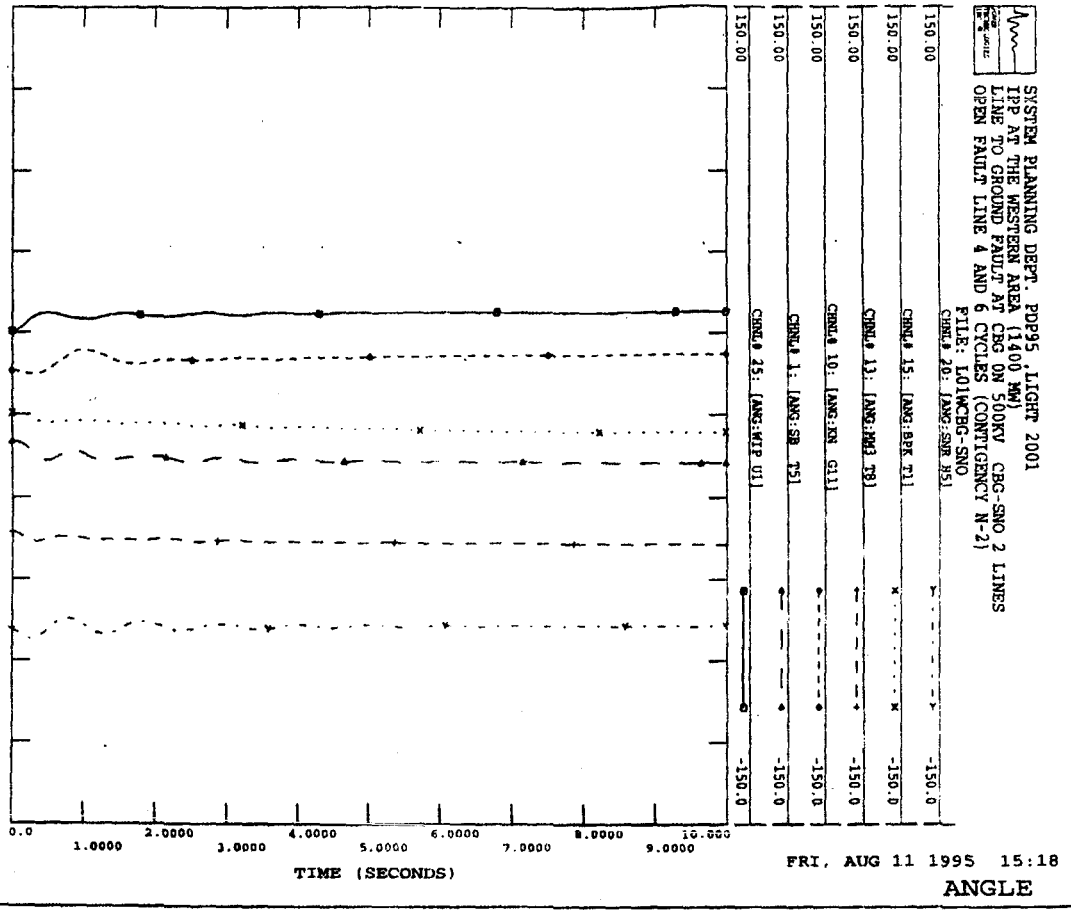

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2001
IPP AT THE WESTERN AREA (1400 MW)
3 PHASE FAULT AT BSP2 ON 500KV BSP2-CBG LINE
OPEN FAULT LINE 4 CYCLES
FILE: L01W
CHNL# 20: [ANG:SNR H5]
CHNL# 15: [ANG:BPK T1]
CHNL# 13: [ANG:MRG T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB T5]
CHNL# 25: [ANG:MIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, AUG 17 1995 09:54
ANGLE

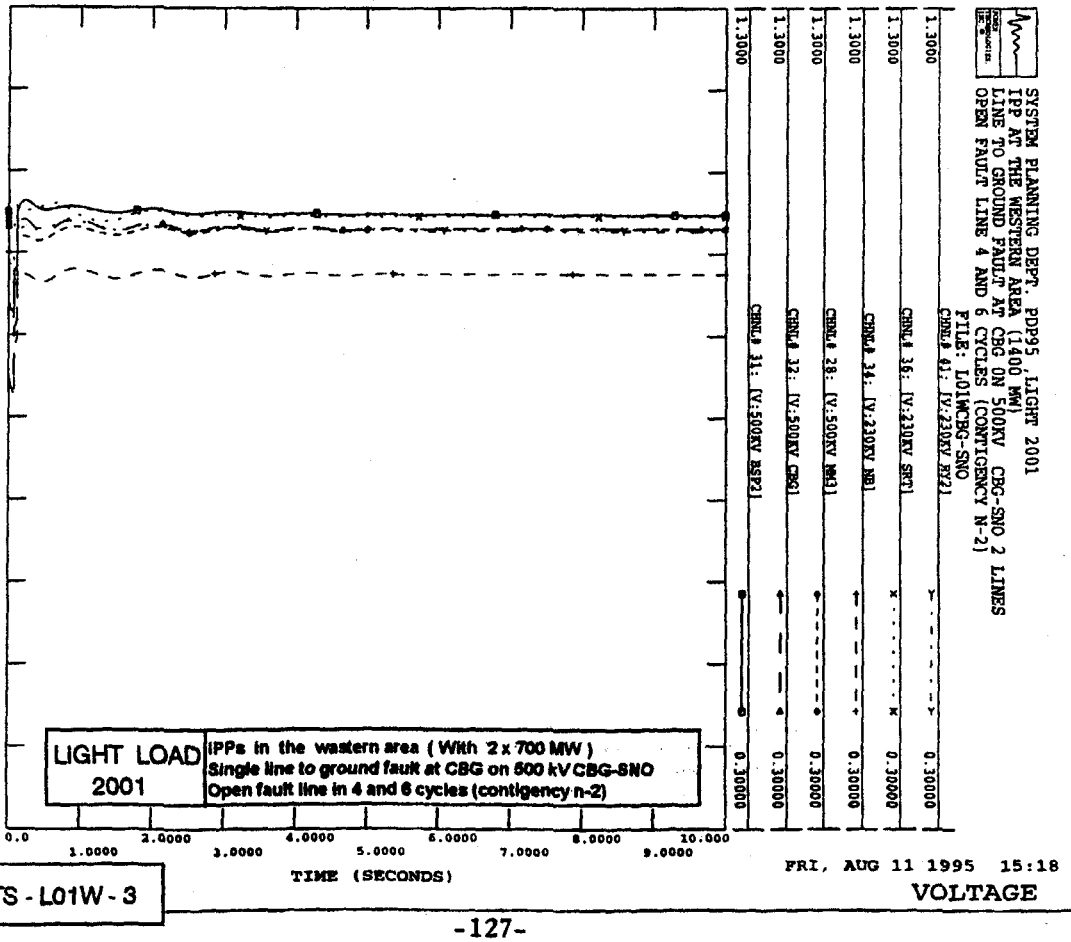

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2001
IPP AT THE WESTERN AREA (1400 MW)
3 PHASE FAULT AT BSP2 ON 500KV BSP2-CBG LINE
OPEN FAULT LINE 4 CYCLES
FILE: L01W
CHNL# 41: [V:230KV RY2]
CHNL# 36: [V:230KV SR1]
CHNL# 34: [V:230KV NR1]
CHNL# 28: [V:500KV MR3]
CHNL# 32: [V:500KV CBG]
CHNL# 33: [V:500KV BSP2]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, AUG 17 1995 09:54
VOLTAGE
LIGHT LOAD
2001
IPPs in the western area (With 2 x 700 MW)
3 phase fault at BSP2 on 500 kV BSP2-CBG line
Open fault line in 4 cycles
CASE TS - L01W - 1



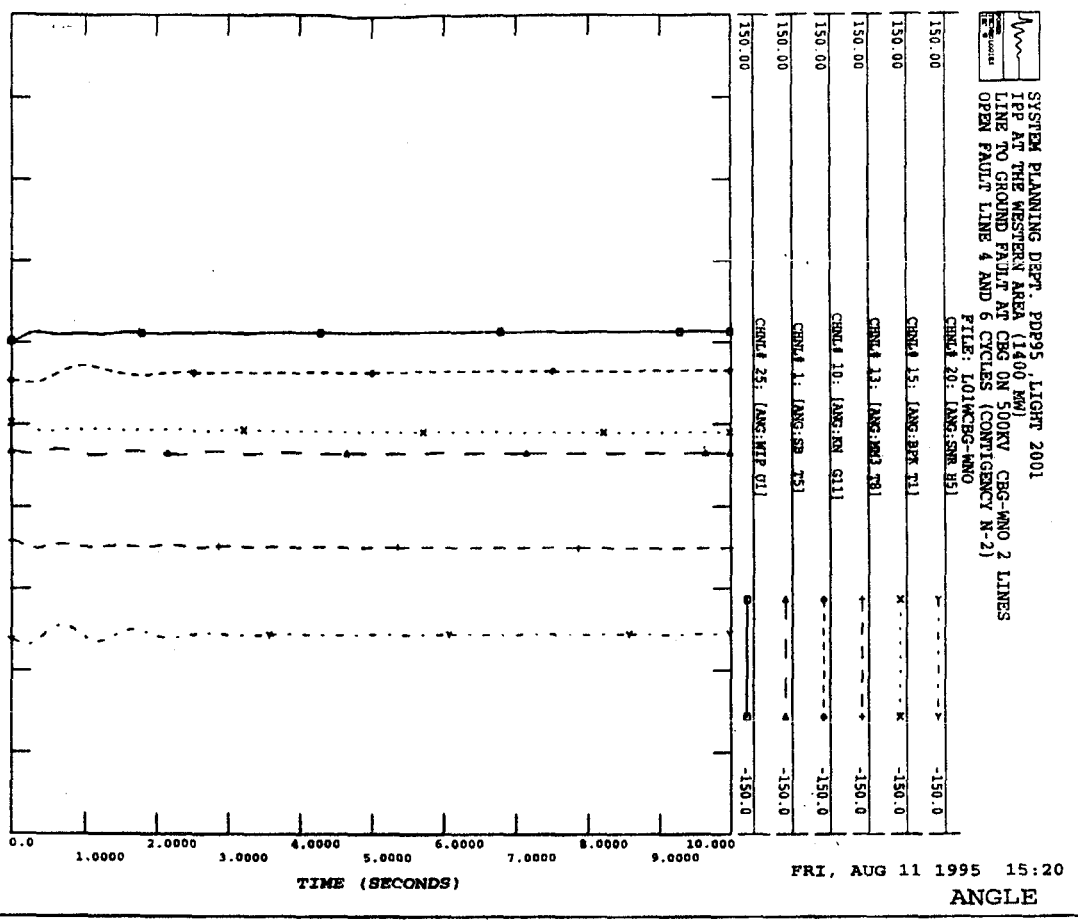


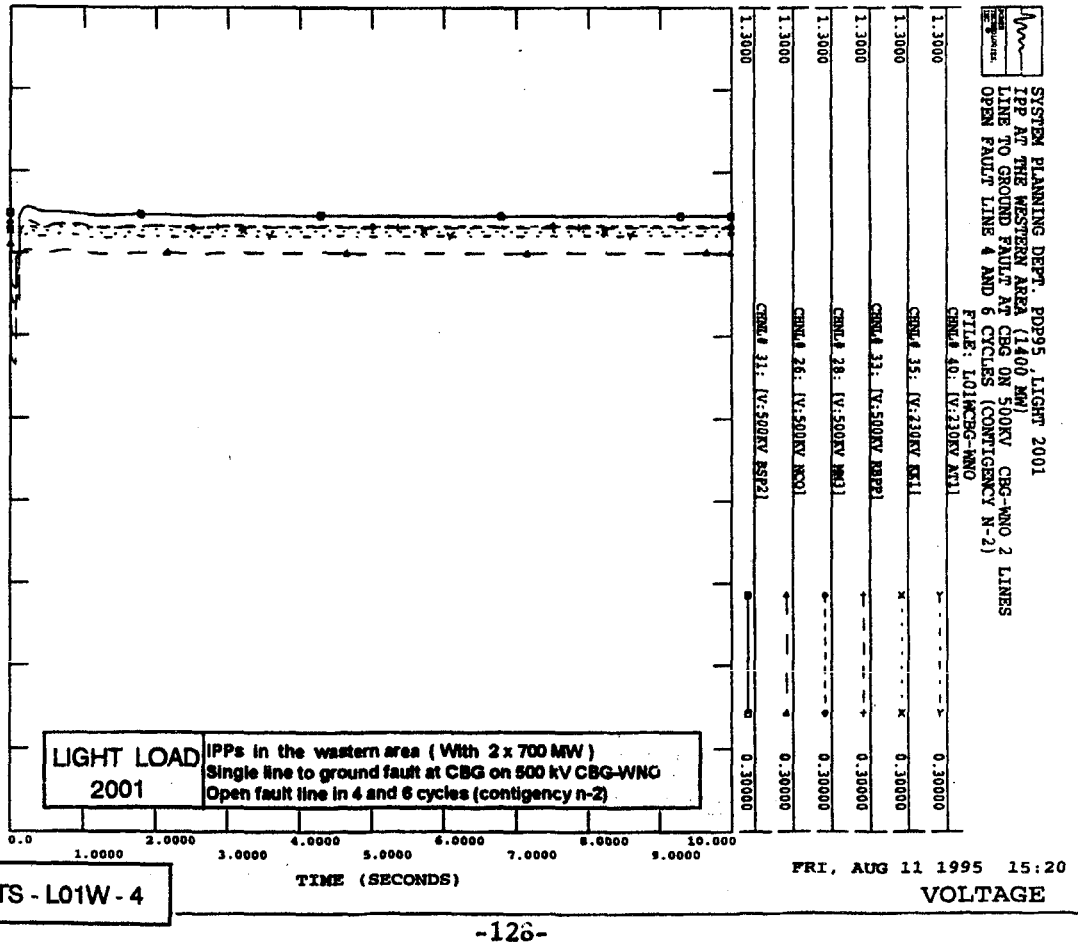
CASE TS - L01W - 2



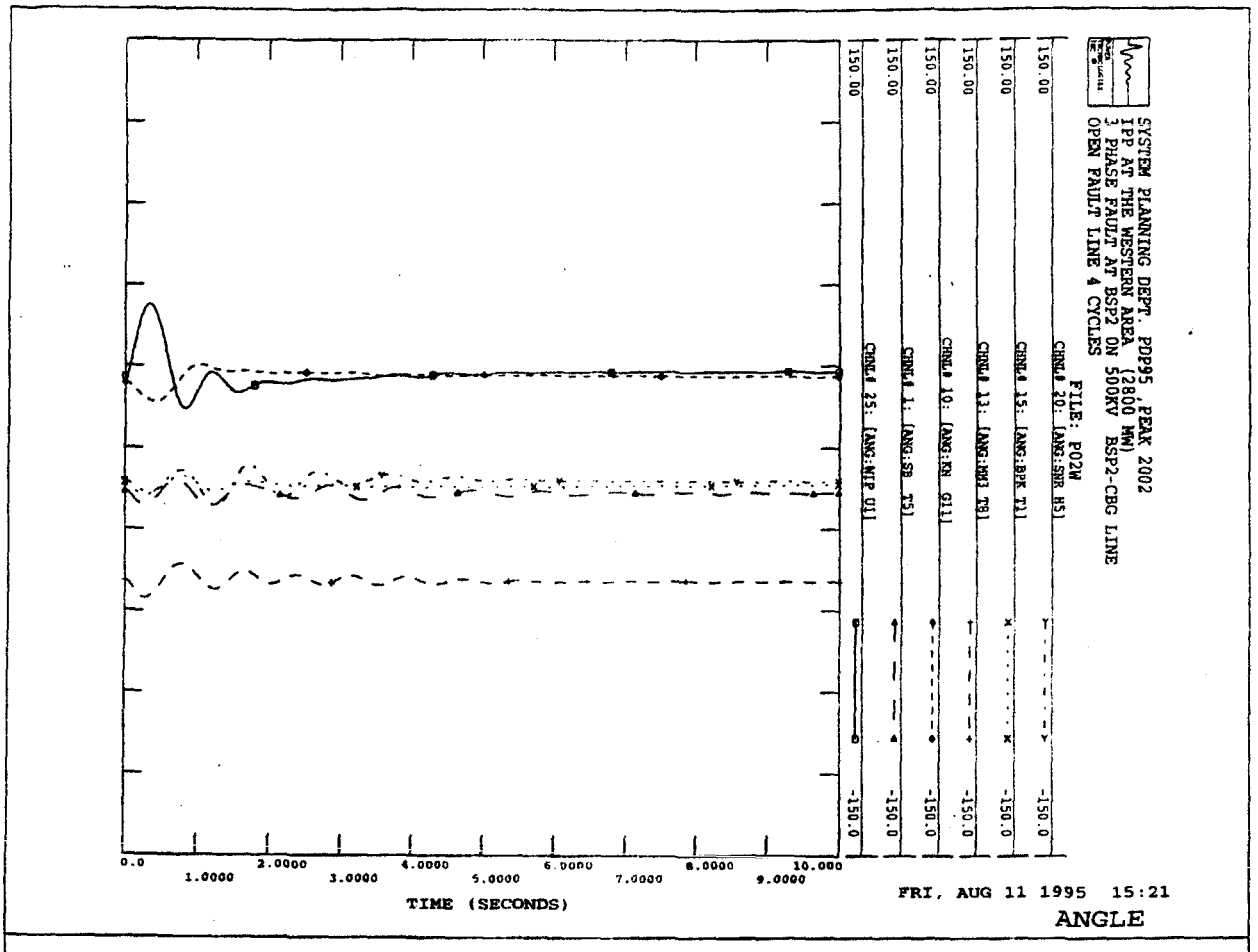


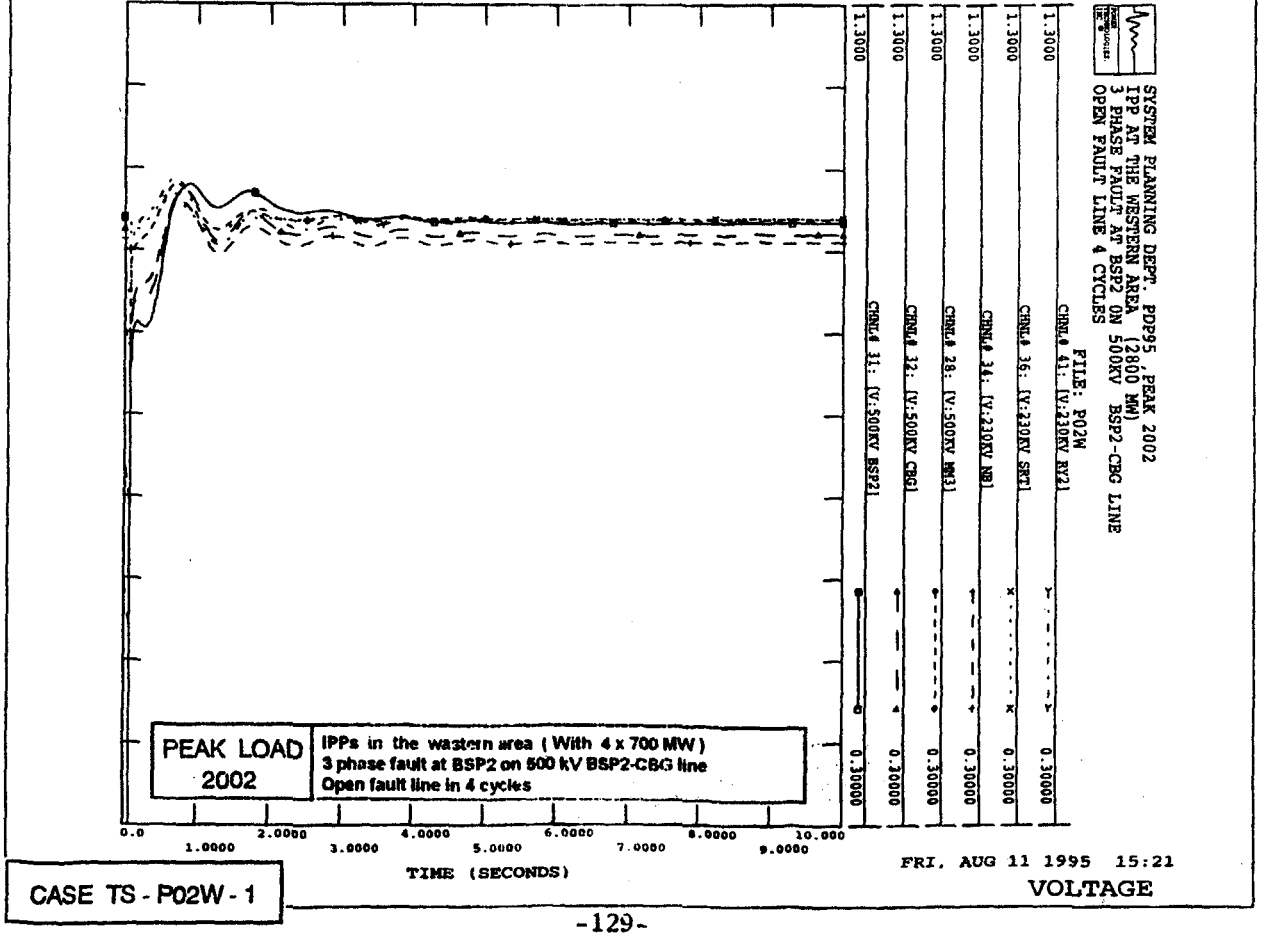
CASE TS - L01W - 3



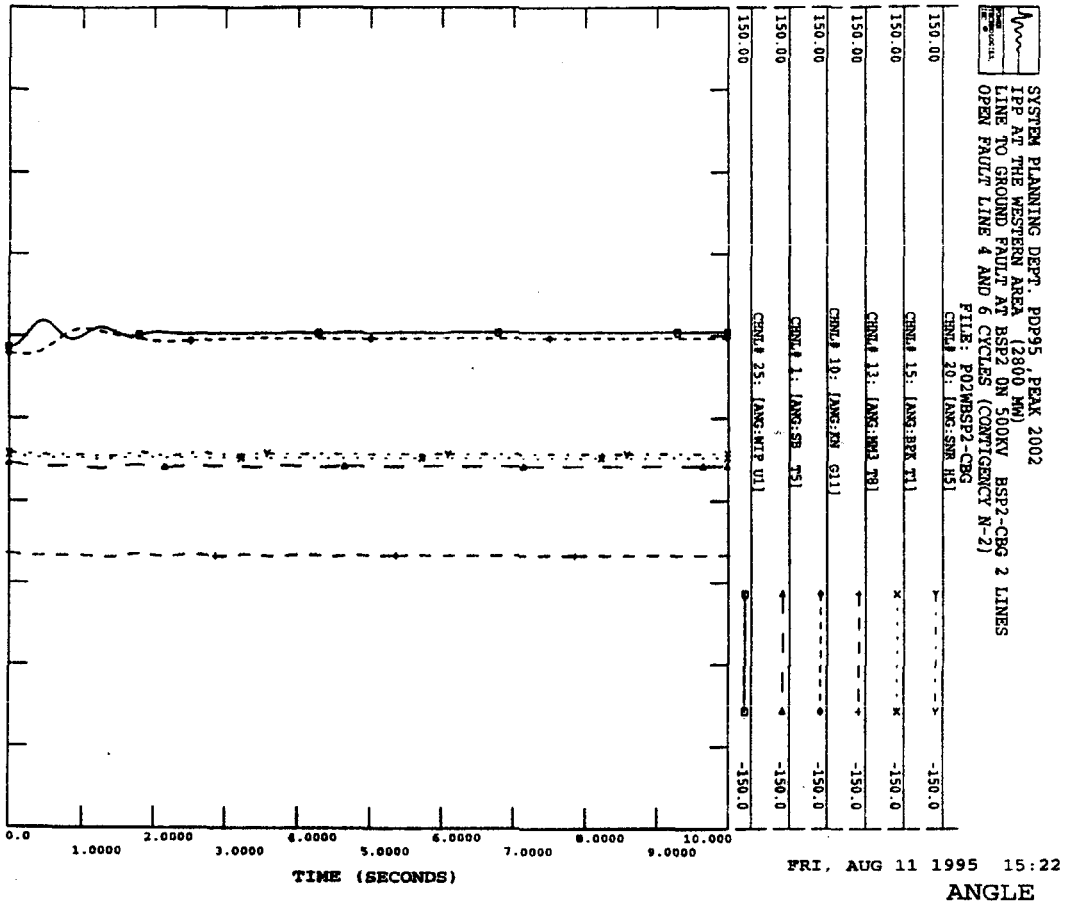


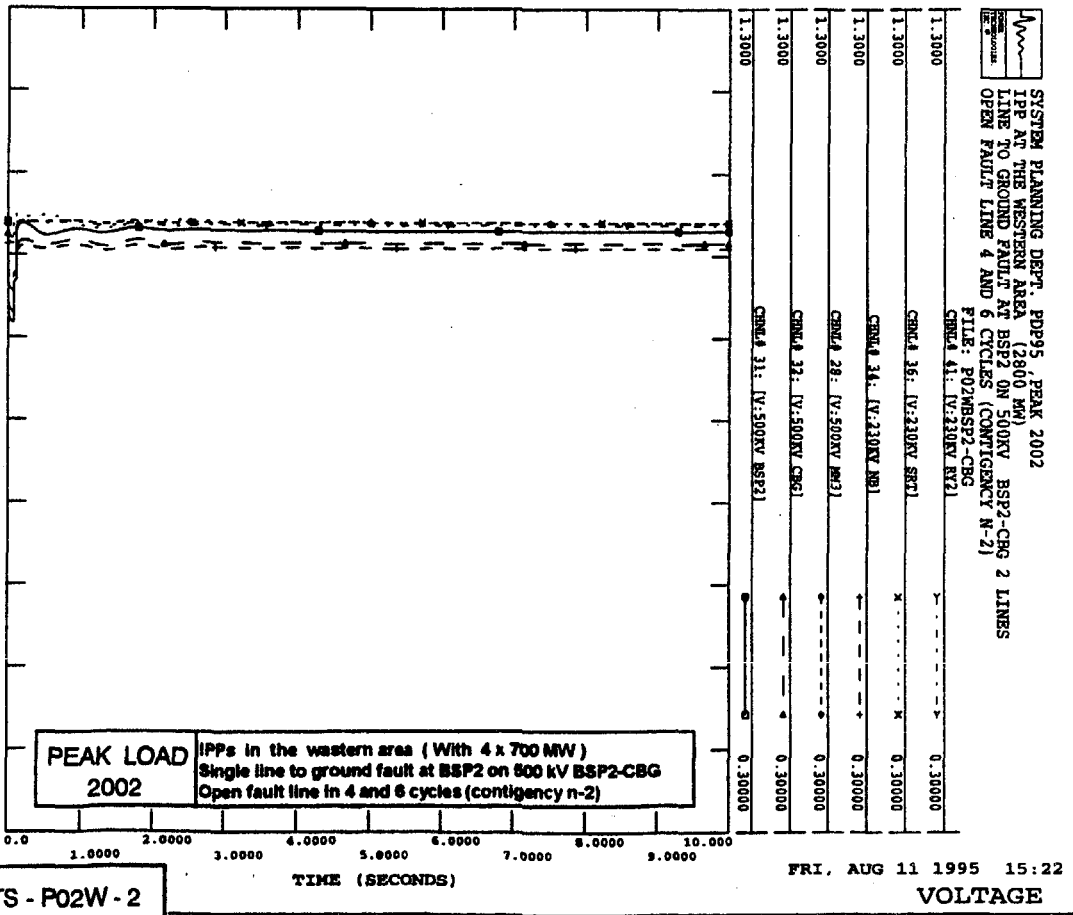
CASE TS - L01W - 4



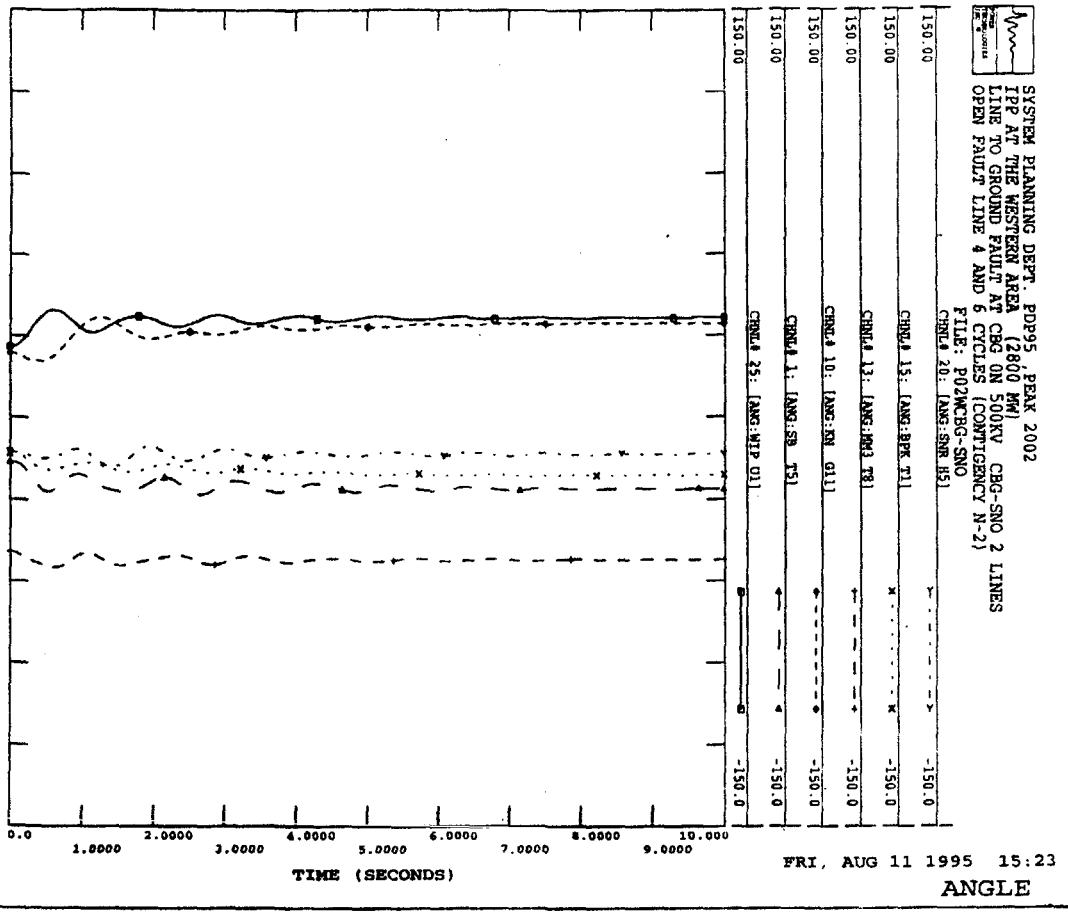


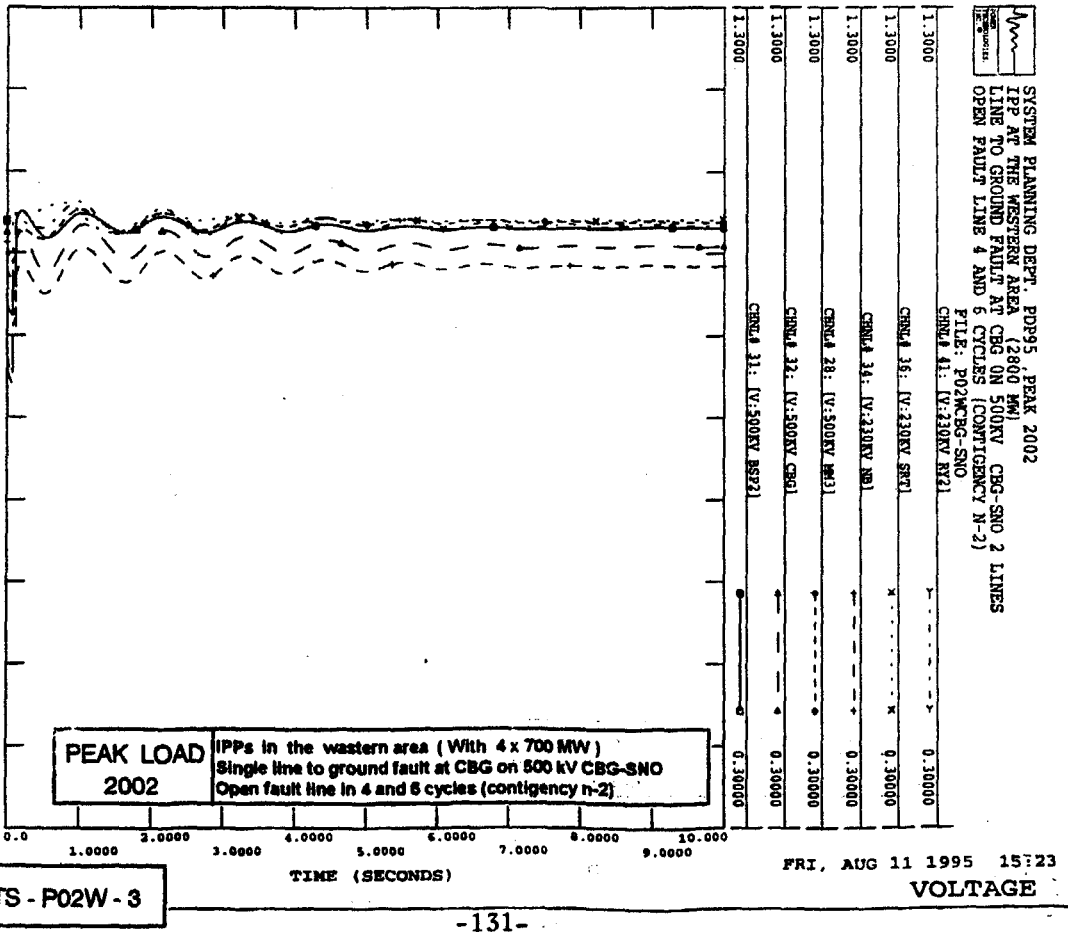
CASE TS - P02W - 1



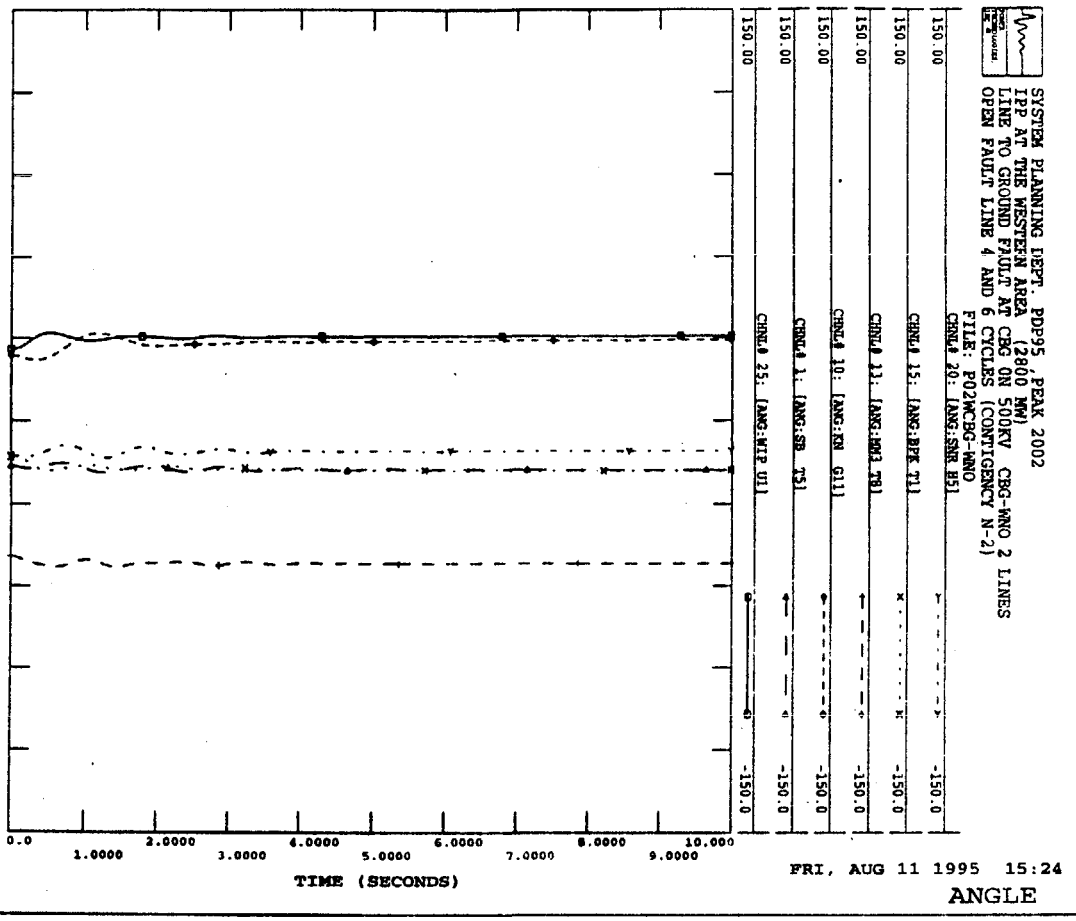


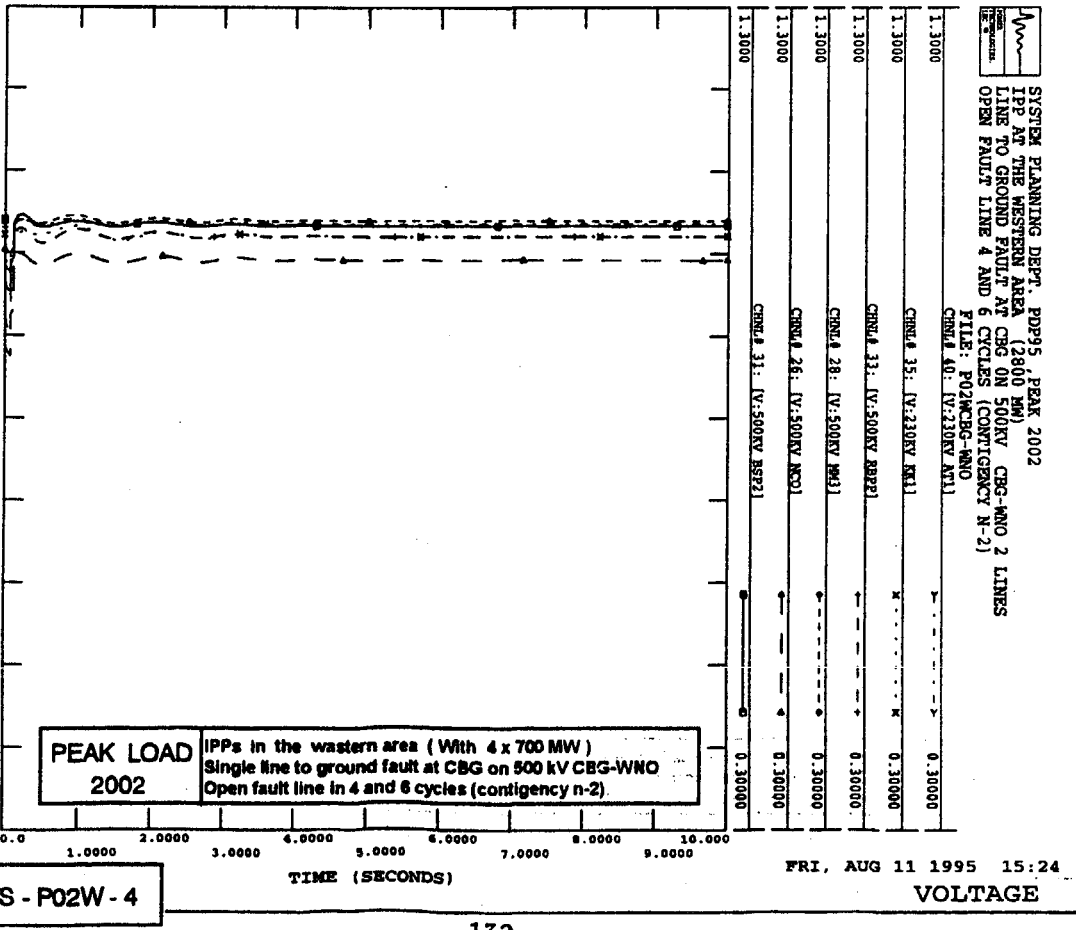
CASE TS - P02W - 2



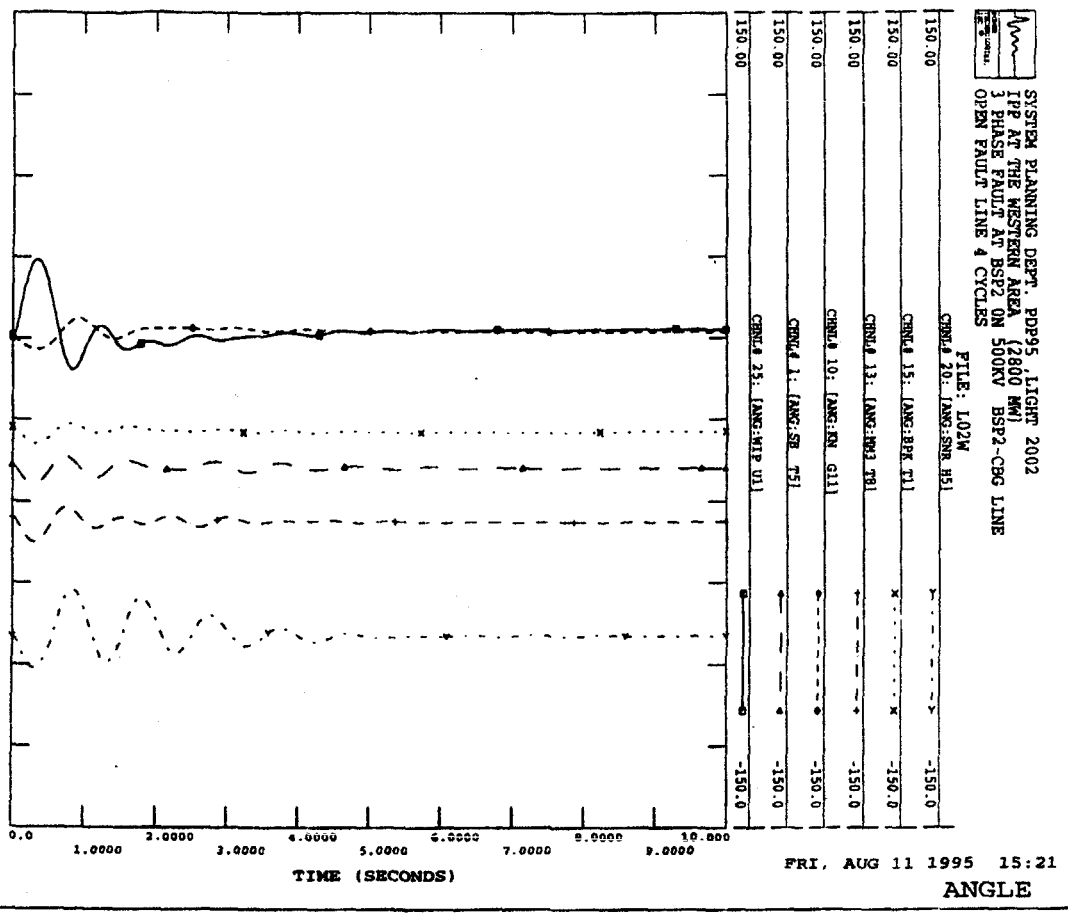


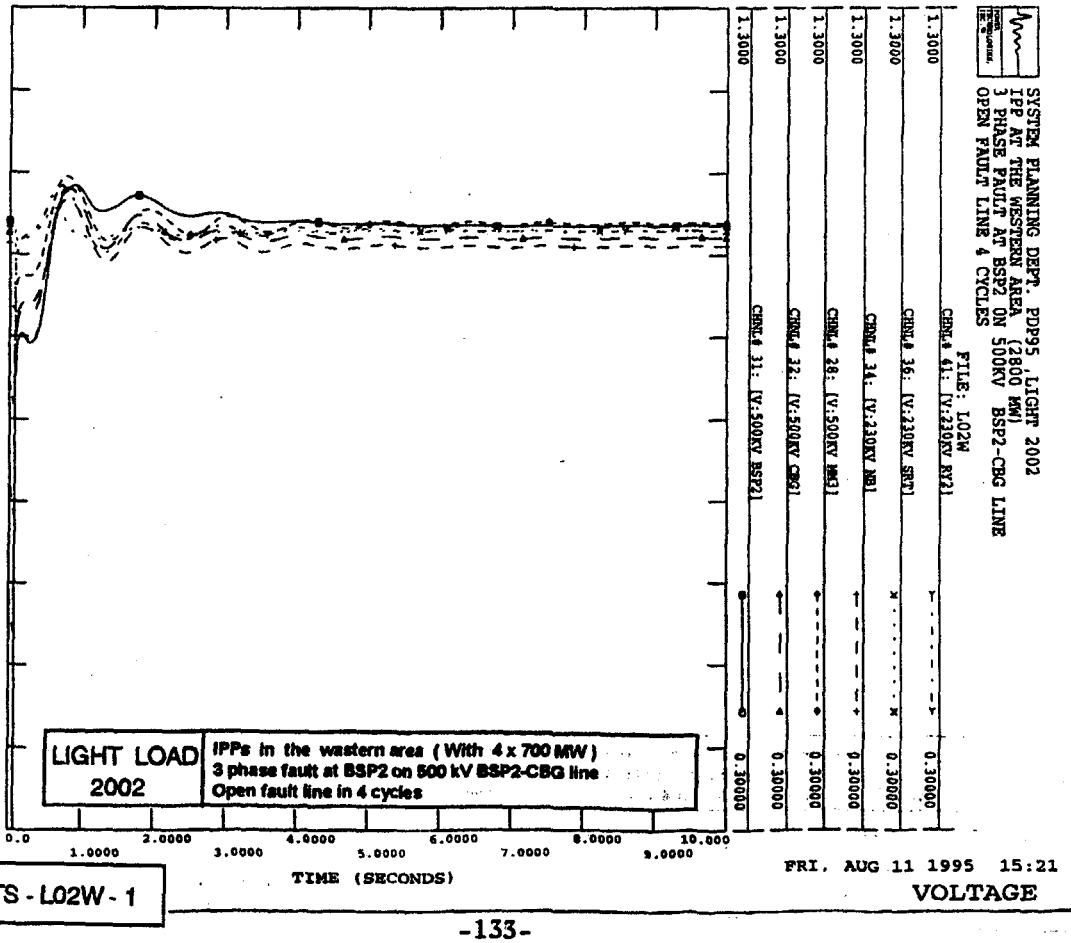
CASE TS - P02W - 3



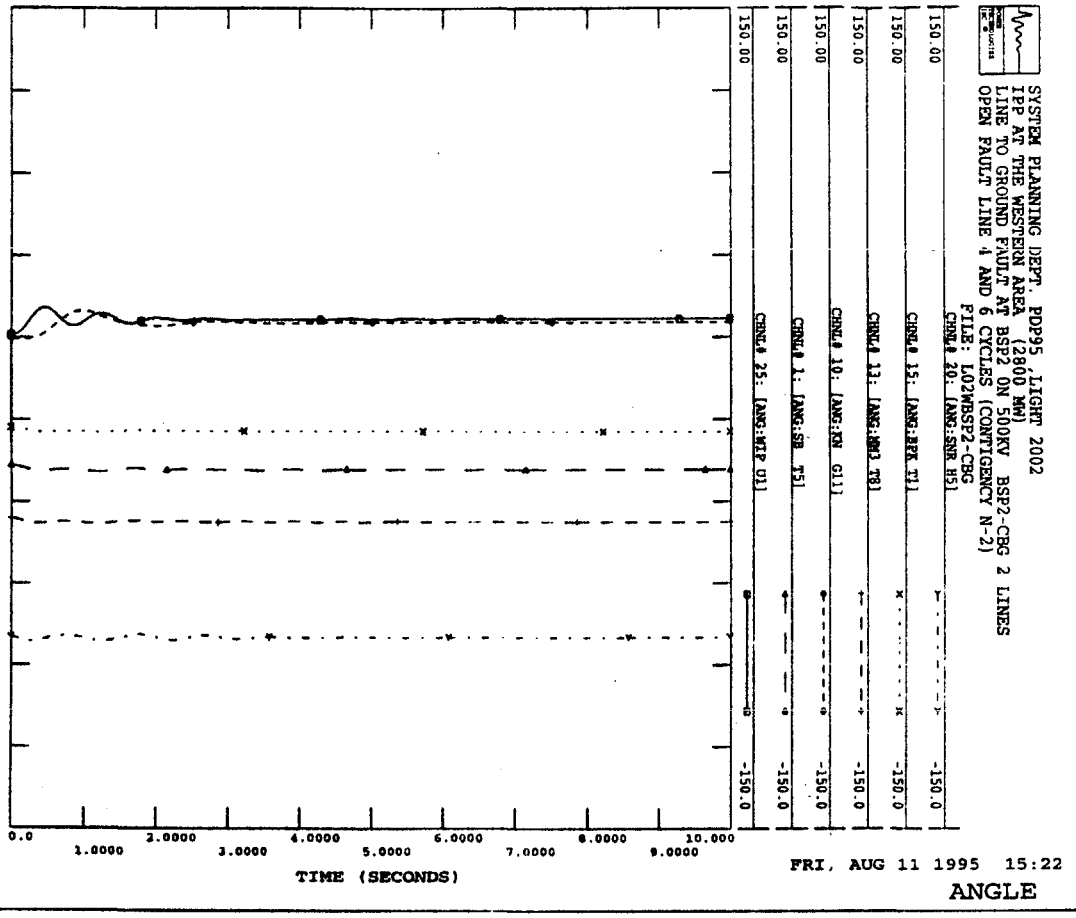


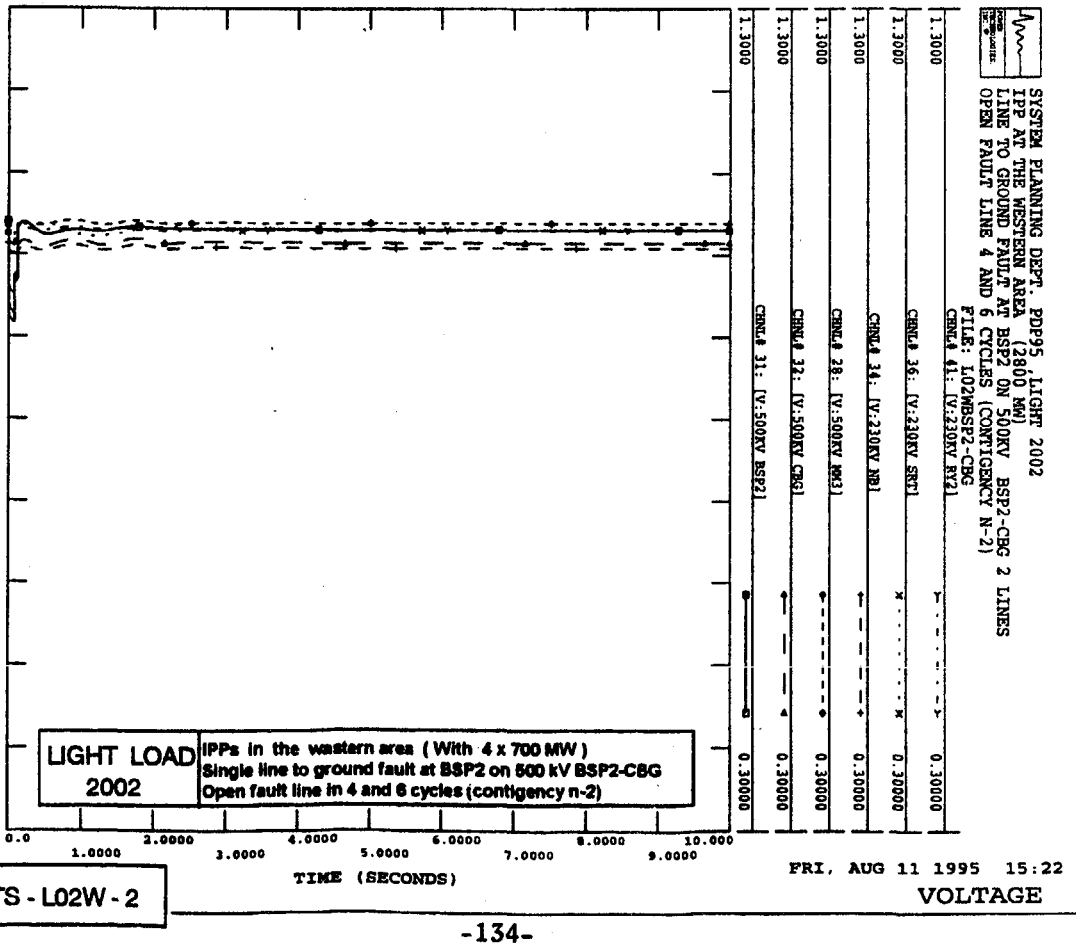
CASE TS - P02W - 4



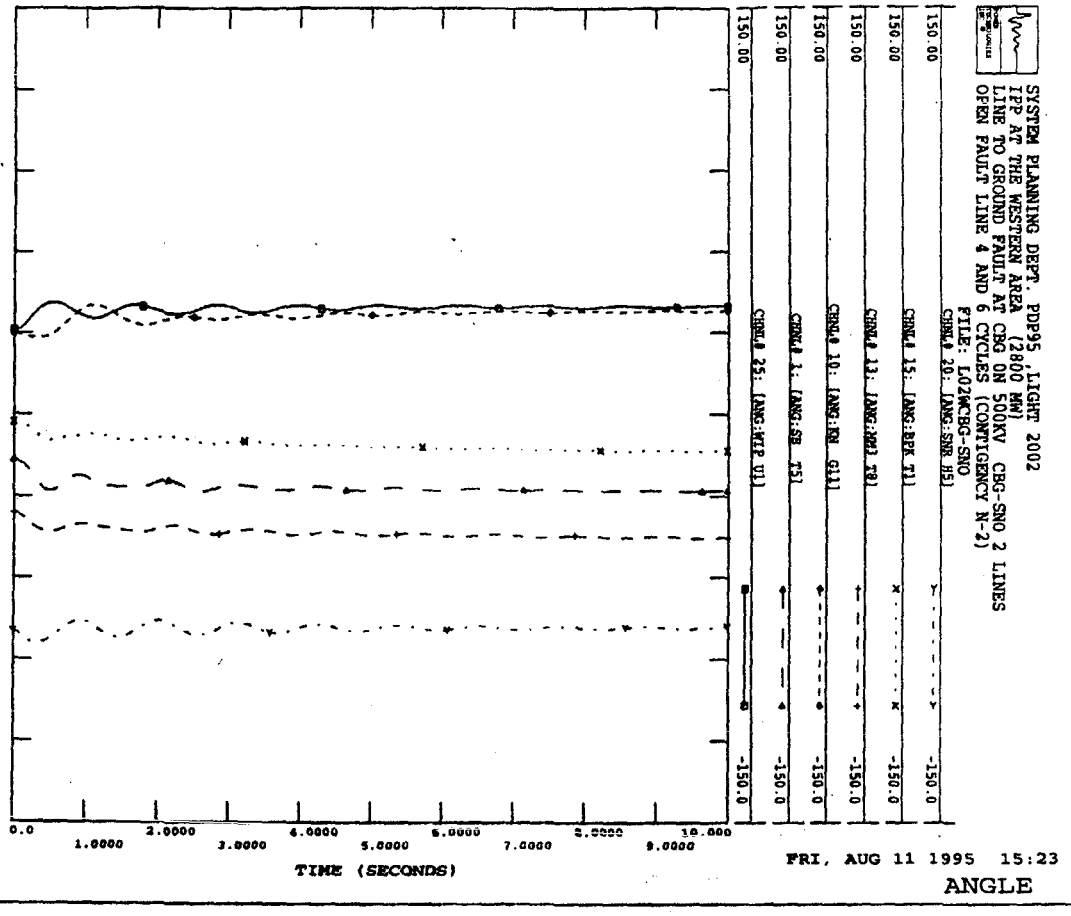


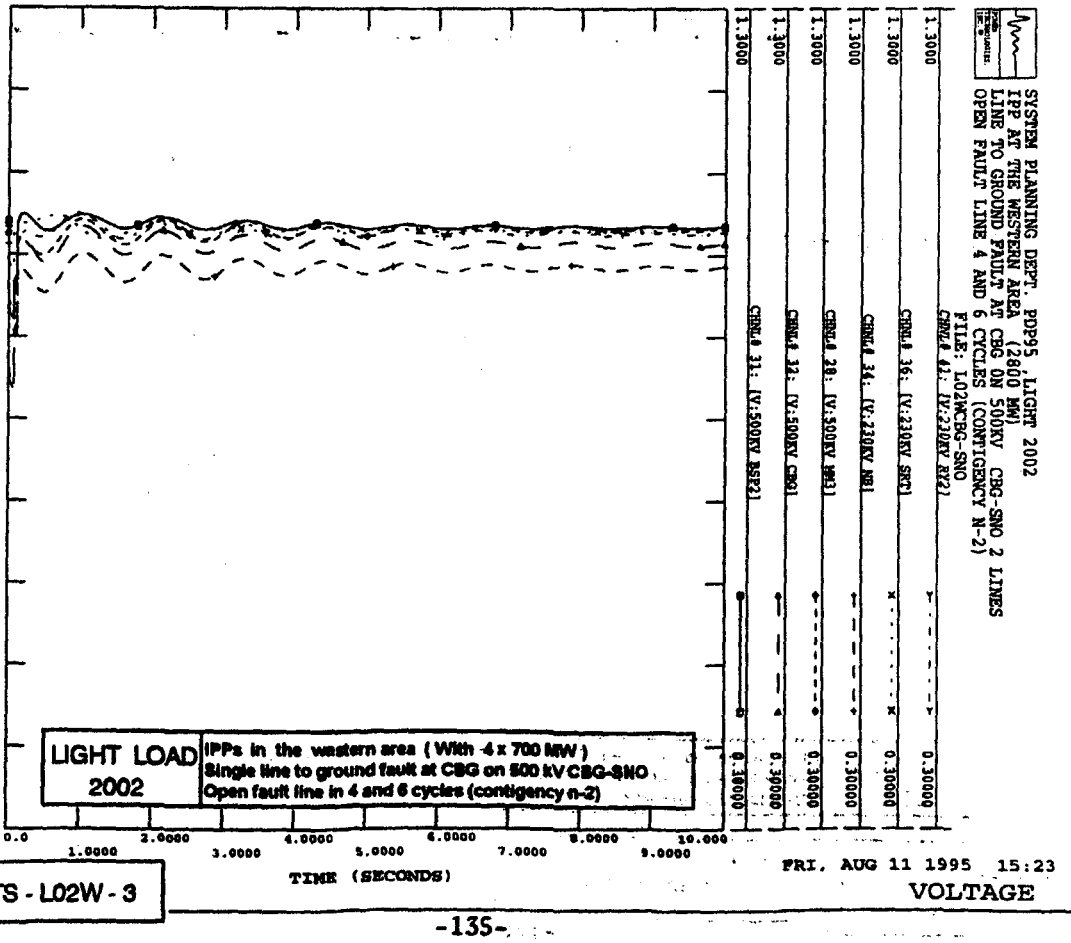
CASE TS - L02W - 1



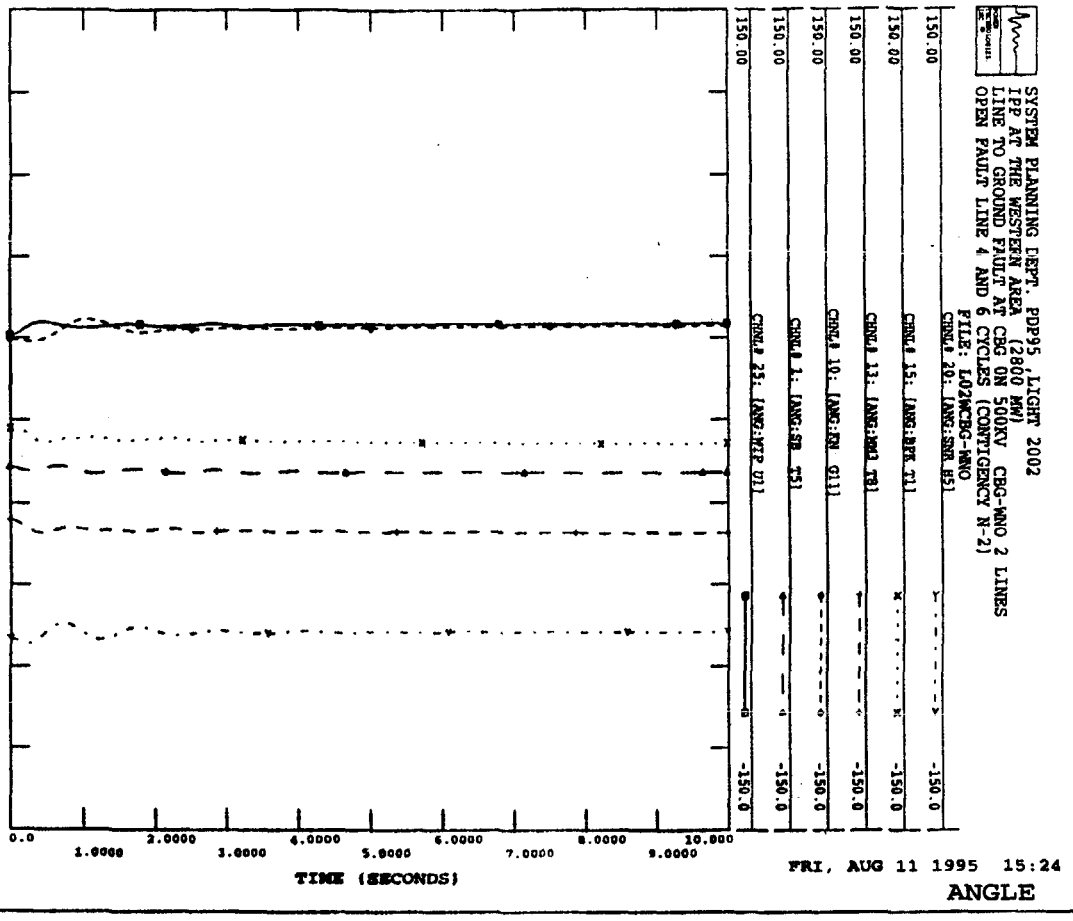


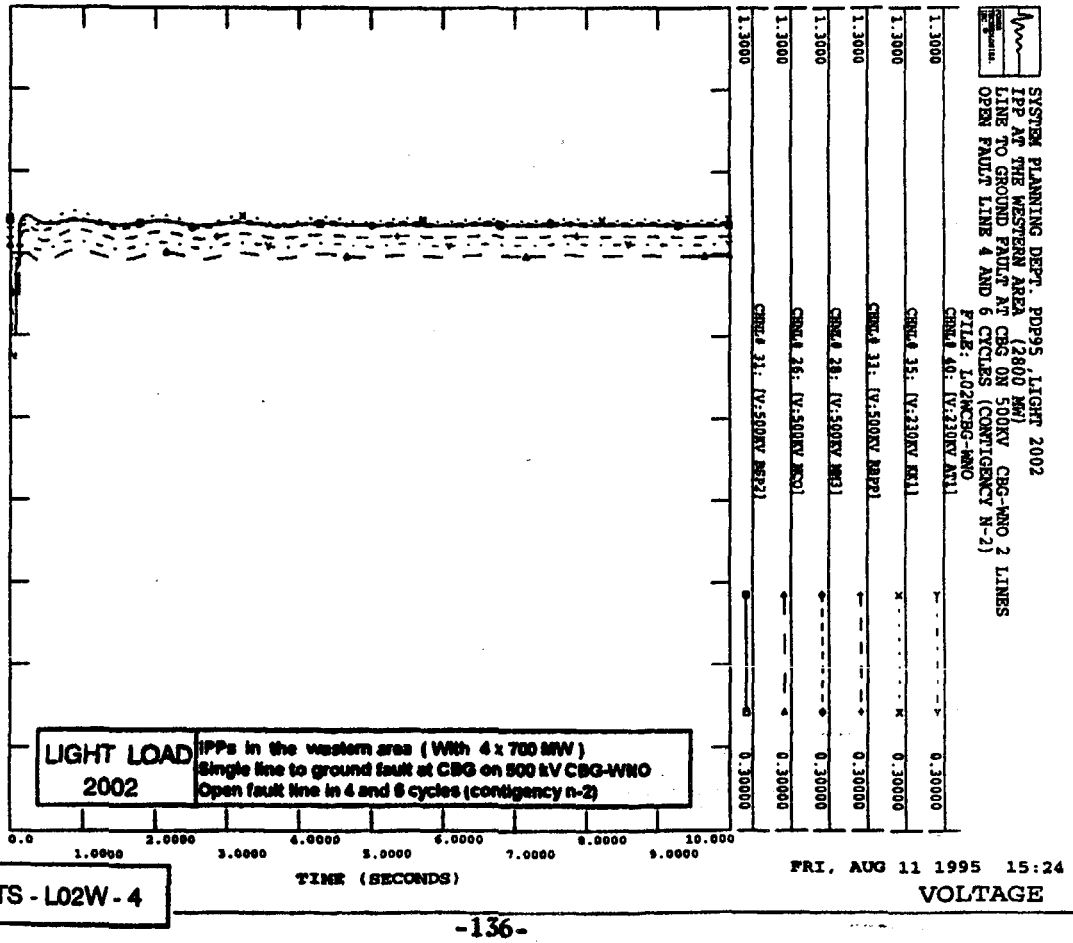
CASE TS - L02W - 2



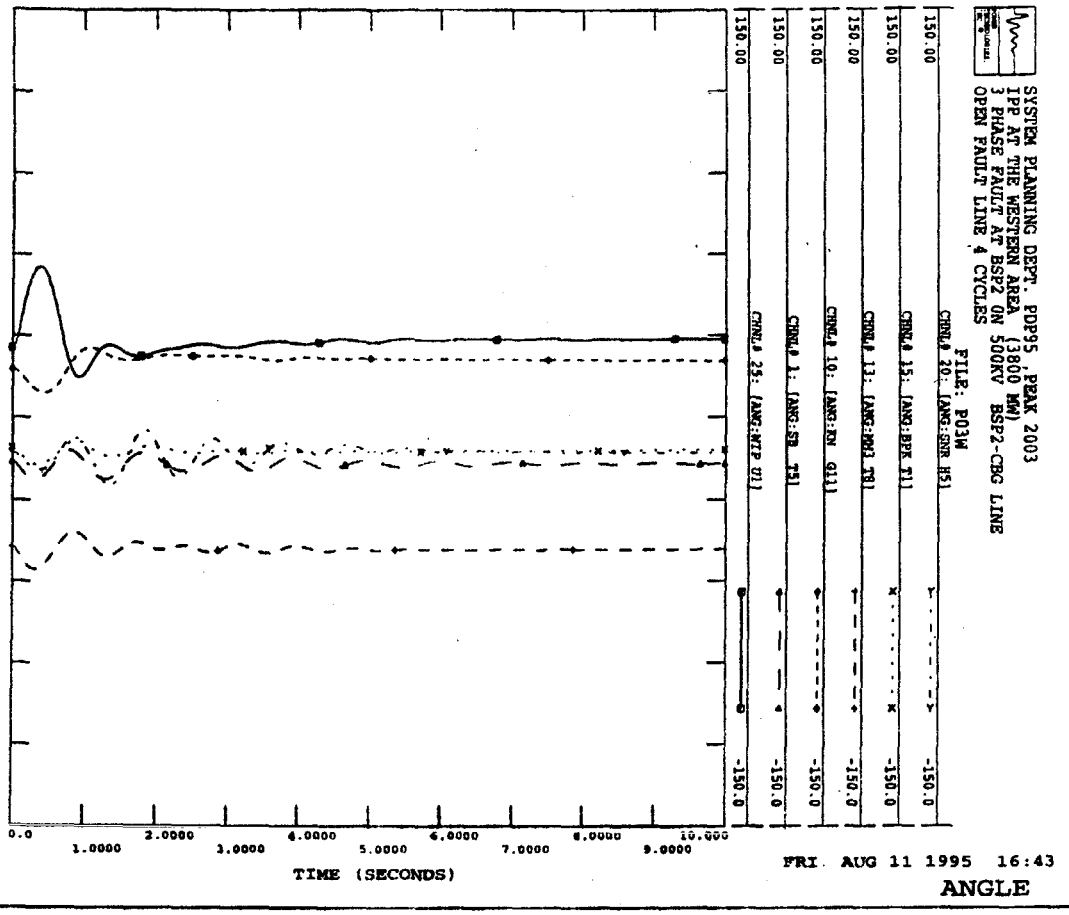


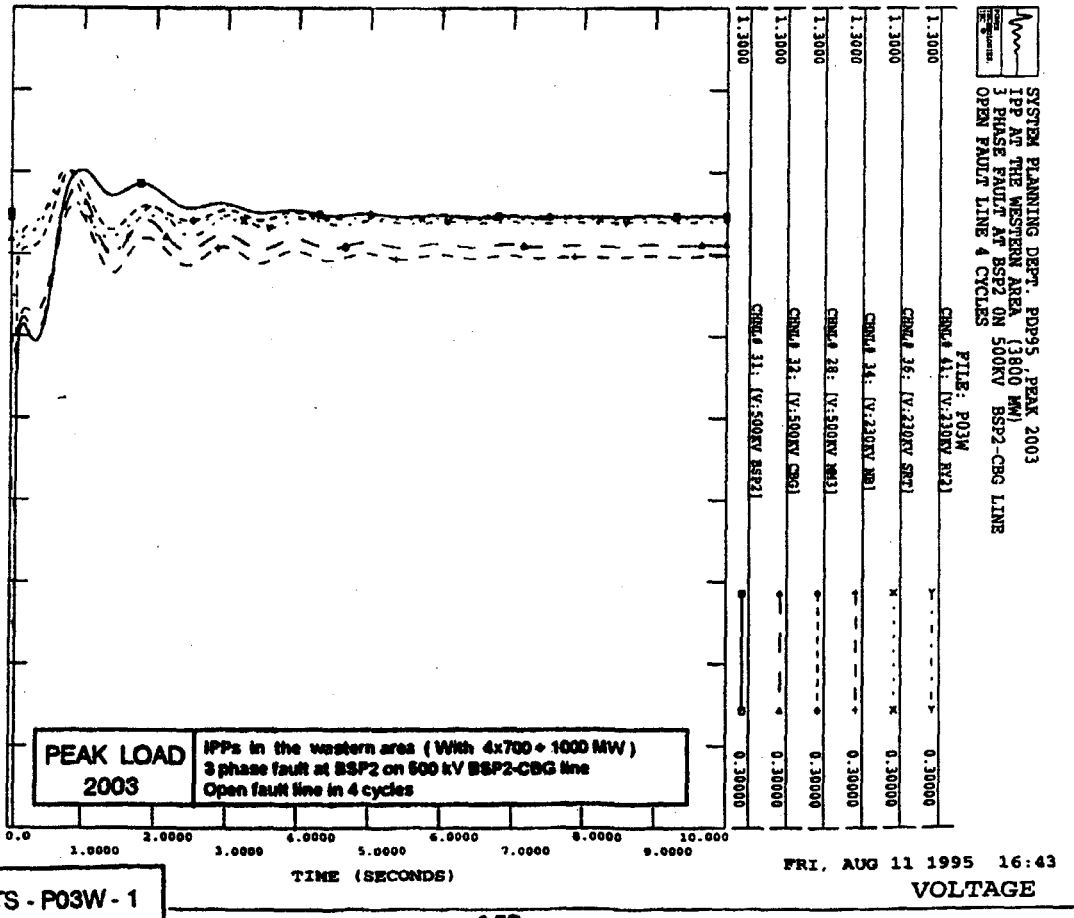
CASE TS - L02W - 3



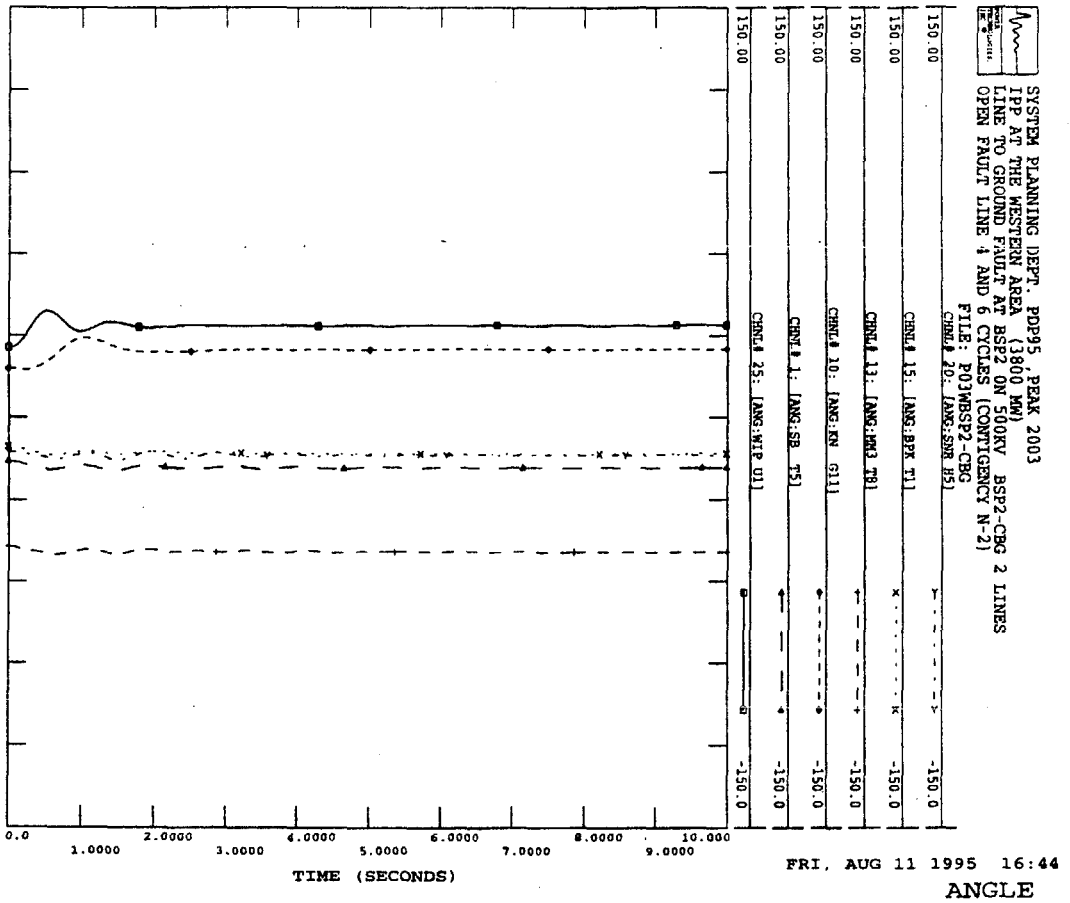


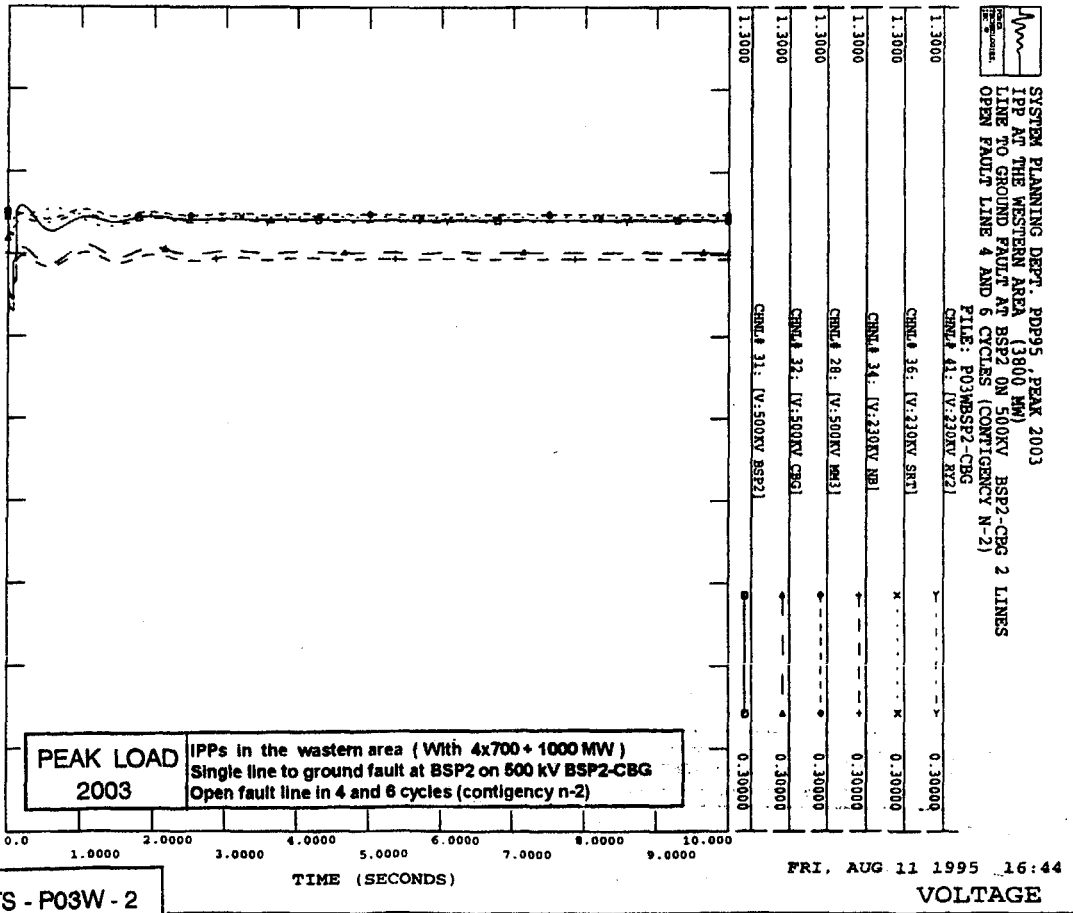
CASE TS - L02W - 4



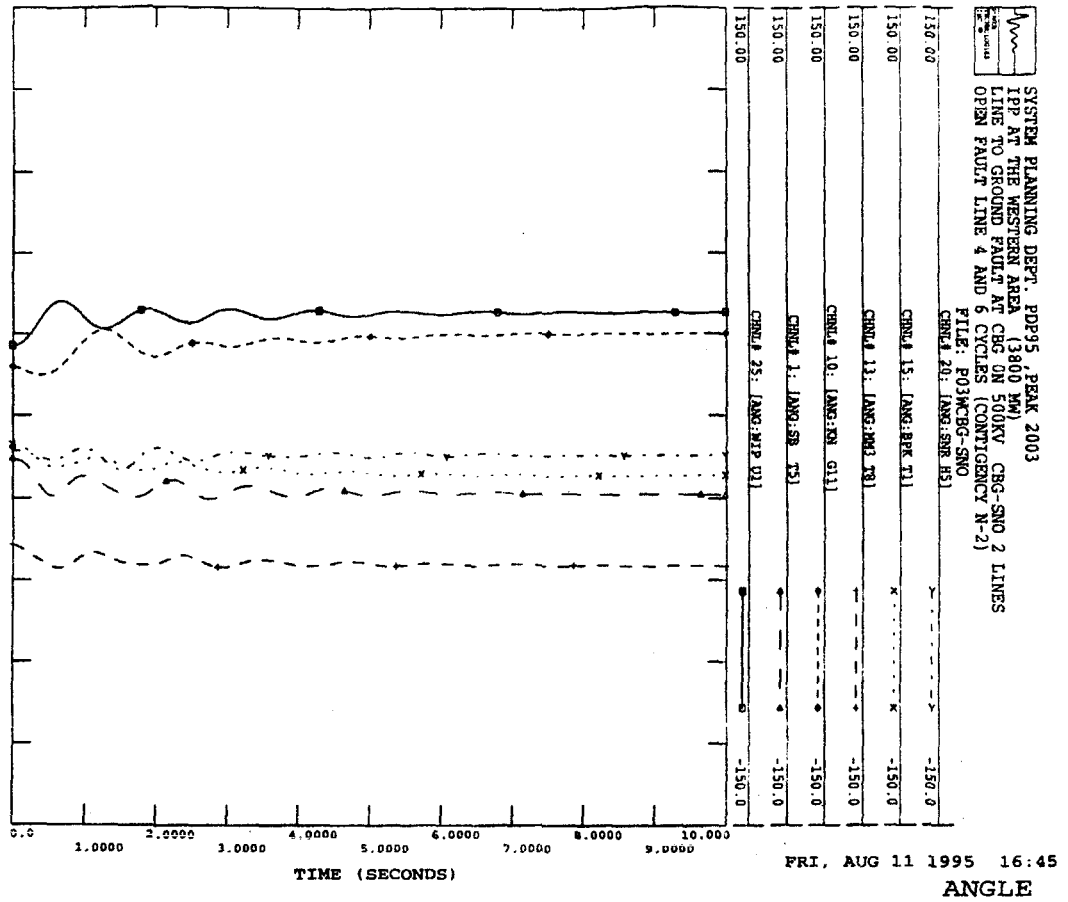


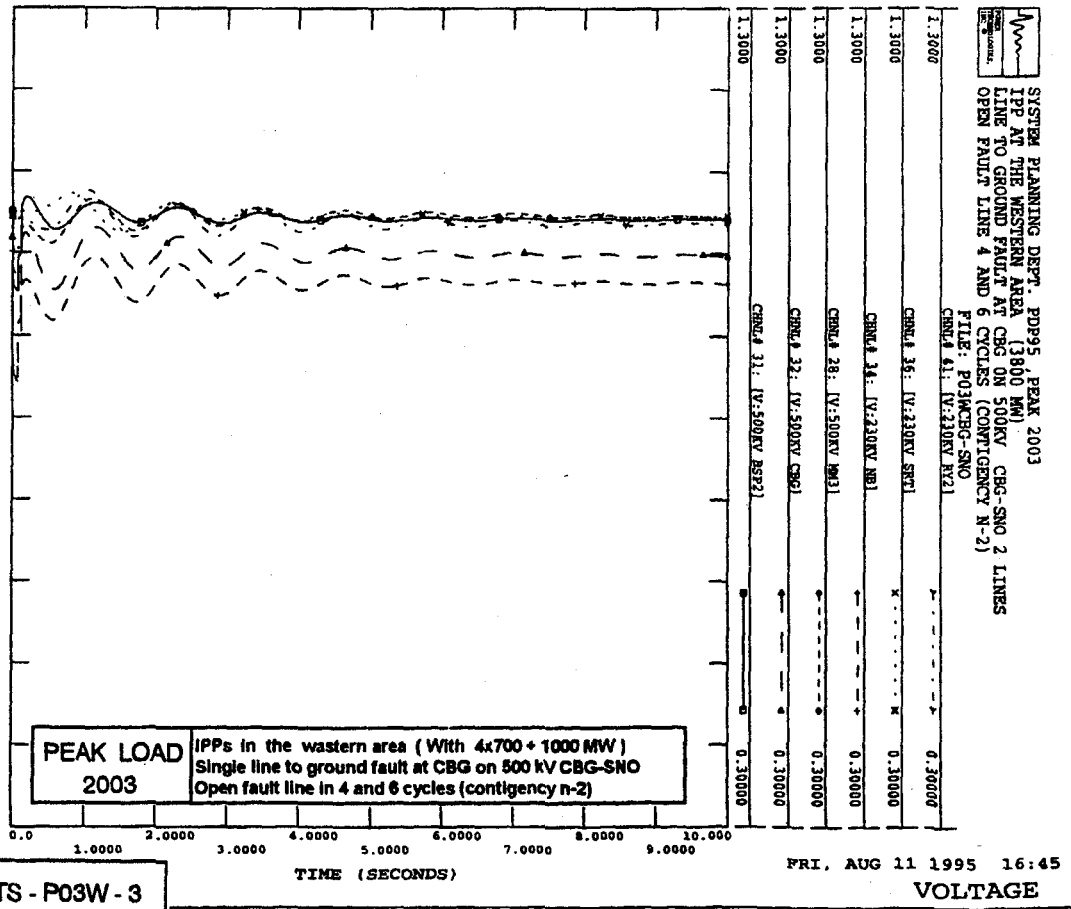
CASE TS - P03W - 1



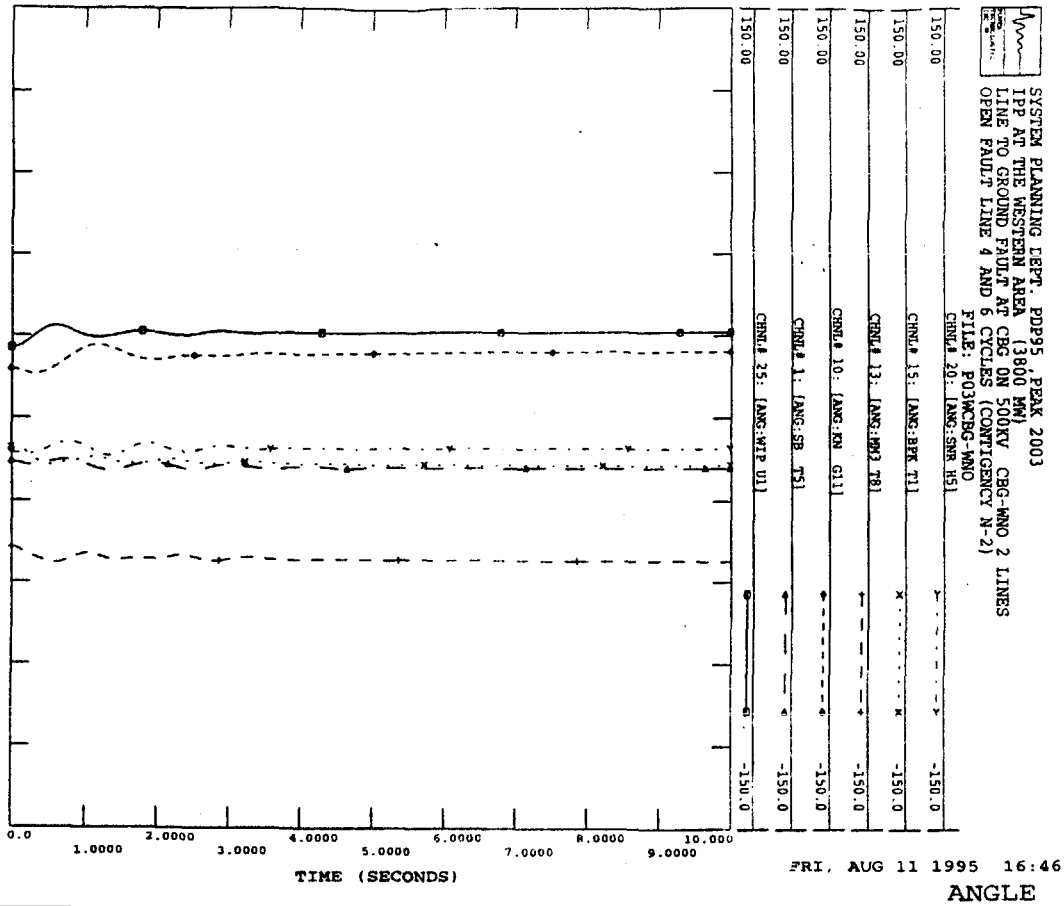


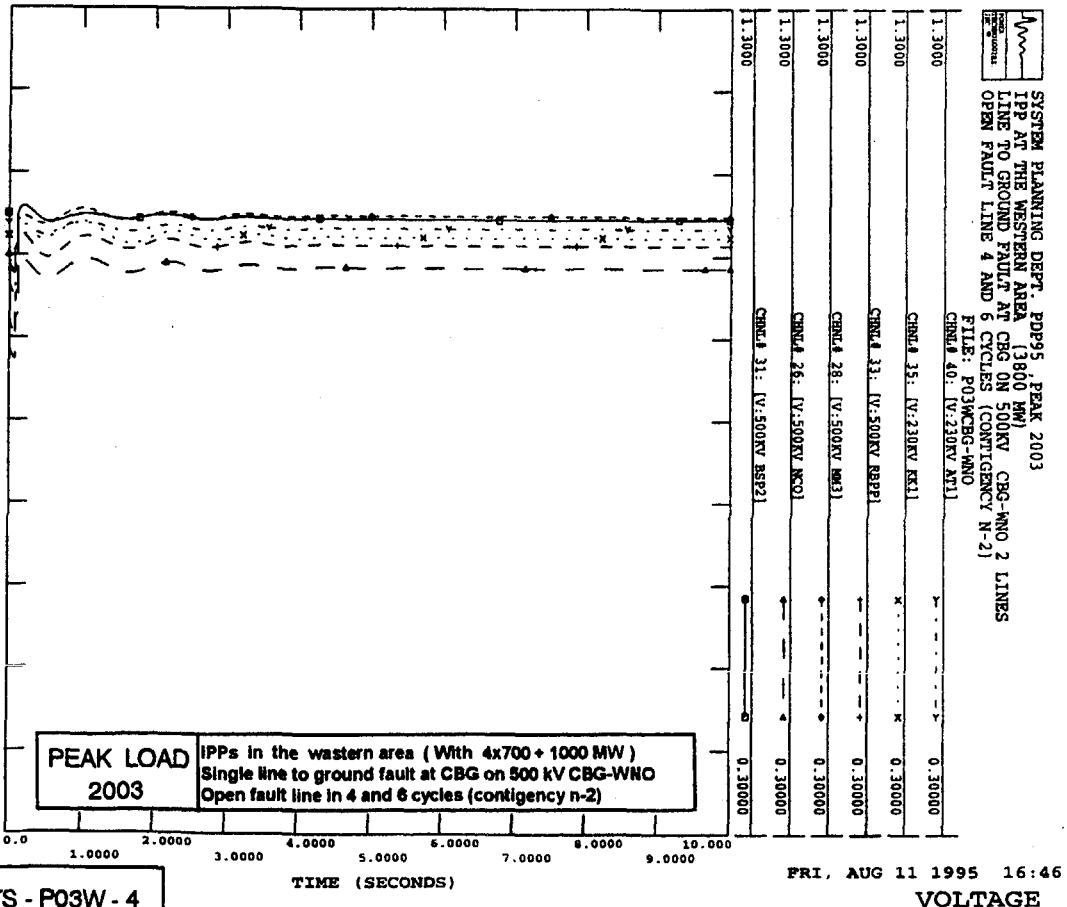
CASE TS - P03W - 2



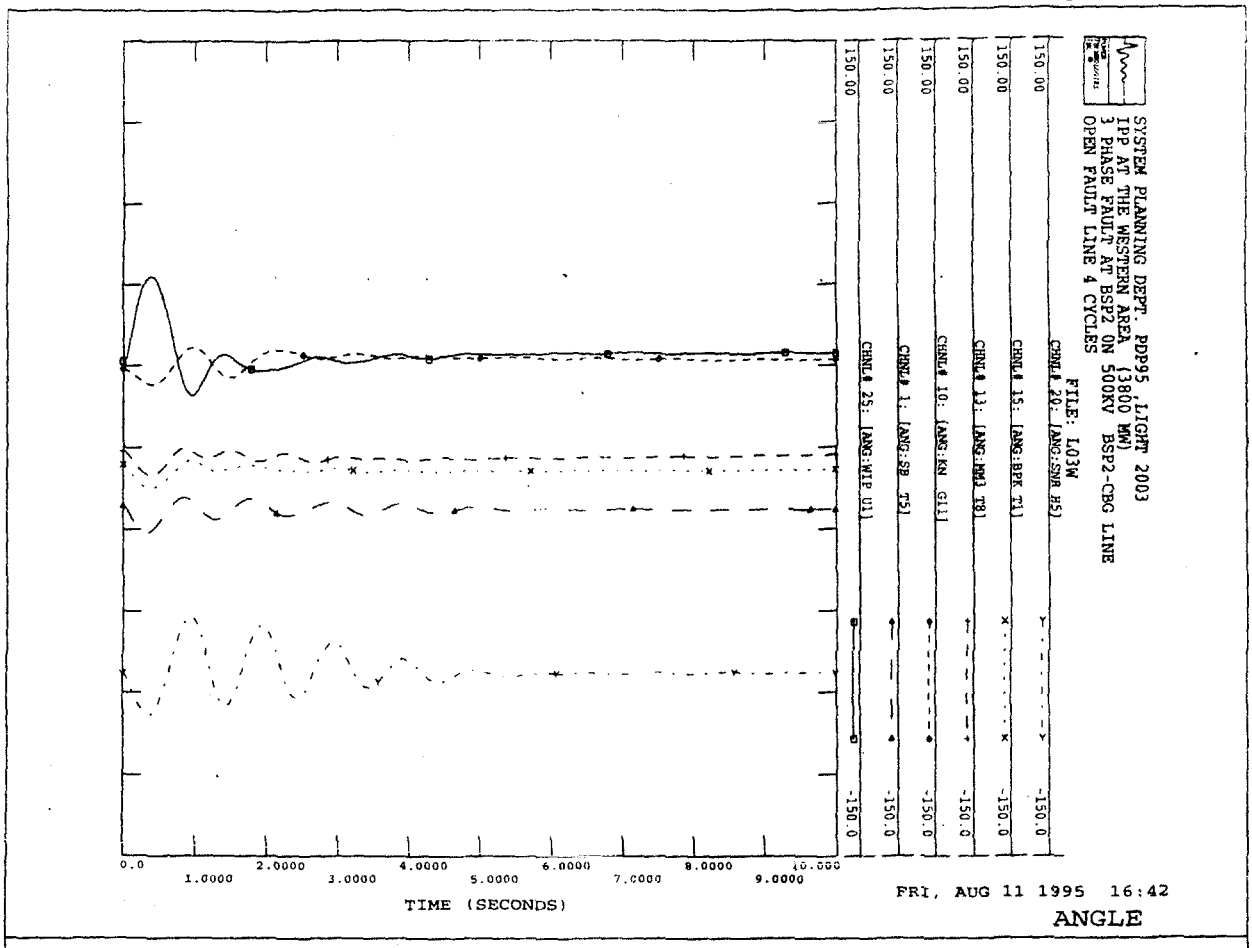


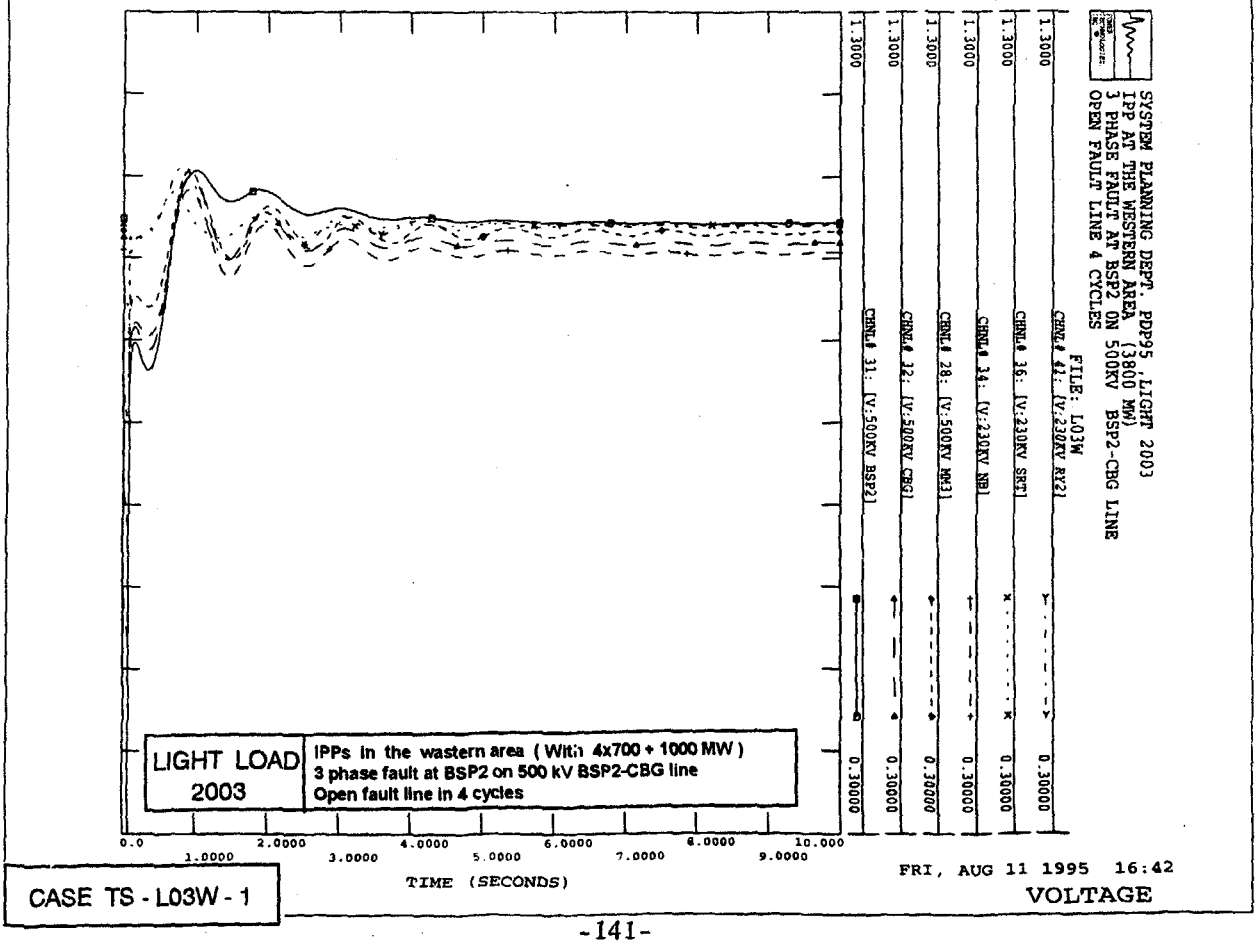
CASE TS - P03W - 3

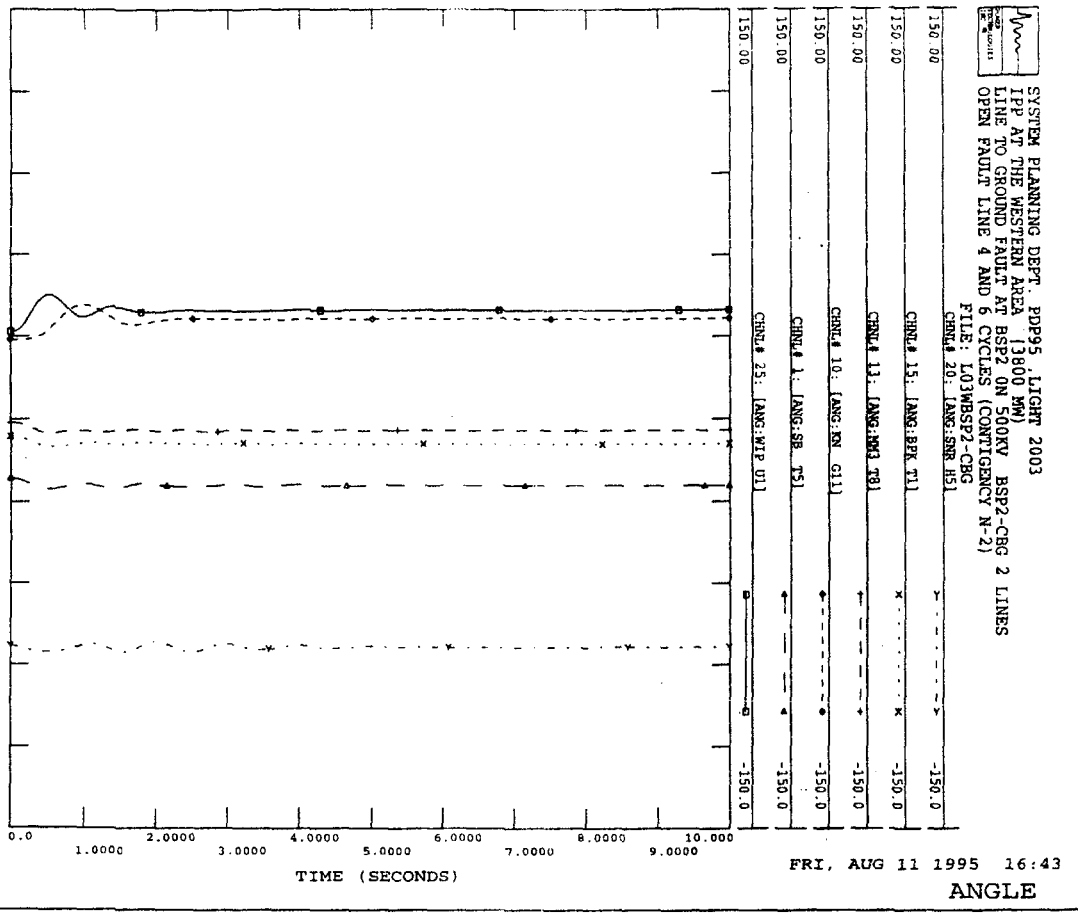


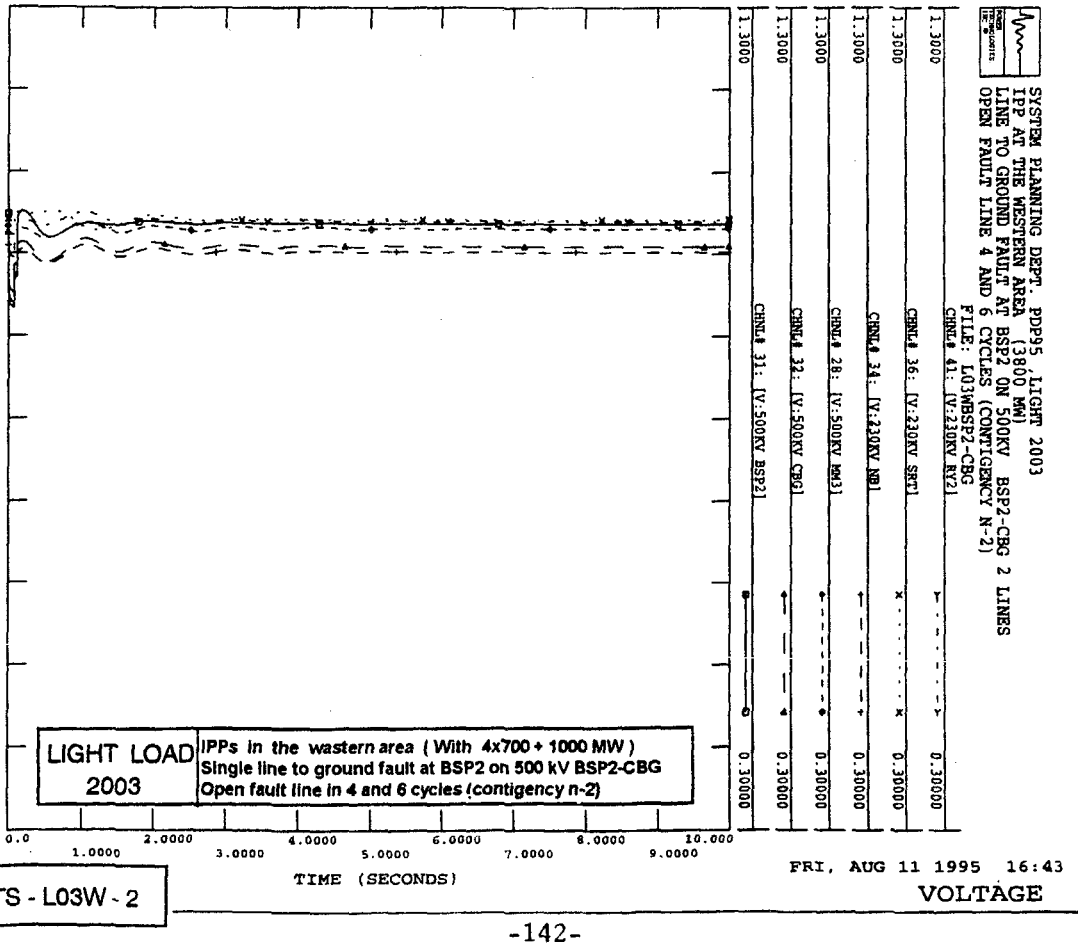


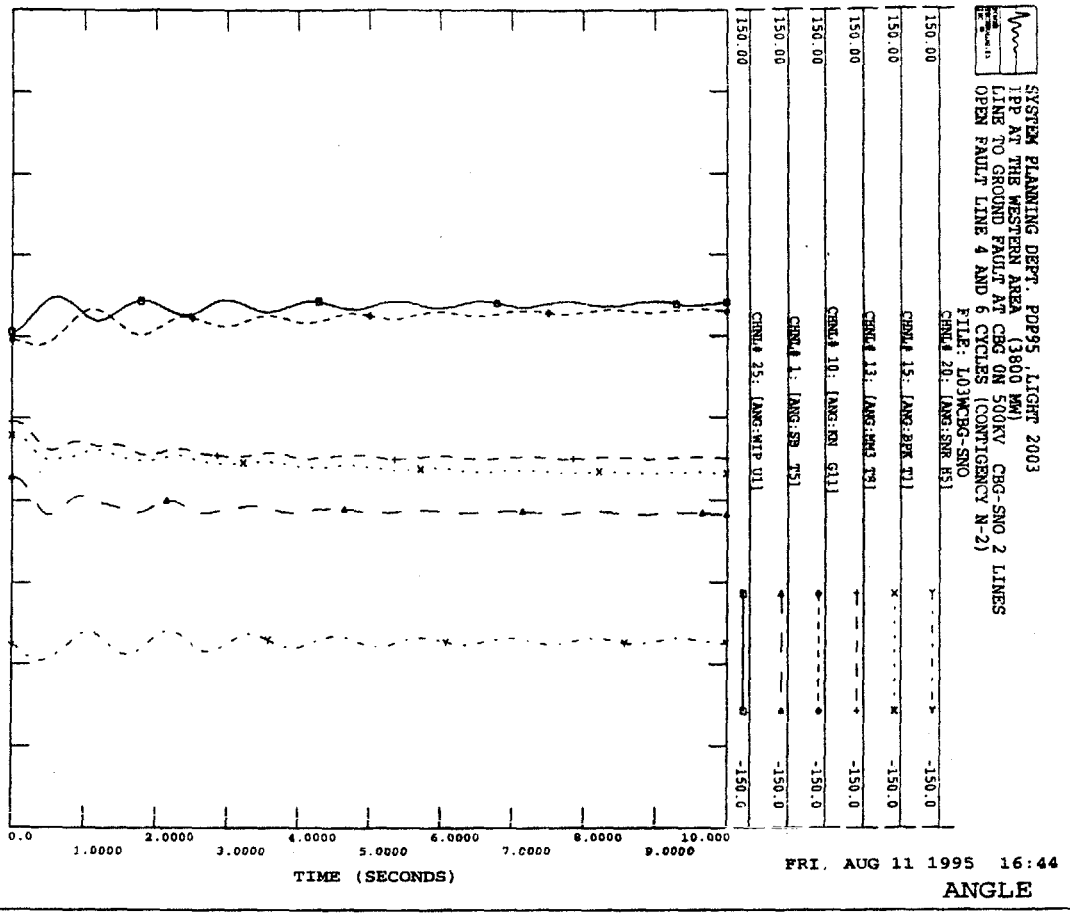
CASE TS - P03W - 4

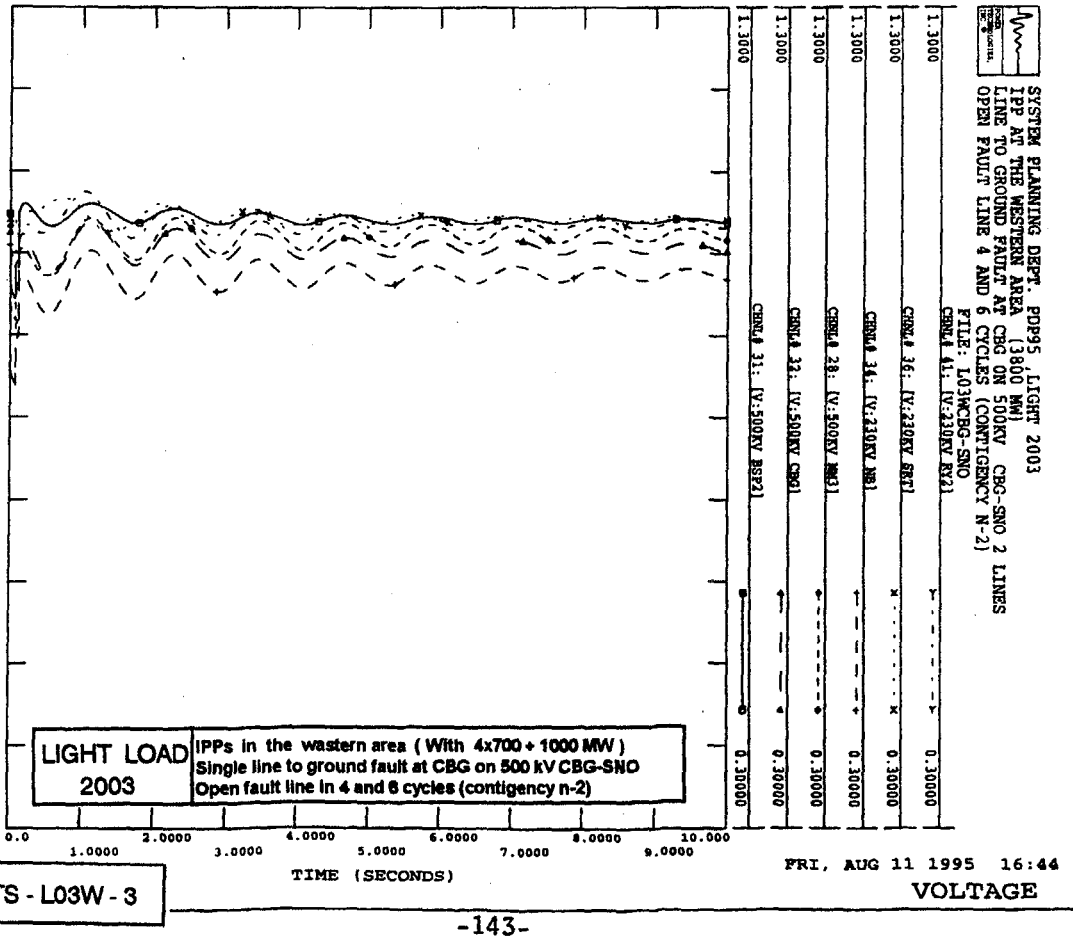

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2003
IPP AT THE WESTERN AREA (3800 MW)
3 PHASE FAULT AT BSP2 ON 500KV BSP2-CBG LINE
OPEN FAULT LINE 4 CYCLES
FILE: L03W
CHNL# 20: [ANG:SNR H5]
CHNL# 15: [ANG:BPK T1]
CHNL# 11: [ANG:MM3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB T5]
CHNL# 25: [ANG:WIP U11]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 16:42
ANGLE


SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2003
IPP AT THE WESTERN AREA (3800 MW)
3 PHASE FAULT AT BSP2 ON 500KV BSP2-CBG LINE
OPEN FAULT LINE 4 CYCLES
FILE: L03W
CHNL# 41: [V:230KV RY2]
CHNL# 16: [V:230KV SR1]
CHNL# 14: [V:230KV NB]
CHNL# 28: [V:500KV MM3]
CHNL# 12: [V:500KV CBG]
CHNL# 31: [V:500KV BSP2]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 16:42
VOLTAGE
LIGHT LOAD
2003
IPPs in the wastern area (With 4x700 + 1000 MW)
3 phase fault at BSP2 on 500 kV BSP2-CBG line
Open fault line in 4 cycles
CASE TS - L03W - 1

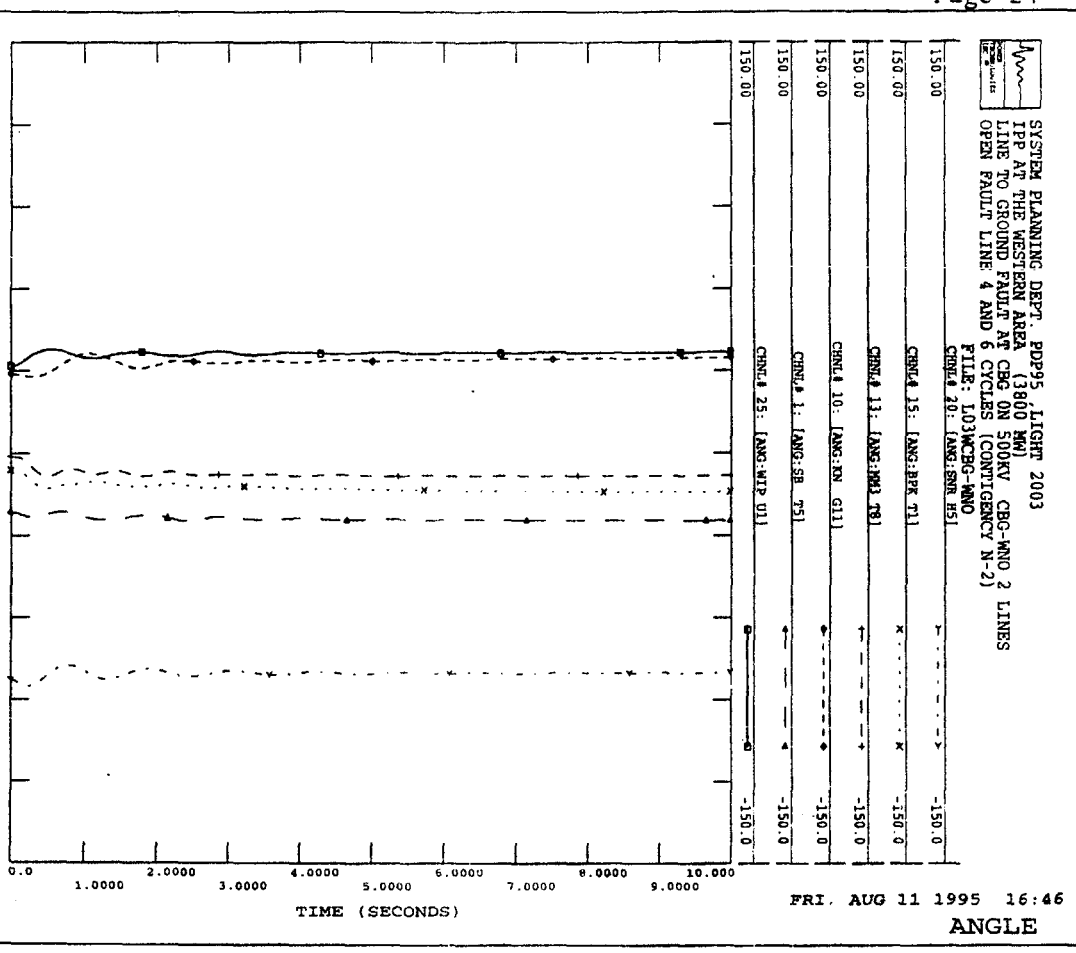

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2003
IPP AT THE WESTERN AREA (3800 MW)
LINE TO GROUND FAULT AT BSP2 ON 500KV BSP2-CBG 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L03WBSP2-CBG
CHNL# 20: [ANG:SNR H5]
CHNL# 15: [ANG:BFK T1]
CHNL# 11: [ANG:MM3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SR TS]
CHNL# 25: [ANG:WIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 16:43
ANGLE

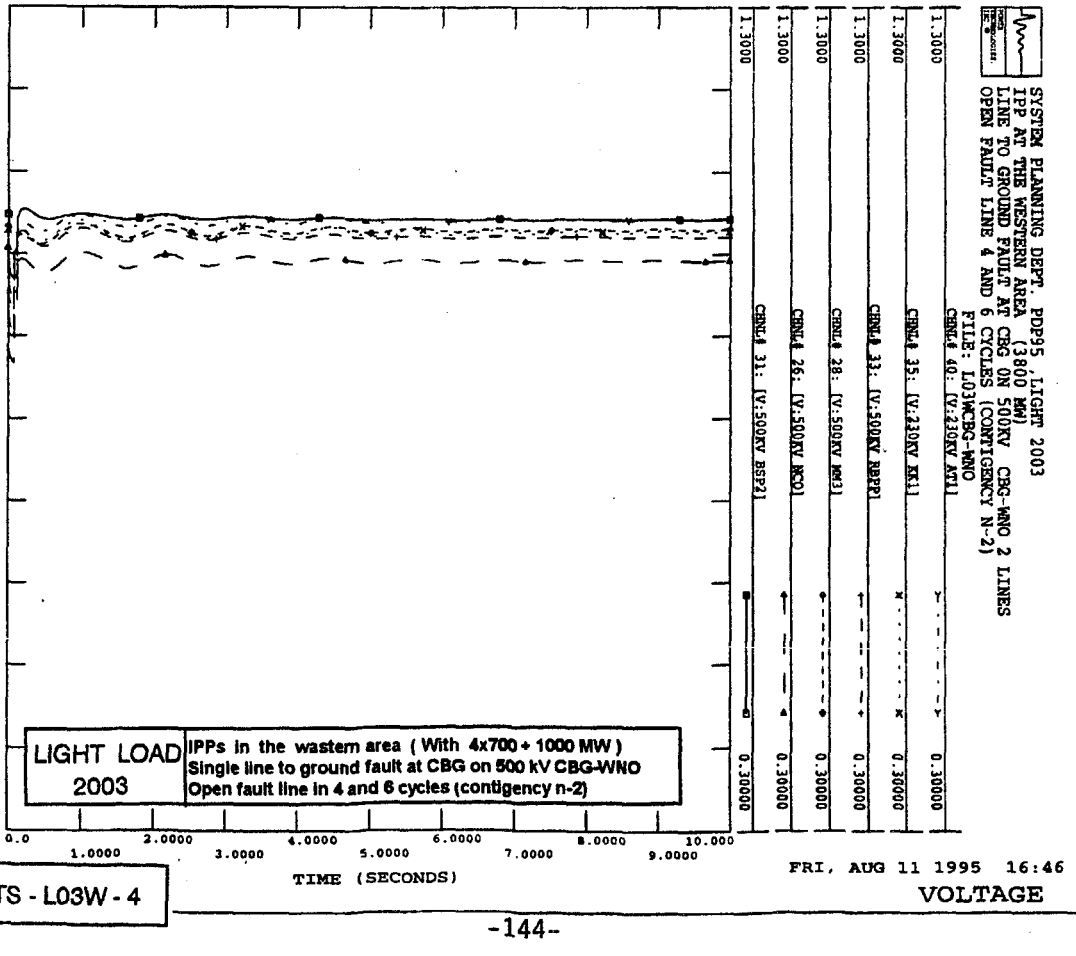

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2003
IPP AT THE WESTERN AREA (3800 MW)
LINE TO GROUND FAULT AT BSP2 ON 500KV BSP2-CBG 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L03WBSP2-CBG
CHNL# 41: [V:230KV RY2]
CHNL# 36: [V:230KV SR1]
CHNL# 34: [V:230KV NB]
CHNL# 28: [V:500KV MM3]
CHNL# 32: [V:500KV CBG]
CHNL# 31: [V:500KV BSP2]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 16:43
VOLTAGE
LIGHT LOAD
2003
IPPs in the wastern area (With 4x700 + 1000 MW)
Single line to ground fault at BSP2 on 500 kV BSP2-CBG
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS - L03W - 2



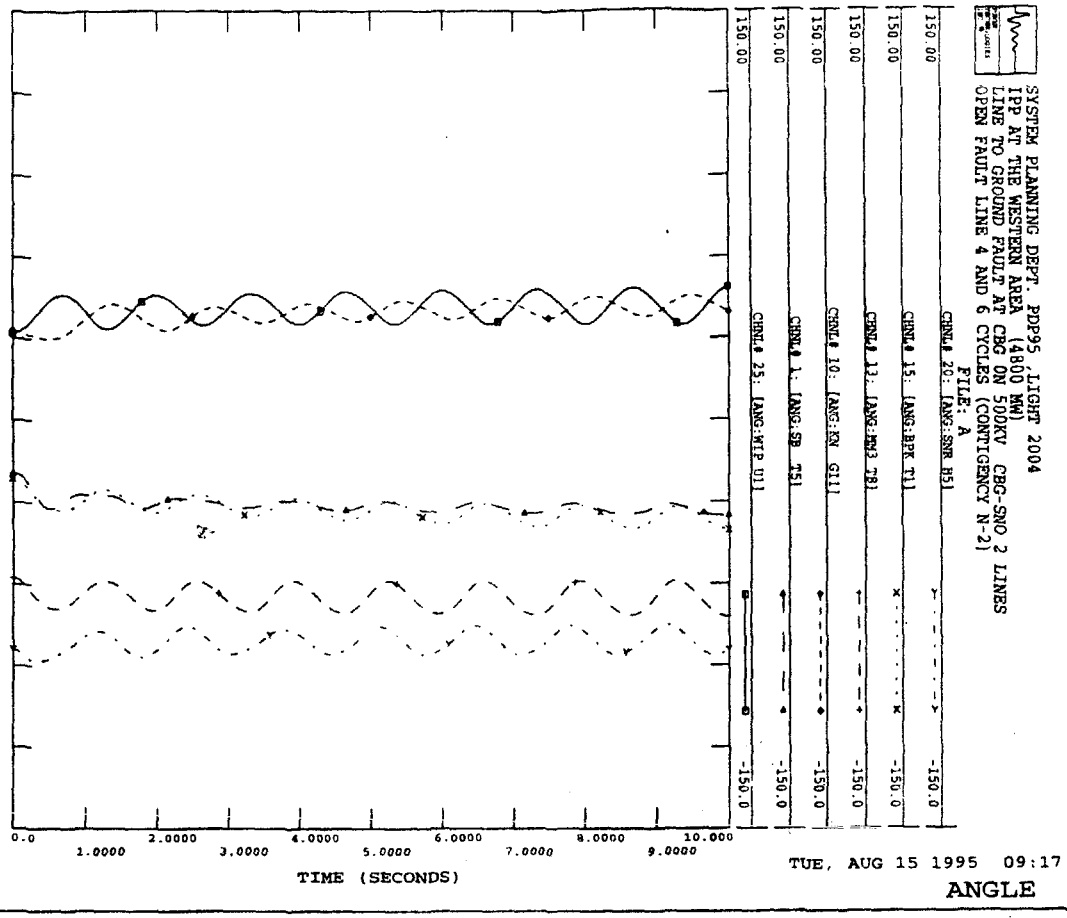


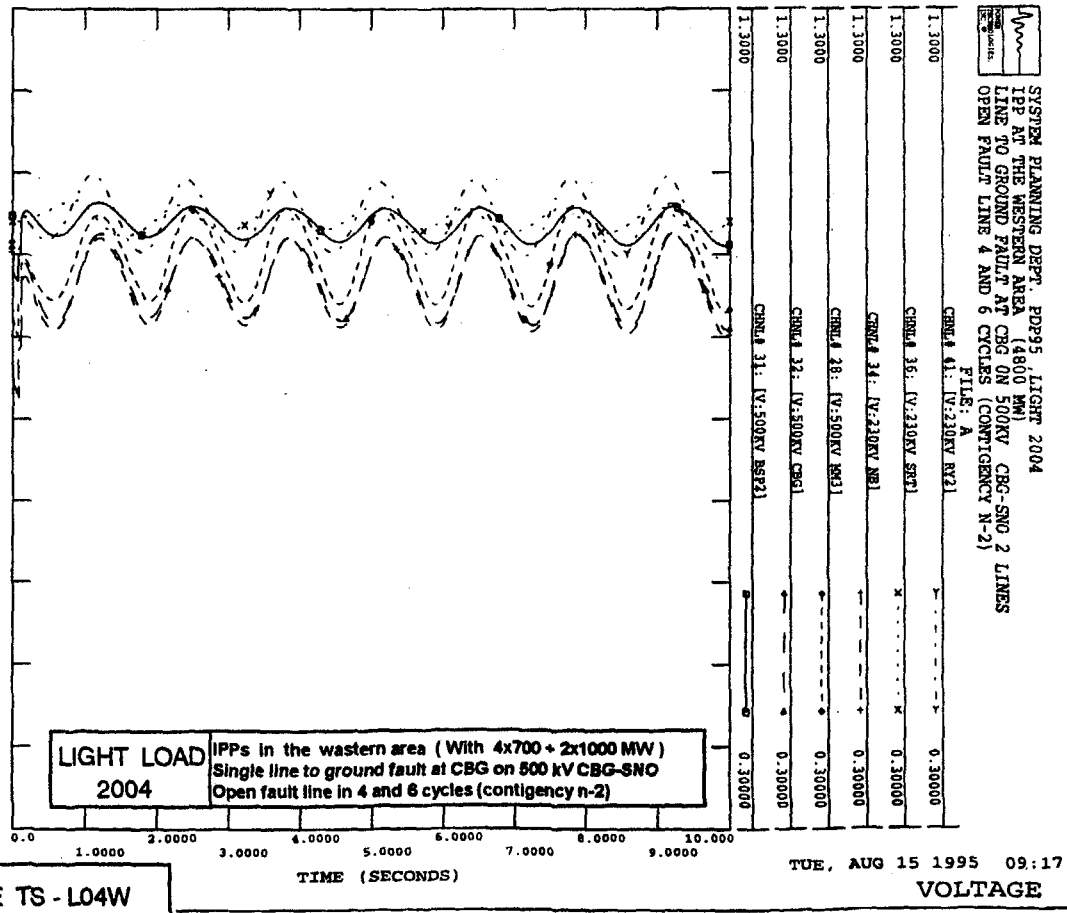
CASE TS - L03W - 3



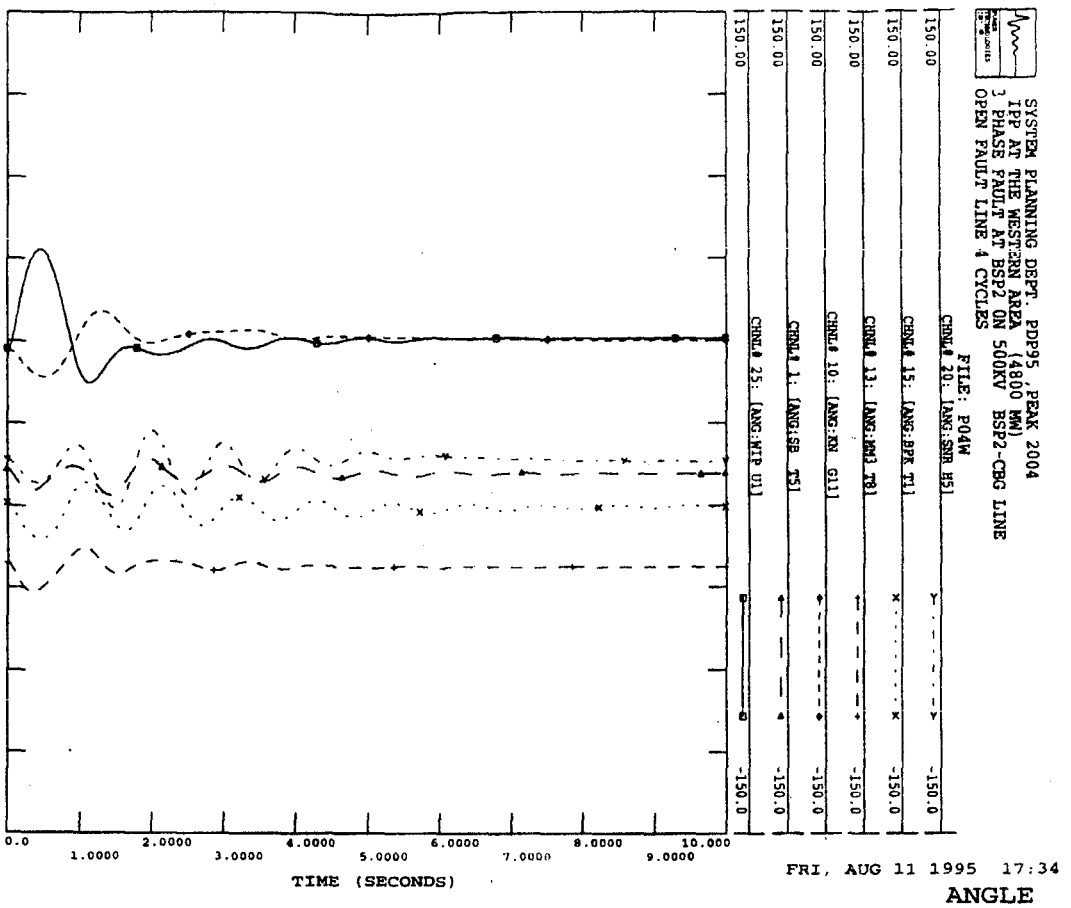


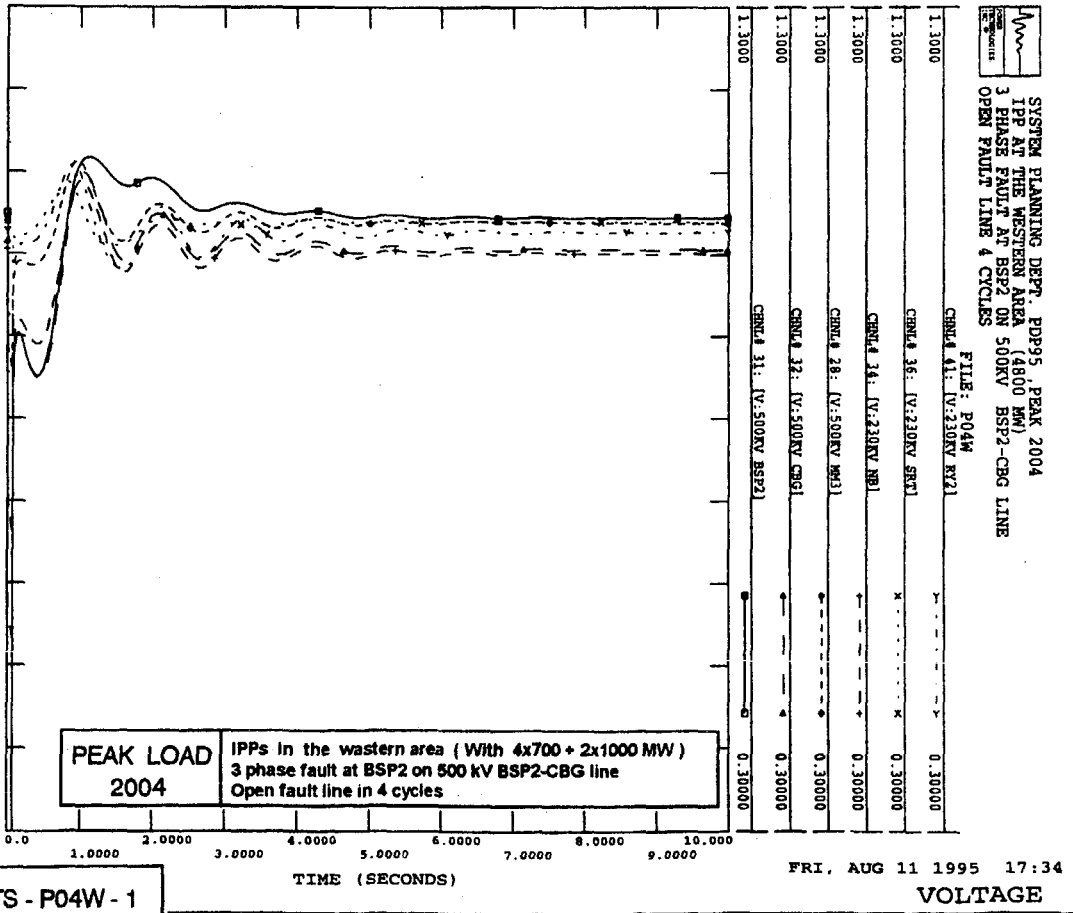
CASE TS - L03W - 4


SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2004
IPP AT THE WESTERN AREA (4800 MW)
LINE TO GROUND FAULT AT CBG ON 500KV CBG-SNO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: A
CHNL# 20: [ANG:SNR B5]
CHNL# 15: [ANG:BPK T1]
CHNL# 13: [ANG:KH3 7B]
CHNL# 10: [ANG:EN G11]
CHNL# 1: [ANG:SB T5]
CHNL# 25: [ANG:MIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, AUG 15 1995 09:17
ANGLE

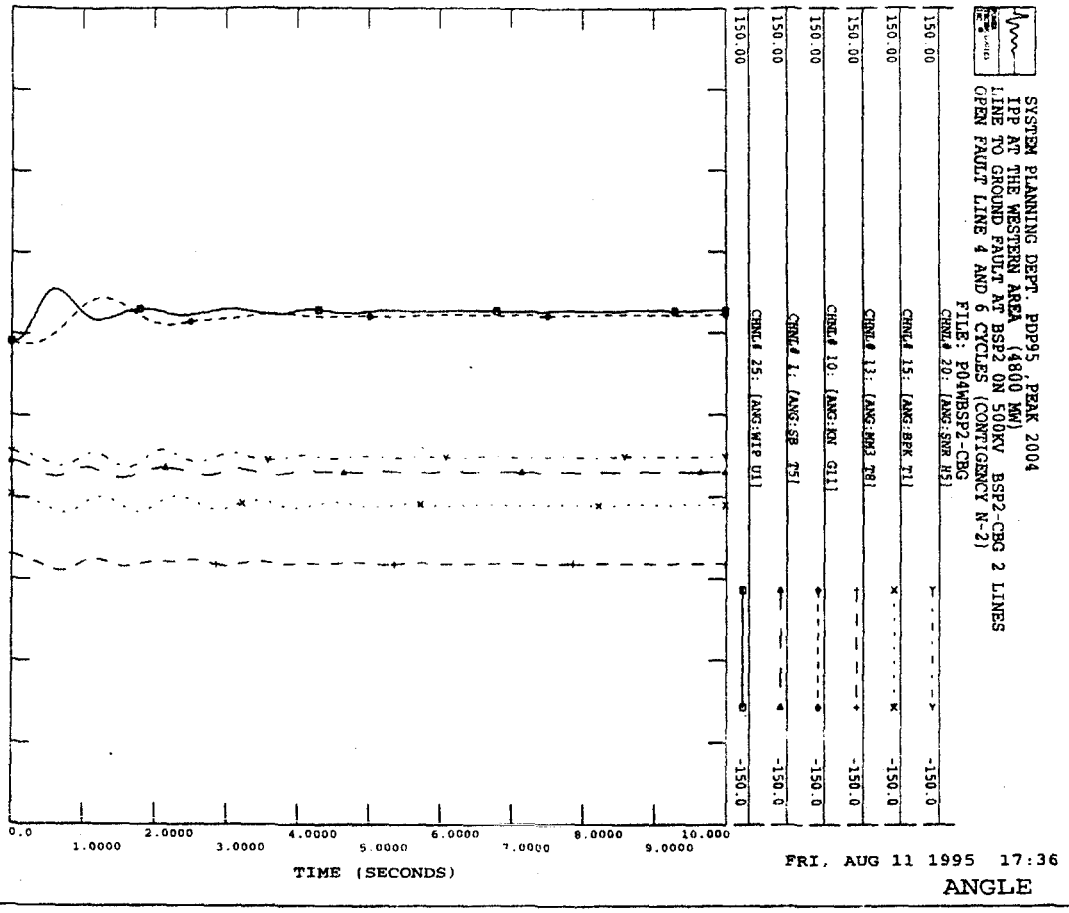

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2004
IPP AT THE WESTERN AREA (4800 MW)
LINE TO GROUND FAULT AT CBG ON 500KV CBG-SNO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: A
CHNL# 41: [V:230KV RV2]
CHNL# 36: [V:230KV SET1]
CHNL# 34: [V:230KV NB]
CHNL# 28: [V:500KV KM3]
CHNL# 32: [V:500KV CBG]
CHNL# 31: [V:500KV BSF2]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, AUG 15 1995 09:17
VOLTAGE
LIGHT LOAD 2004
IPPs in the wastern area (With 4x700 + 2x1000 MW)
Single line to ground fault at CBG on 500 kV CBG-SNO
Open fault line in 4 and 6 cycles (contigency n-2)

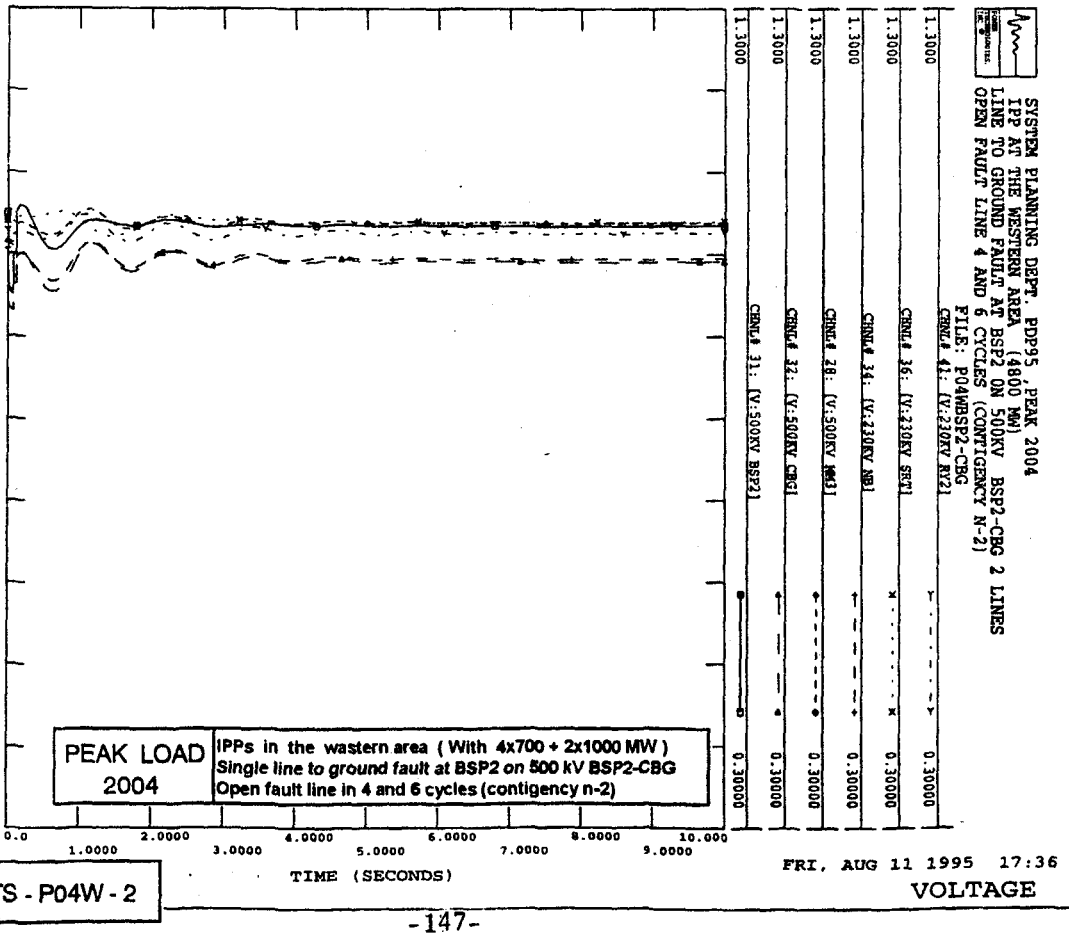
CASE TS - L04W



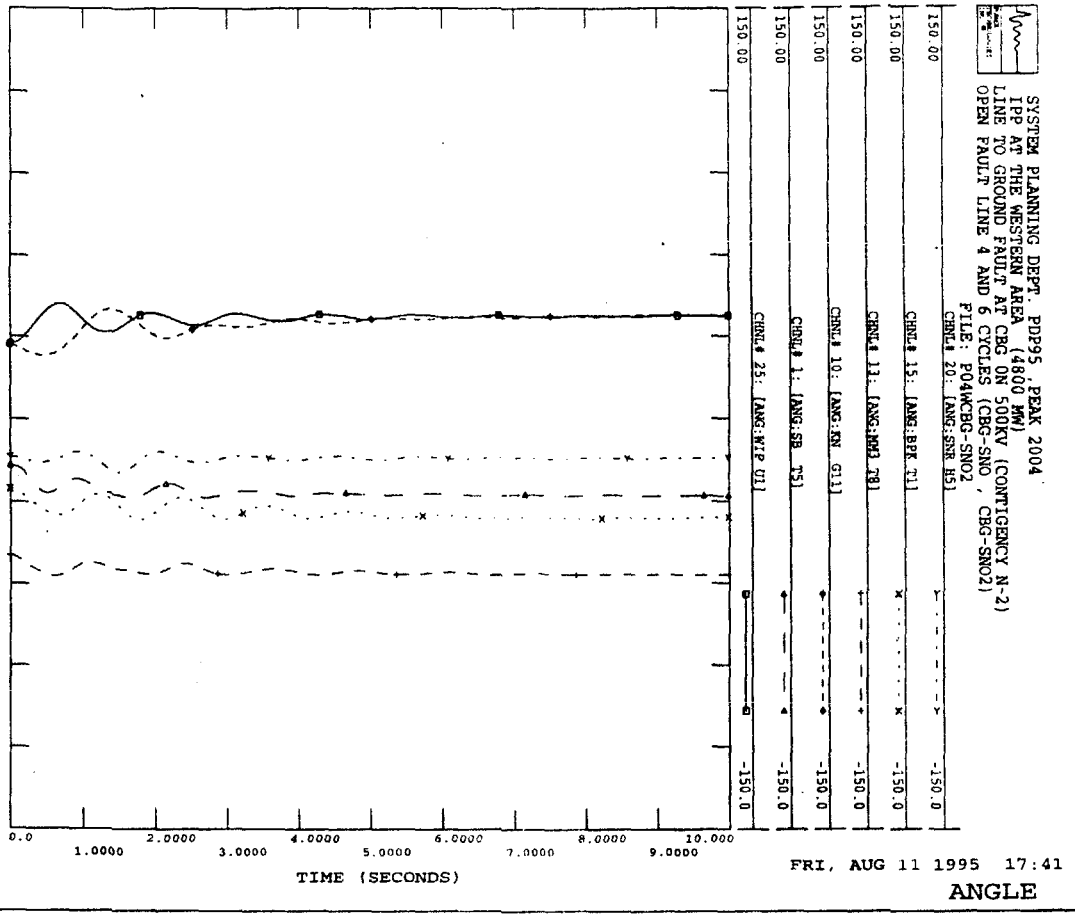


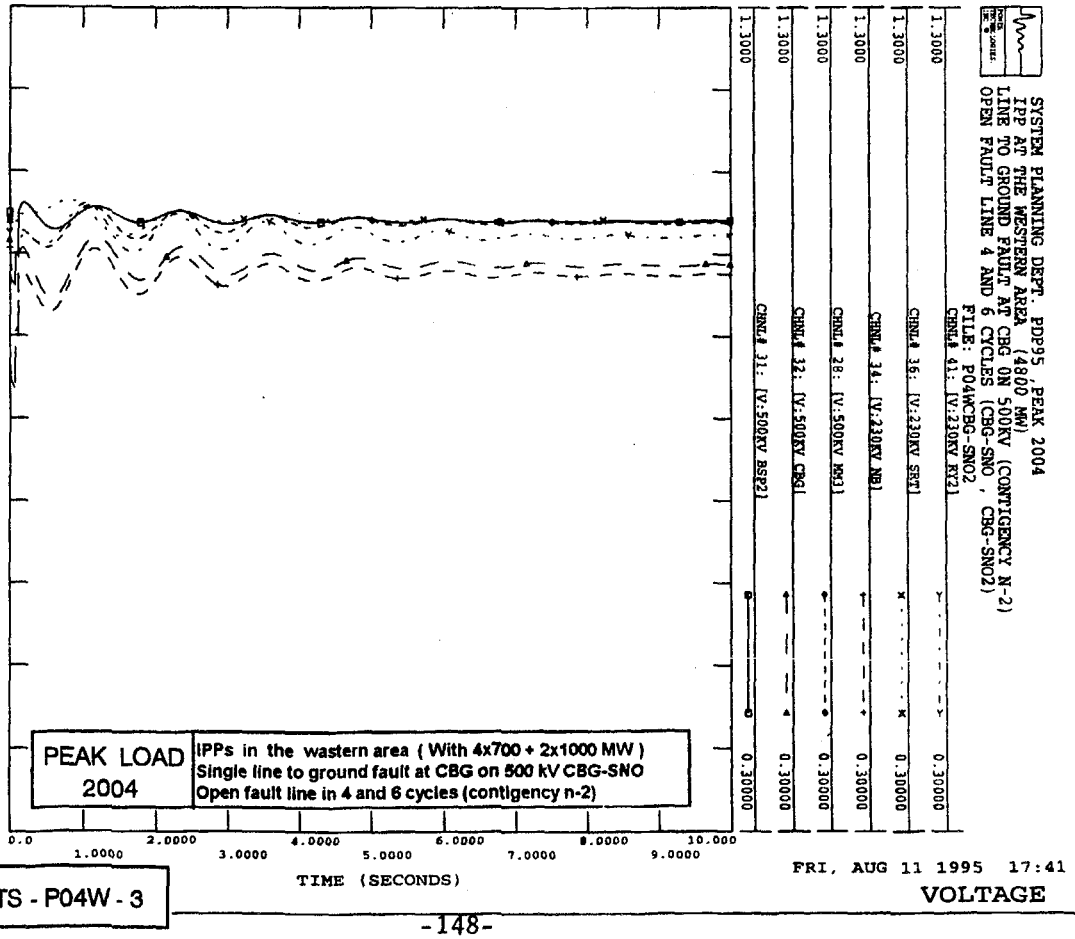
CASE TS - P04W - 1



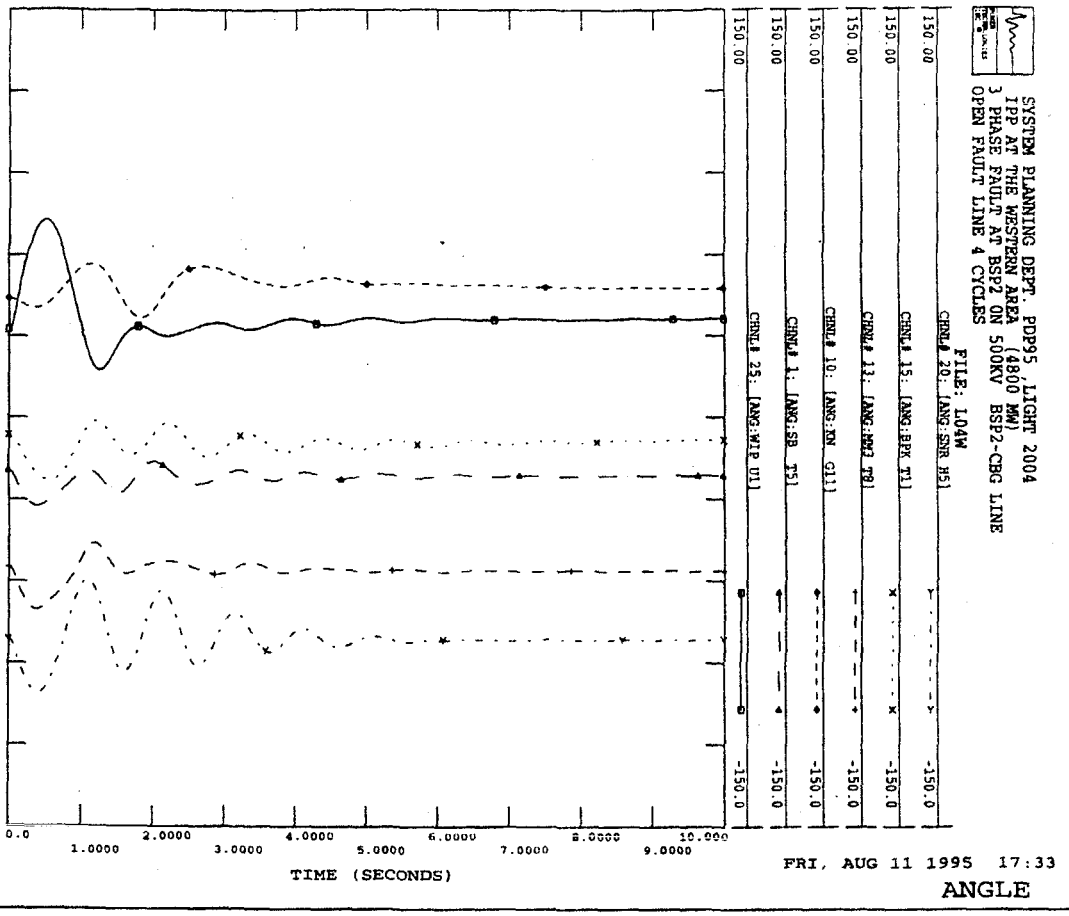


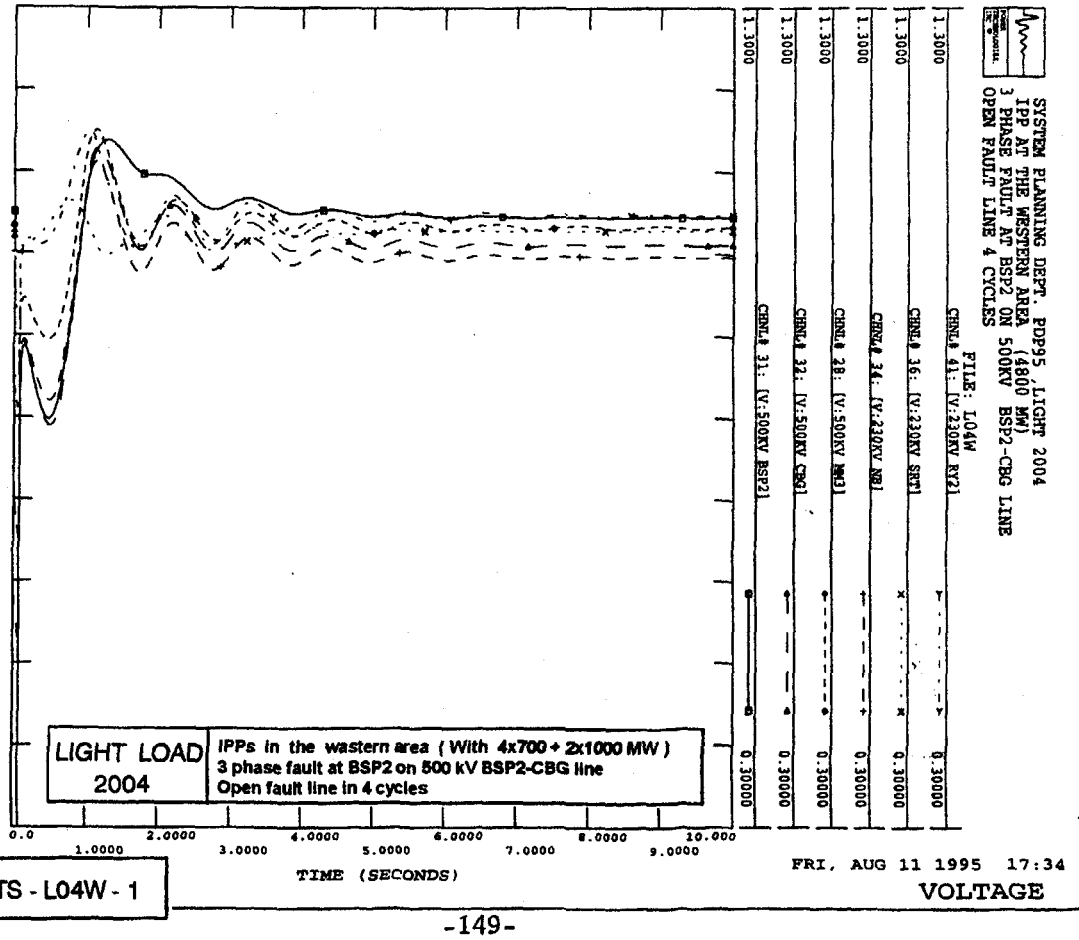
CASE TS - P04W - 2



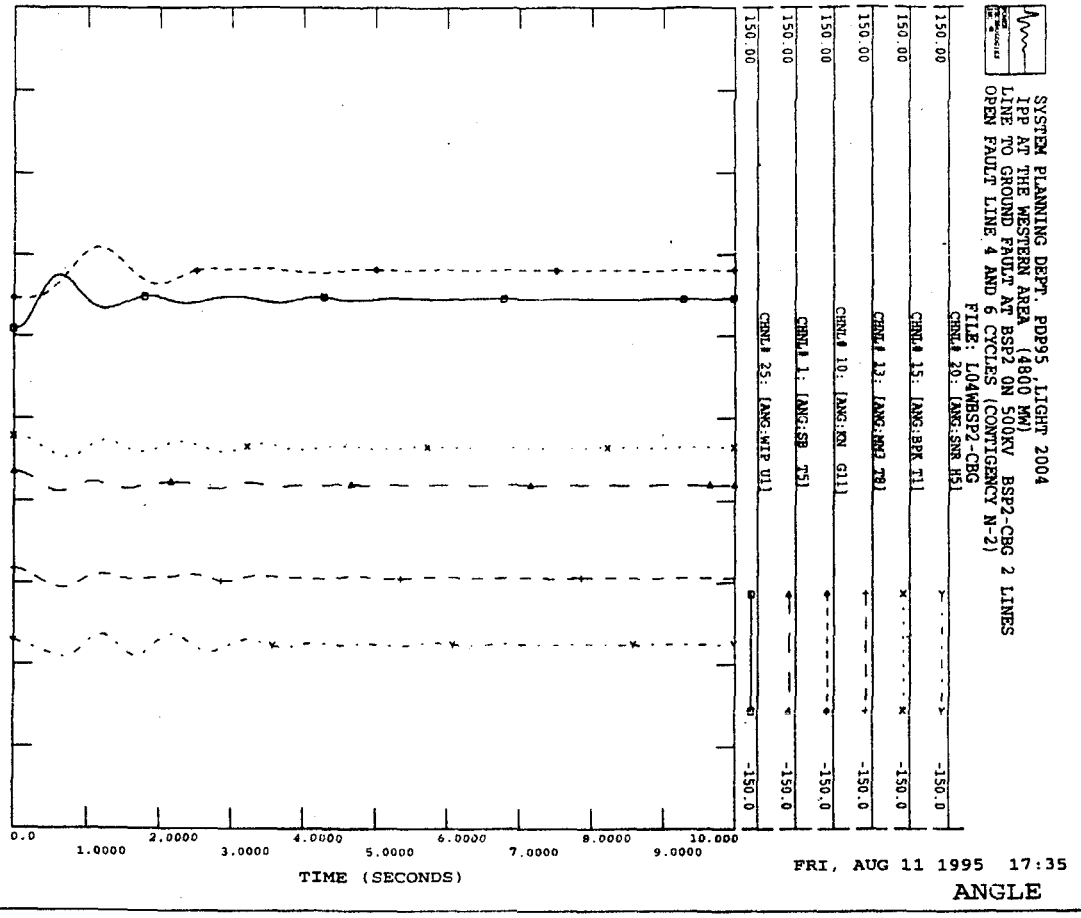


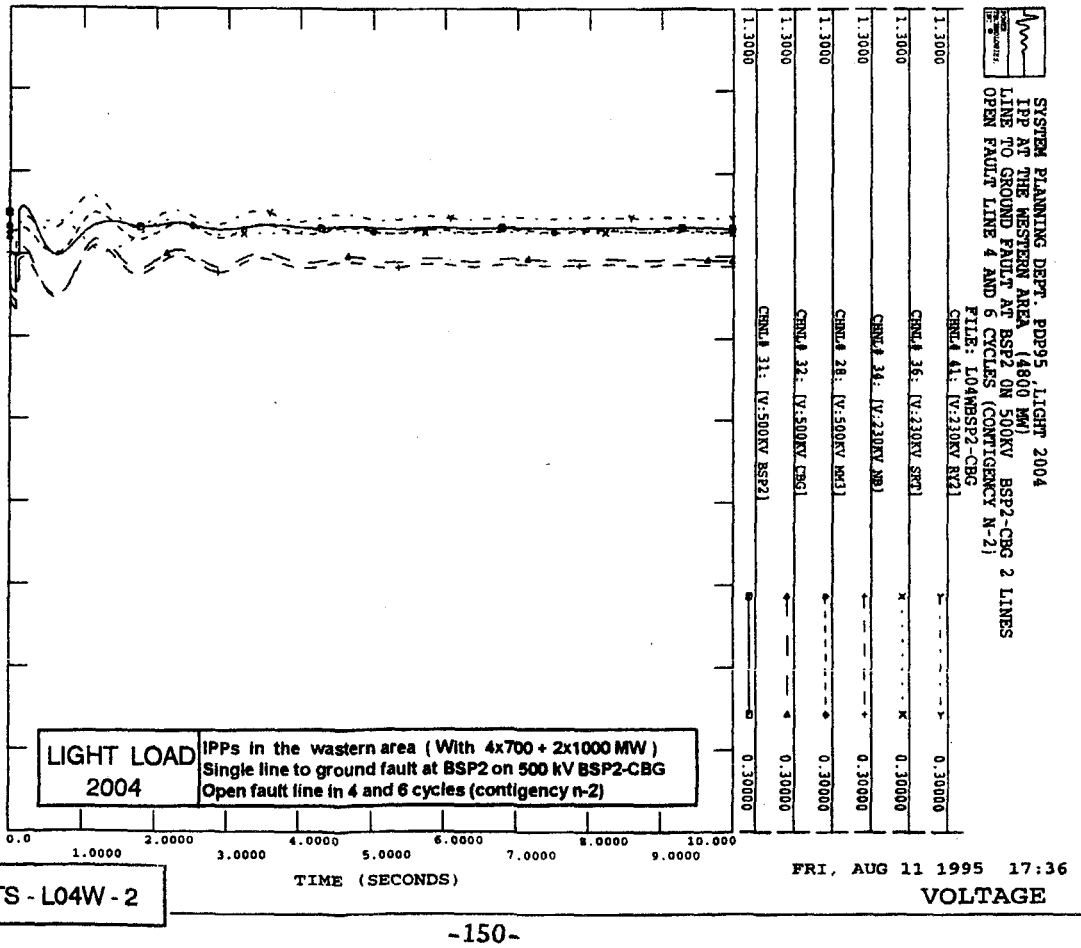
CASE TS - P04W - 3



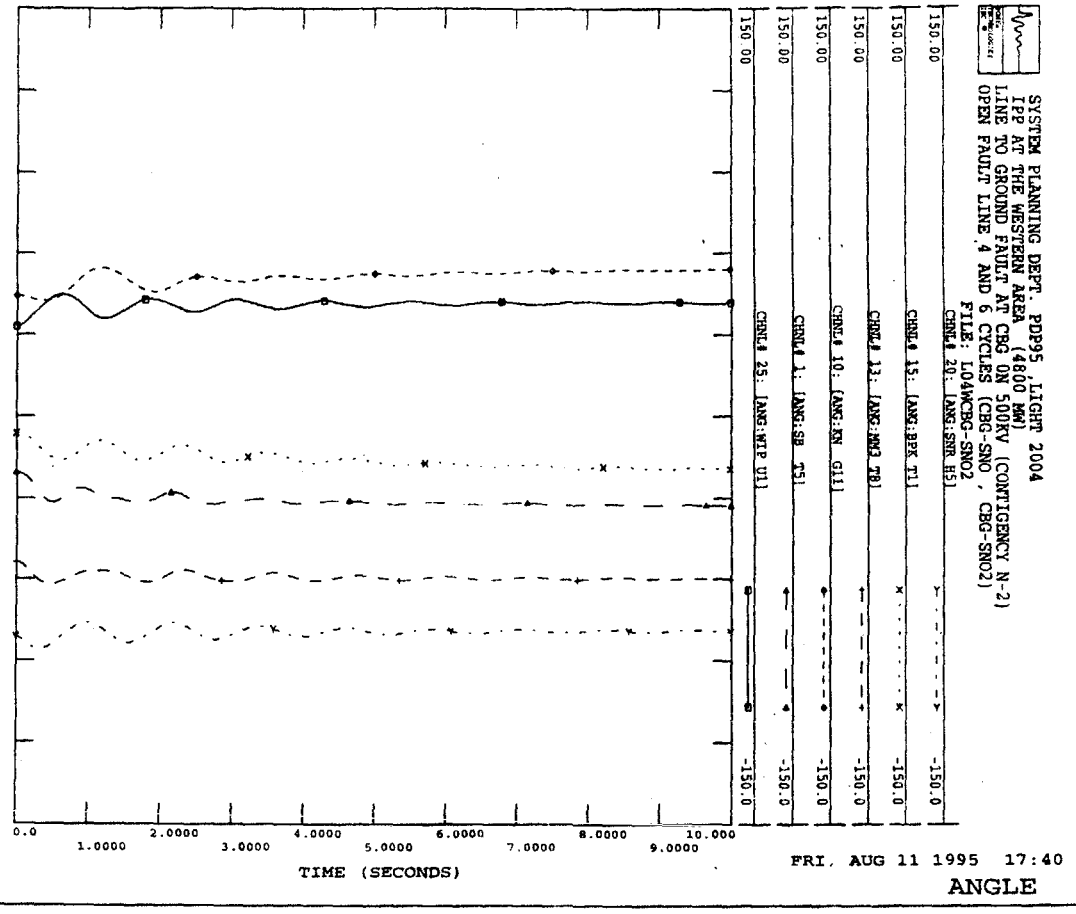


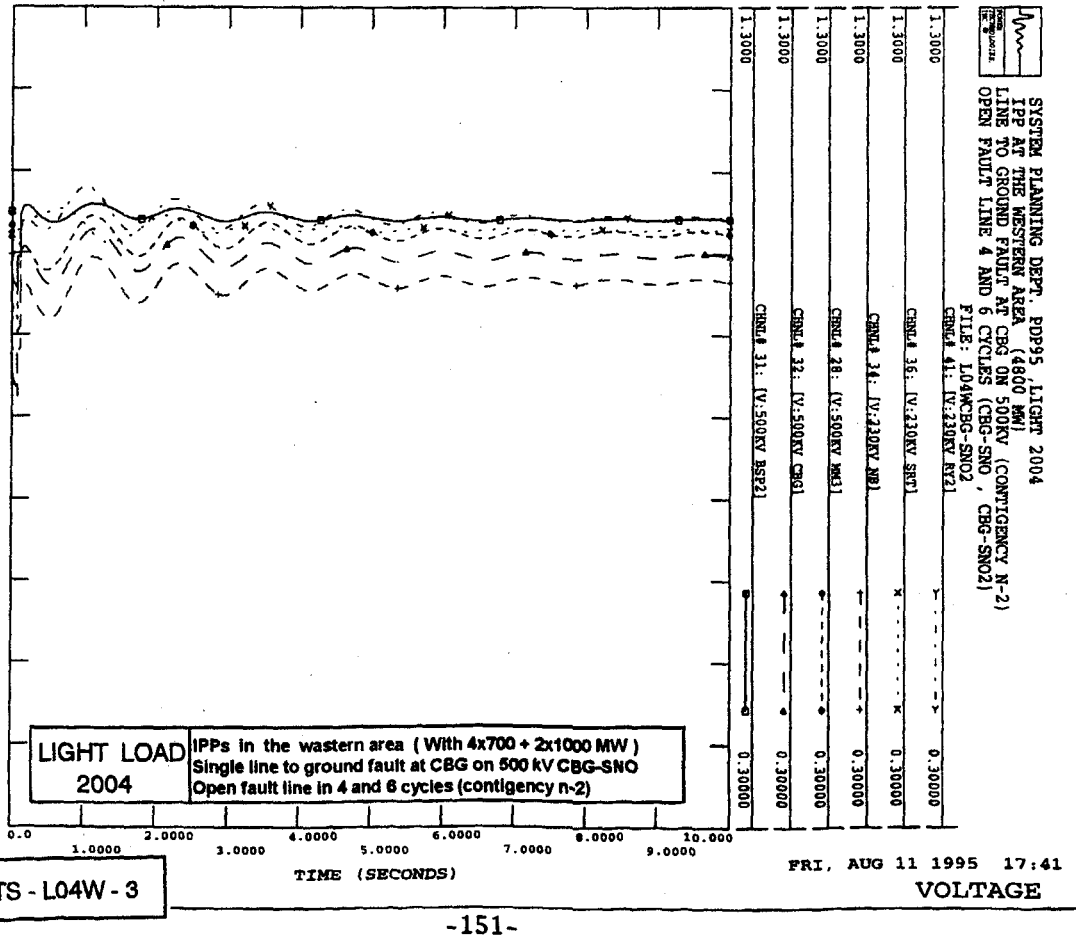
CASE TS - L04W - 1

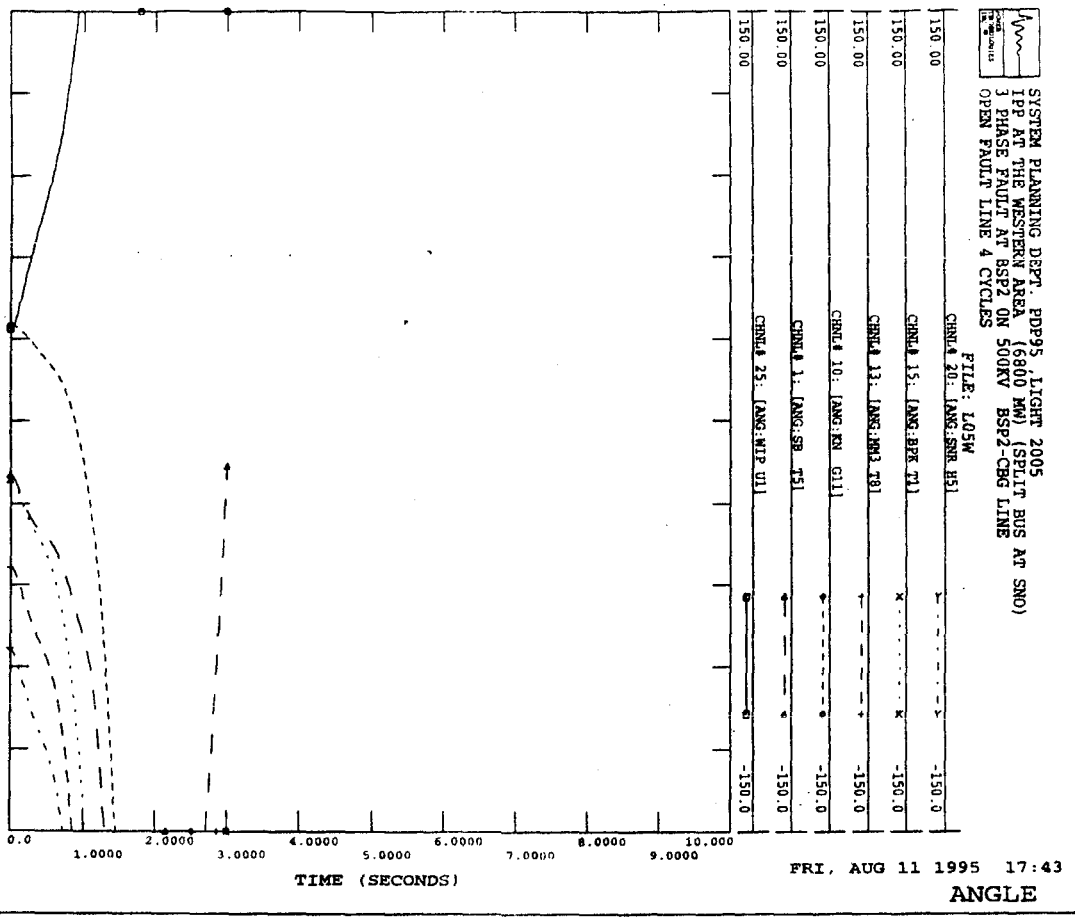


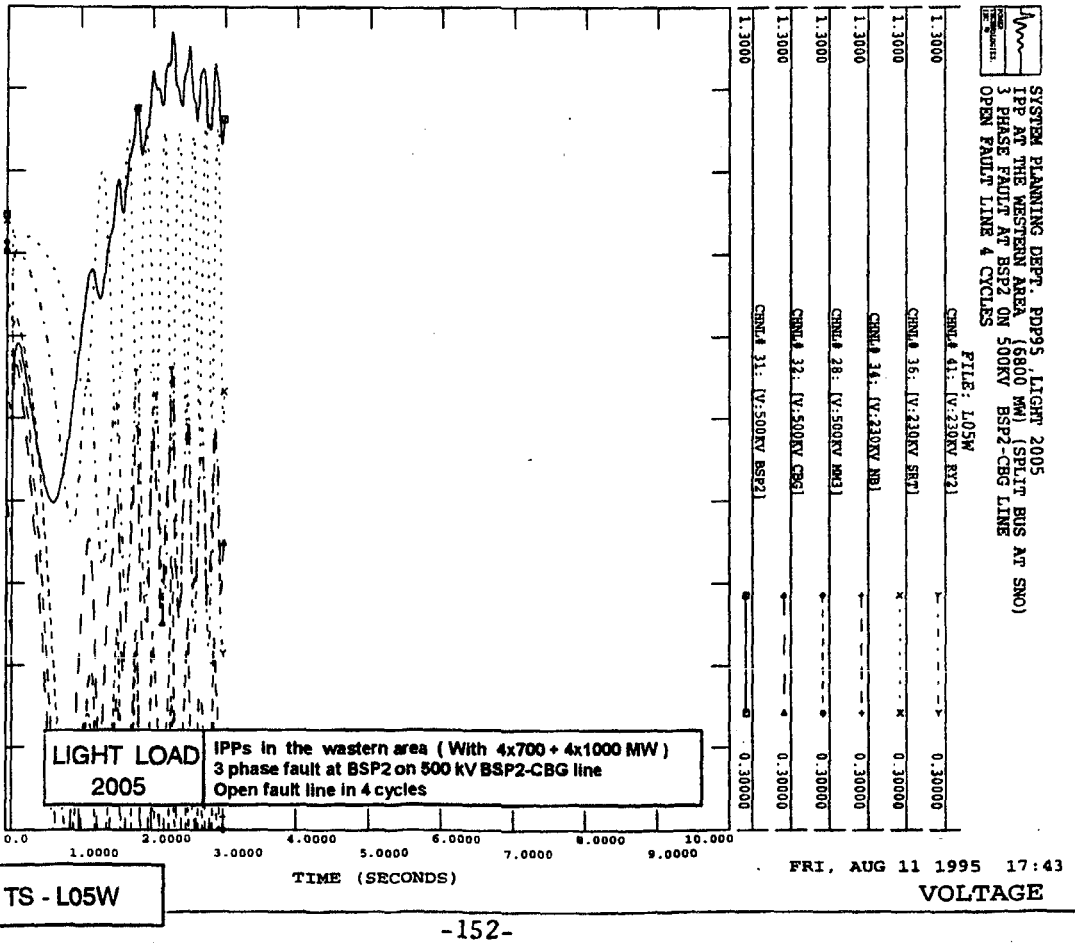


CASE TS - L04W - 2

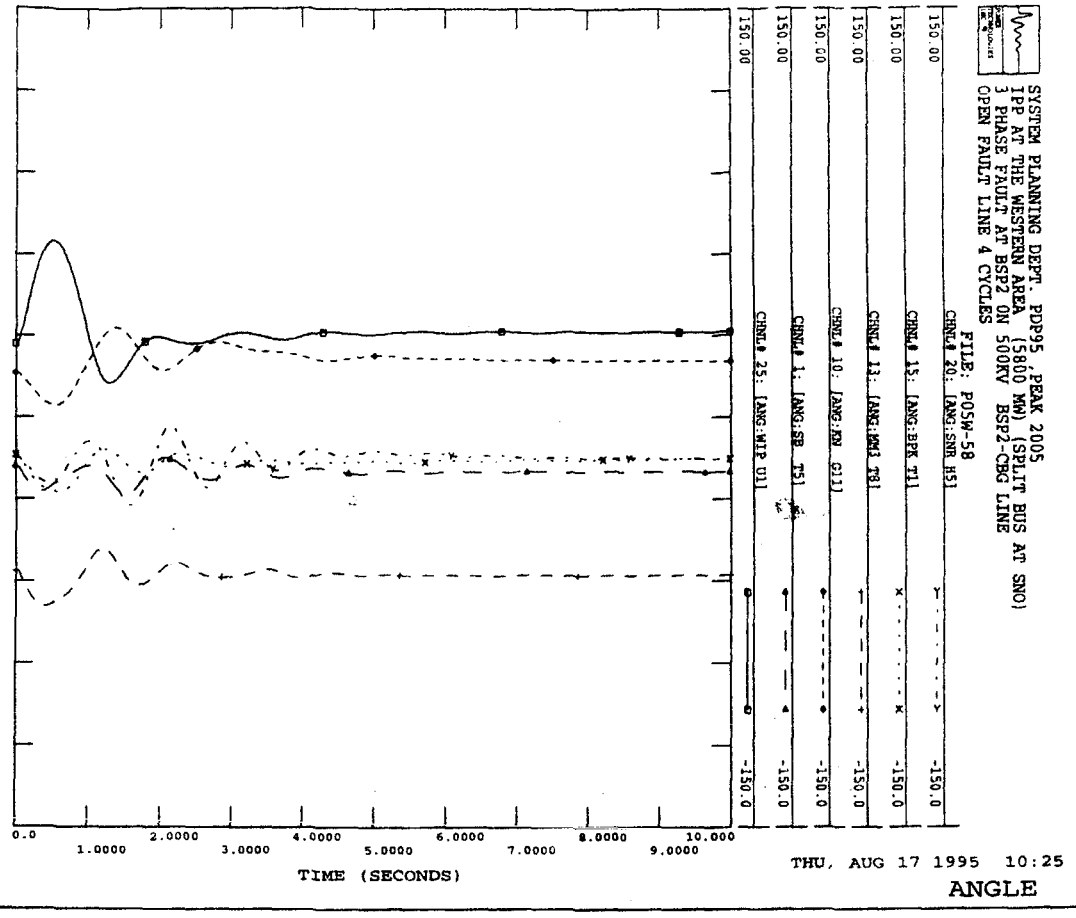

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2004
IPP AT THE WESTERN AREA (4800 MW)
LINE TO GROUND FAULT AT CBG ON 500KV (CONTIGENCY N-2)
OPEN FAULT LINE 4 AND 6 CYCLES (CBG-SNO , CBG-SNO2)
FILE: L04WCBG-SNO2
CHNL# 20: [ANG:SNR H5]
CHNL# 15: [ANG:BRK T1]
CHNL# 12: [ANG:MM3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB T5]
CHNL# 25: [ANG:WIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 17:40
ANGLE

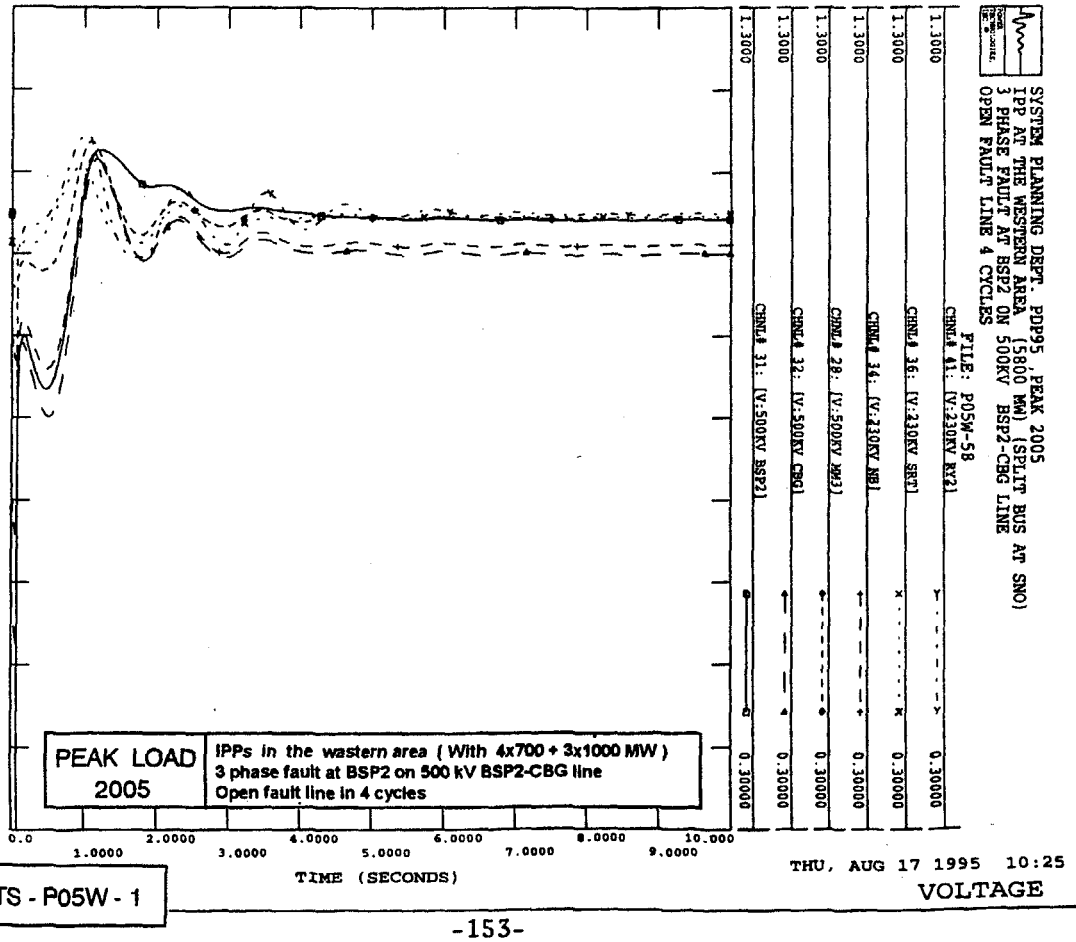

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2004
IPP AT THE WESTERN AREA (4800 MW)
LINE TO GROUND FAULT AT CBG ON 500KV (CONTIGENCY N-2)
OPEN FAULT LINE 4 AND 6 CYCLES (CBG-SNO , CBG-SNO2)
FILE: L04WCBG-SNO2
CHNL# 41: [V:230KV RY2]
CHNL# 36: [V:230KV SN7]
CHNL# 34: [V:230KV NB]
CHNL# 28: [V:500KV MM3]
CHNL# 32: [V:500KV CBG]
CHNL# 31: [V:500KV BSP2]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 17:41
VOLTAGE
LIGHT LOAD
2004
IPPs in the wastern area (With 4x700 + 2x1000 MW)
Single line to ground fault at CBG on 500 kV CBG-SNO
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS - L04W - 3


SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2005
IPP AT THE WESTERN AREA (6800 MW) (SPLIT BUS AT SNO)
3 PHASE FAULT AT BSP2 ON 500KV BSP2-CBG LINE
OPEN FAULT LINE 4 CYCLES
FILE: L05W
CHNL# 20: [ANG:SNK H5]
CHNL# 15: [ANG:BPK T1]
CHNL# 13: [ANG:MM3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB T5]
CHNL# 25: [ANG:WIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 17:43
ANGLE

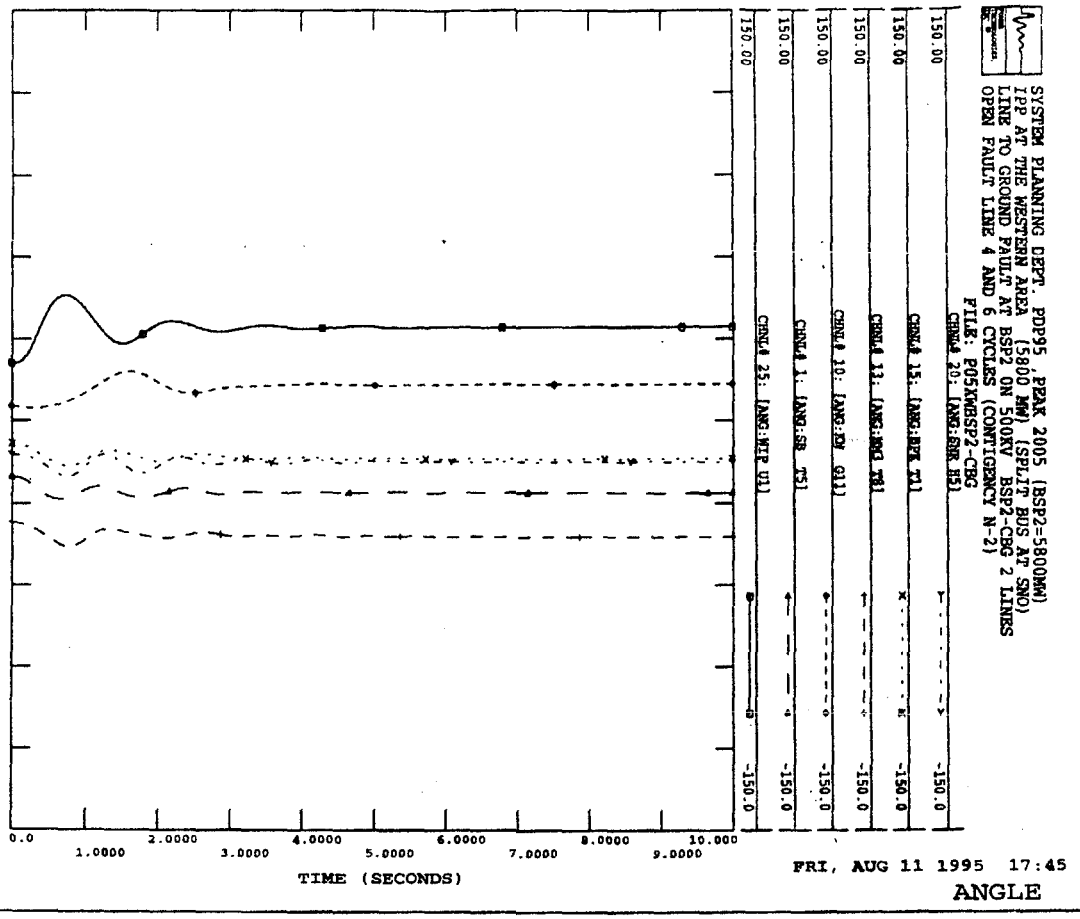

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2005
IPP AT THE WESTERN AREA (6800 MW) (SPLIT BUS AT SNO)
3 PHASE FAULT AT BSP2 ON 500KV BSP2-CBG LINE
OPEN FAULT LINE 4 CYCLES
FILE: L05W
CHNL# 41: [V:230KV KT2]
CHNL# 36: [V:230KV SRT]
CHNL# 34: [V:230KV NB1]
CHNL# 28: [V:500KV MM3]
CHNL# 32: [V:500KV CBG]
CHNL# 31: [V:500KV BSP2]
1.3000
0.30000
LIGHT LOAD
2005
IPPs in the western area (With 4x700 + 4x1000 MW)
3 phase fault at BSP2 on 500 kV BSP2-CBG line
Open fault line in 4 cycles
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 11 1995 17:43
VOLTAGE

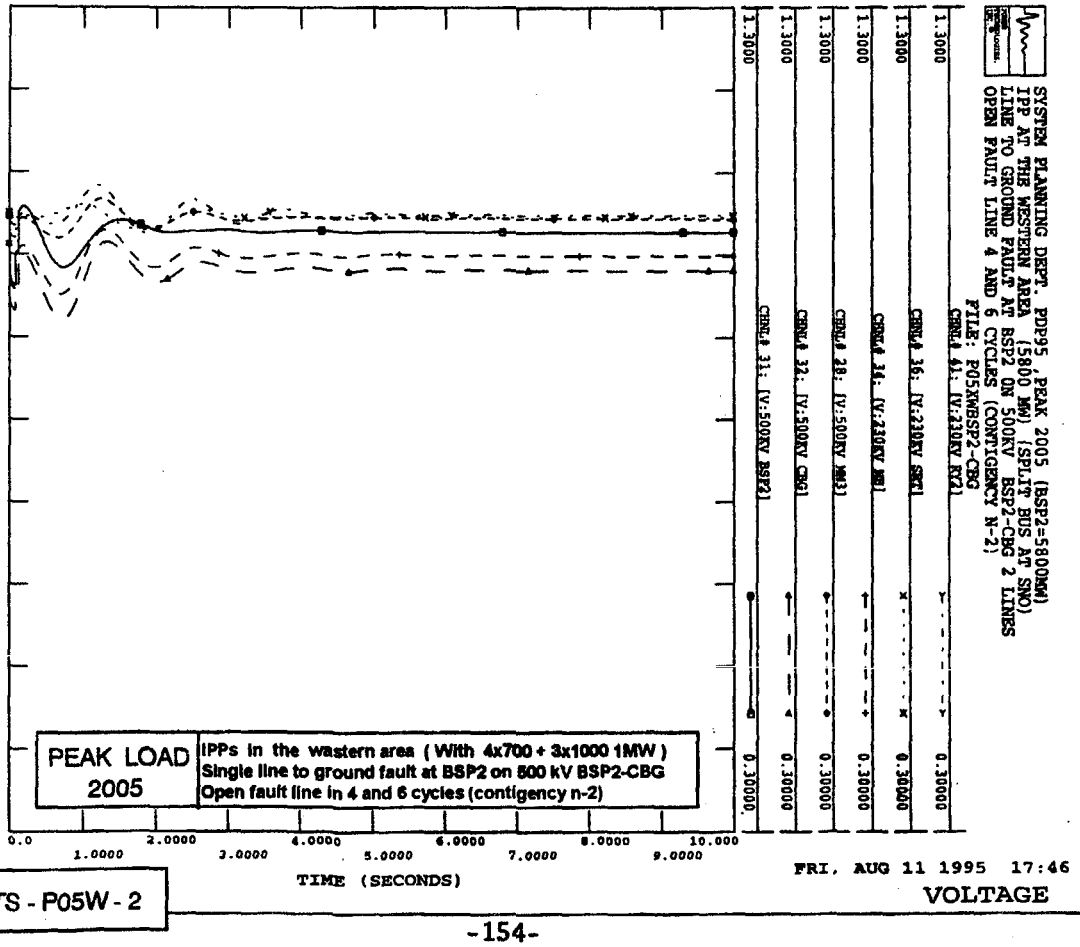
CASE TS - L05W



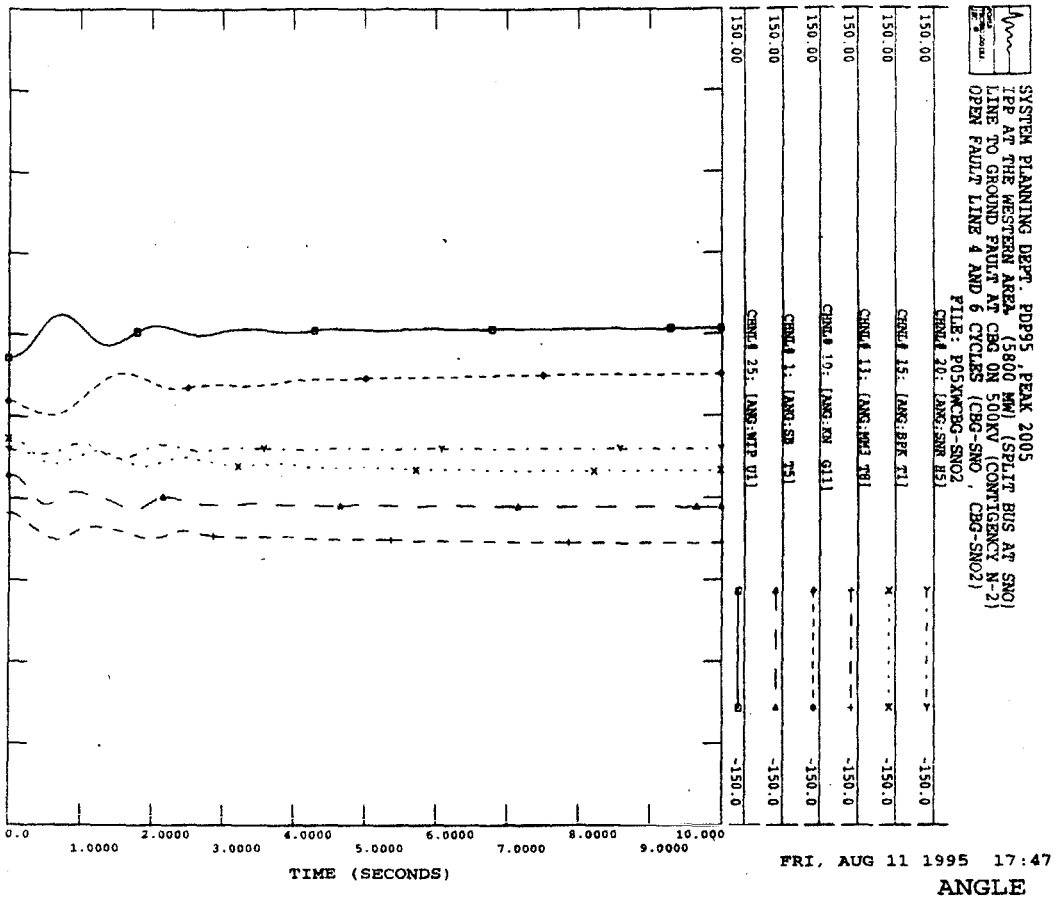


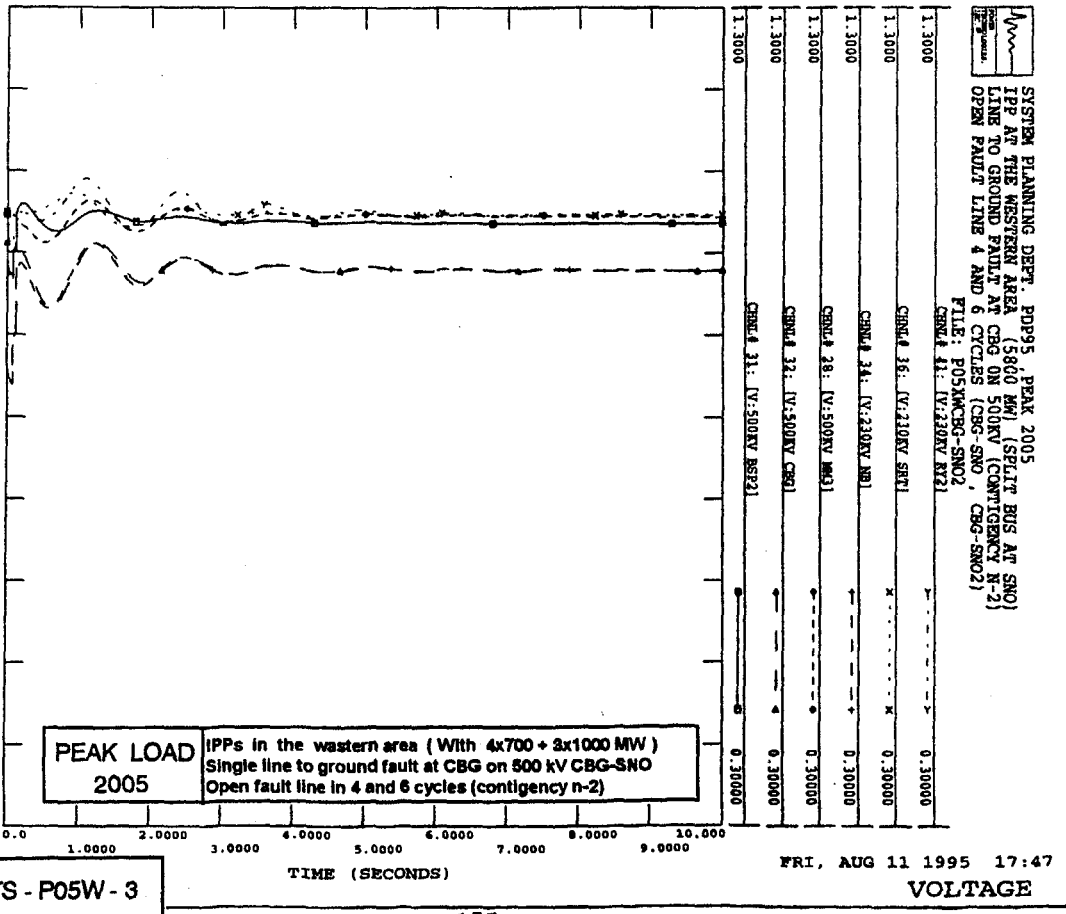
CASE TS - P05W - 1



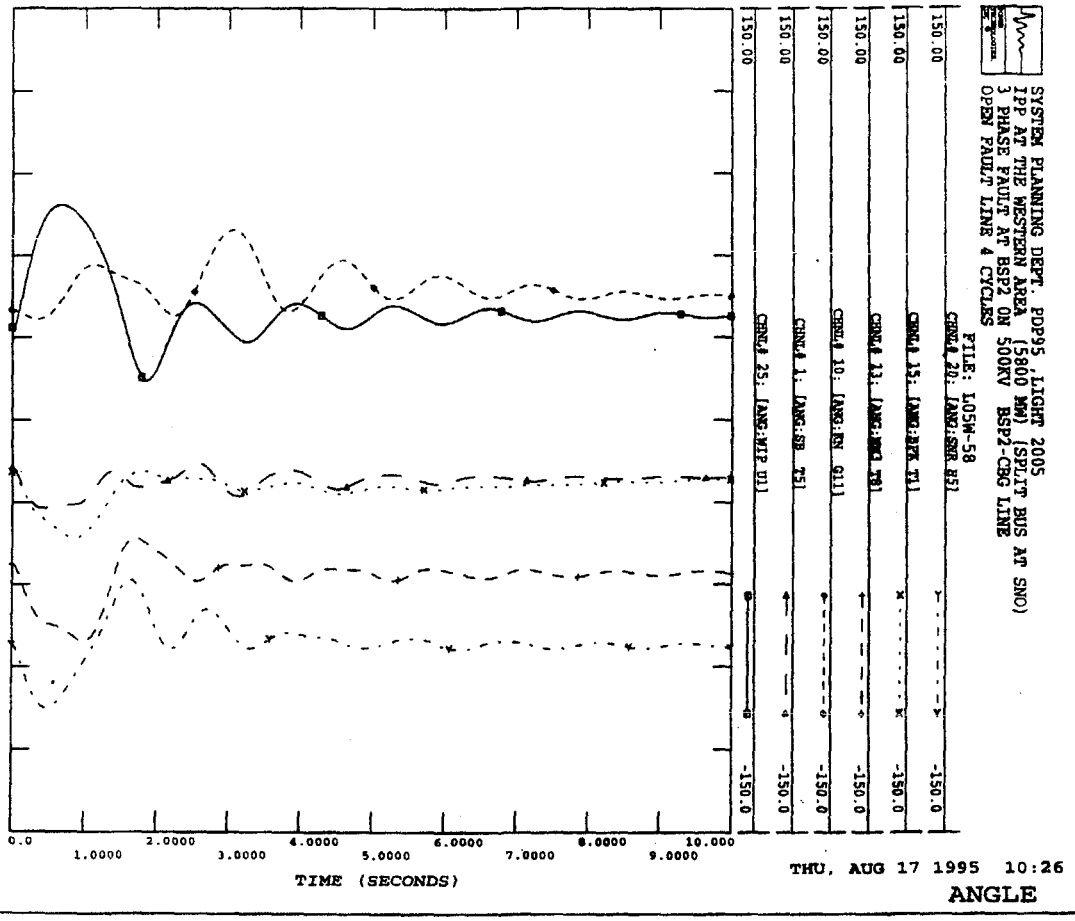


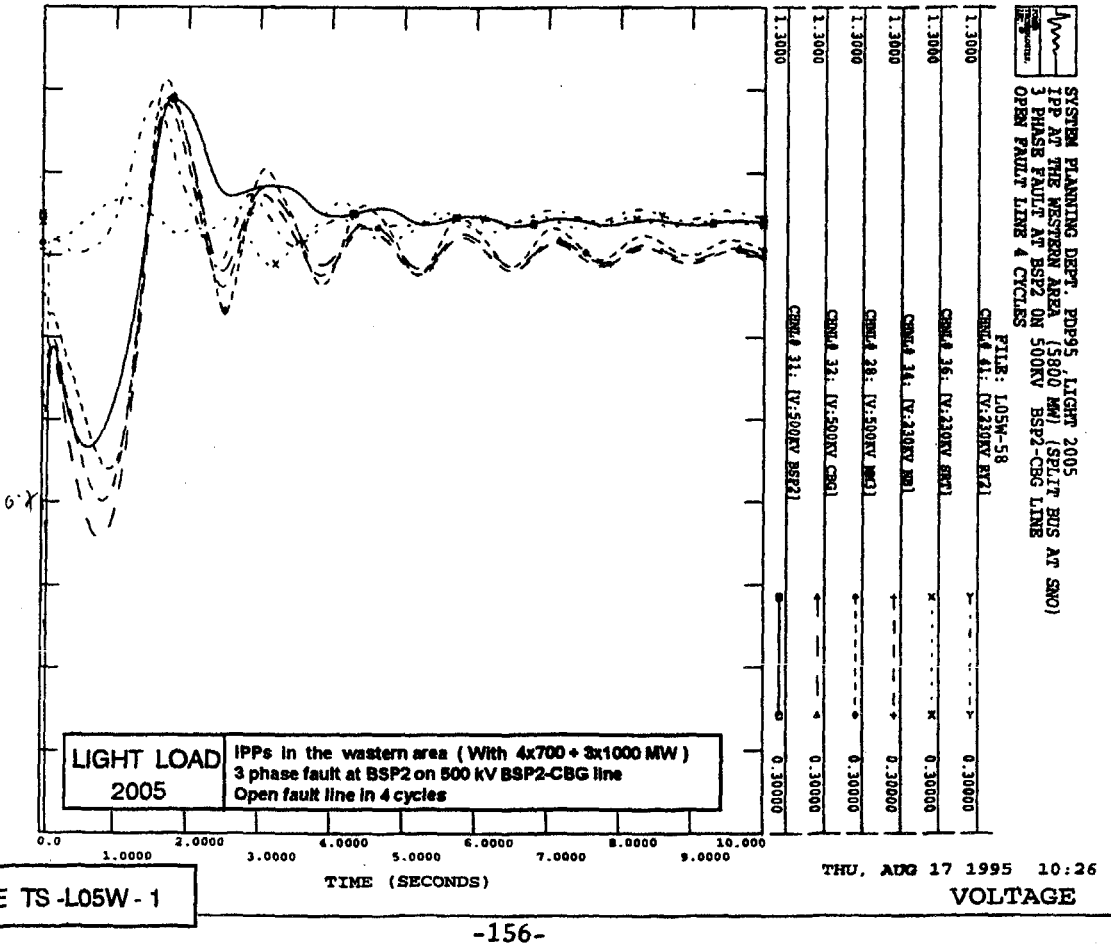
CASE TS - P05W - 2



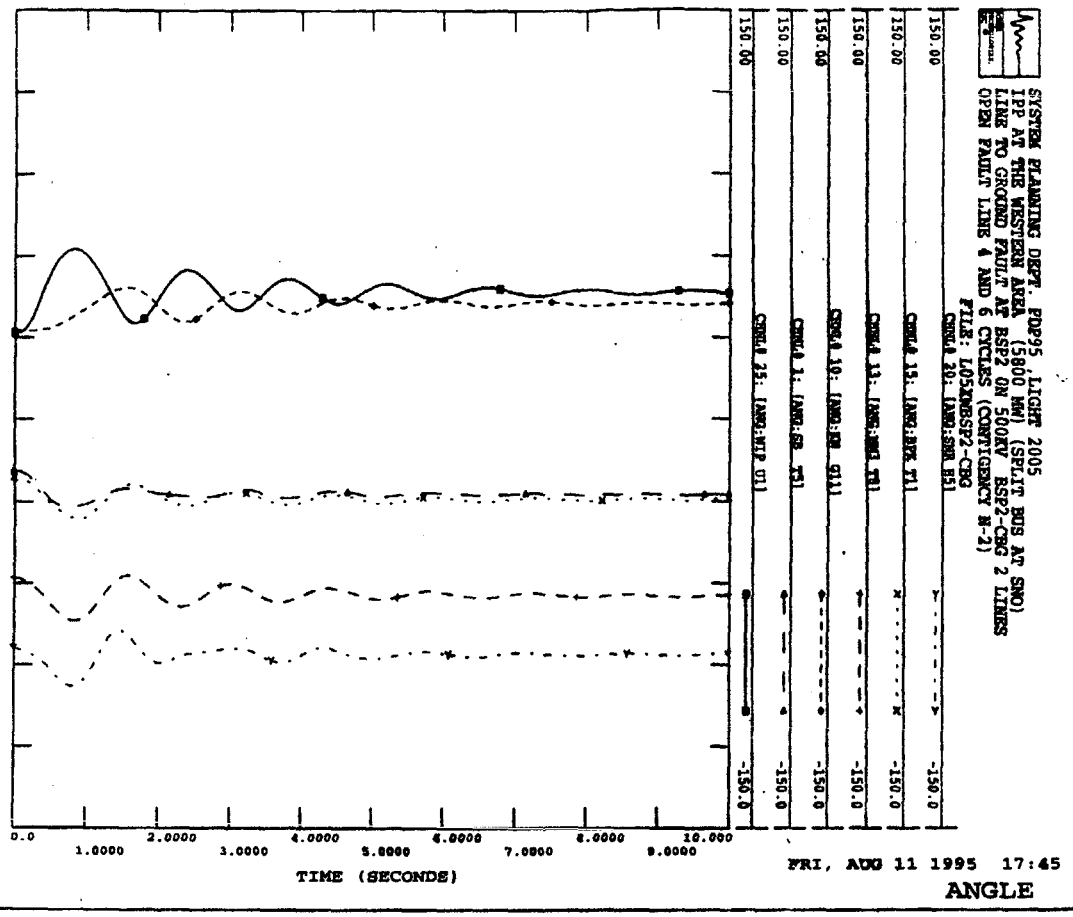


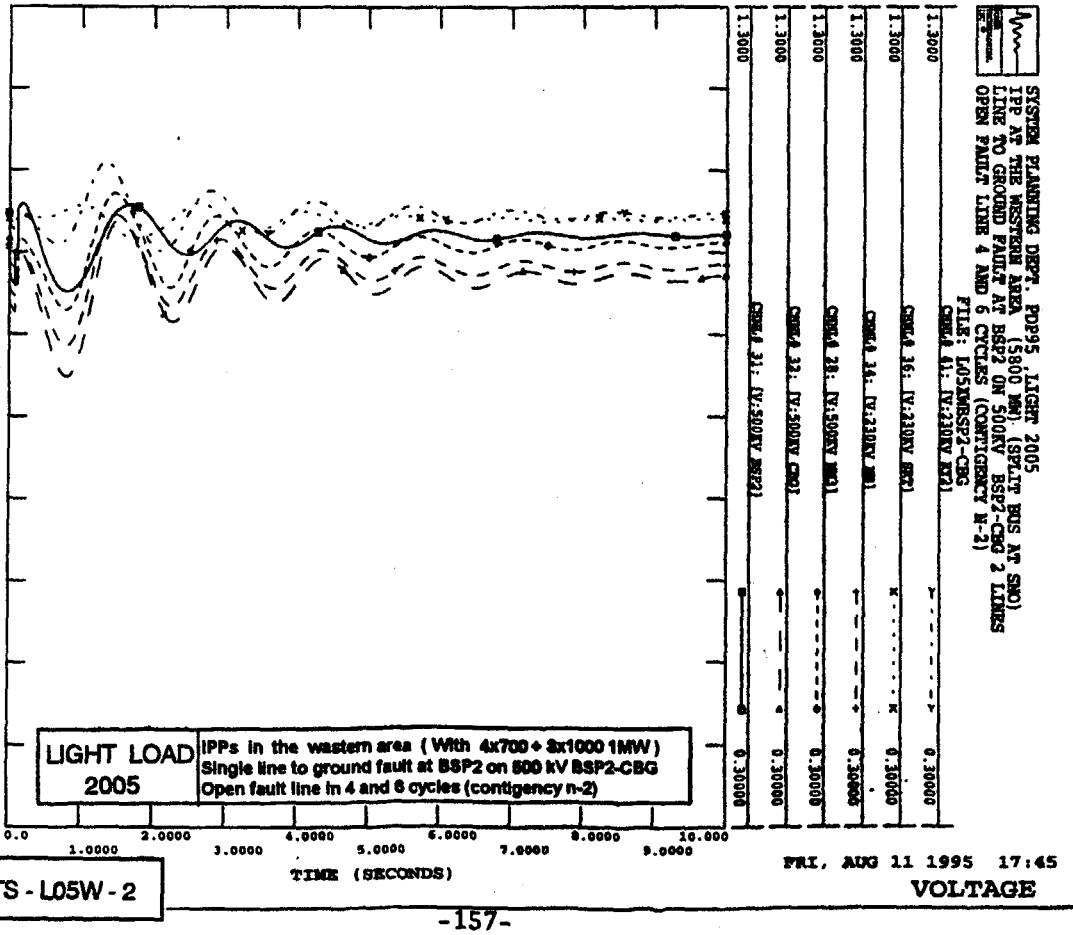
CASE TS - P05W - 3



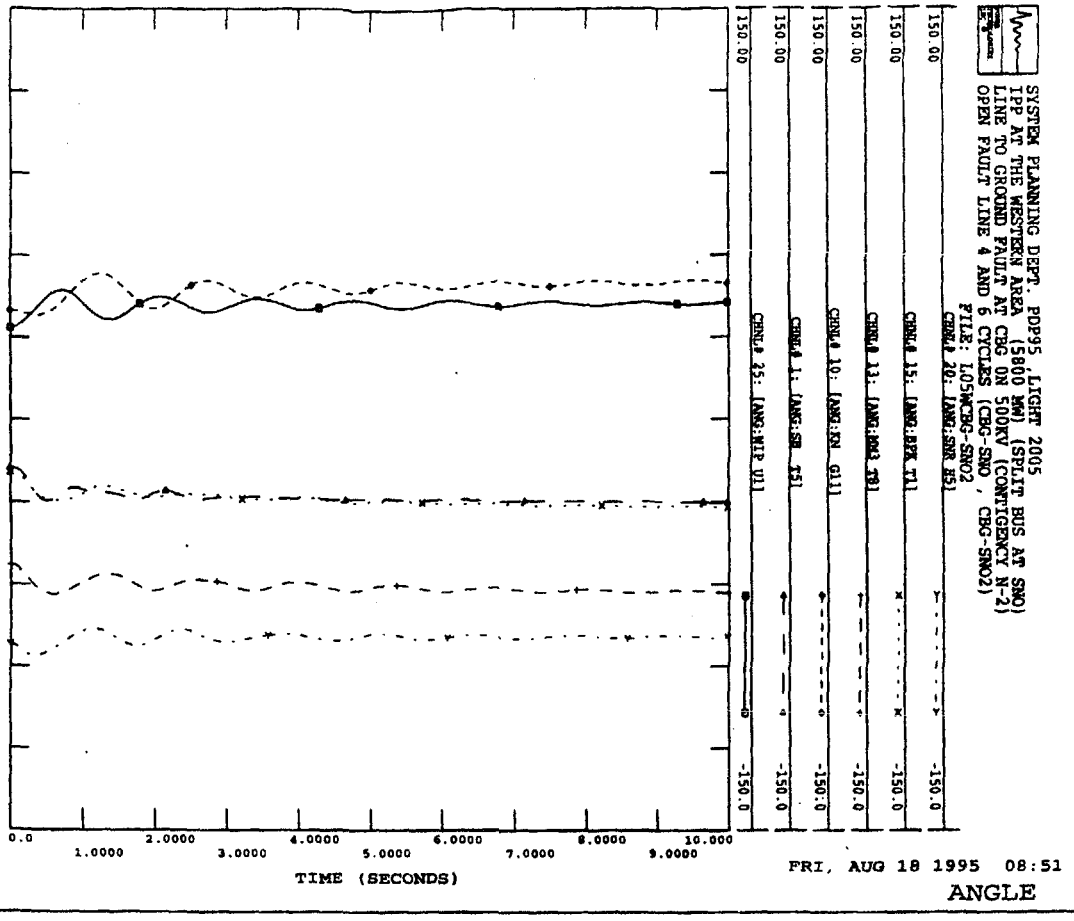


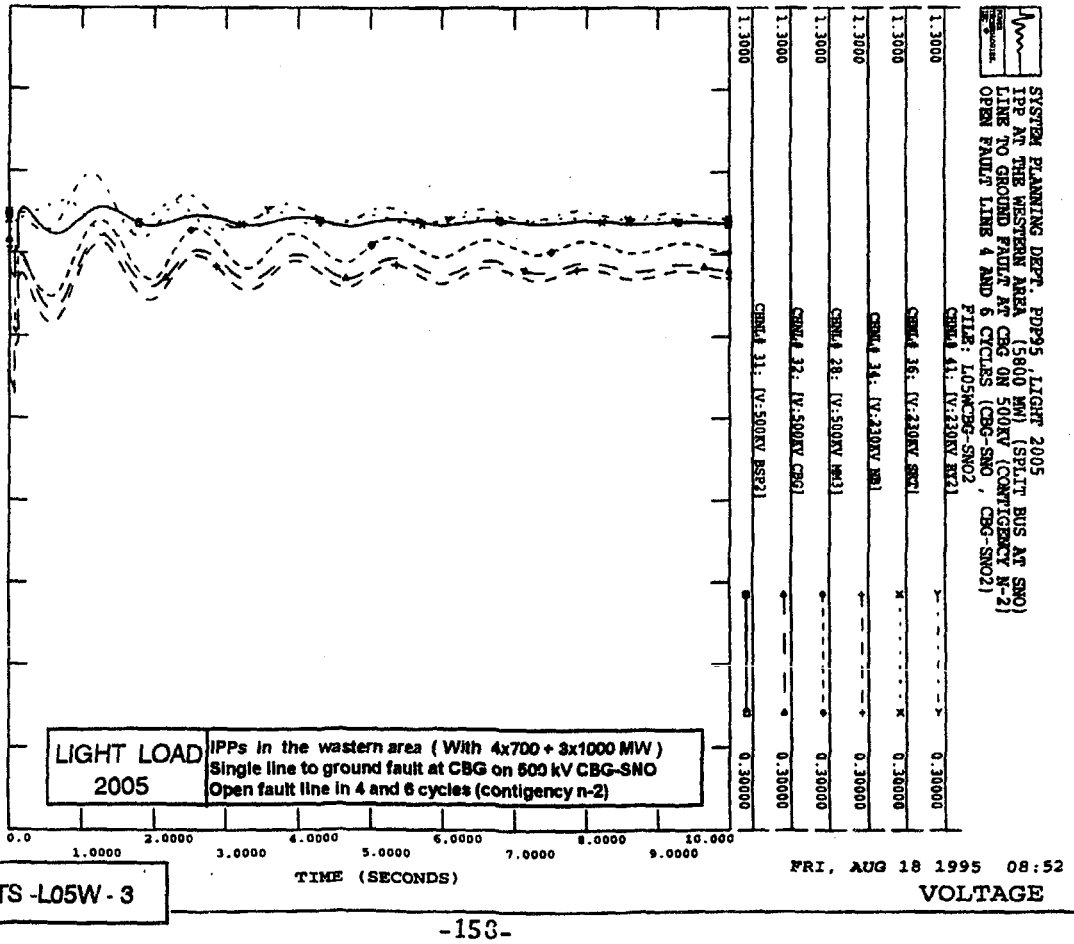
CASE TS -L05W - 1

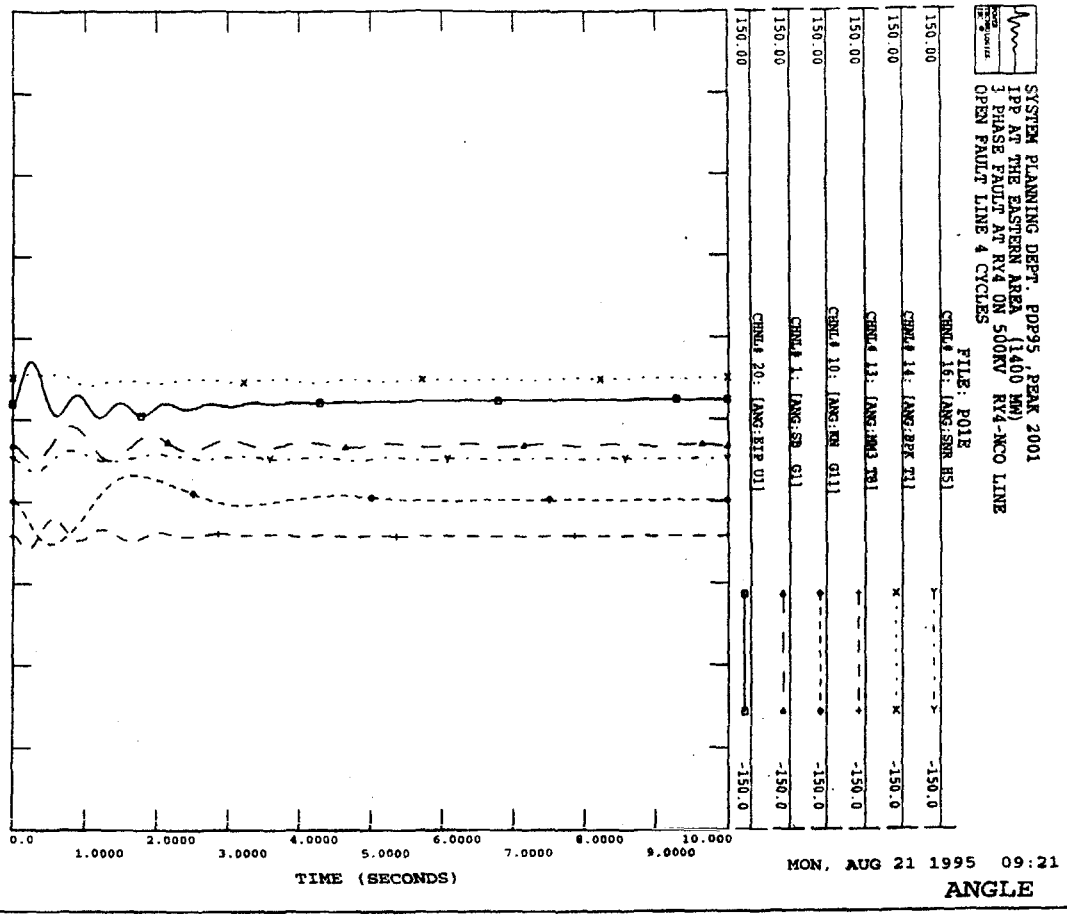


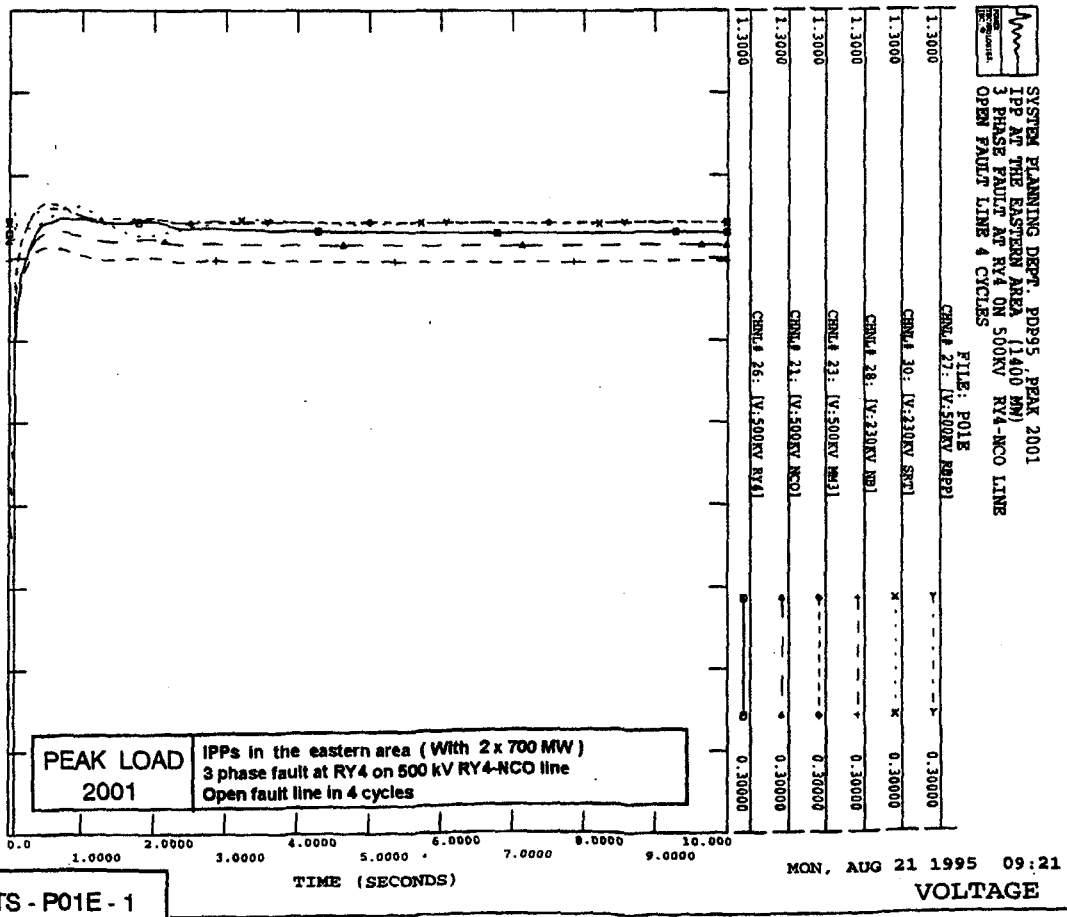


CASE TS - L05W - 2

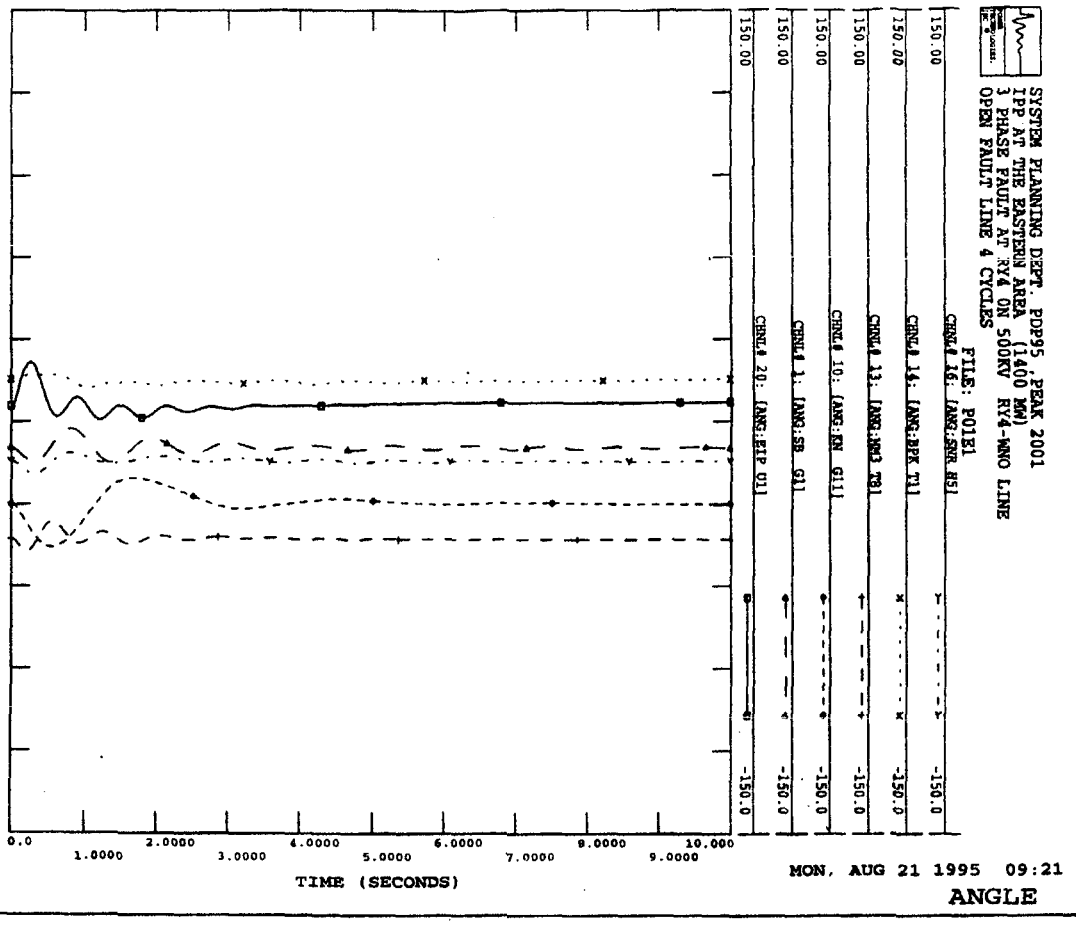

SYSTEM PLANNING DEPT. PDP95 LIGHT 2005
IPP AT THE WESTERN AREA (5800 MW) (SPLIT BUS AT SNO)
LINE TO GROUND FAULT AT CBG ON 500KV (CONTIGENCY N-2)
OPEN FAULT LINE 4 AND 6 CYCLES (CBG-SNO , CBG-SNO2)
FILE: L05WCBG-SNO2
CHNL# 20: [ANG:SNK #5]
CHNL# 15: [ANG:BPK T1]
CHNL# 13: [ANG:BK3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SR T5]
CHNL# 25: [ANG:HIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 18 1995 08:51
ANGLE

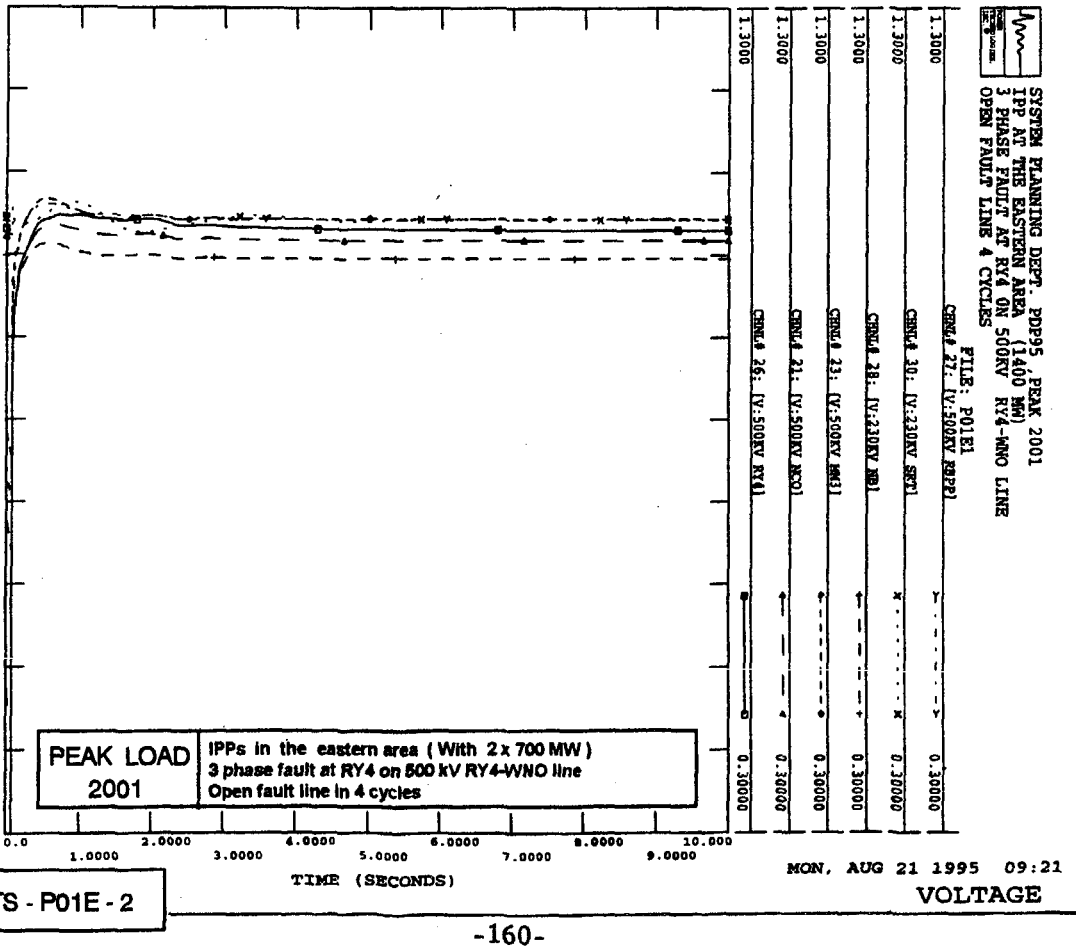

SYSTEM PLANNING DEPT. PDP95 LIGHT 2005
IPP AT THE WESTERN AREA (5800 MW) (SPLIT BUS AT SNO)
LINE TO GROUND FAULT AT CBG ON 500KV (CONTIGENCY N-2)
OPEN FAULT LINE 4 AND 6 CYCLES (CBG-SNO , CBG-SNO2)
FILE: L05WCBG-SNO2
CHNL# 41: [V:230KV #2]
CHNL# 16: [V:230KV SNO]
CHNL# 14: [V:230KV NR]
CHNL# 28: [V:500KV MS]
CHNL# 32: [V:500KV CBG]
CHNL# 31: [V:500KV BSP2]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, AUG 18 1995 08:52
VOLTAGE
LIGHT LOAD
2005
IPPs in the western area (With 4x700 + 3x1000 MW)
Single line to ground fault at CBG on 500 kV CBG-SNO
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS -L05W - 3



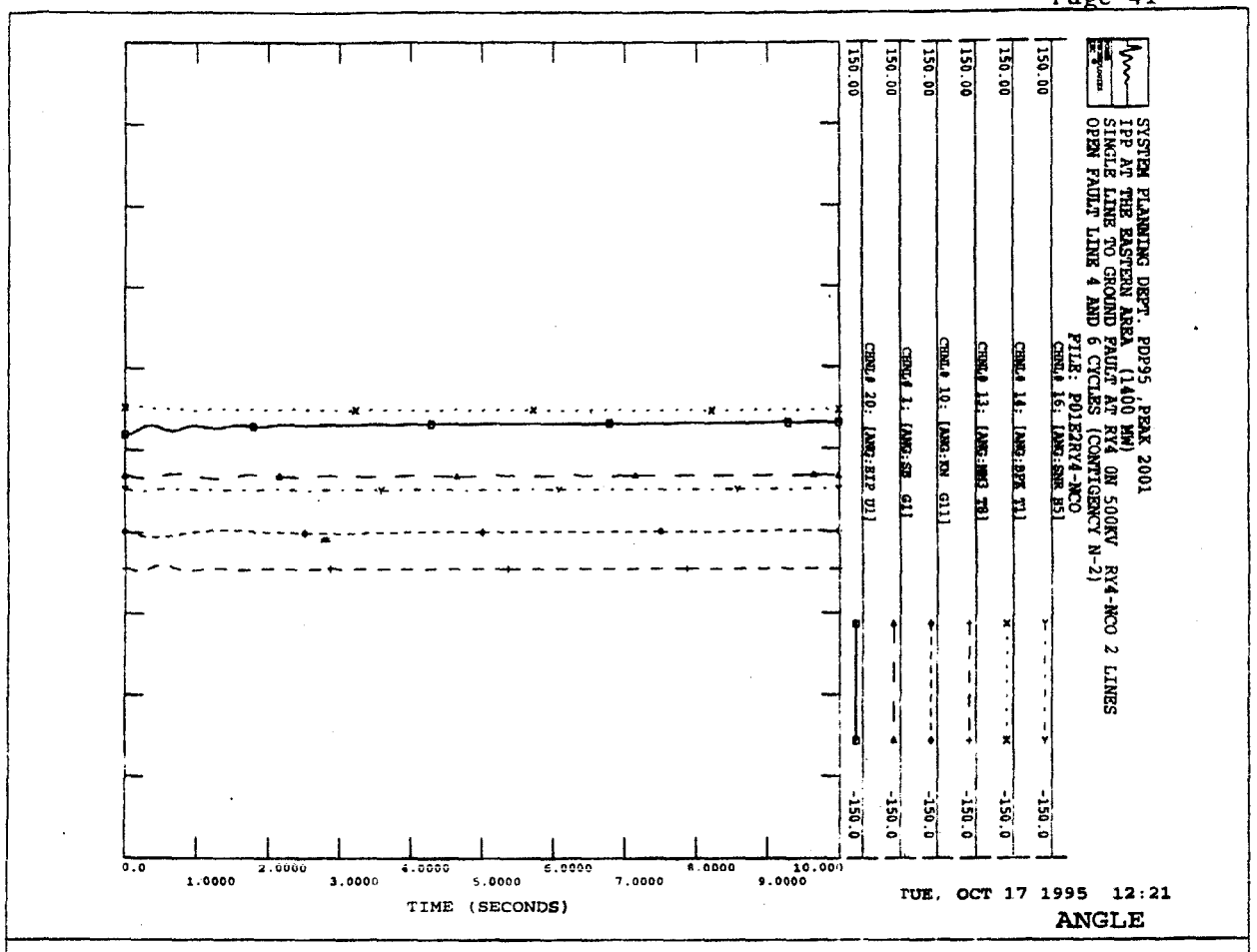


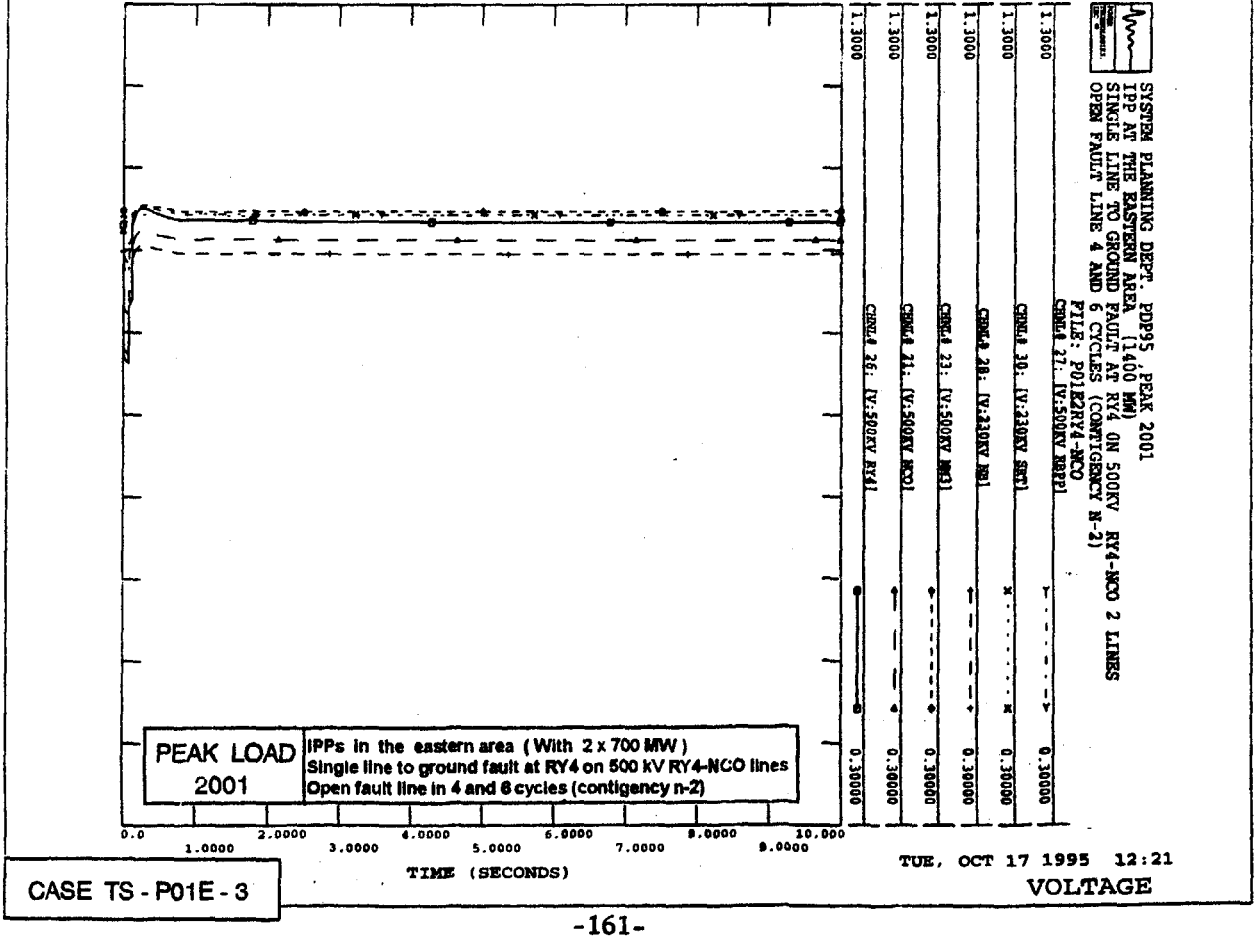
CASE TS - P01E - 1



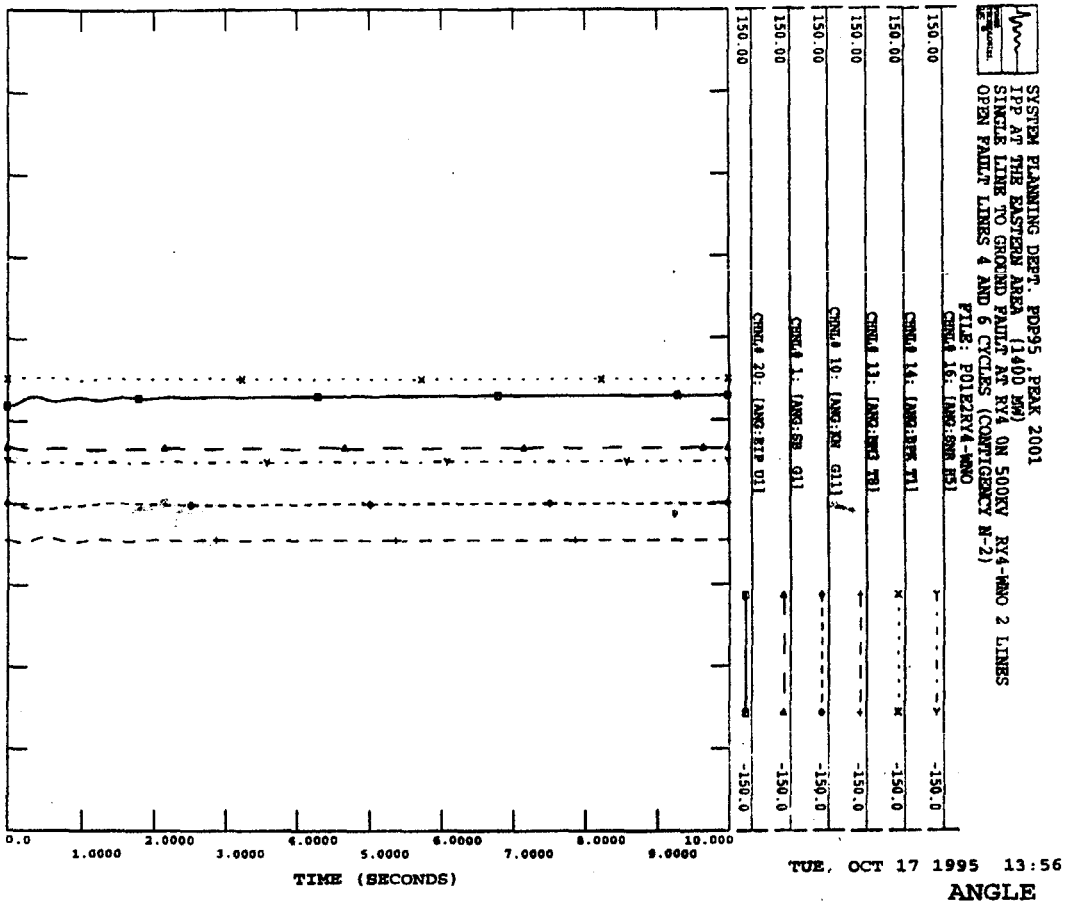


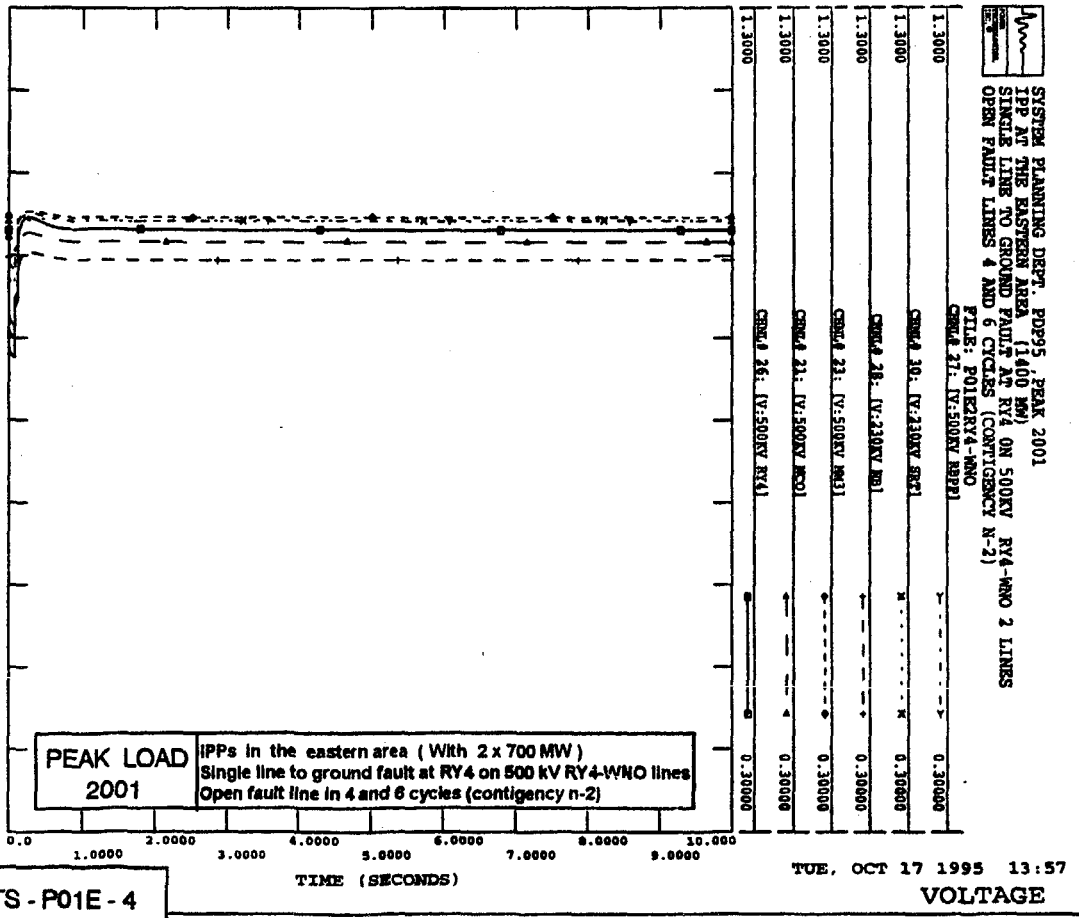
CASE TS - P01E - 2



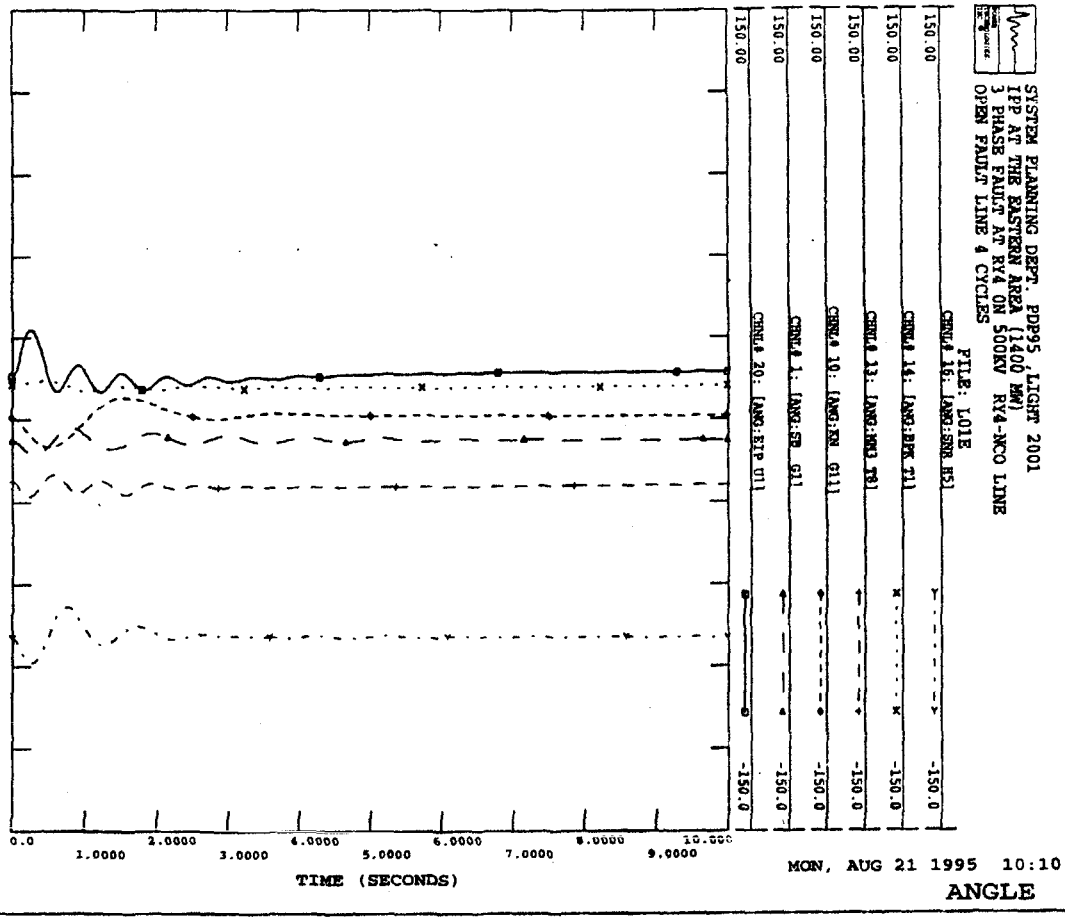


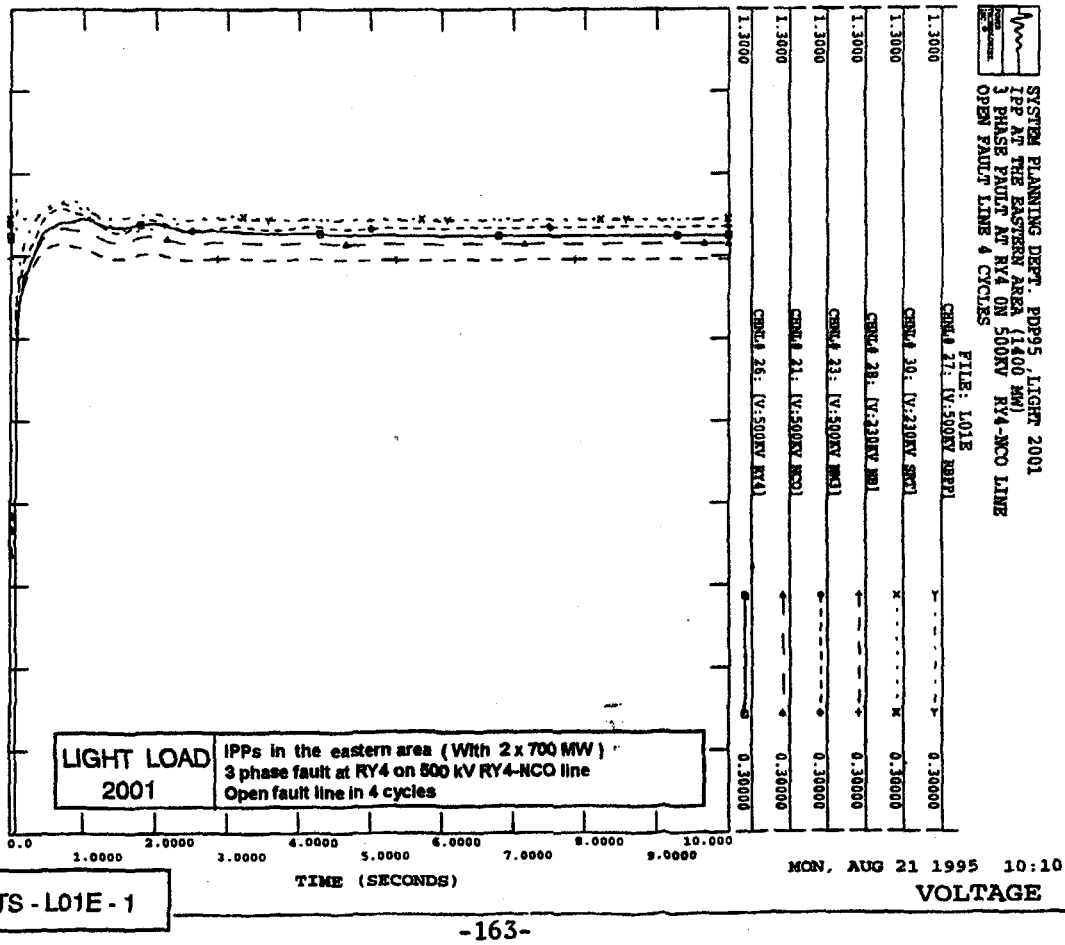
CASE TS - P01E - 3



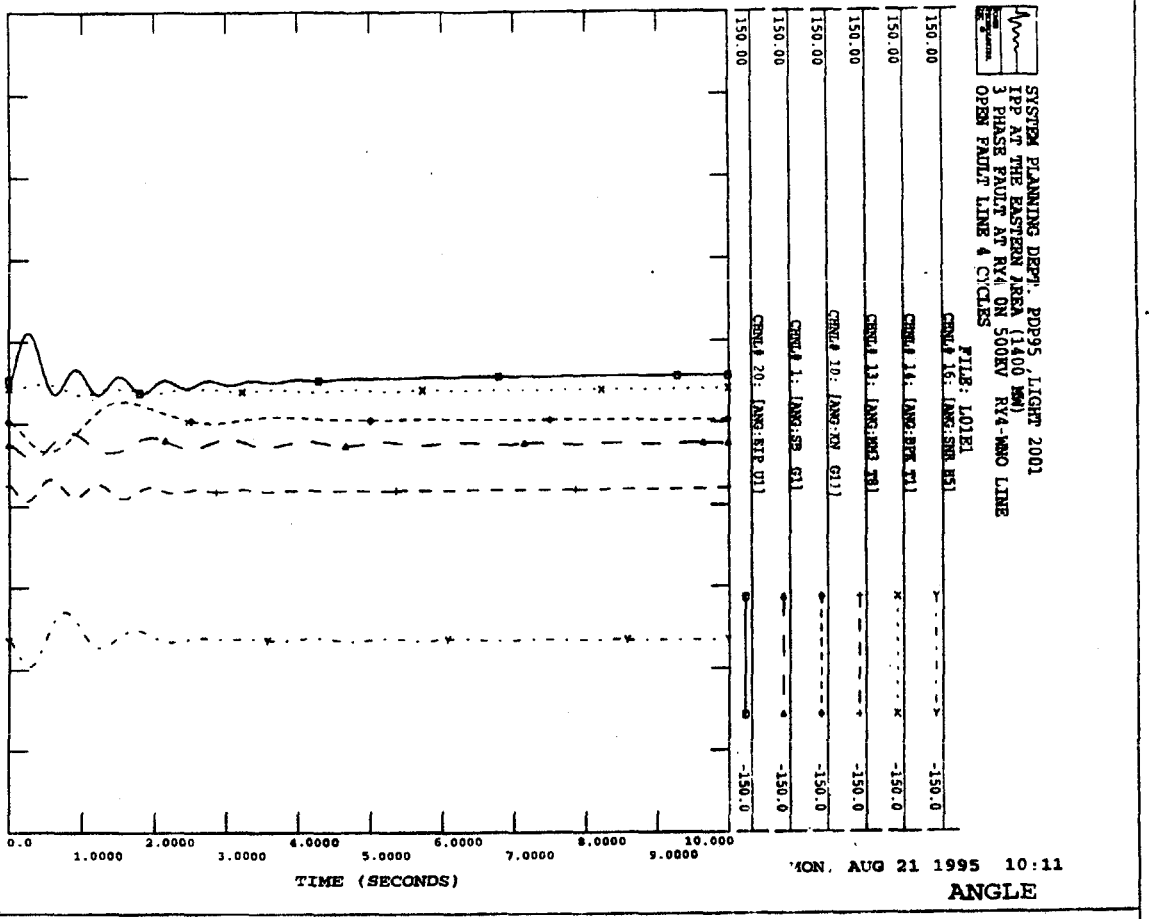


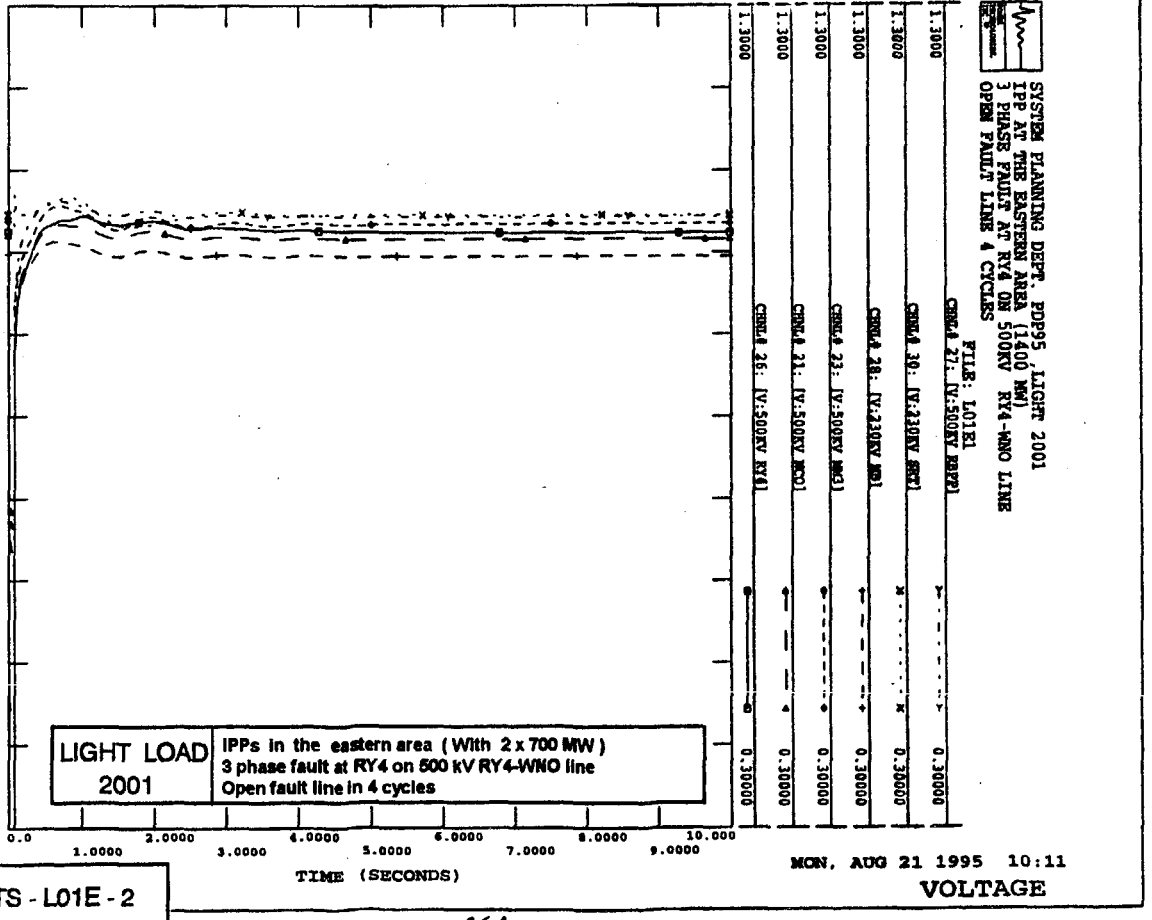
CASE TS - P01E - 4



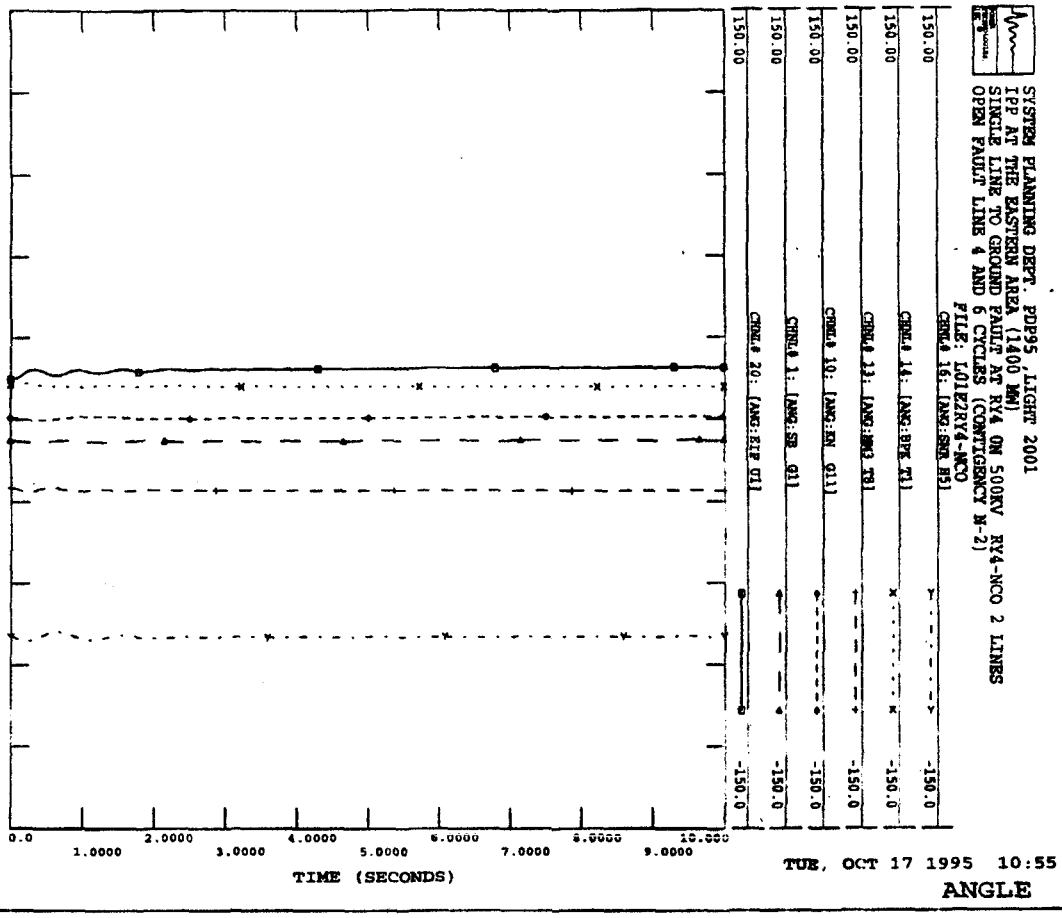


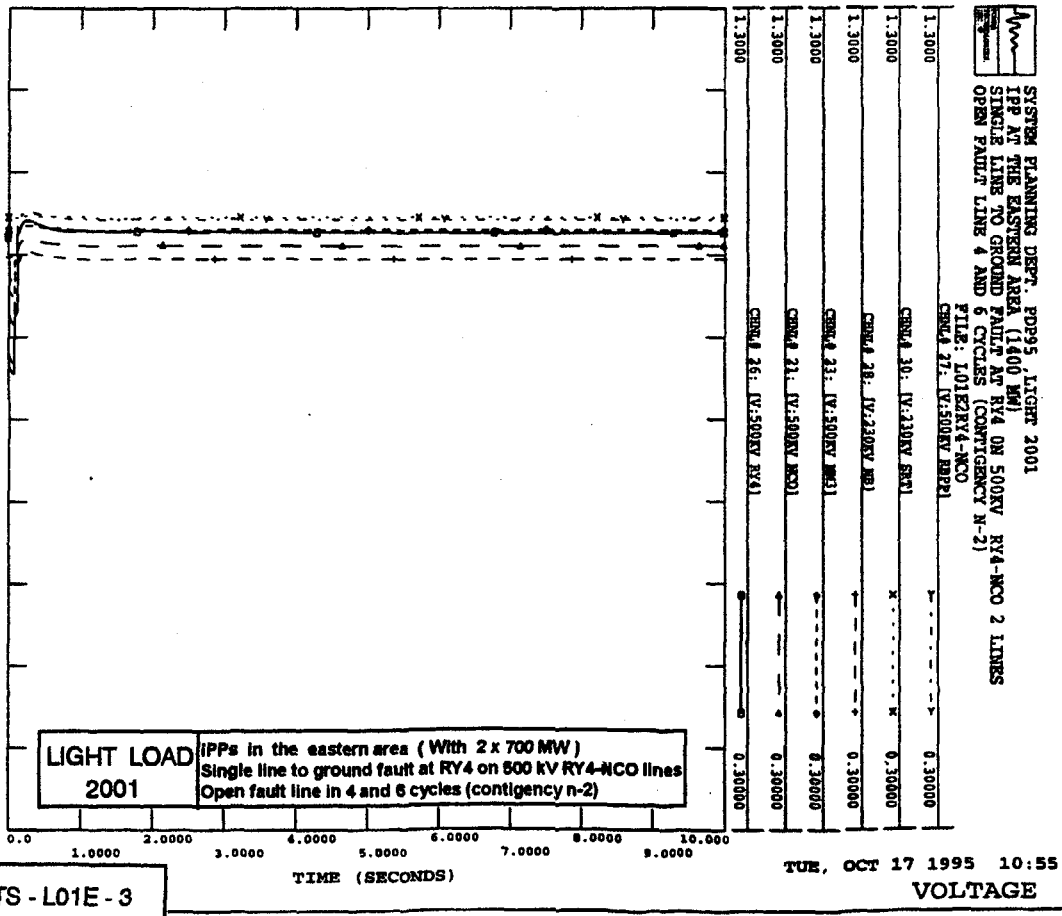
CASE TS - L01E - 1

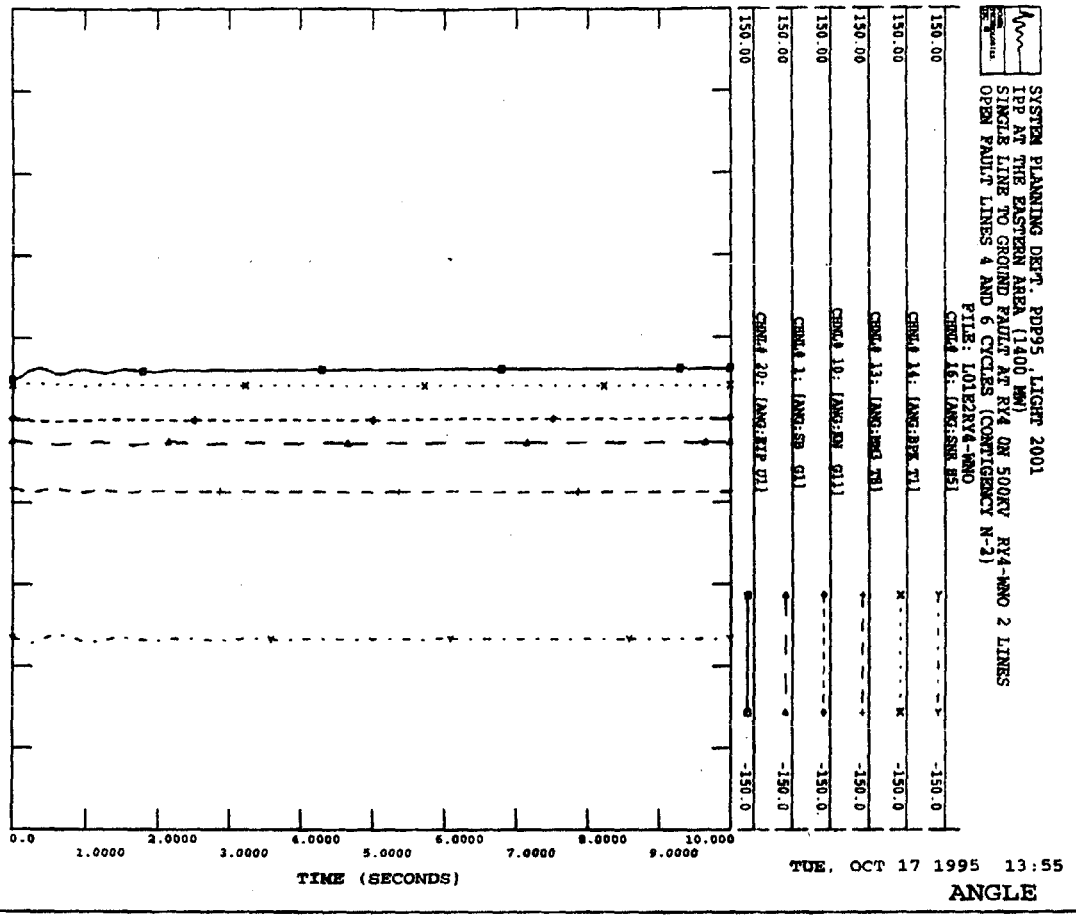


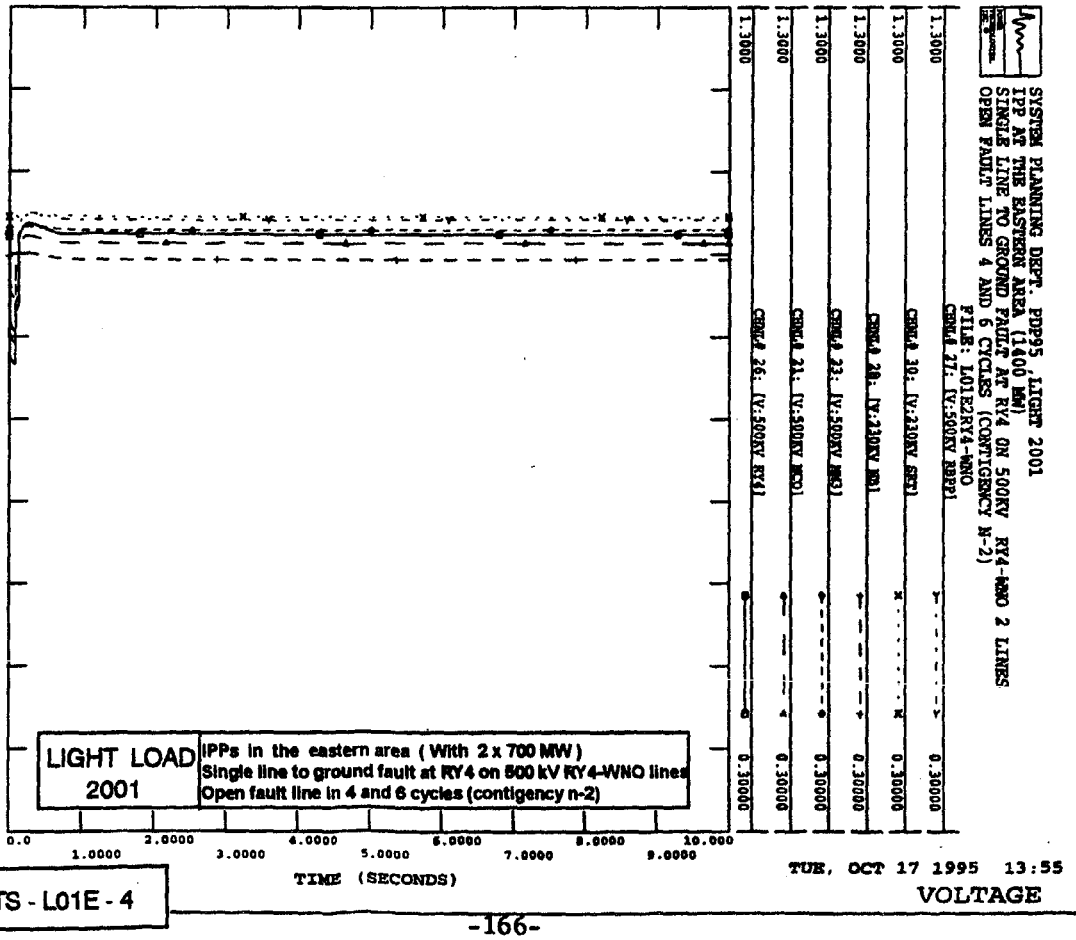


CASE TS - L01E - 2

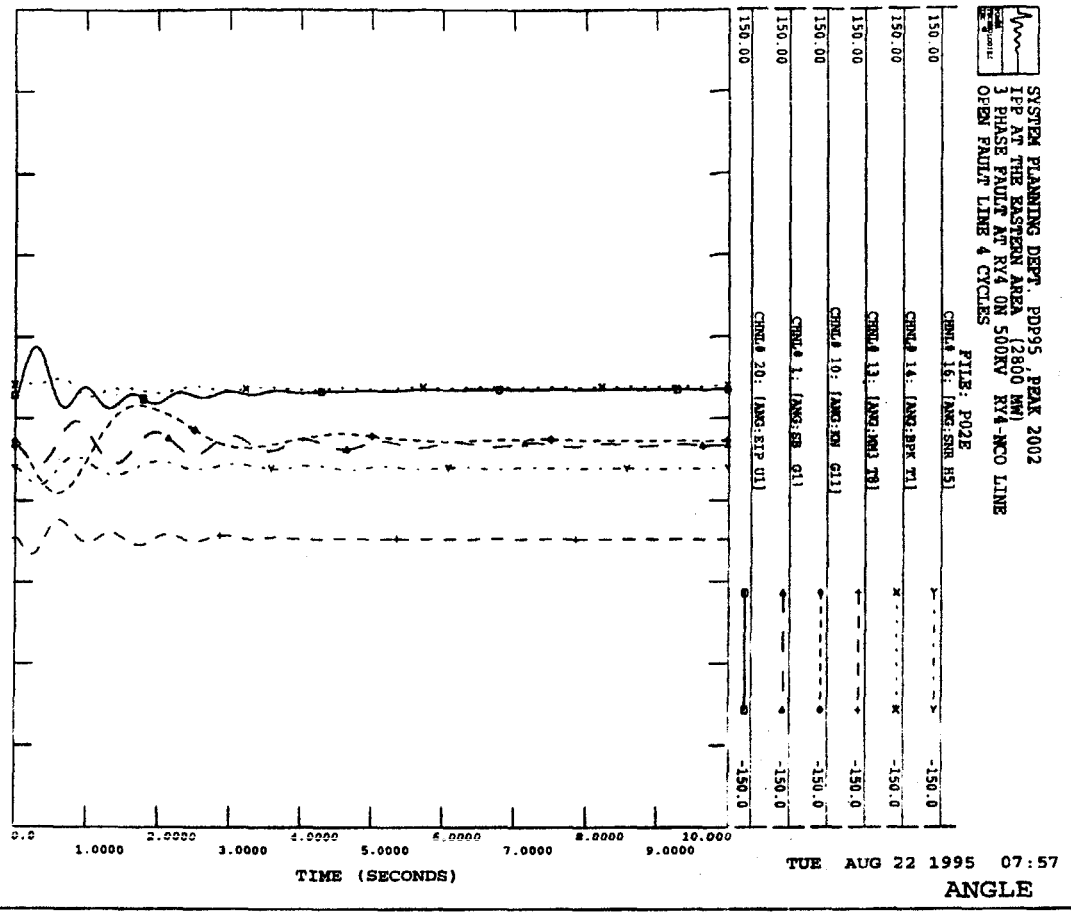

SYSTEM PLANNING DEPT. PDP95, LIGHT 2001
IPP AT THE EASTERN AREA (1400 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-NCO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L01E2RY4-NCO
CHNL# 16: [ANG:BRK M5]
CHNL# 14: [ANG:BYK T1]
CHNL# 13: [ANG:BM3 T8]
CHNL# 10: [ANG:BN G11]
CHNL# 1: [ANG:SE G11]
CHNL# 20: [ANG:ELP G11]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 10:55
ANGLE

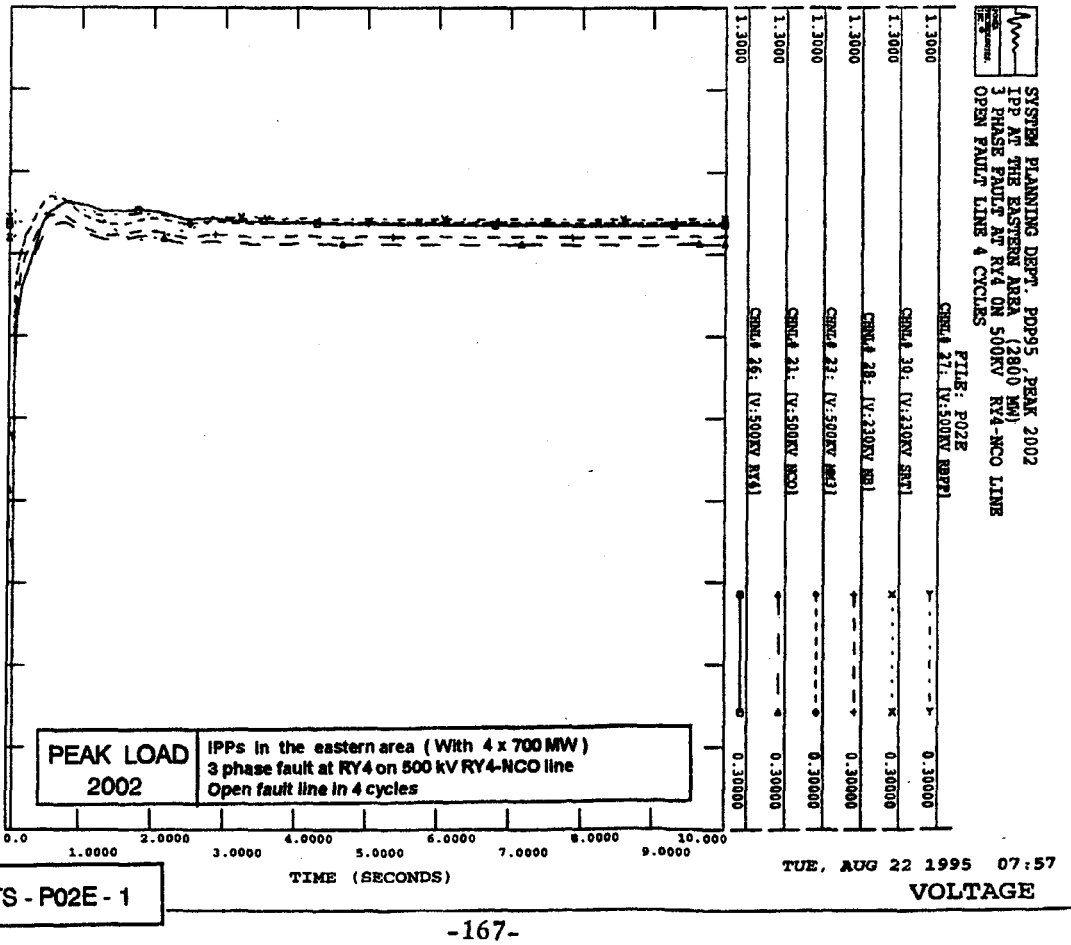

SYSTEM PLANNING DEPT. PDP95, LIGHT 2001
IPP AT THE EASTERN AREA (1400 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-NCO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L01E2RY4-NCO
CHNL# 27: [V:500KV BRP2]
CHNL# 30: [V:230KV SR1]
CHNL# 28: [V:230KV MB]
CHNL# 23: [V:500KV MM1]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 10:55
VOLTAGE
LIGHT LOAD
2001
IPPs in the eastern area (With 2 x 700 MW)
Single line to ground fault at RY4 on 500 kV RY4-NCO lines
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS - L01E - 3



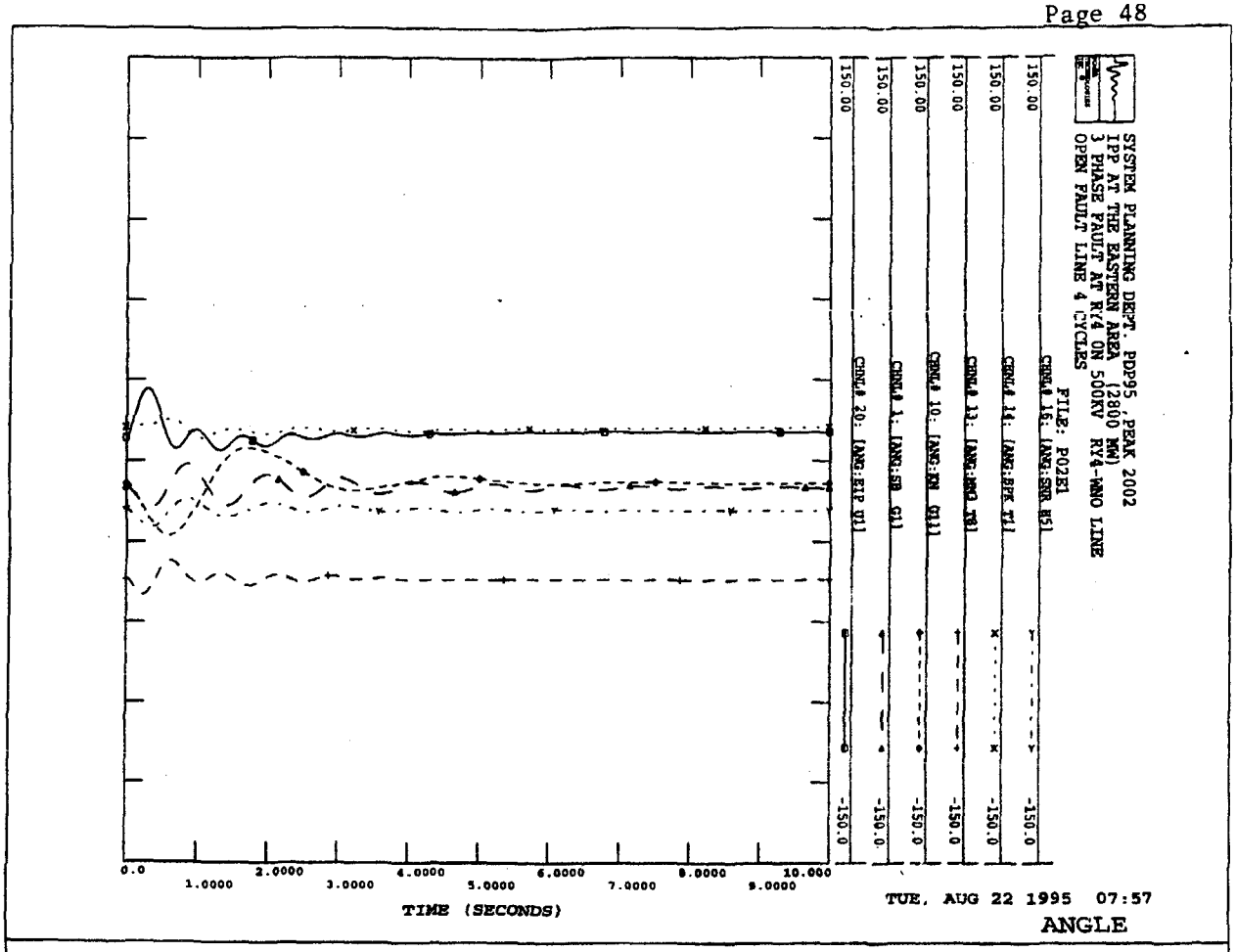


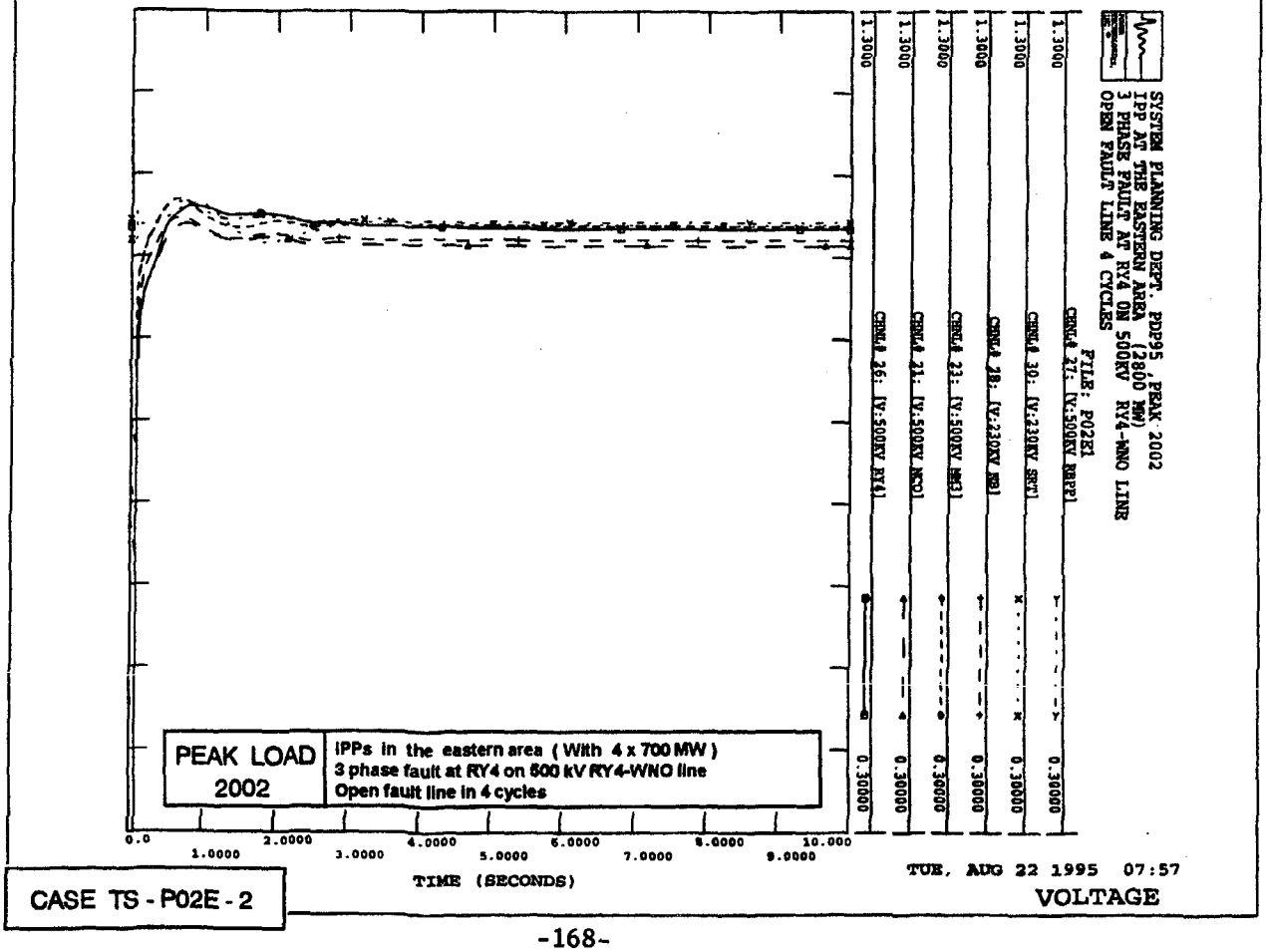
CASE TS - L01E - 4



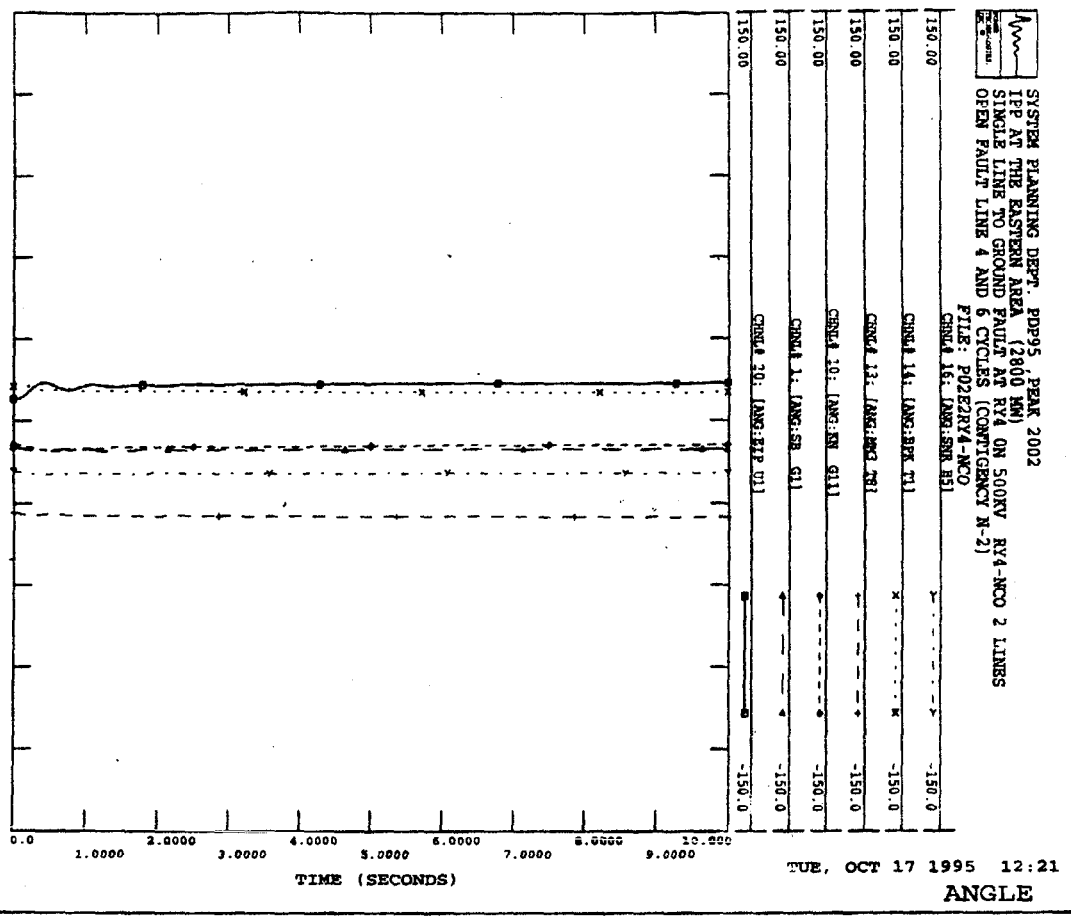


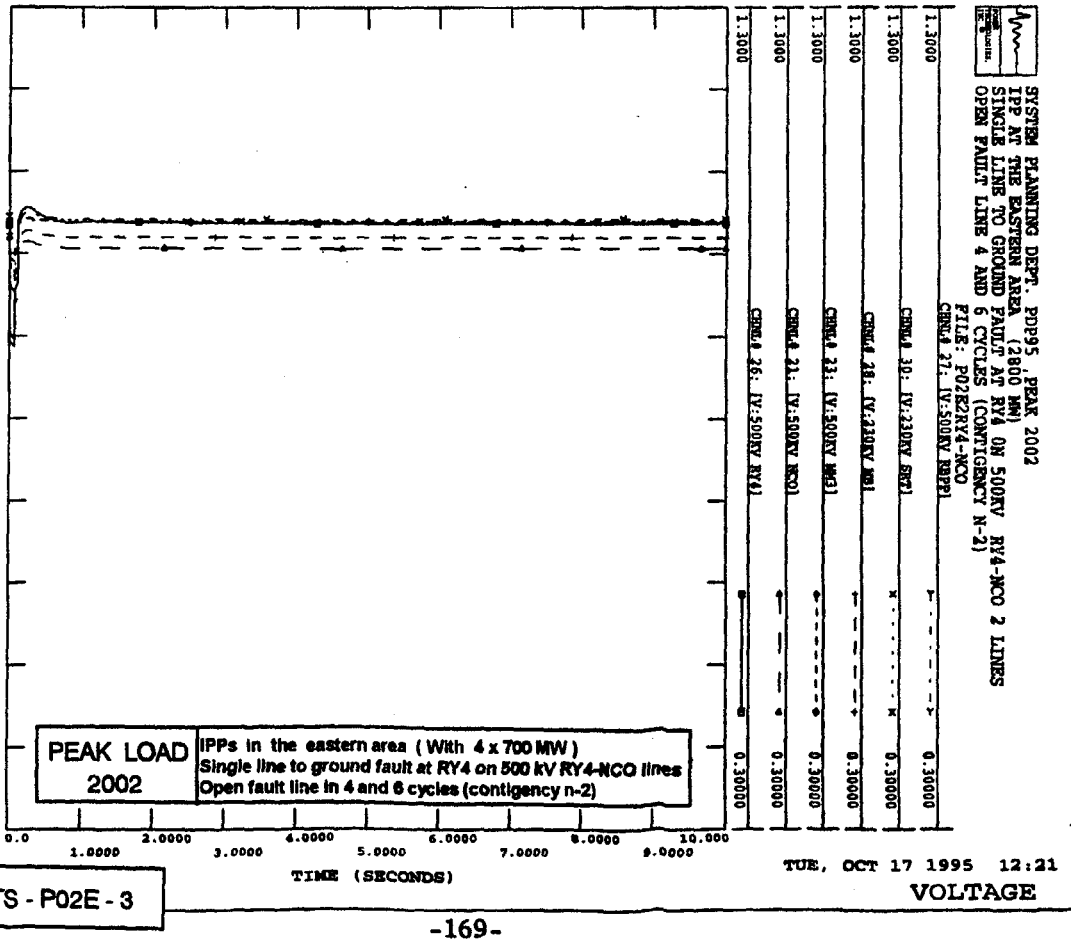
CASE TS - P02E - 1



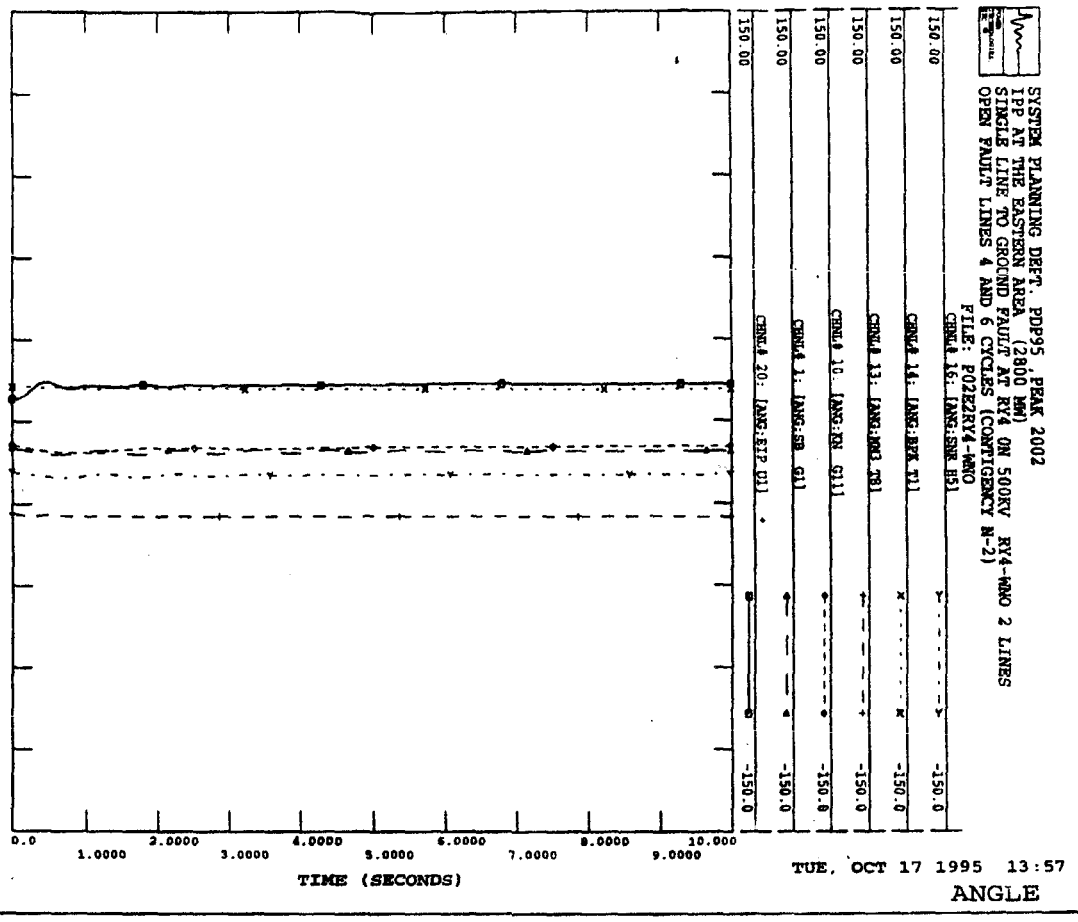


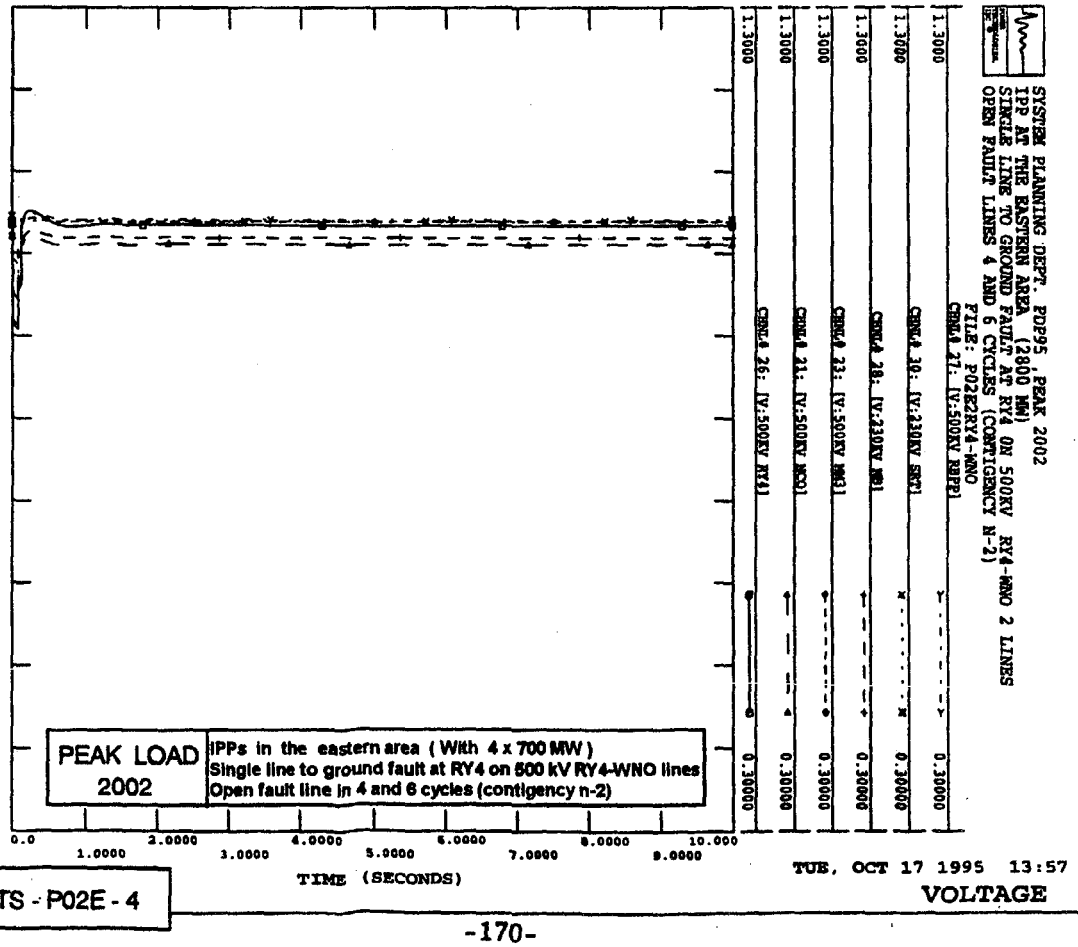
CASE TS - P02E - 2



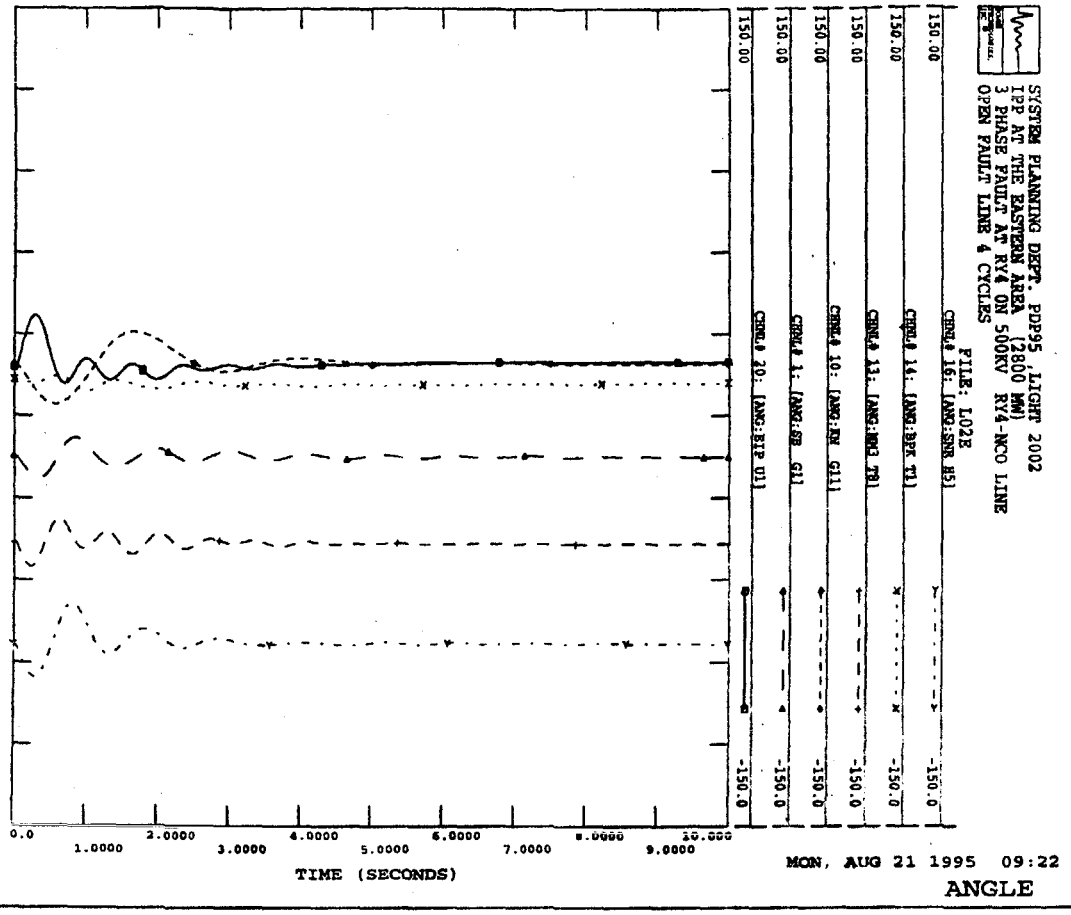


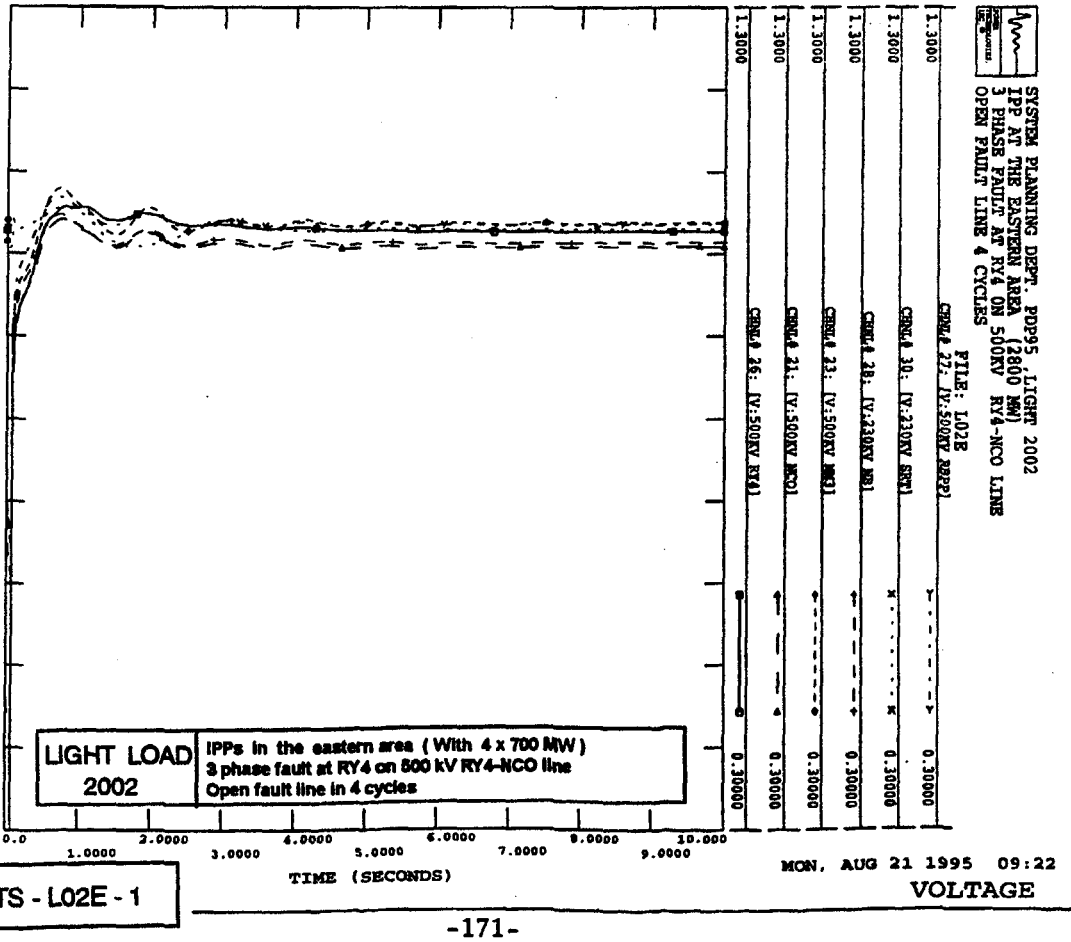
CASE TS - P02E - 3



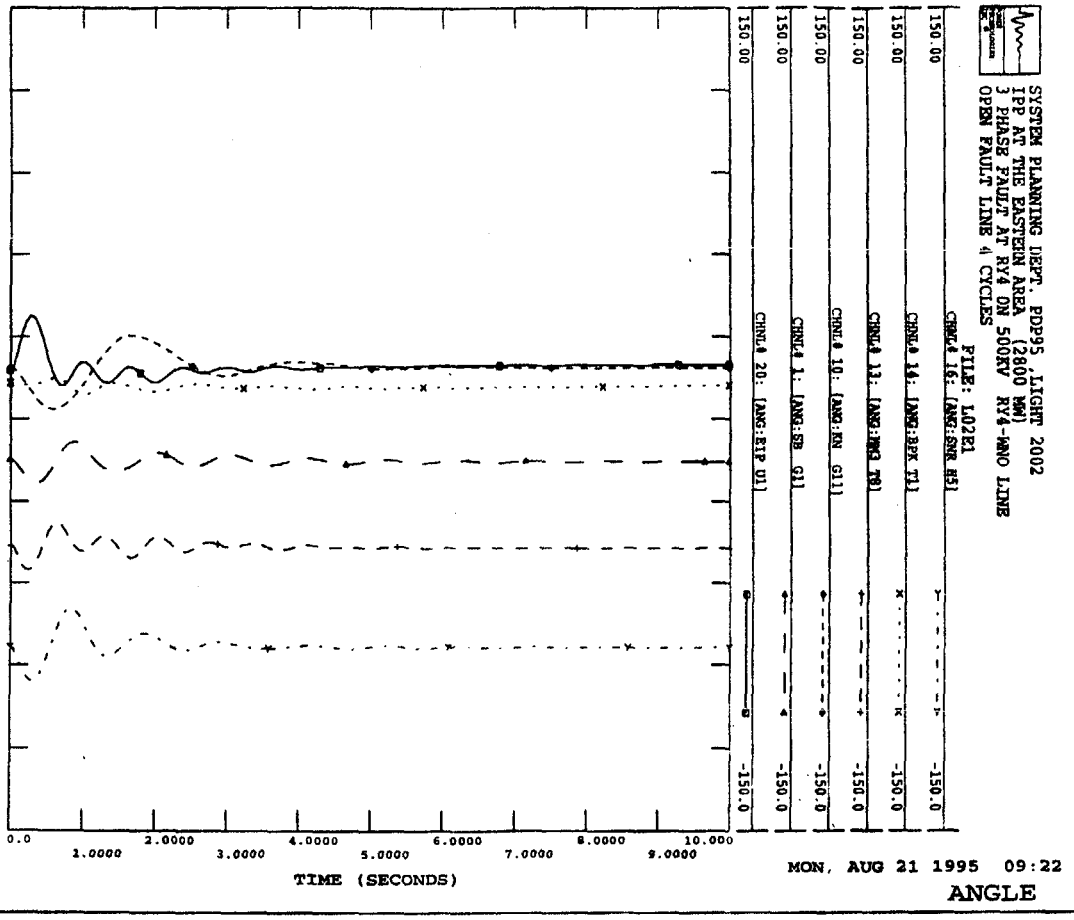


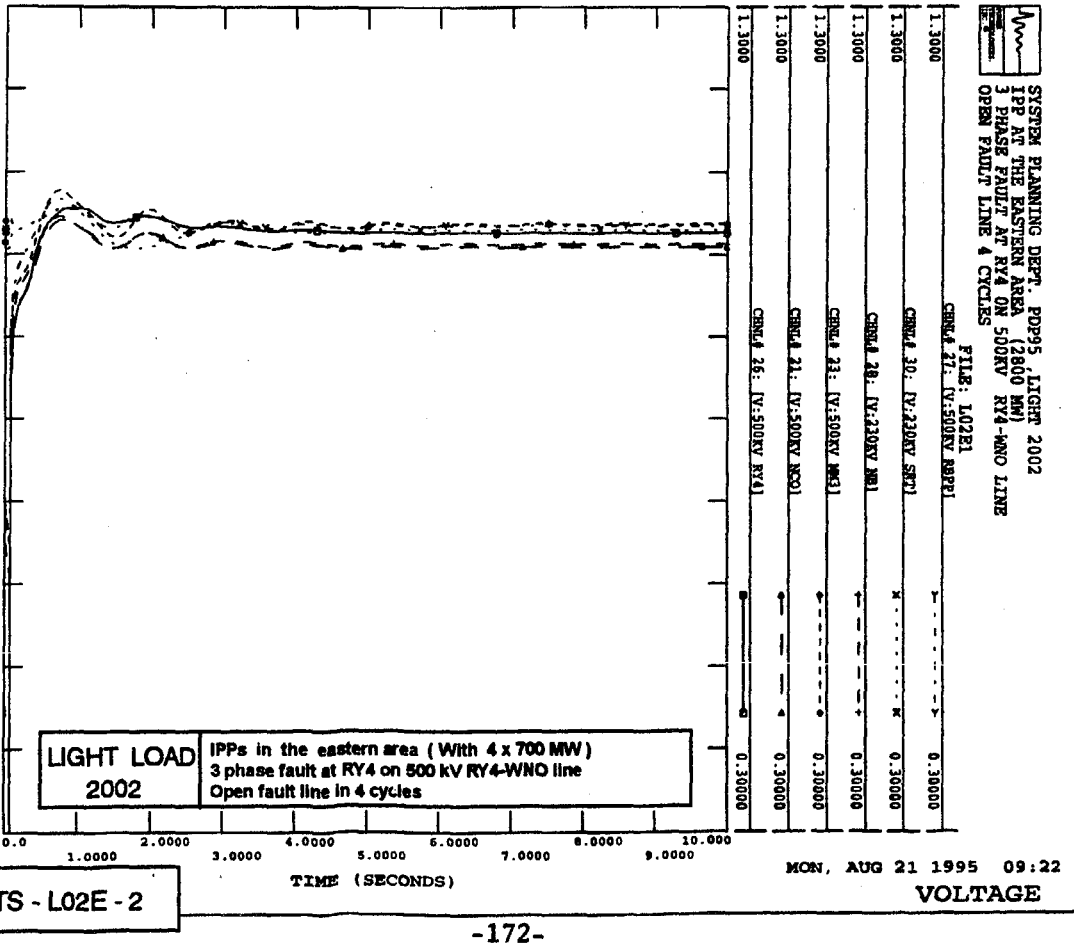
CASE TS - P02E - 4



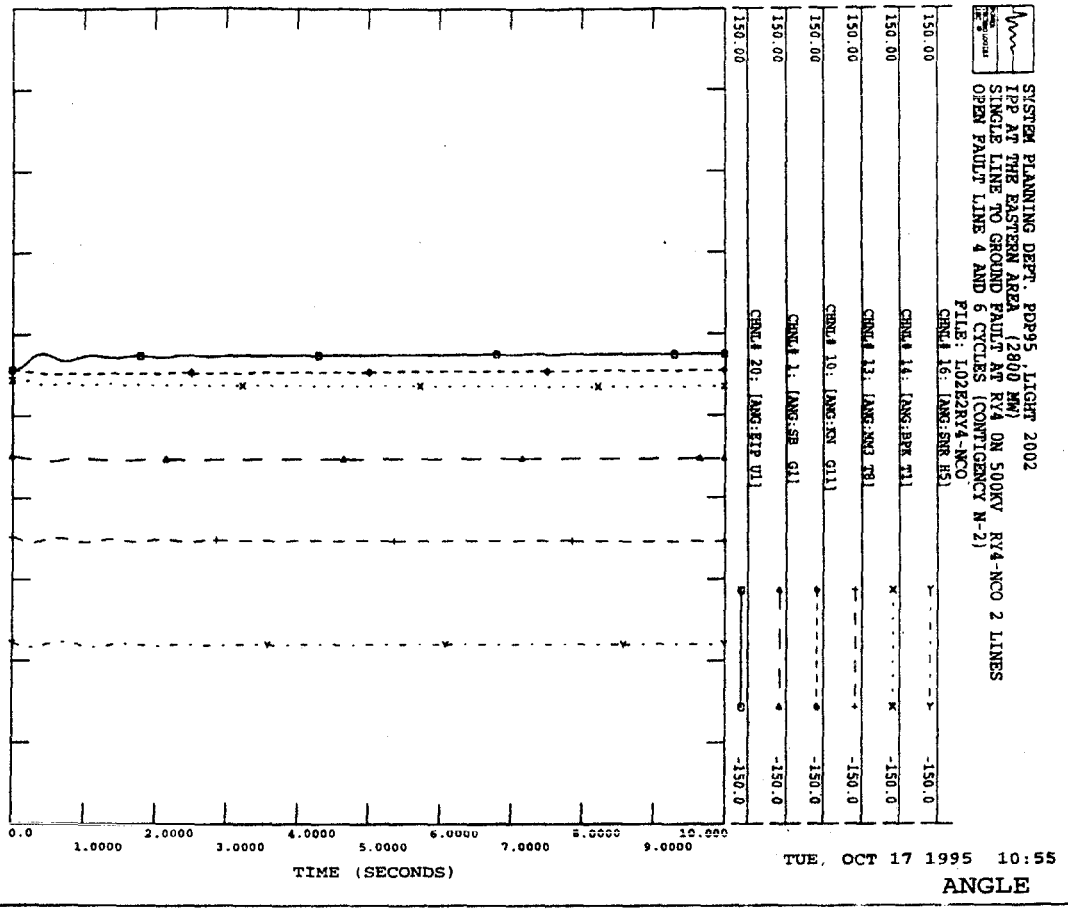


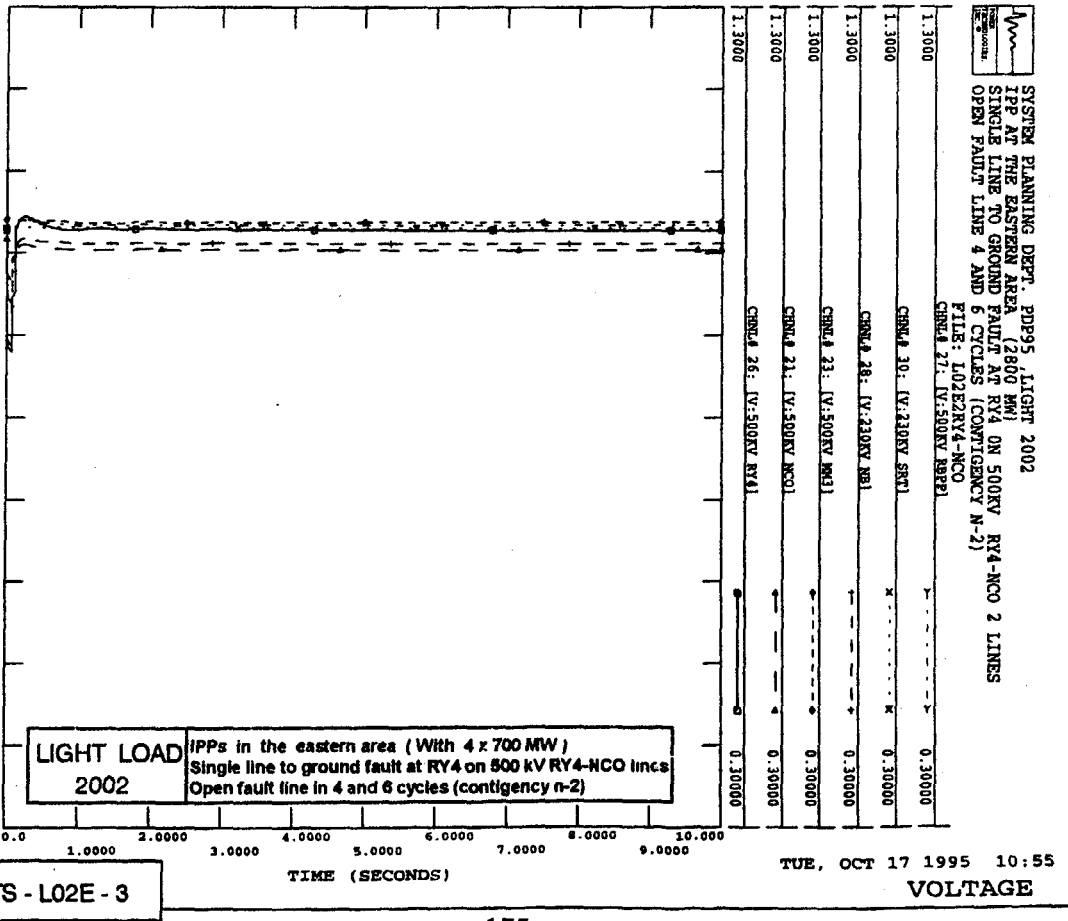
CASE TS - L02E - 1

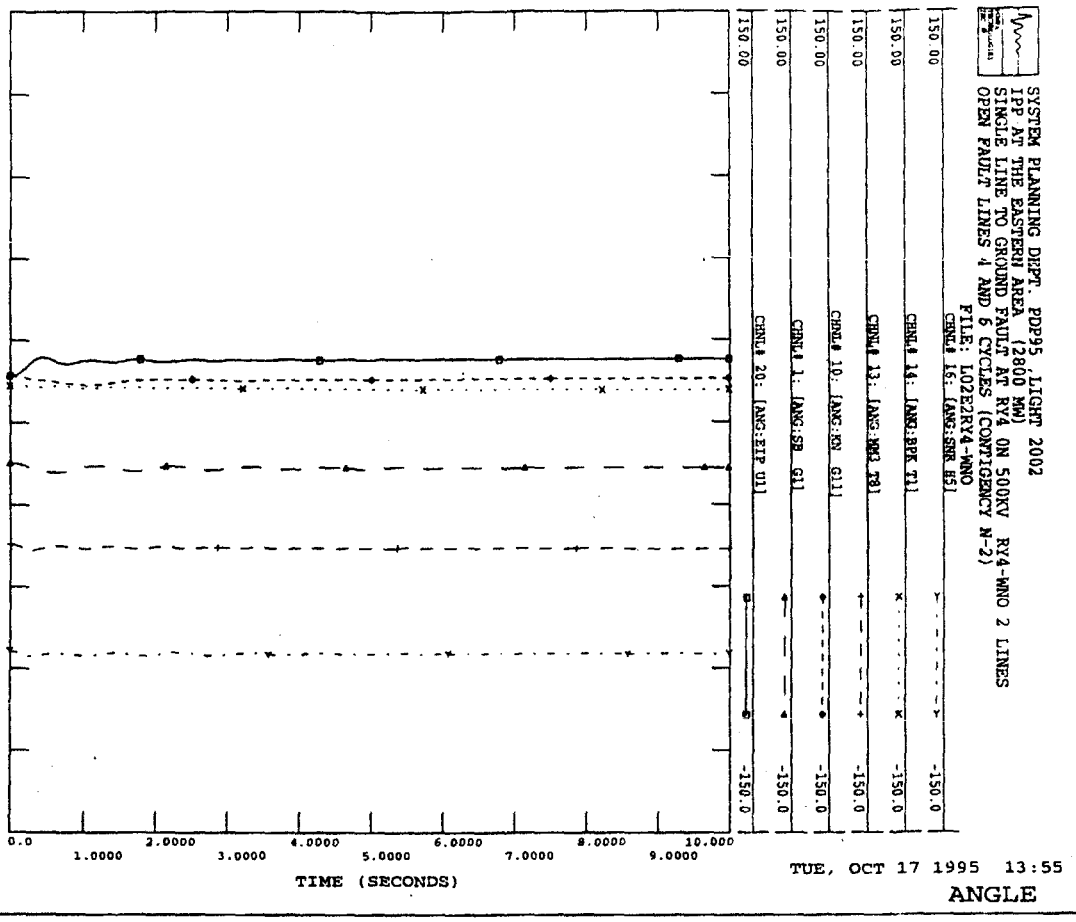


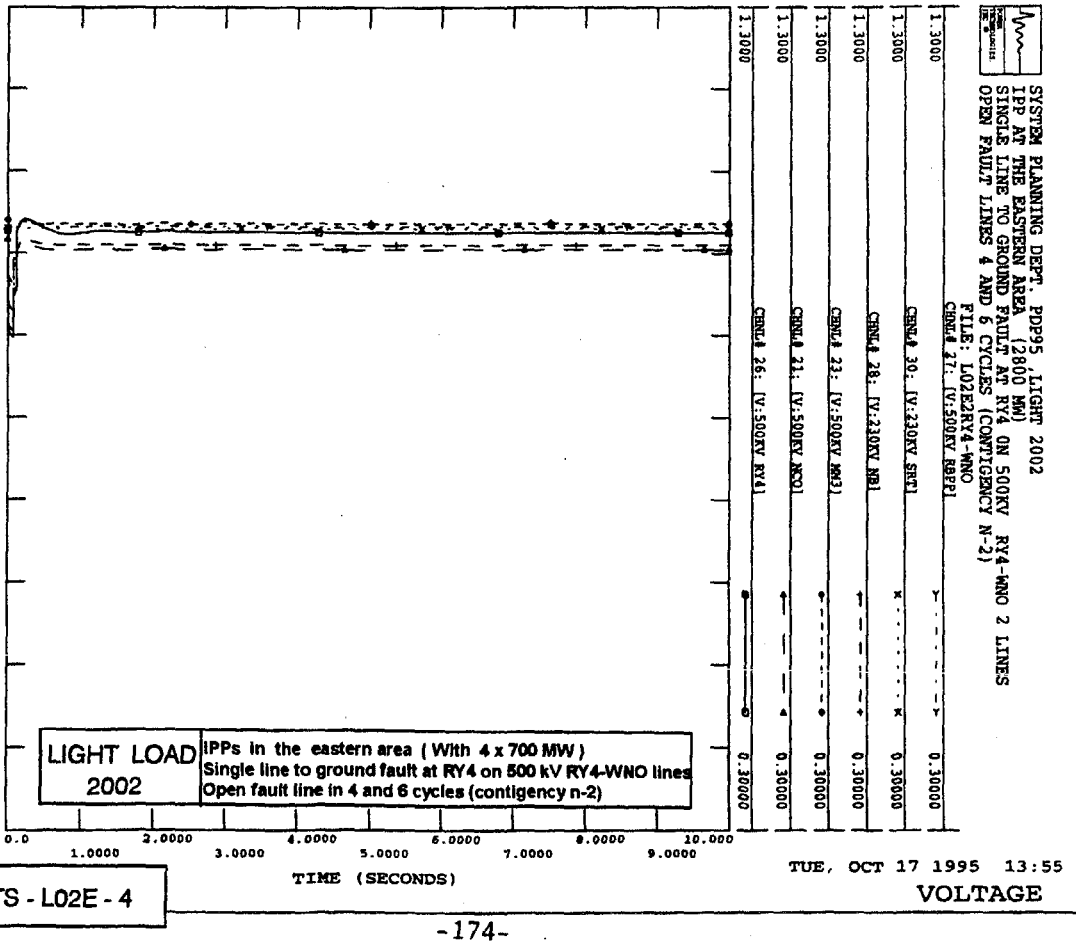


CASE TS - L02E - 2

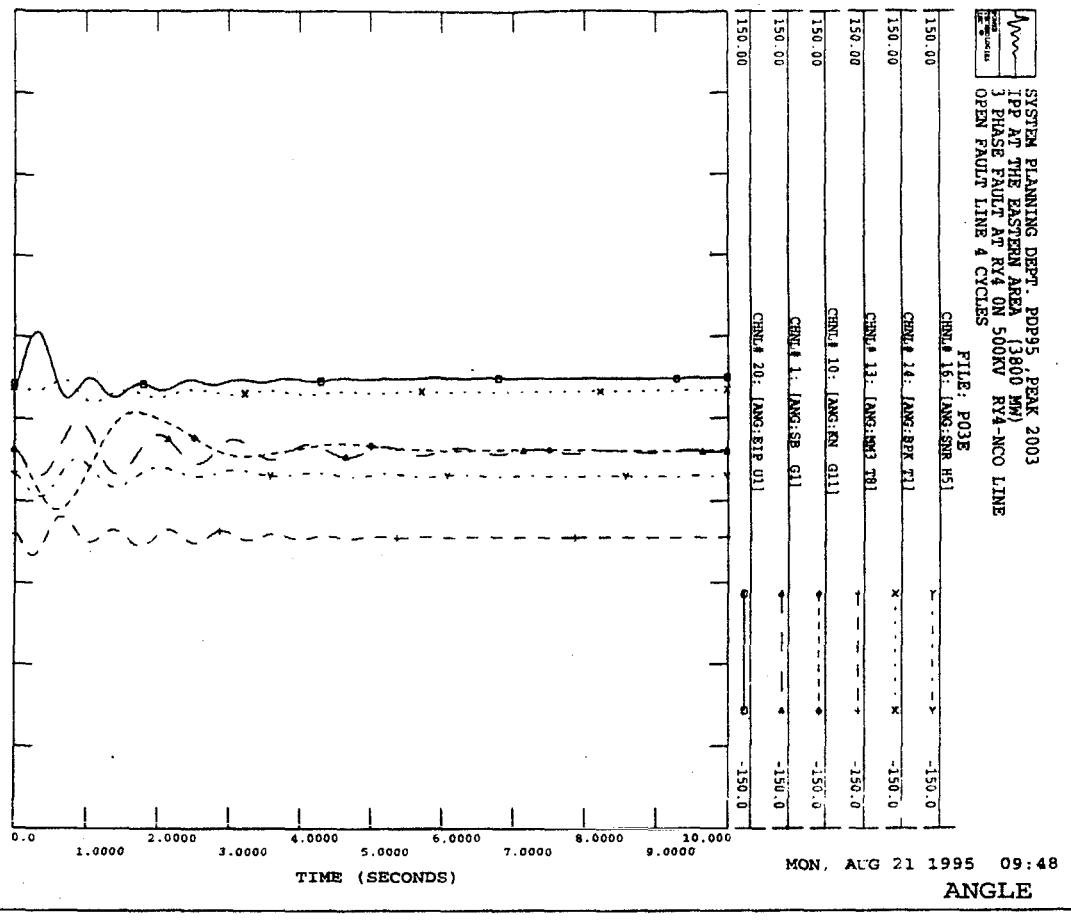

SYSTEM PLANNING DEPT. PDP95 ;LIGHT 2002
IPP AT THE EASTERN AREA (2800 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-NCO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L02E2RY4-NCO
CHNL# 16: [ANG:SNR 85]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:NN3 T8]
CHNL# 10: [ANG:EN G11]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:BIP V1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 10:55
ANGLE

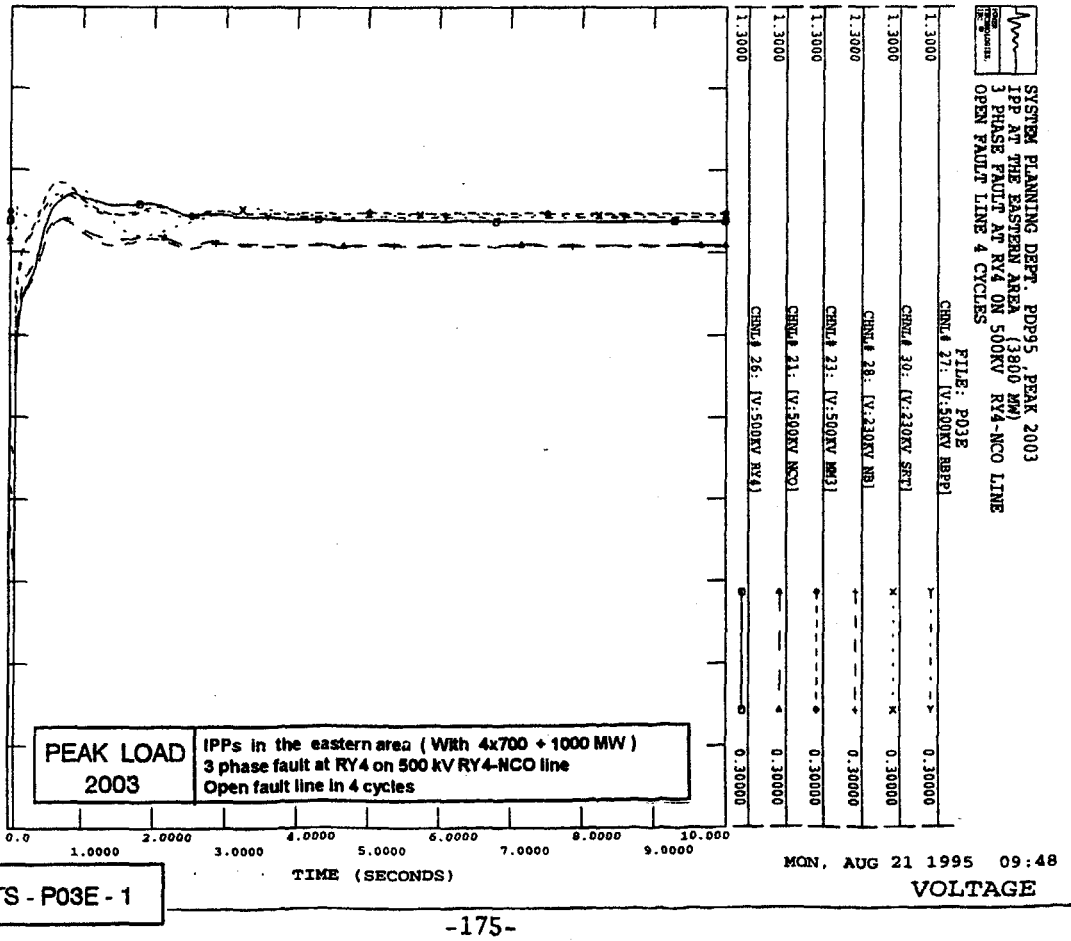

SYSTEM PLANNING DEPT. PDP95 ;LIGHT 2002
IPP AT THE EASTERN AREA (2800 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-NCO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L02E2RY4-NCO
CHNL# 27: [V:500KV NBPE]
CHNL# 30: [V:230KV SRT]
CHNL# 28: [V:230KV NB]
CHNL# 23: [V:500KV MN3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 10:55
VOLTAGE
LIGHT LOAD
2002
IPPs in the eastern area (With 4 x 700 MW)
Single line to ground fault at RY4 on 500 kV RY4-NCO lincs
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS - L02E - 3



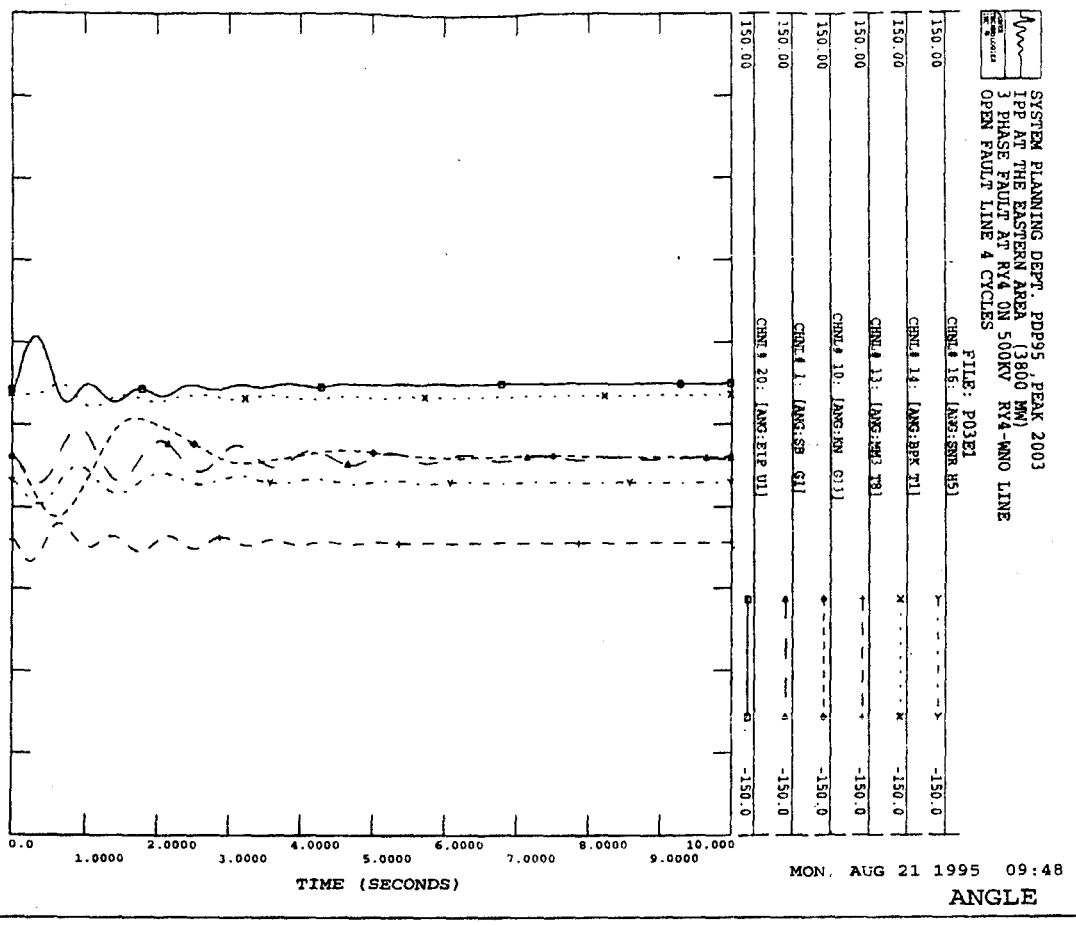


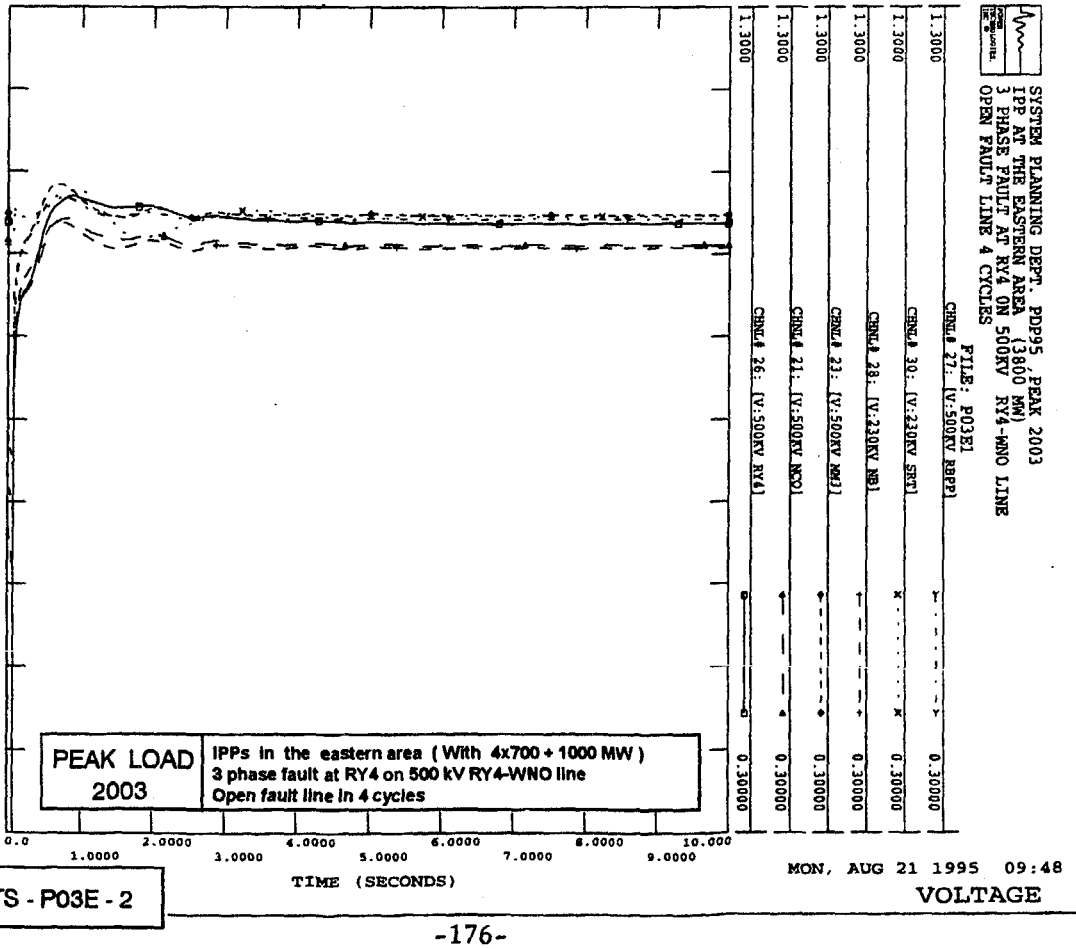
CASE TS - L02E - 4



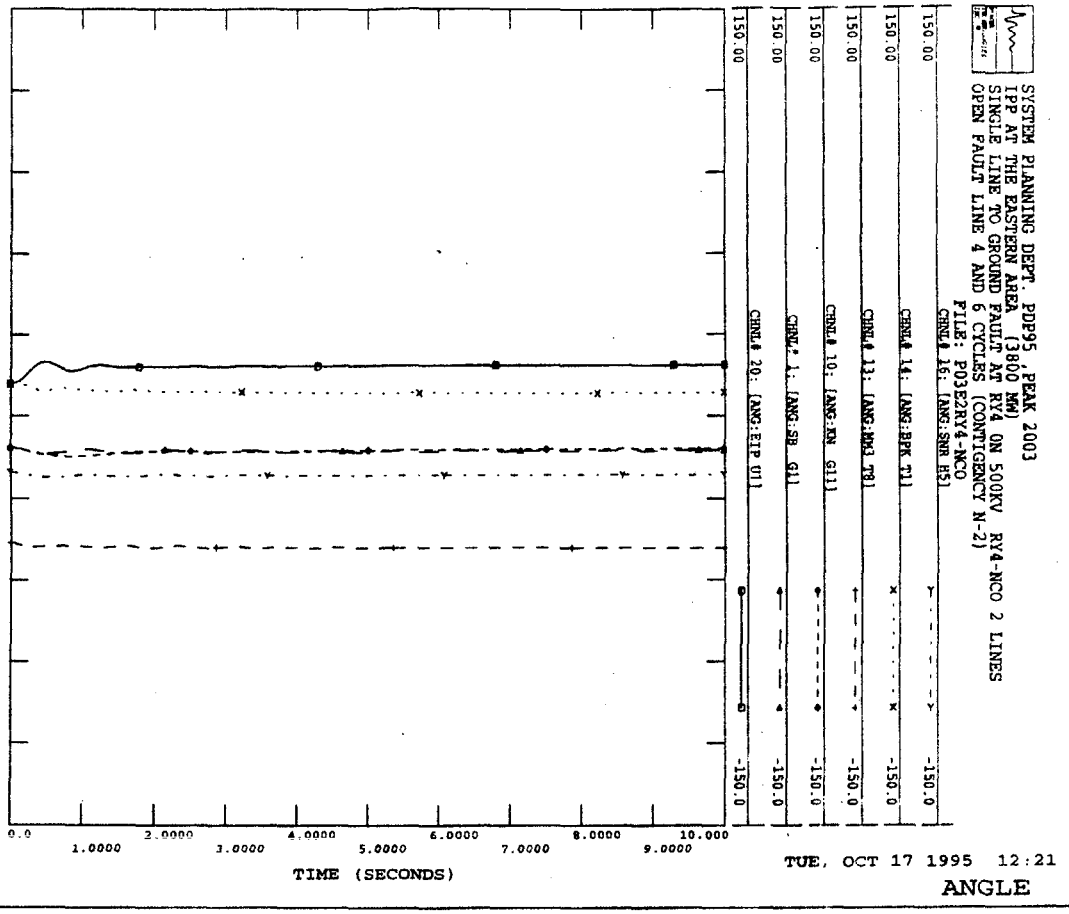


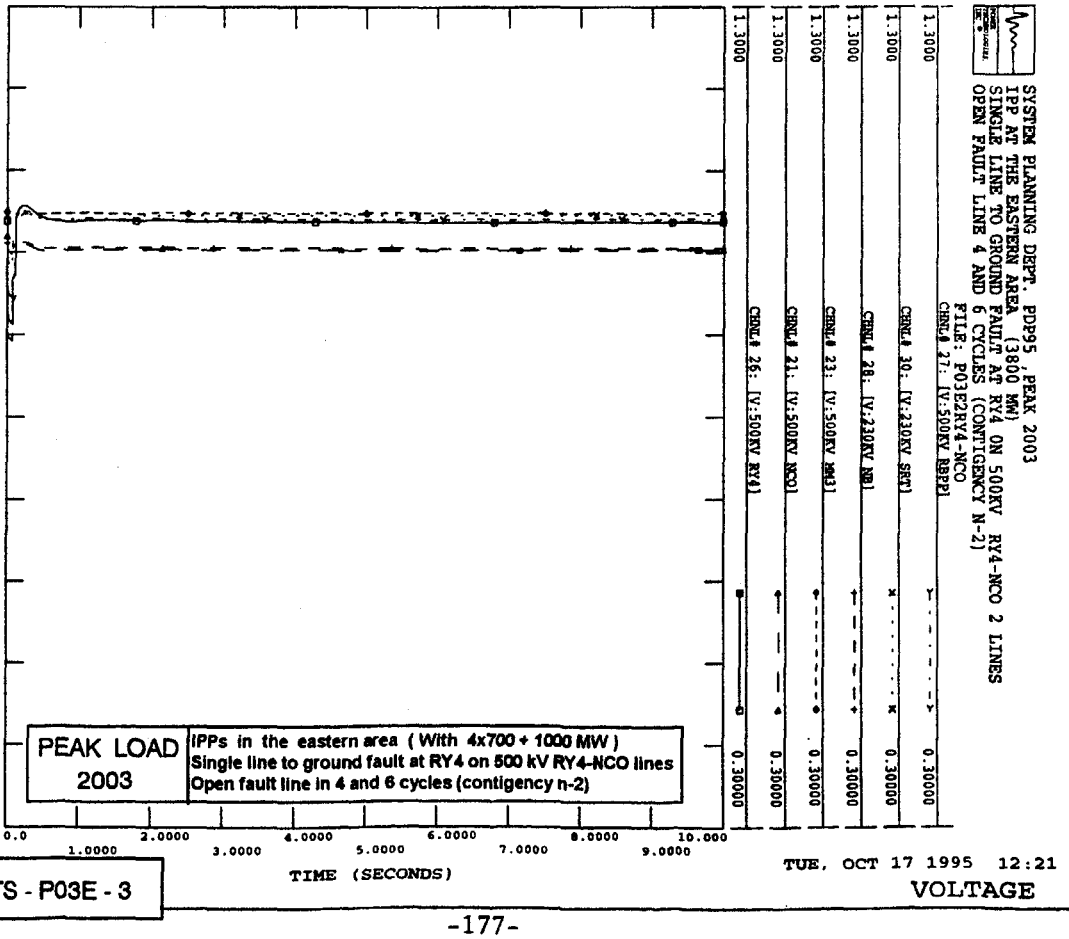
CASE TS - P03E - 1



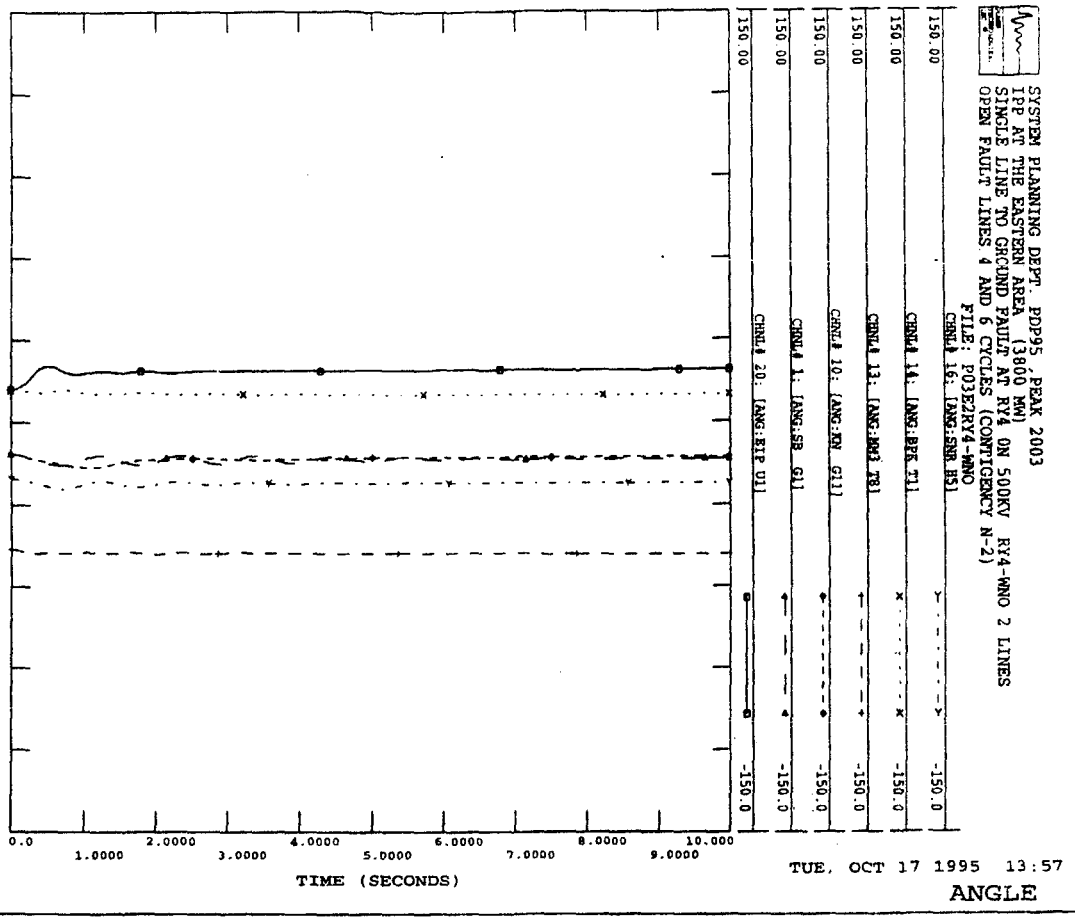


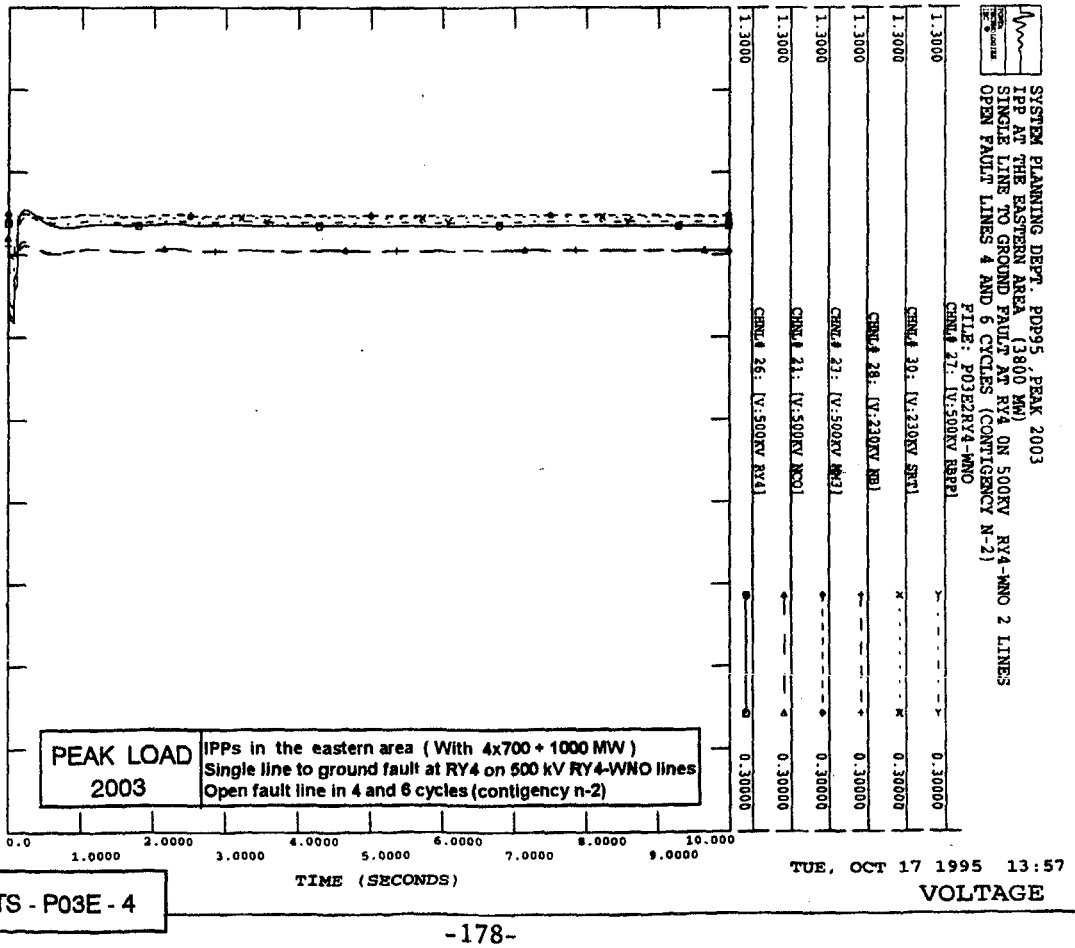
CASE TS - P03E - 2



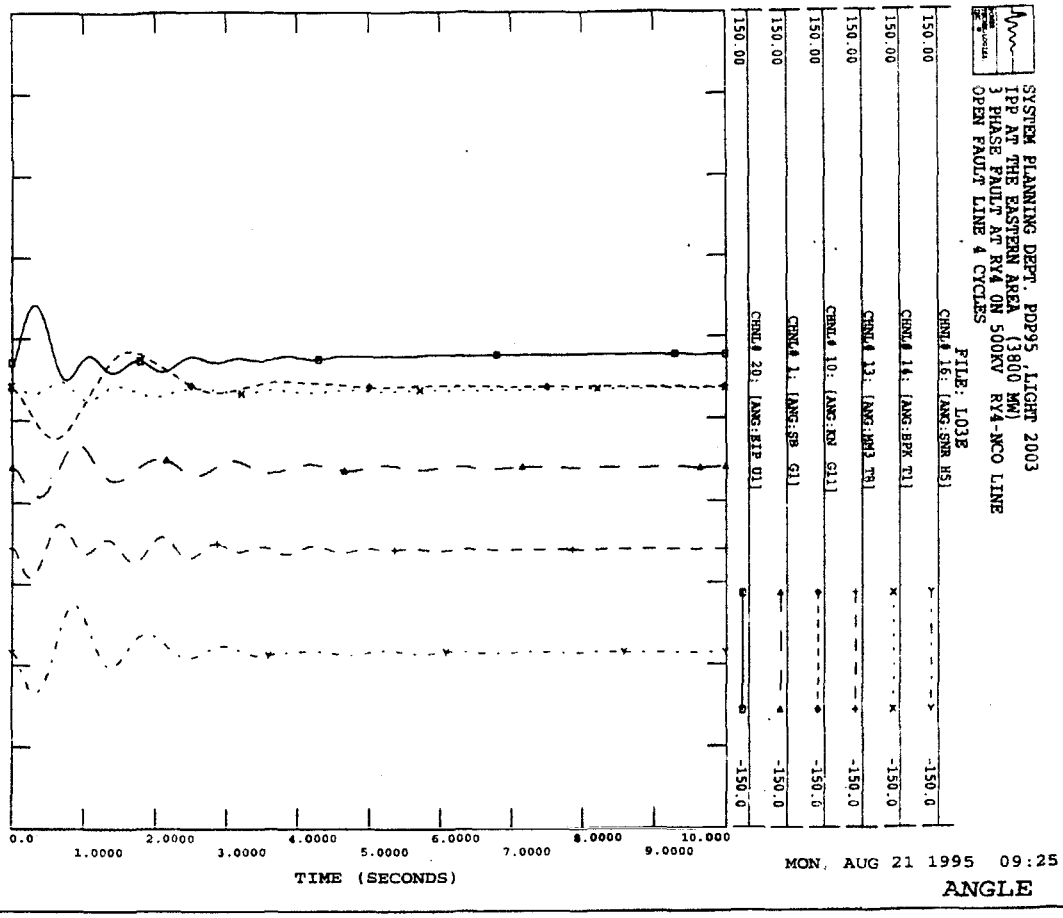


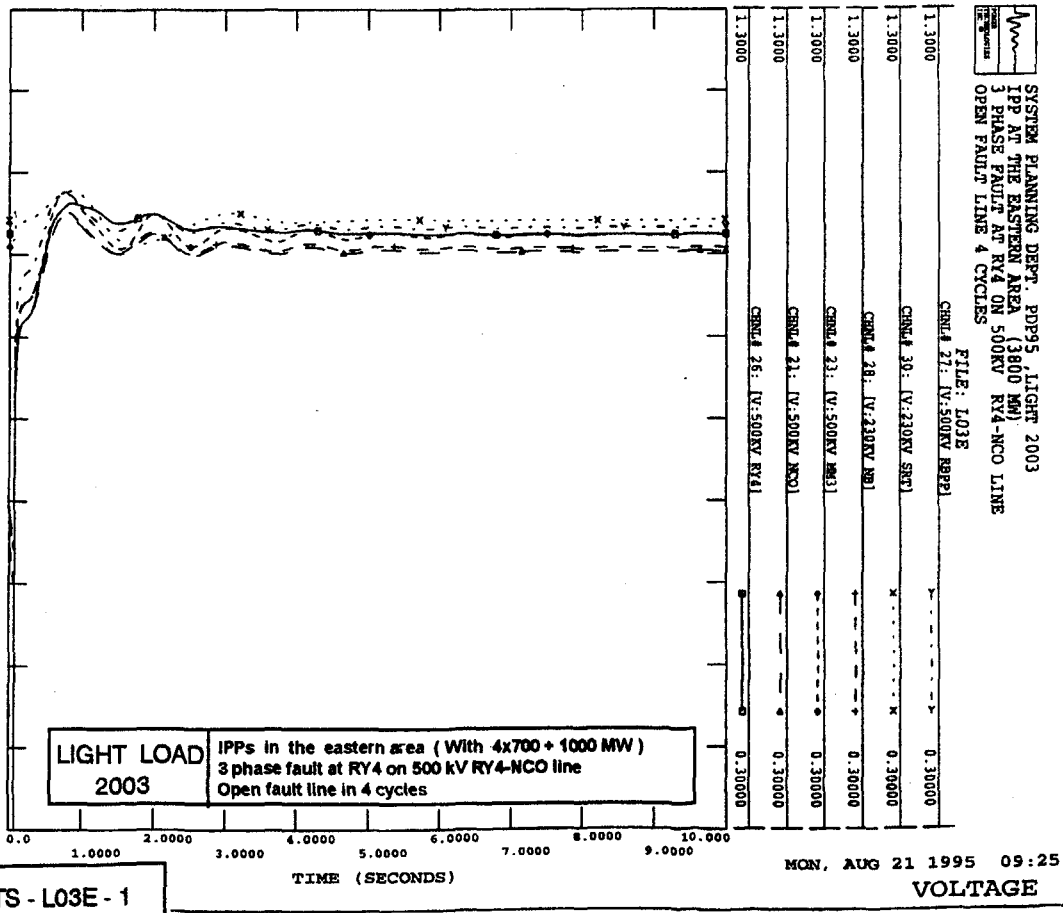
CASE TS - P03E - 3



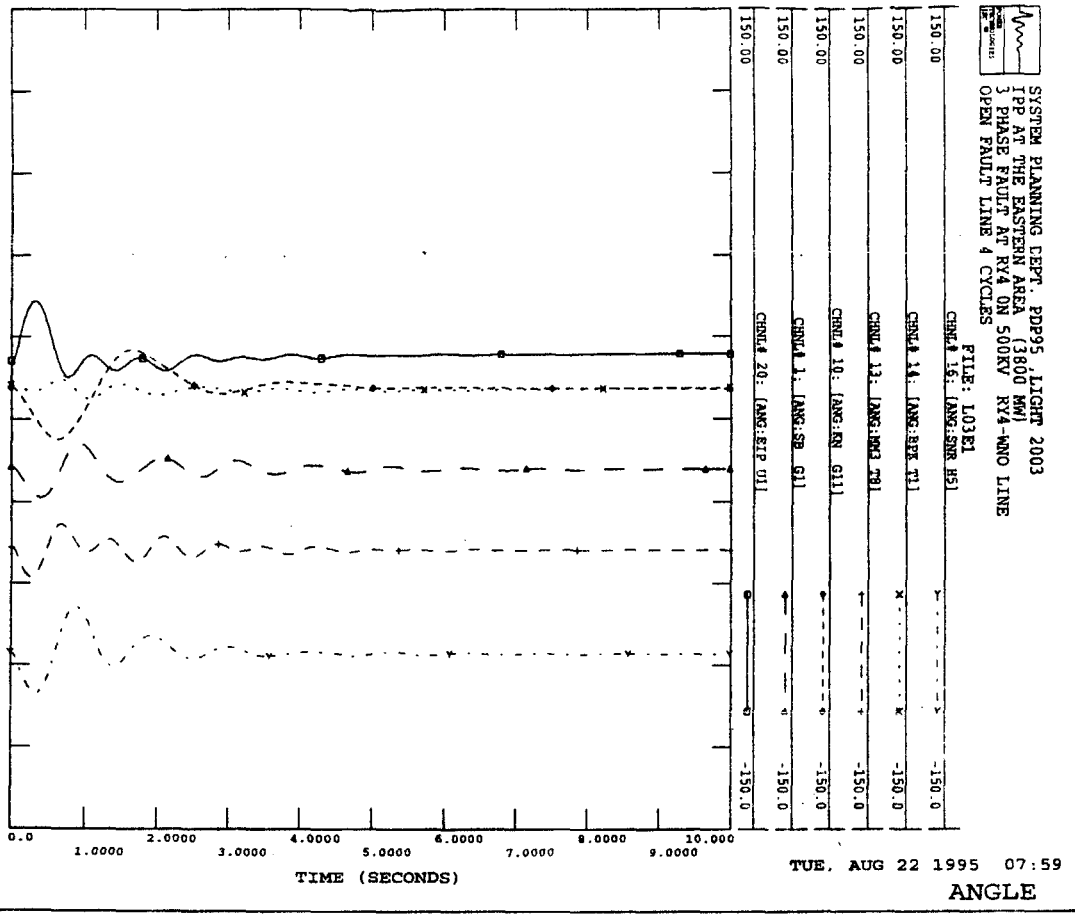


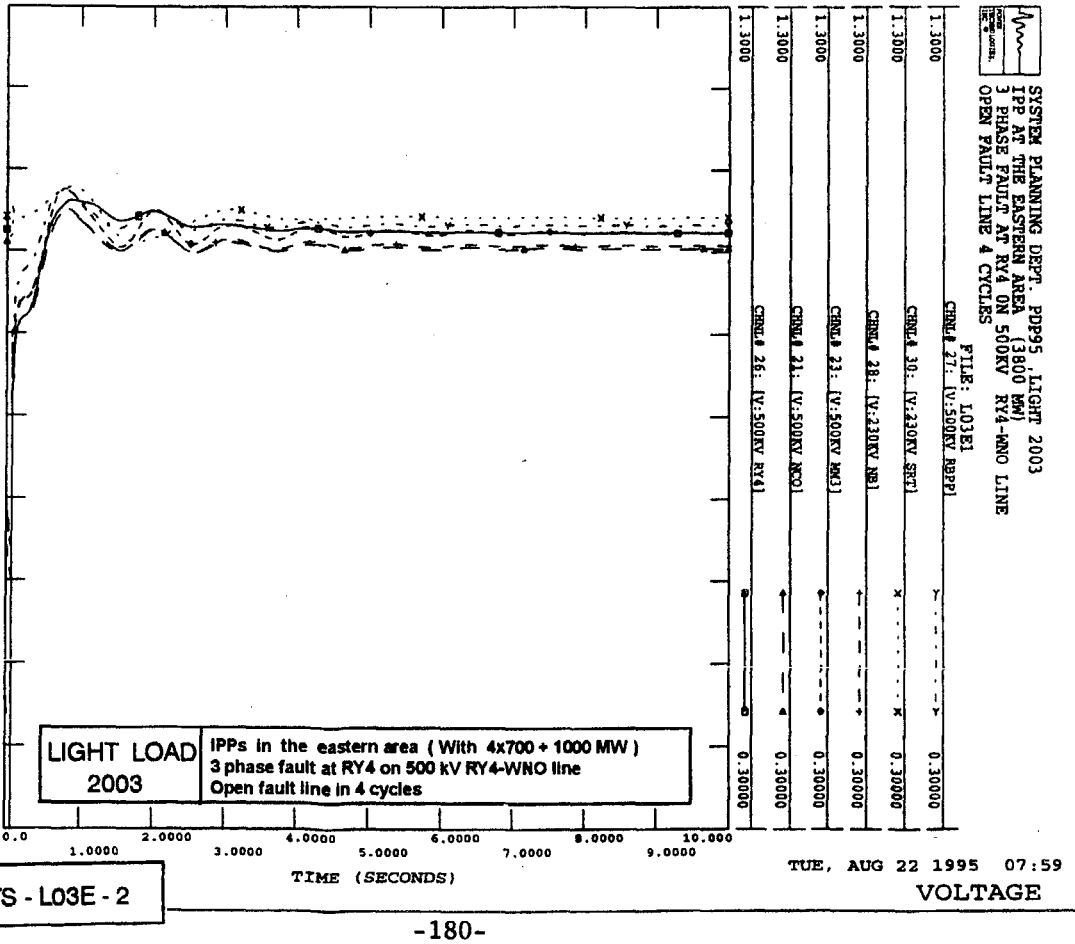
CASE TS - P03E - 4



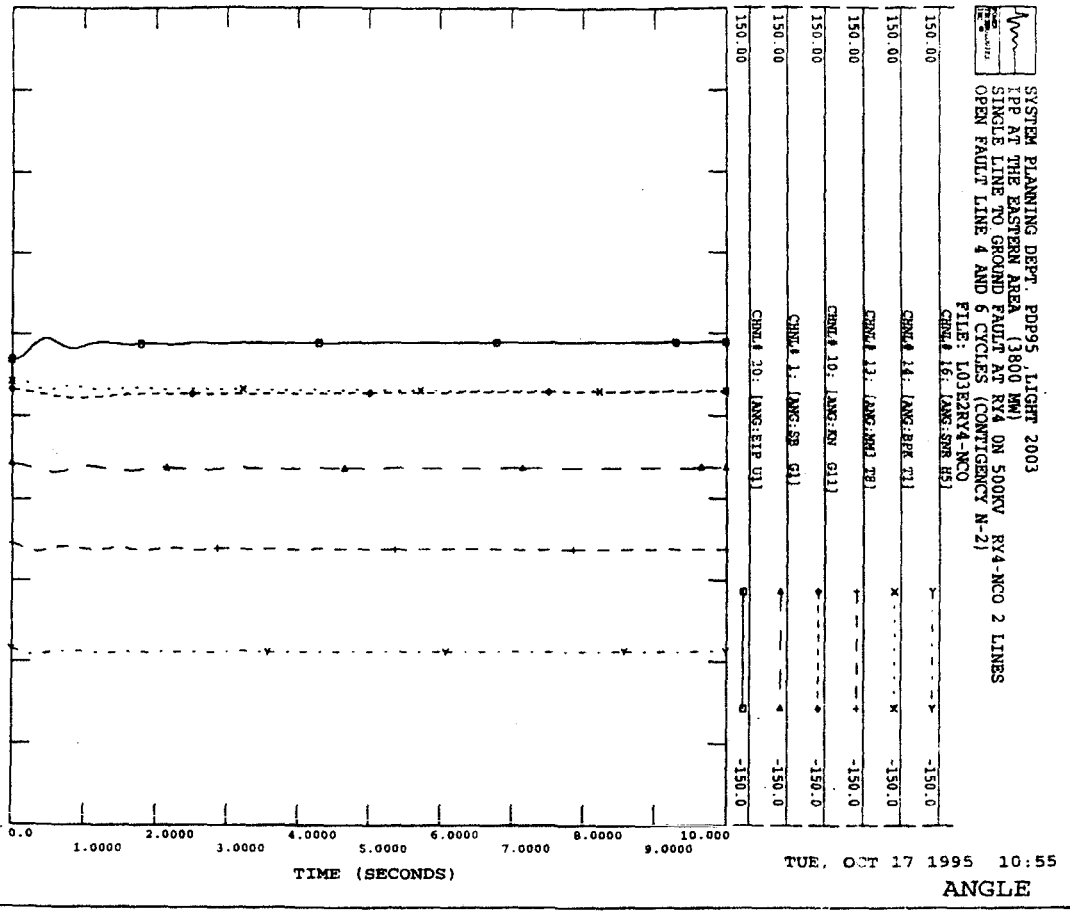


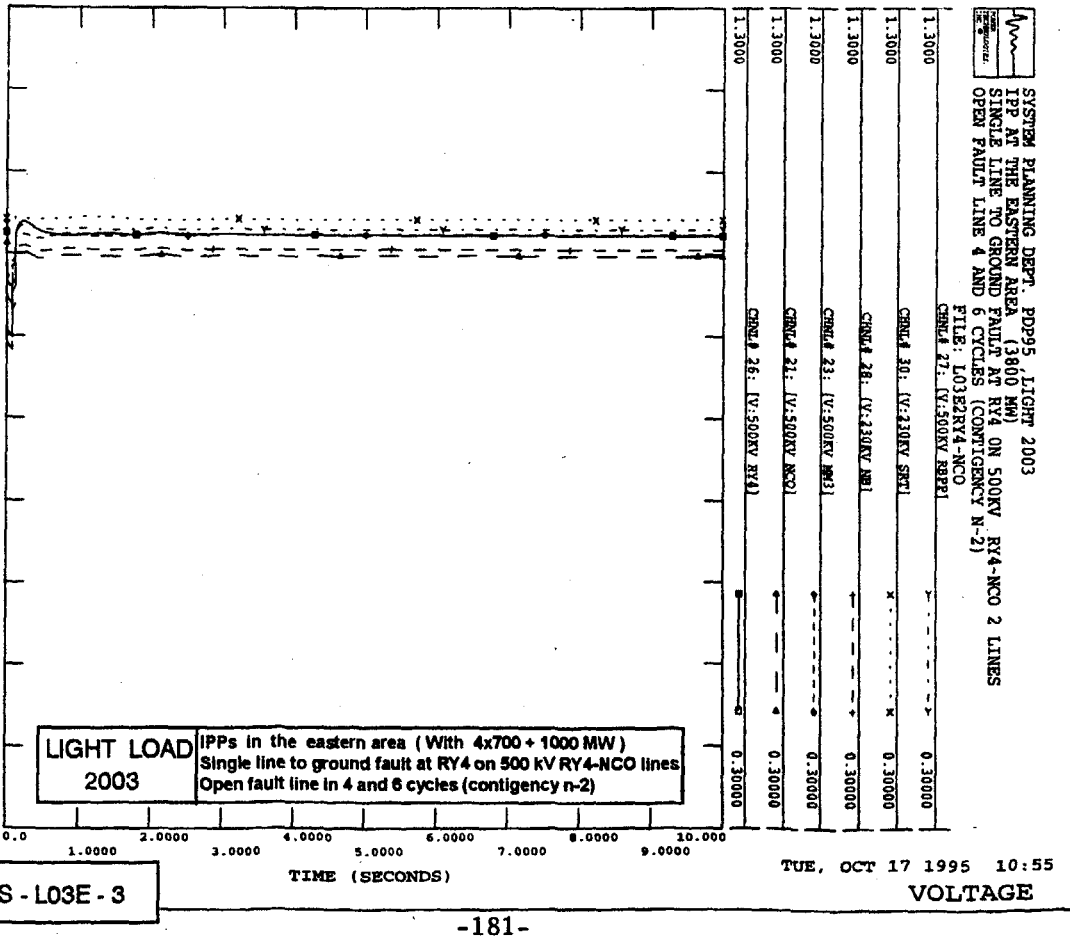
CASE TS - L03E - 1



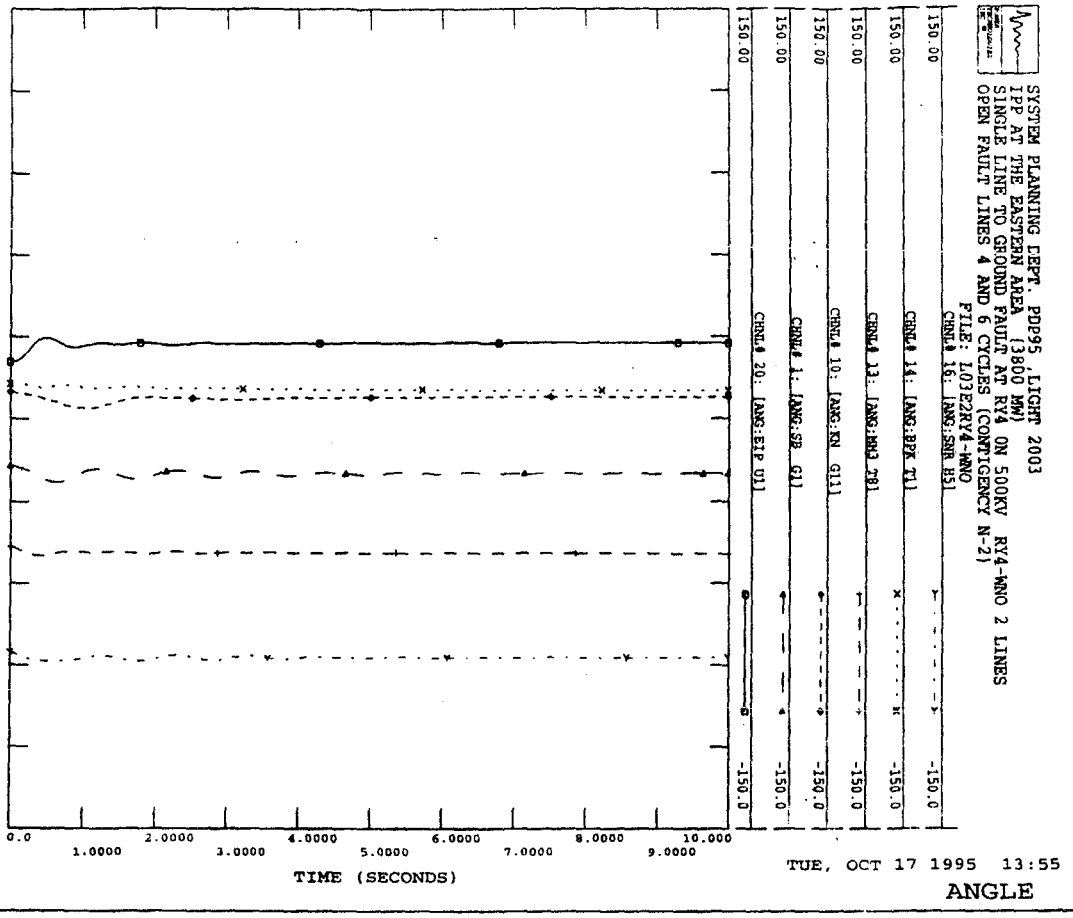


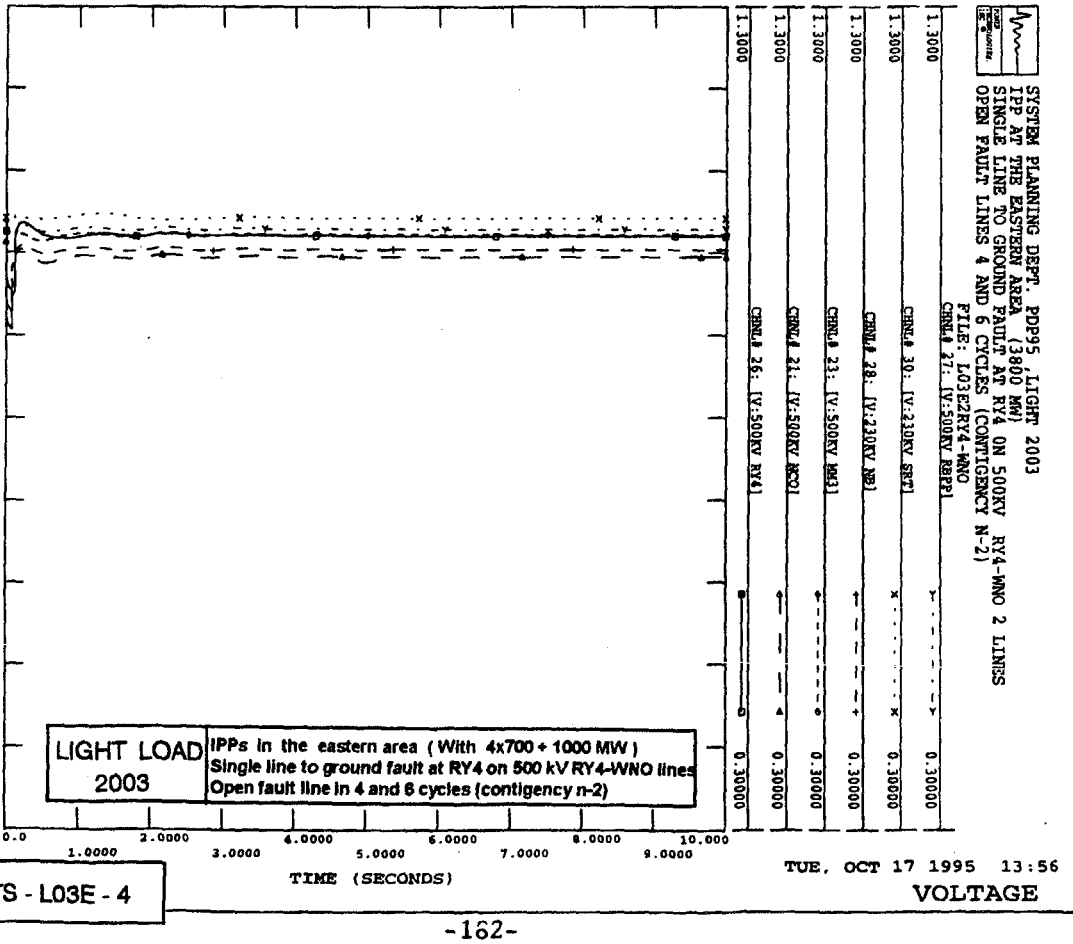
CASE TS - L03E - 2

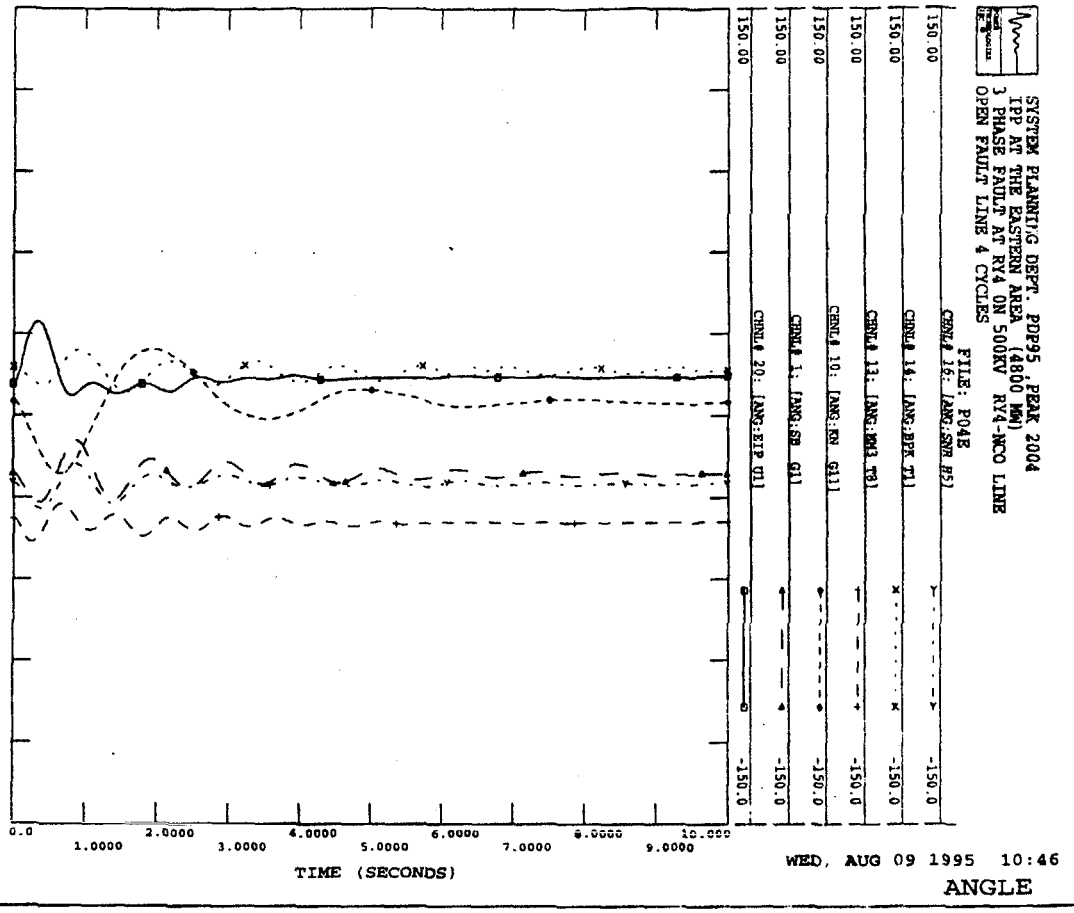


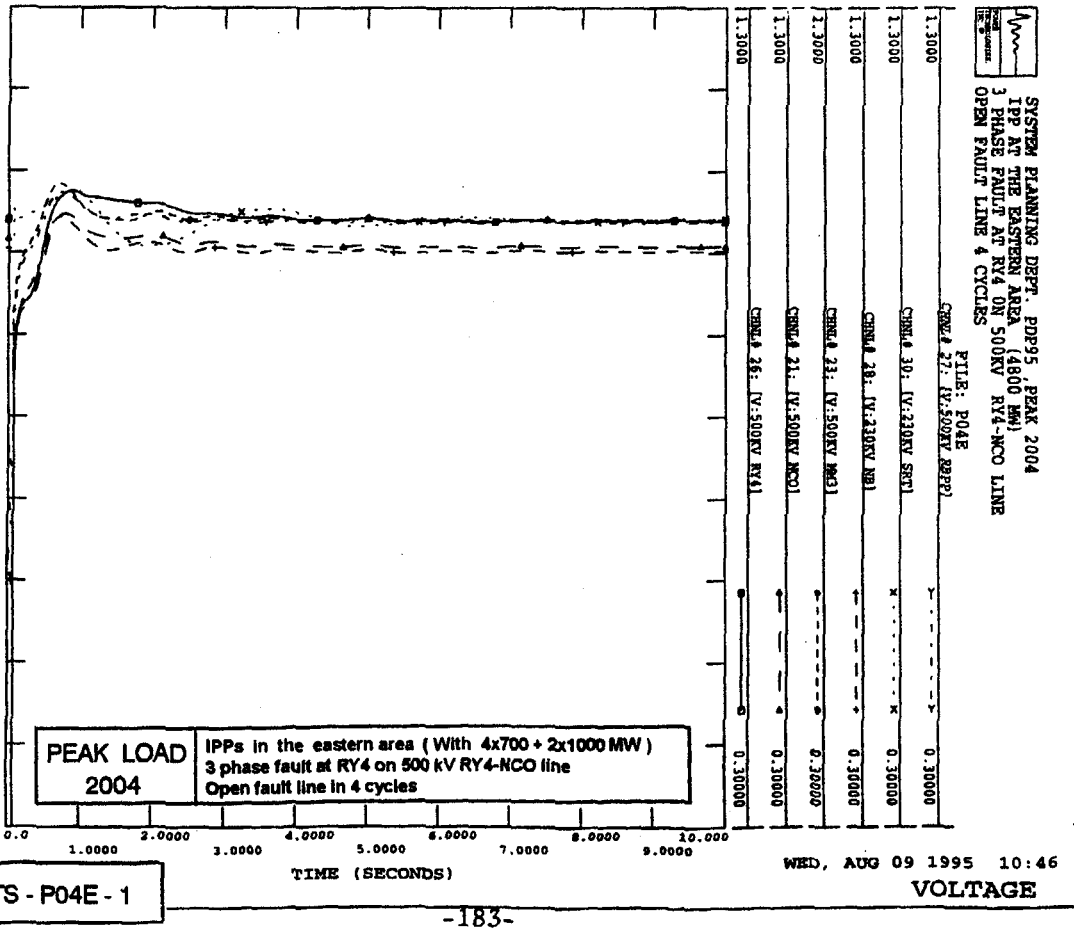


CASE TS - L03E - 3

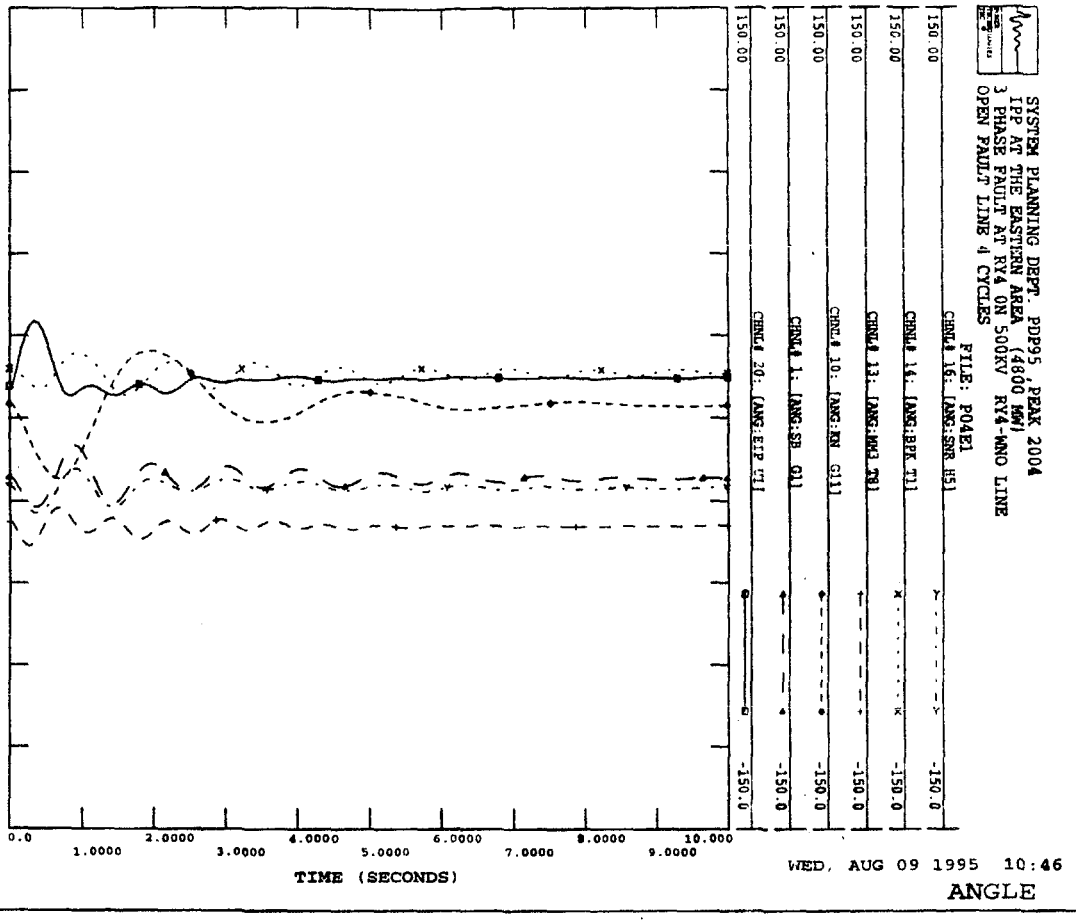

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2003
IPP AT THE EASTERN AREA (3800 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-WNO 2 LINES
OPEN FAULT LINES 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L03E2RY4-WNO
CHNL# 16: [ANG:SNR H5]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:BR3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:E1P U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 13:55
ANGLE

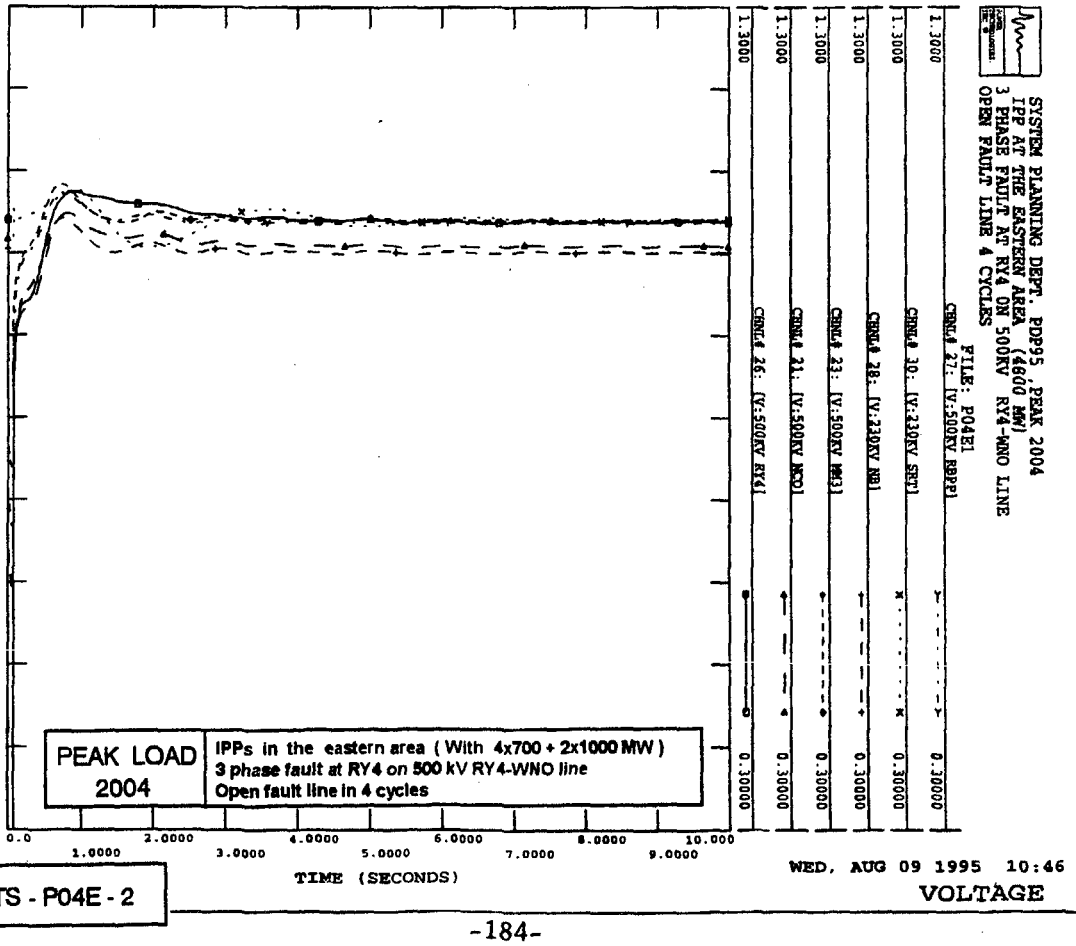

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2003
IPP AT THE EASTERN AREA (3800 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-WNO 2 LINES
OPEN FAULT LINES 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: L03E2RY4-WNO
CHNL# 27: [V:500KV RBPP]
CHNL# 30: [V:230KV SE2]
CHNL# 28: [V:230KV AE]
CHNL# 23: [V:500KV MW3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 13:56
VOLTAGE
LIGHT LOAD
2003
IPPs in the eastern area (With 4x700 + 1000 MW)
Single line to ground fault at RY4 on 500 kV RY4-WNO lines
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS - L03E - 4

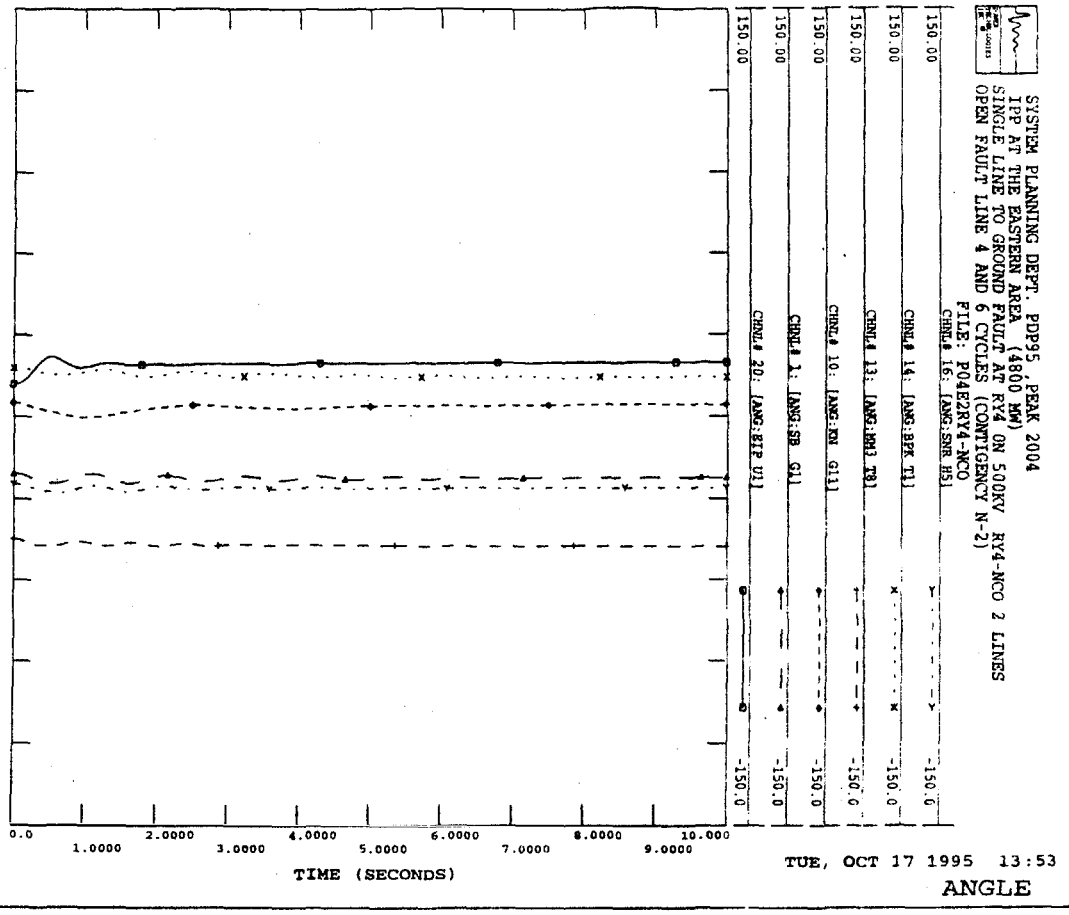


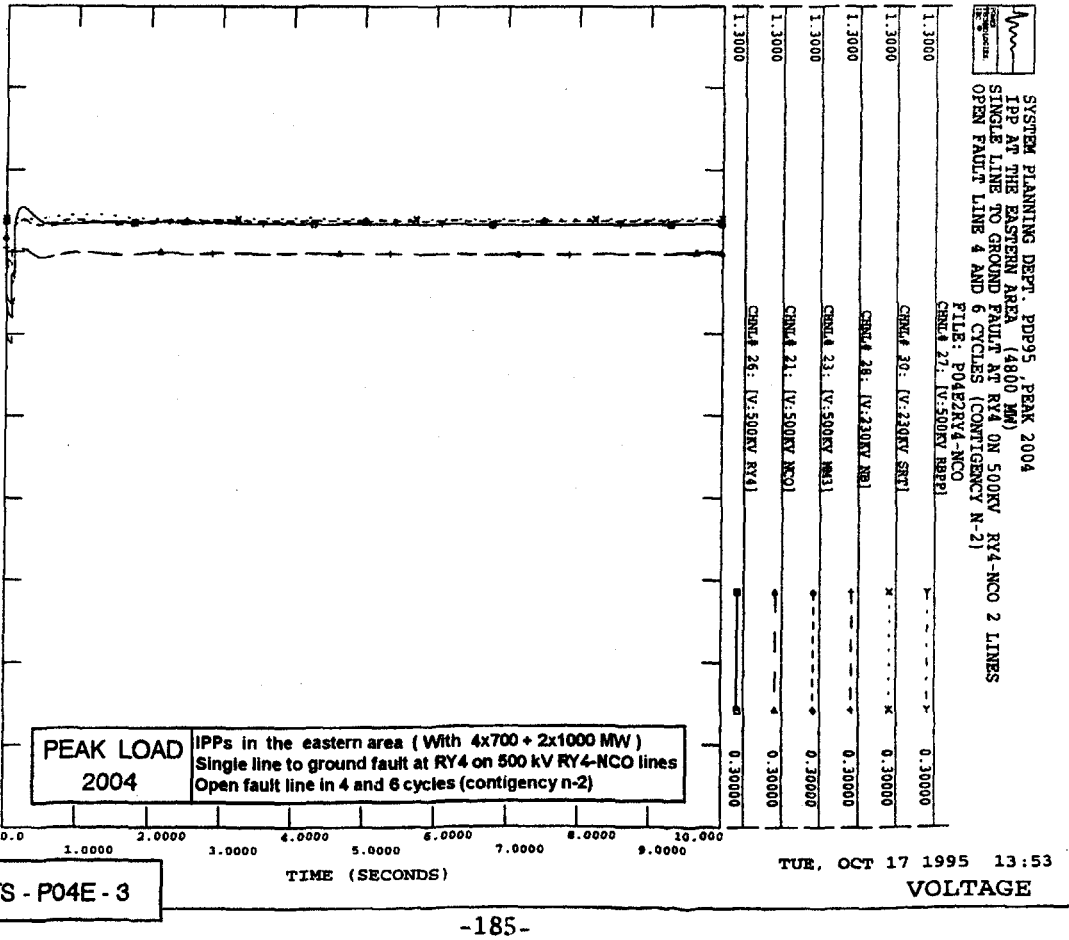


CASE TS - P04E - 1

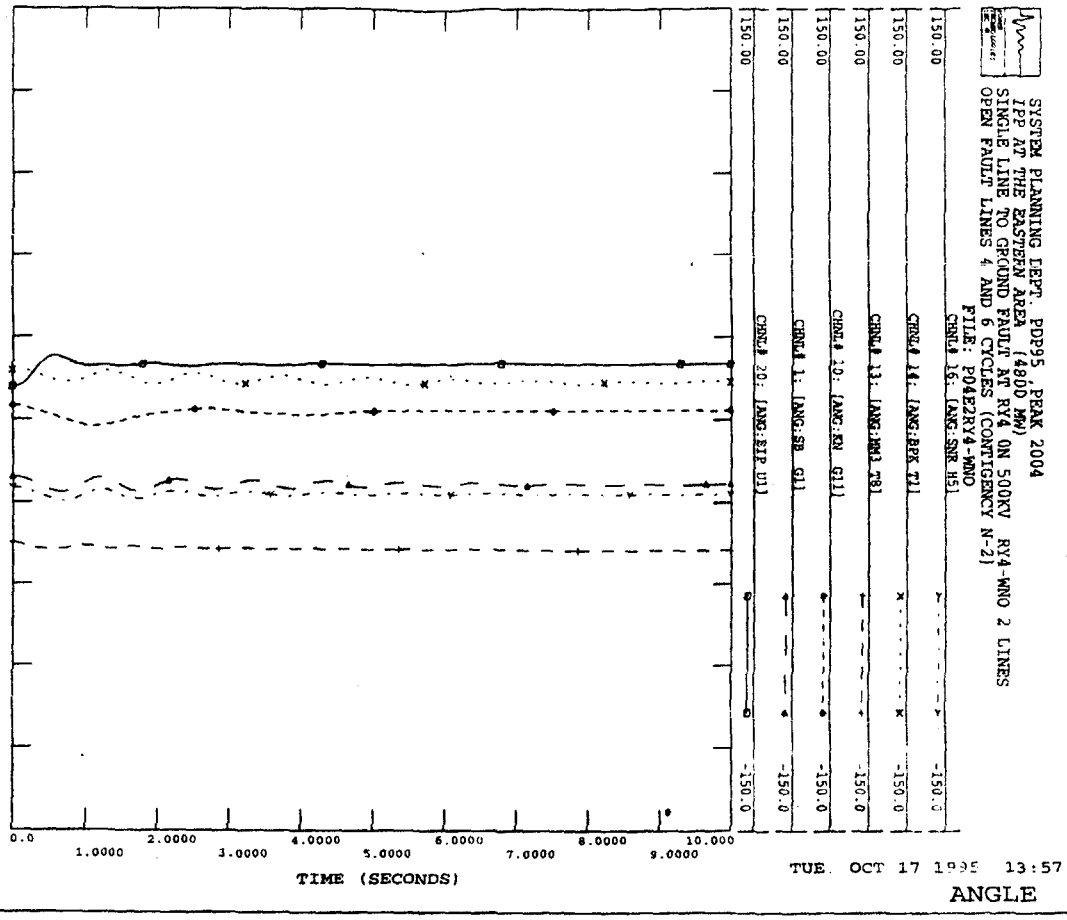

SYSTEM PLANNING DEPT. PDP95 ,PEAK 2004
IPP AT THE EASTERN AREA (4800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-WNO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P04E1
CHNL# 16: [ANG:SHR HS]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:NW3 T8]
CHNL# 10: [ANG:EN G11]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:ETP T1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, AUG 09 1995 10:46
ANGLE

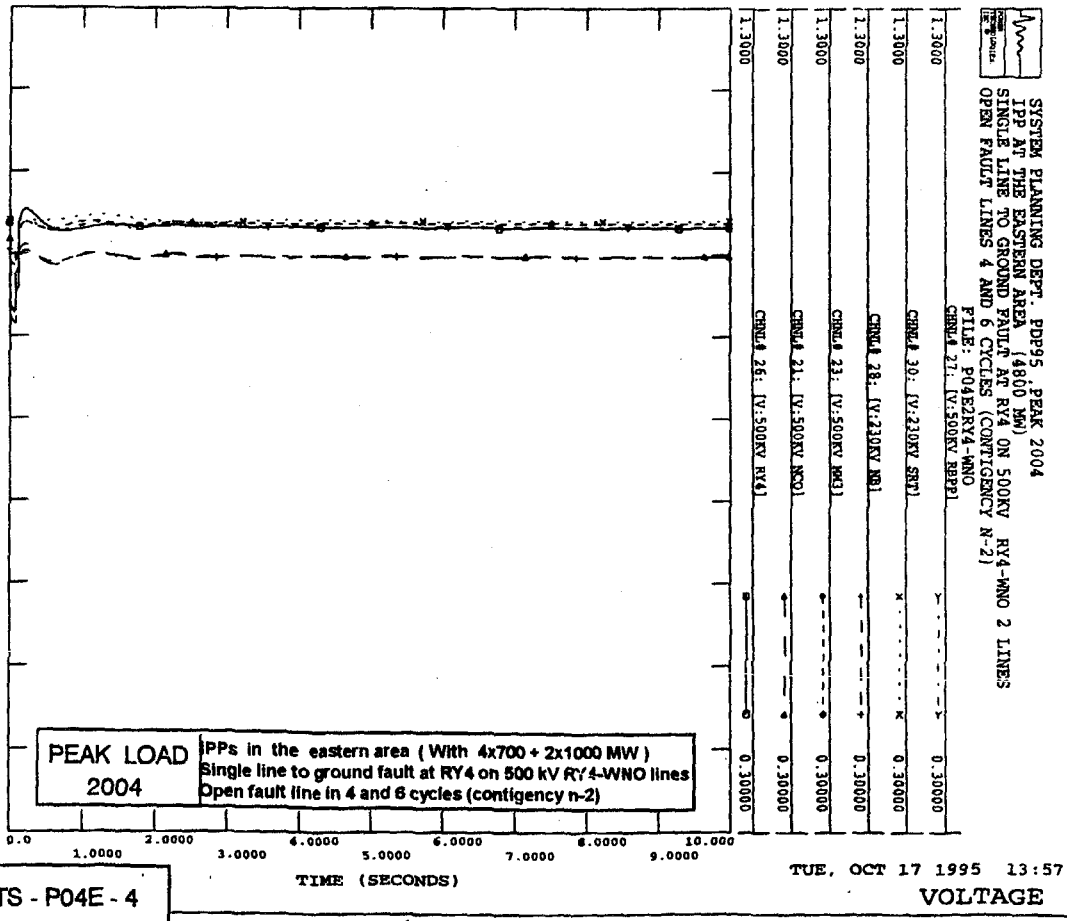

SYSTEM PLANNING DEPT. PDP95 ,PEAK 2004
IPP AT THE EASTERN AREA (4800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-WNO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P04E1
CHNL# 27: [V:500KV BBP1]
CHNL# 30: [V:230KV SET1]
CHNL# 28: [V:230KV NB1]
CHNL# 23: [V:500KV NW3]
CHNL# 21: [V:500KV NCO1]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, AUG 09 1995 10:46
VOLTAGE
PEAK LOAD
2004
IPPs in the eastern area (With 4x700 + 2x1000 MW)
3 phase fault at RY4 on 500 kV RY4-WNO line
Open fault line in 4 cycles
CASE TS - P04E - 2



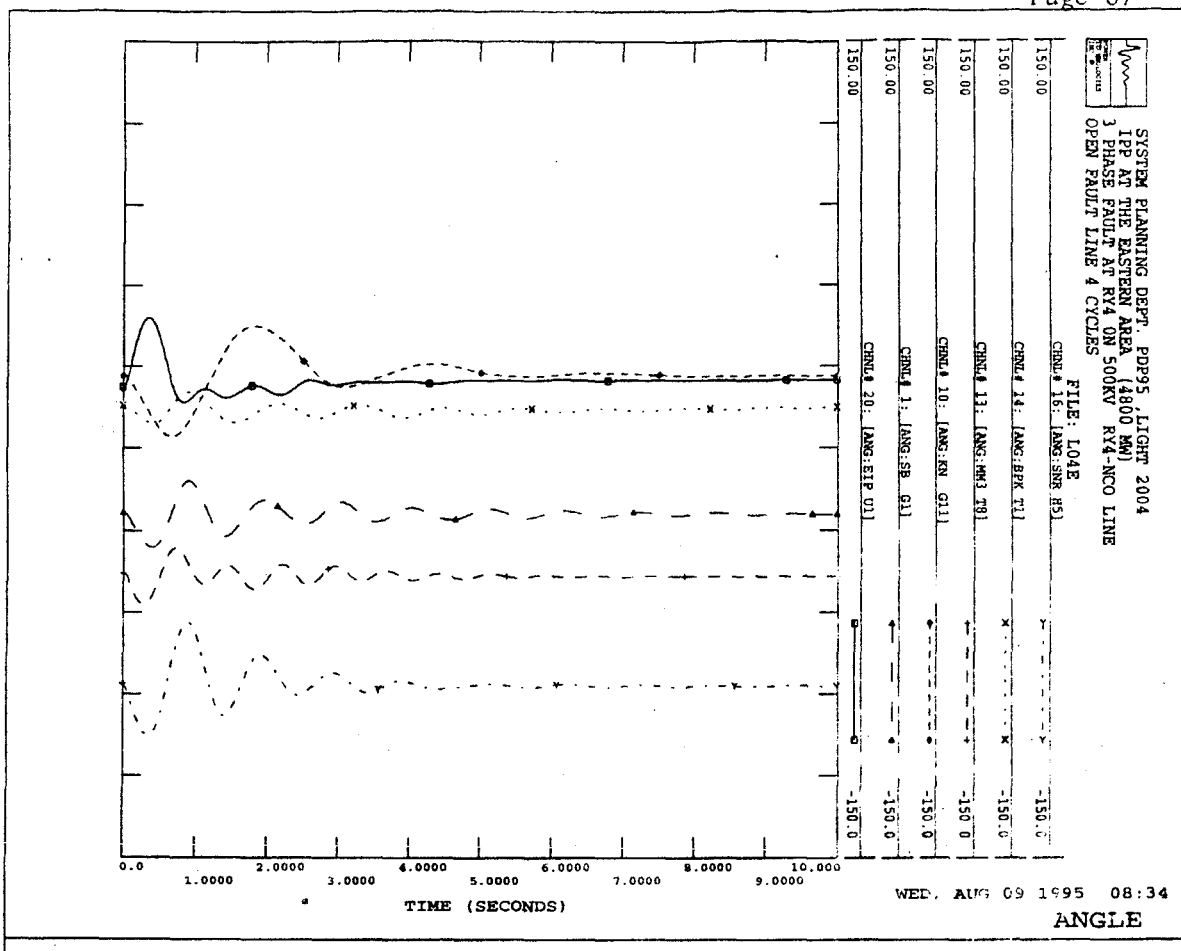


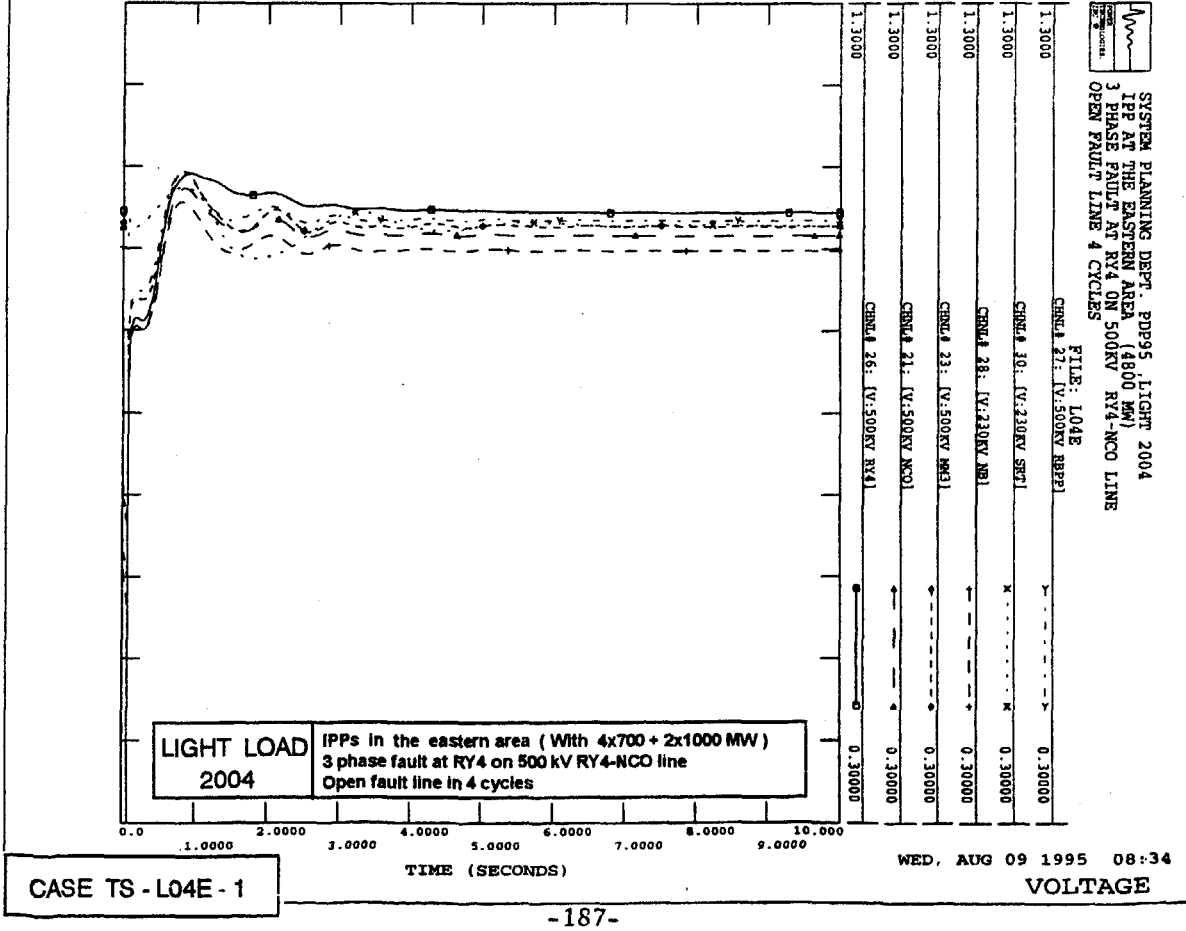
CASE TS - P04E - 3

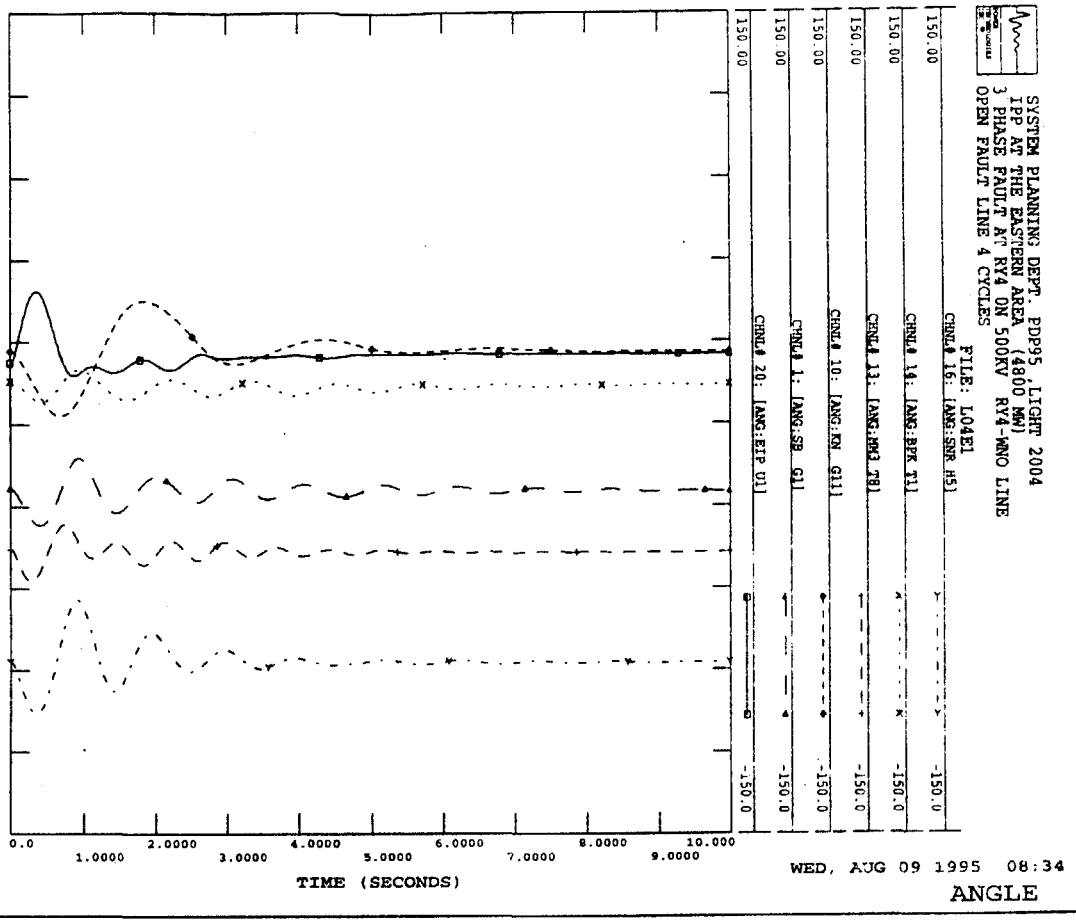


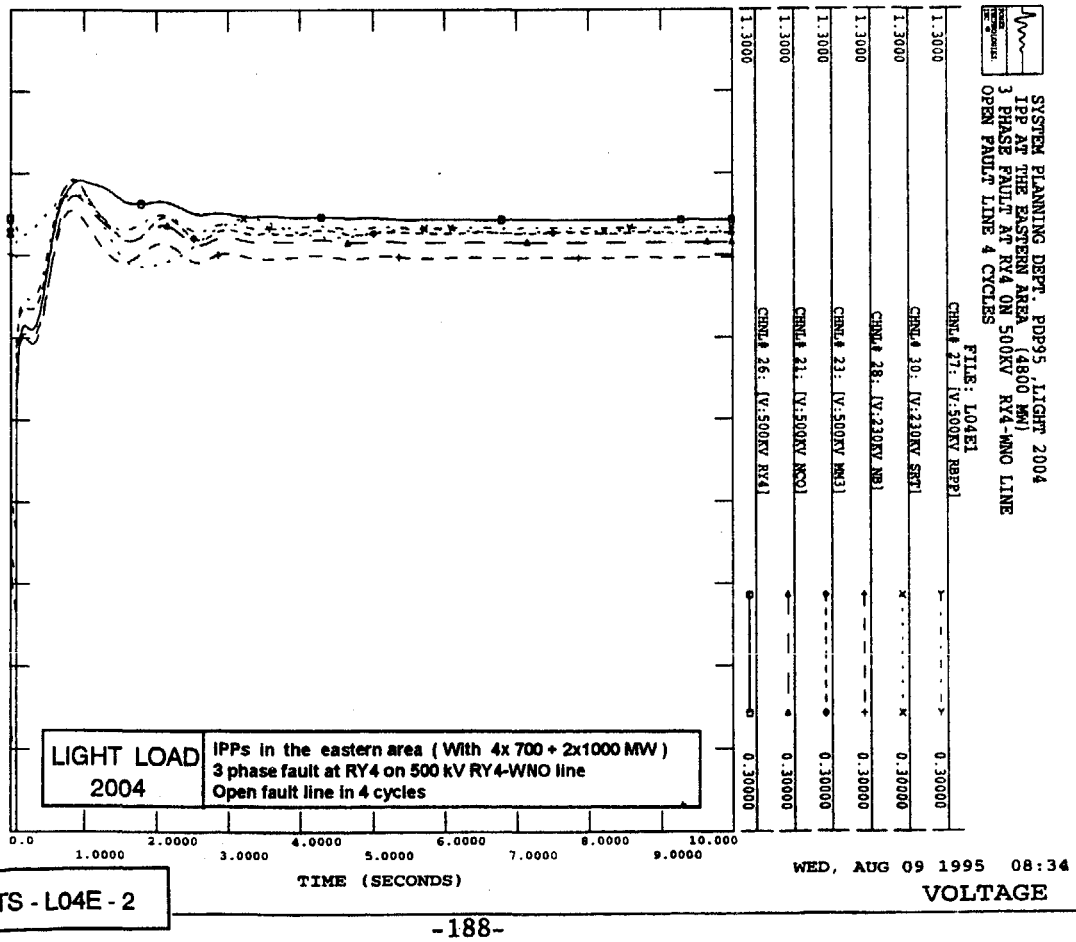


CASE TS - P04E - 4

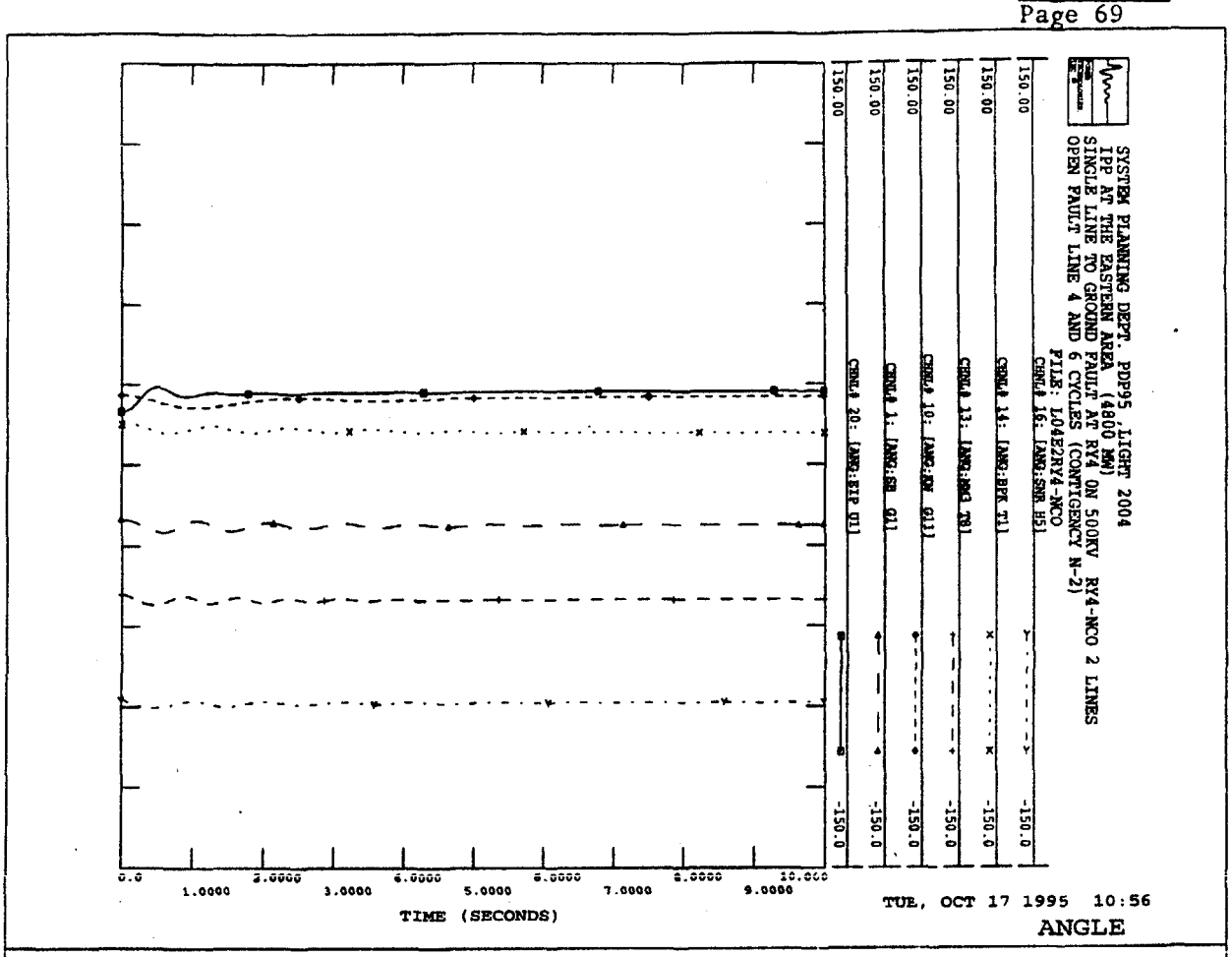

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2004
IPP AT THE EASTERN AREA (4800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: L04E
CHNL# 16: [ANG:SNR H5]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:MM3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:EIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, AUG 09 1995 08:34
ANGLE

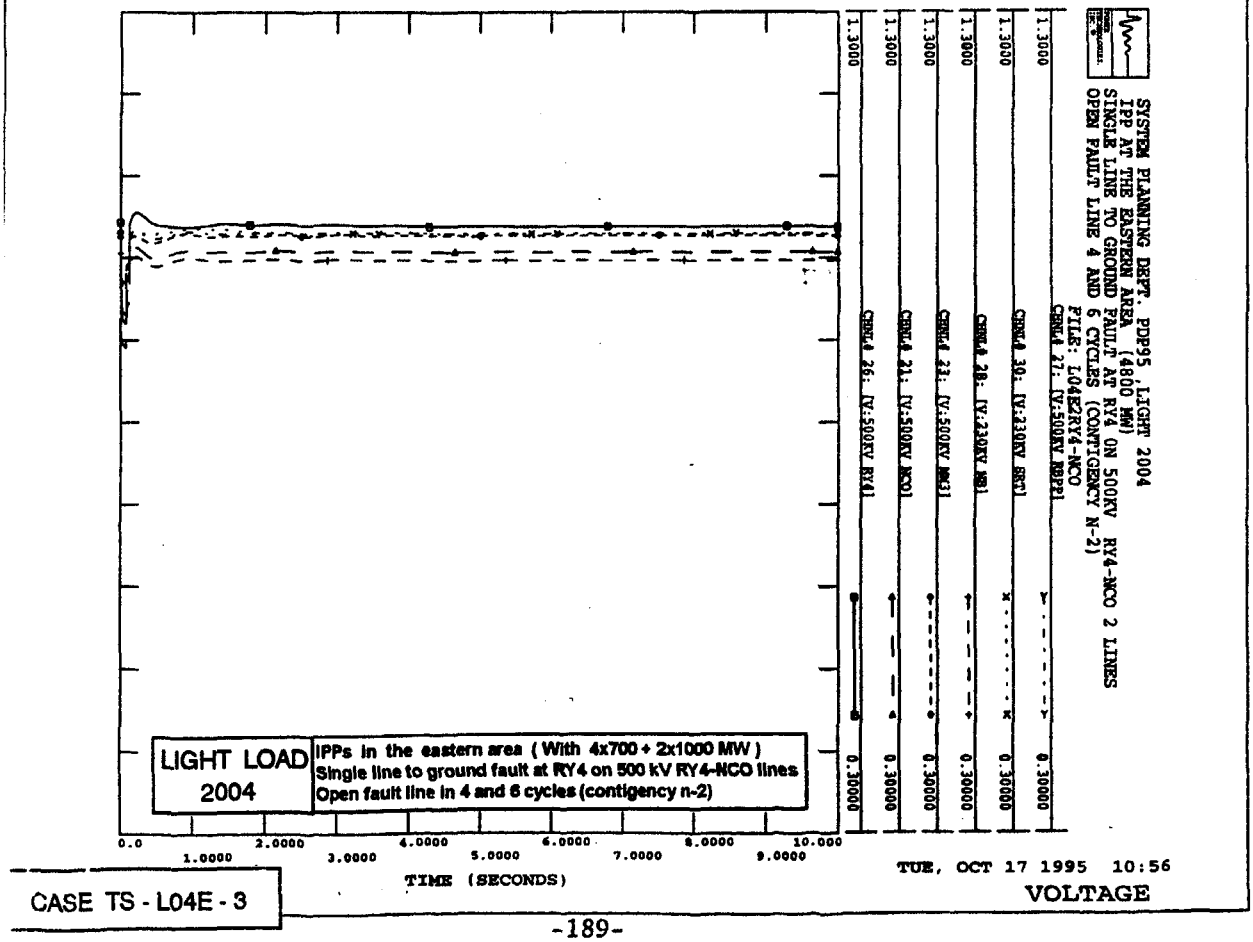

SYSTEM PLANNING DEPT. PDP95 ,LIGHT 2004
IPP AT THE EASTERN AREA (4800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: L04E
CHNL# 27: [V:500KV RBPP]
CHNL# 30: [V:230KV SEP]
CHNL# 28: [V:230KV NB]
CHNL# 23: [V:500KV MM3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, AUG 09 1995 08:34
VOLTAGE
LIGHT LOAD
2004
IPPs in the eastern area (With 4x700 + 2x1000 MW)
3 phase fault at RY4 on 500 kV RY4-NCO line
Open fault line in 4 cycles
CASE TS - L04E - 1



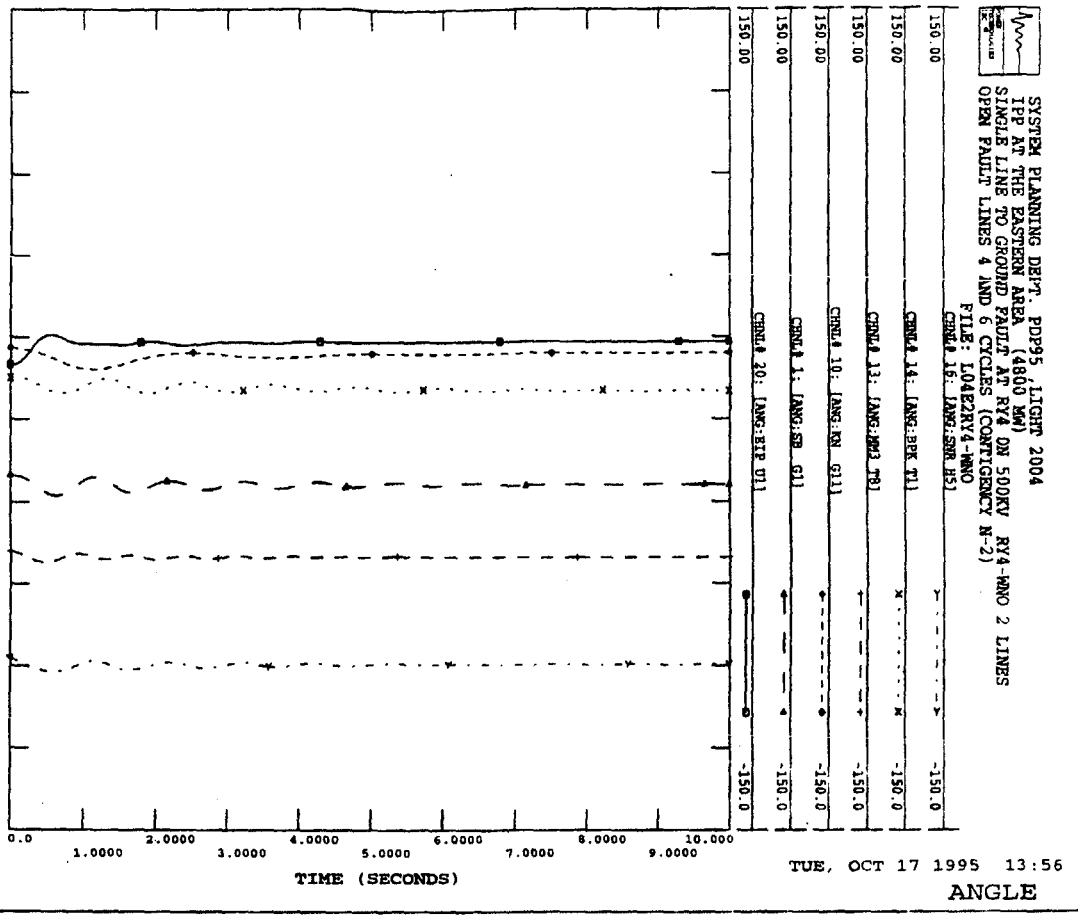


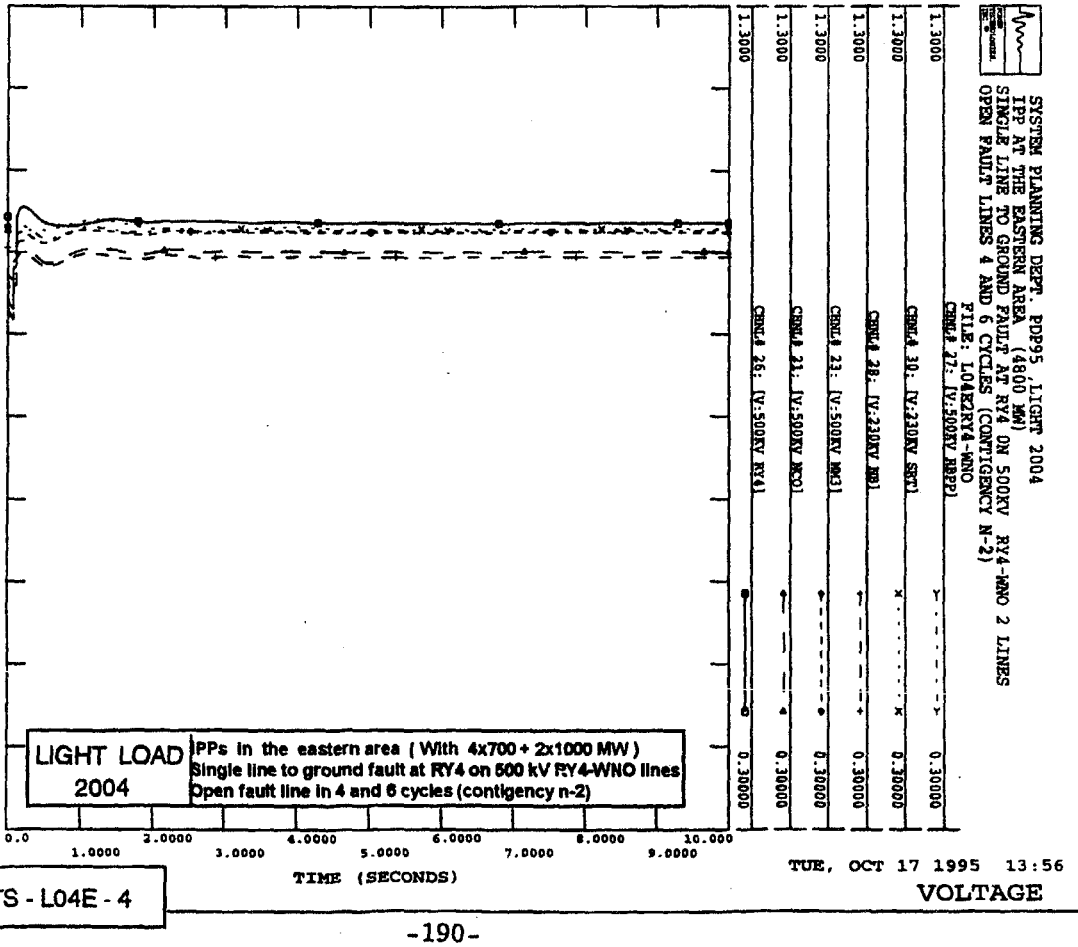
CASE TS - L04E - 2



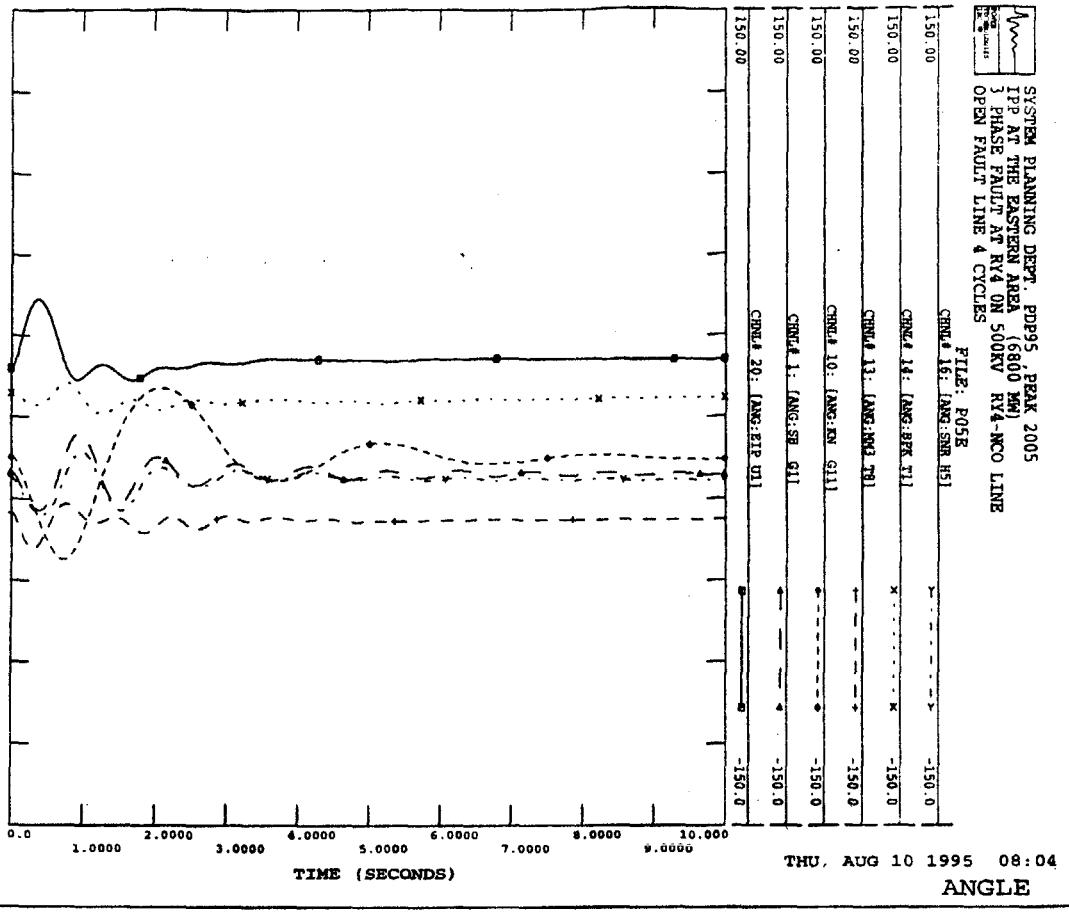


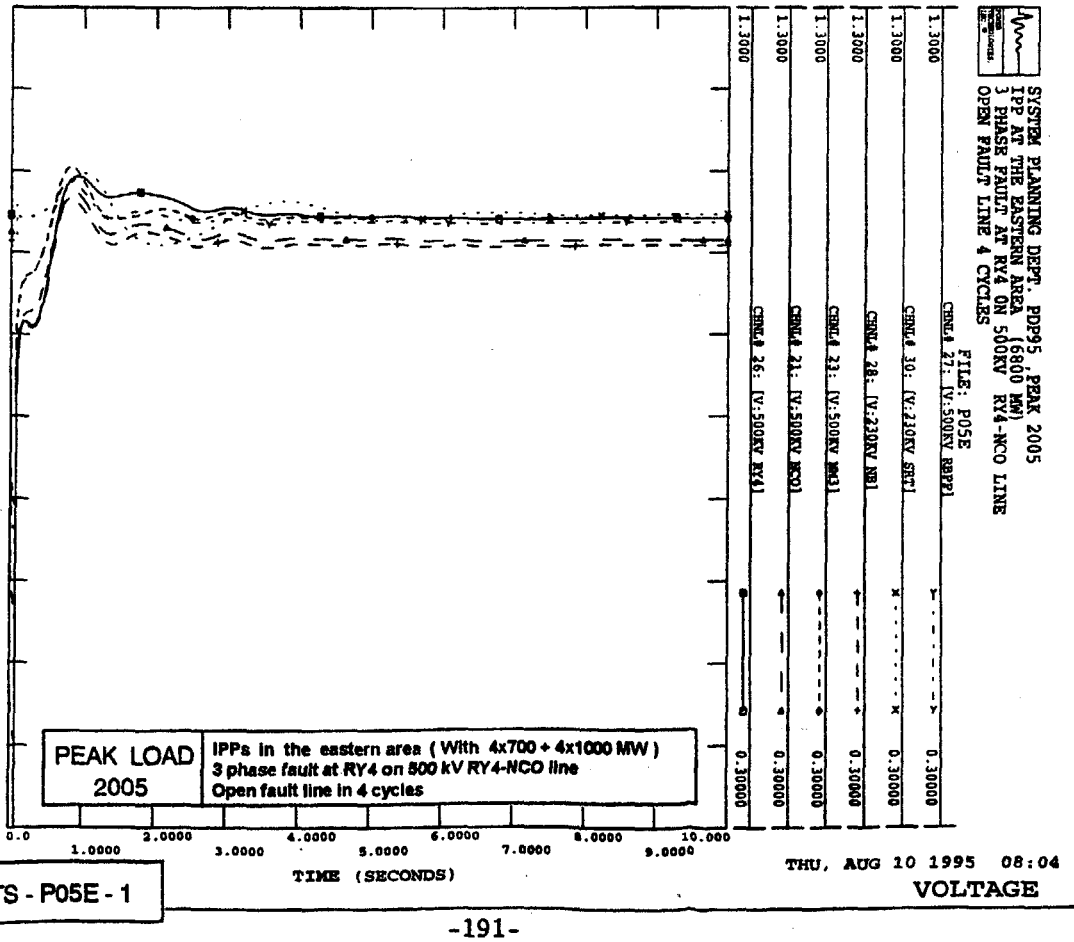
CASE TS - L04E - 3

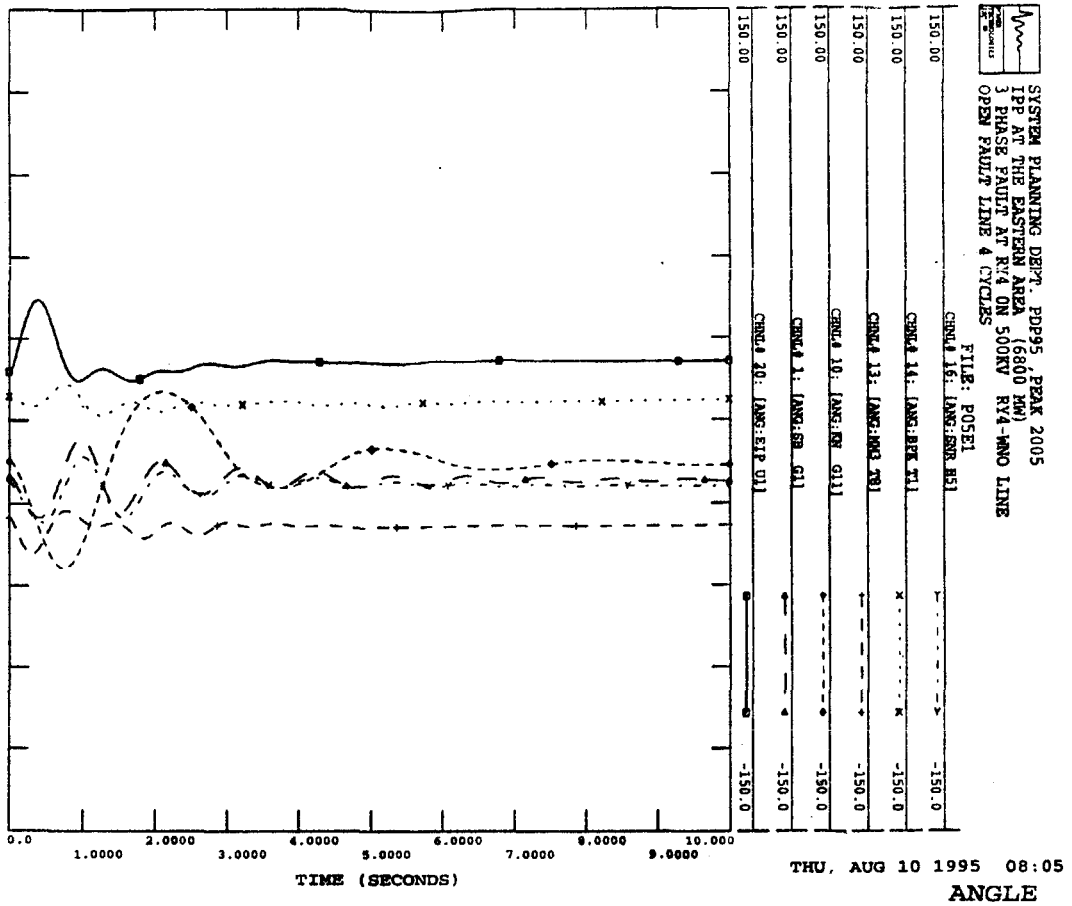


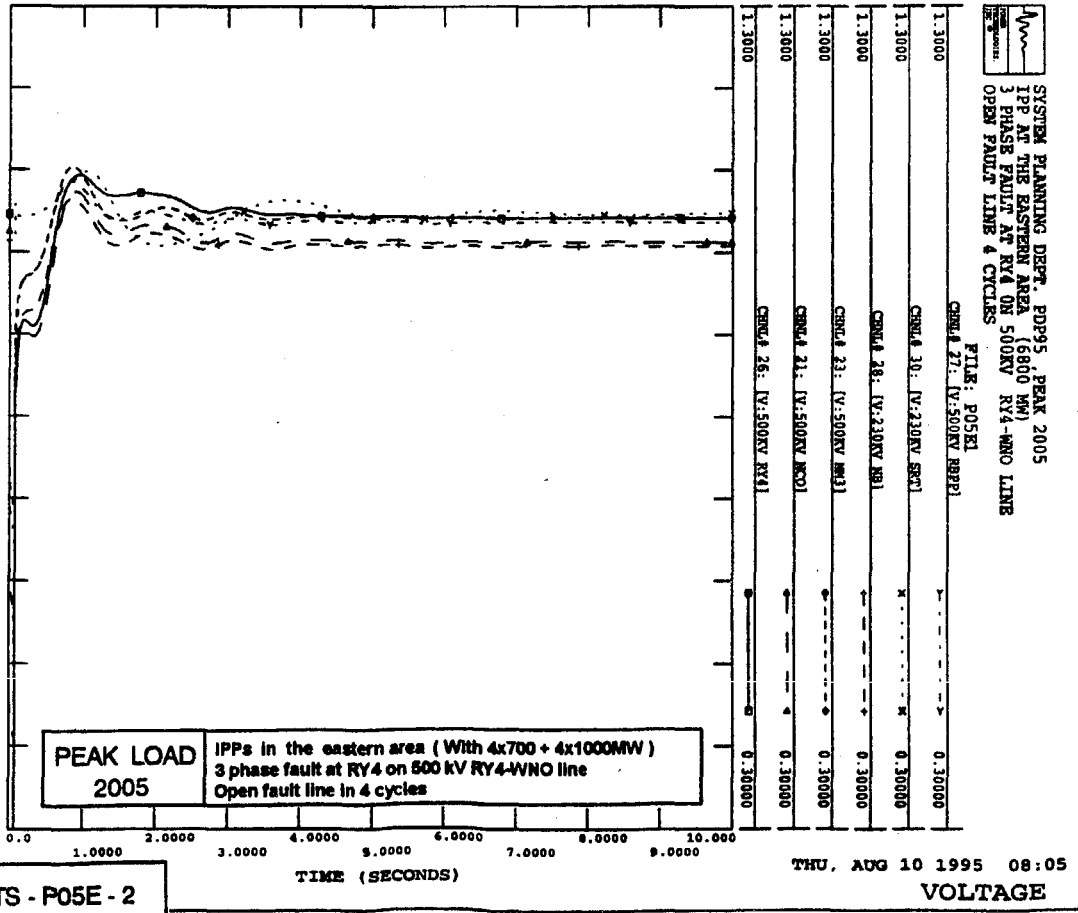


CASE TS - L04E - 4

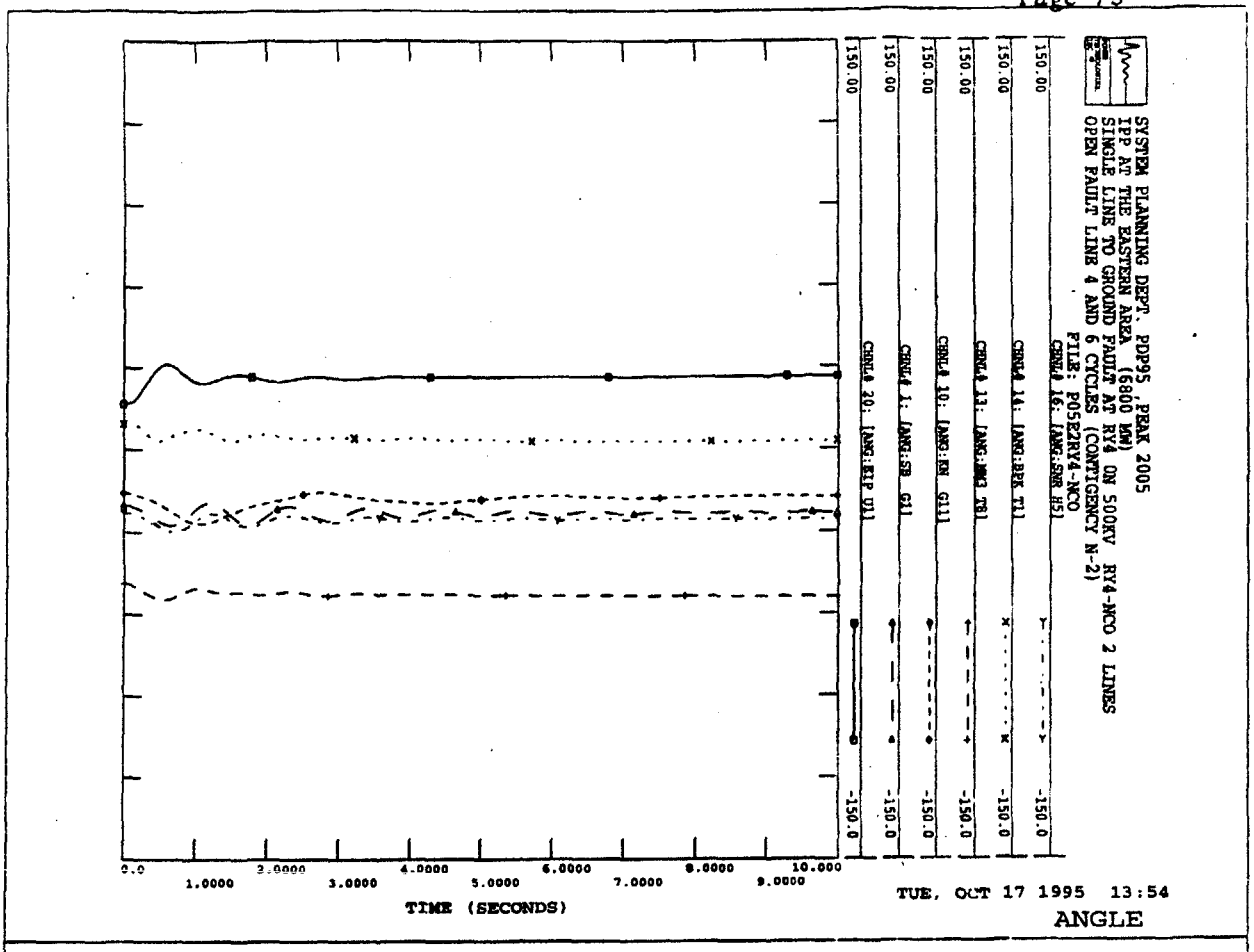

SYSTEM PLANNING DEPT. PDP95 PEAK 2005
IPP AT THE EASTERN AREA (6800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P05E
CHNL# 16: [ANG:SNR H5]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:NKB T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SB G11]
CHNL# 20: [ANG:EIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, AUG 10 1995 08:04
ANGLE

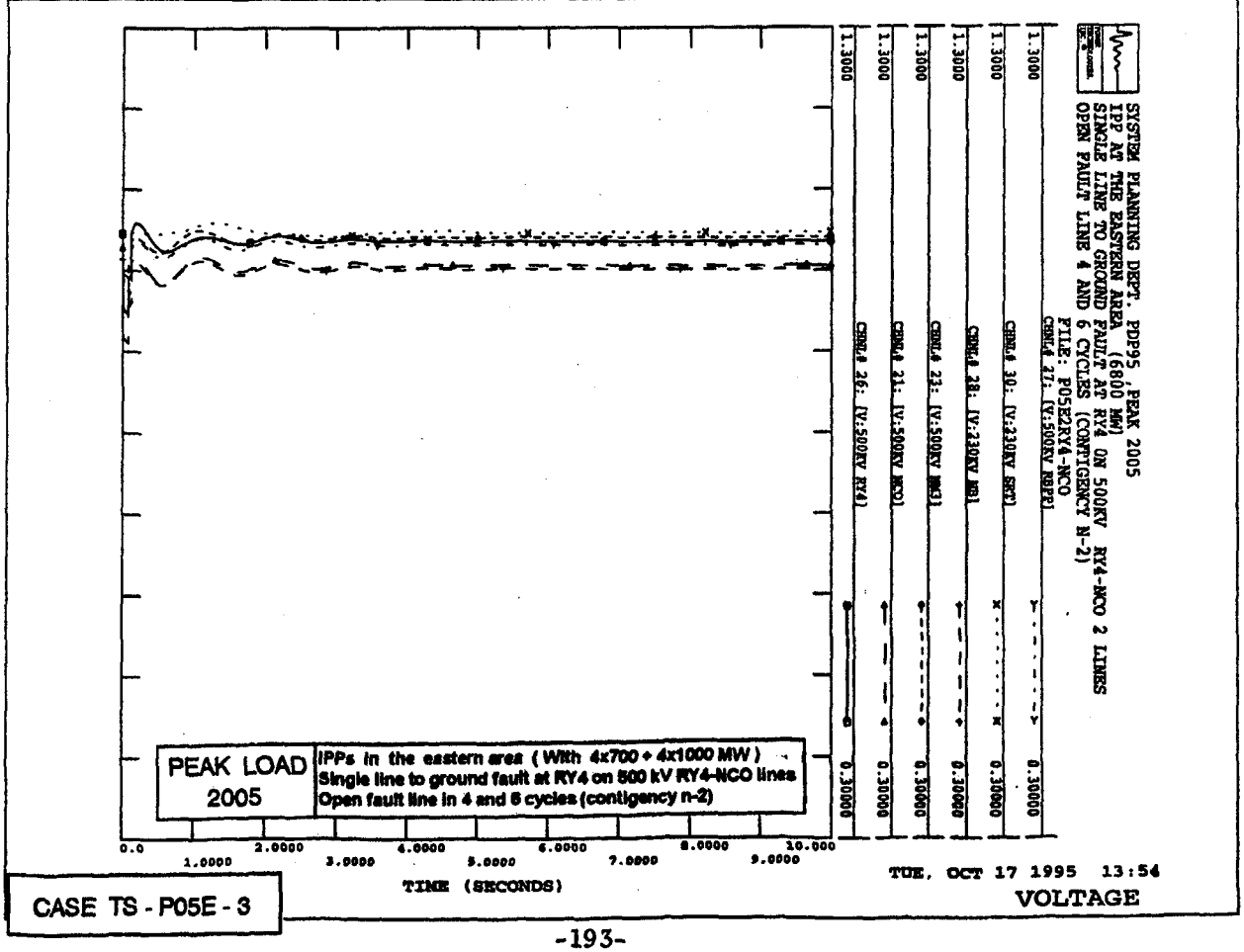

SYSTEM PLANNING DEPT. PDP95 PEAK 2005
IPP AT THE EASTERN AREA (6800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P05E
CHNL# 27: [V:500KV RBPP1]
CHNL# 30: [V:230KV SET1]
CHNL# 28: [V:230KV NB1]
CHNL# 23: [V:500KV MW3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, AUG 10 1995 08:04
VOLTAGE
PEAK LOAD
2005
IPPs in the eastern area (With 4x700 + 4x1000 MW)
3 phase fault at RY4 on 500 kV RY4-NCO line
Open fault line in 4 cycles
CASE TS - P05E - 1

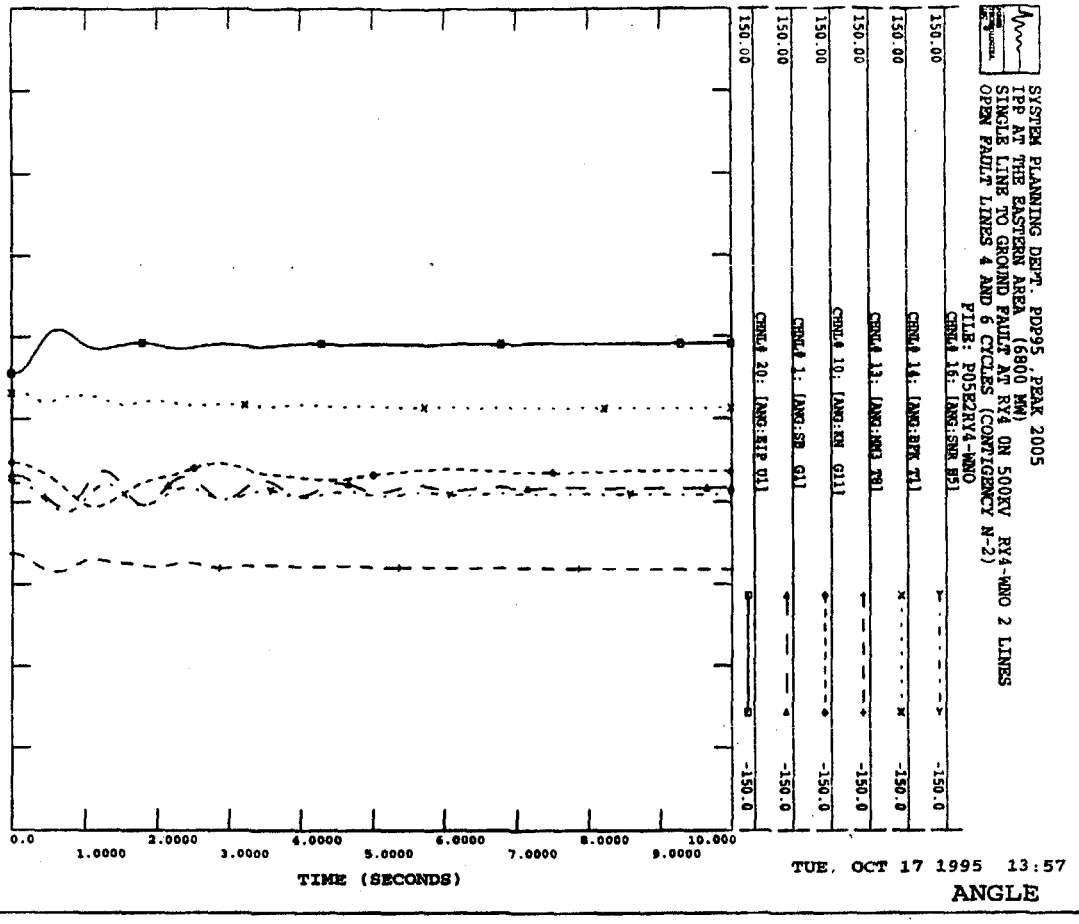


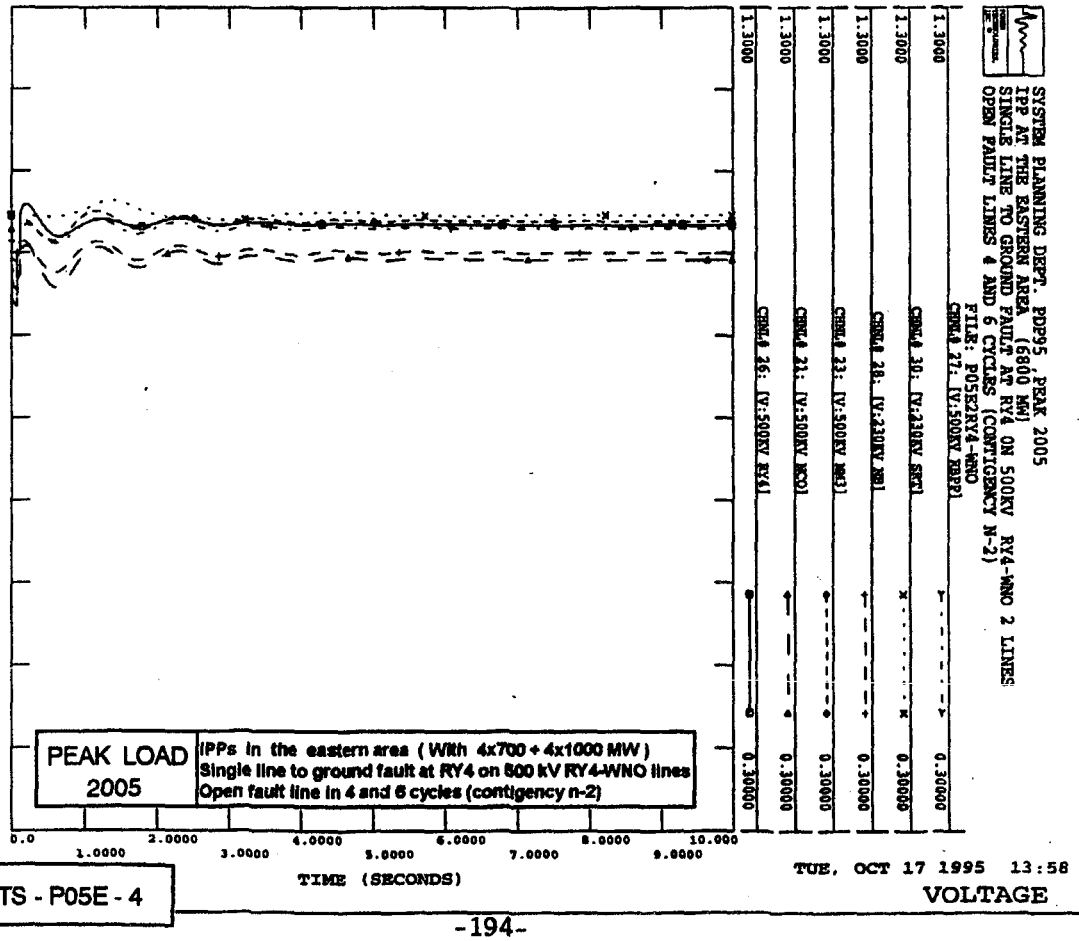


CASE TS - P05E - 2

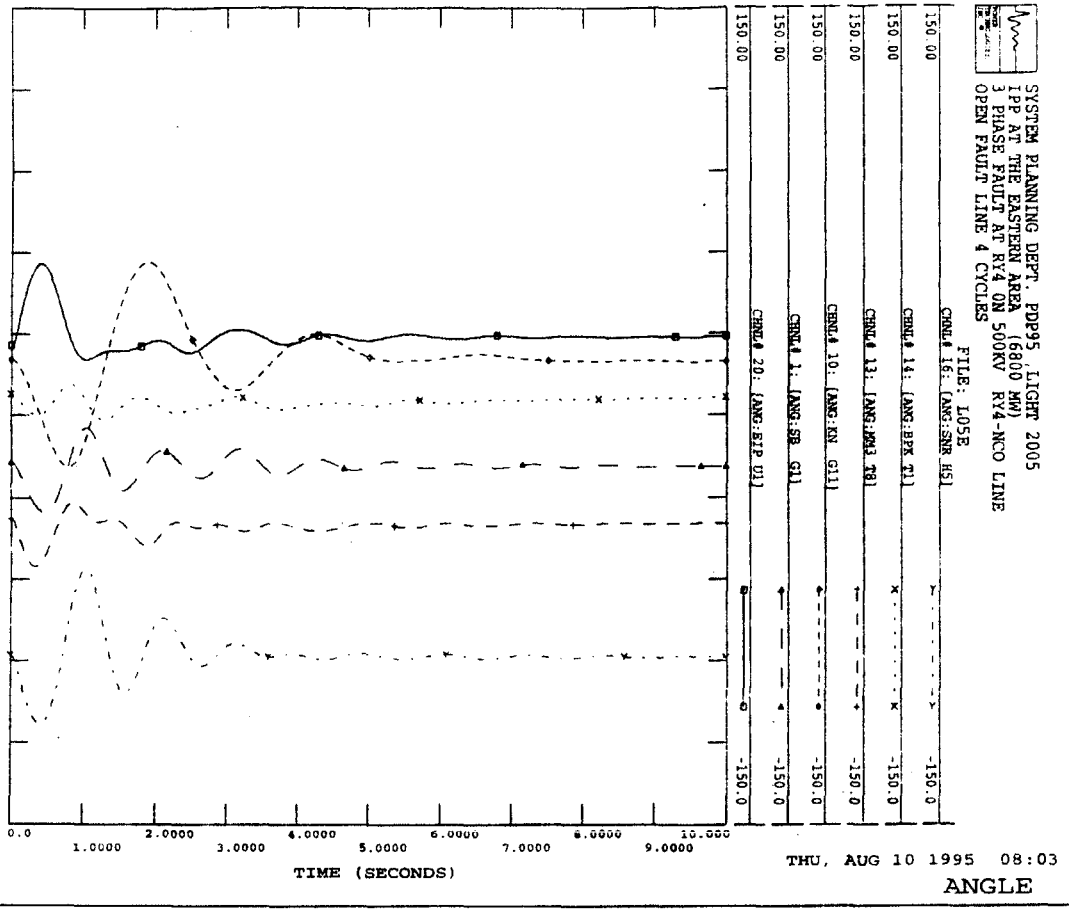

SYSTEM PLANNING DEPT. PDP95 ,PEAK 2005
IPP AT THE EASTERN AREA (6800 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-NCO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: P05E2RY4-NCO
CHNL# 16: [ANG:SNR H5]
CHNL# 14: [ANG:BEK T1]
CHNL# 13: [ANG:MM3 T8]
CHNL# 10: [ANG:EN G11]
CHNL# 1: [ANG:SR G1]
CHNL# 20: [ANG:REP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 13:54
ANGLE

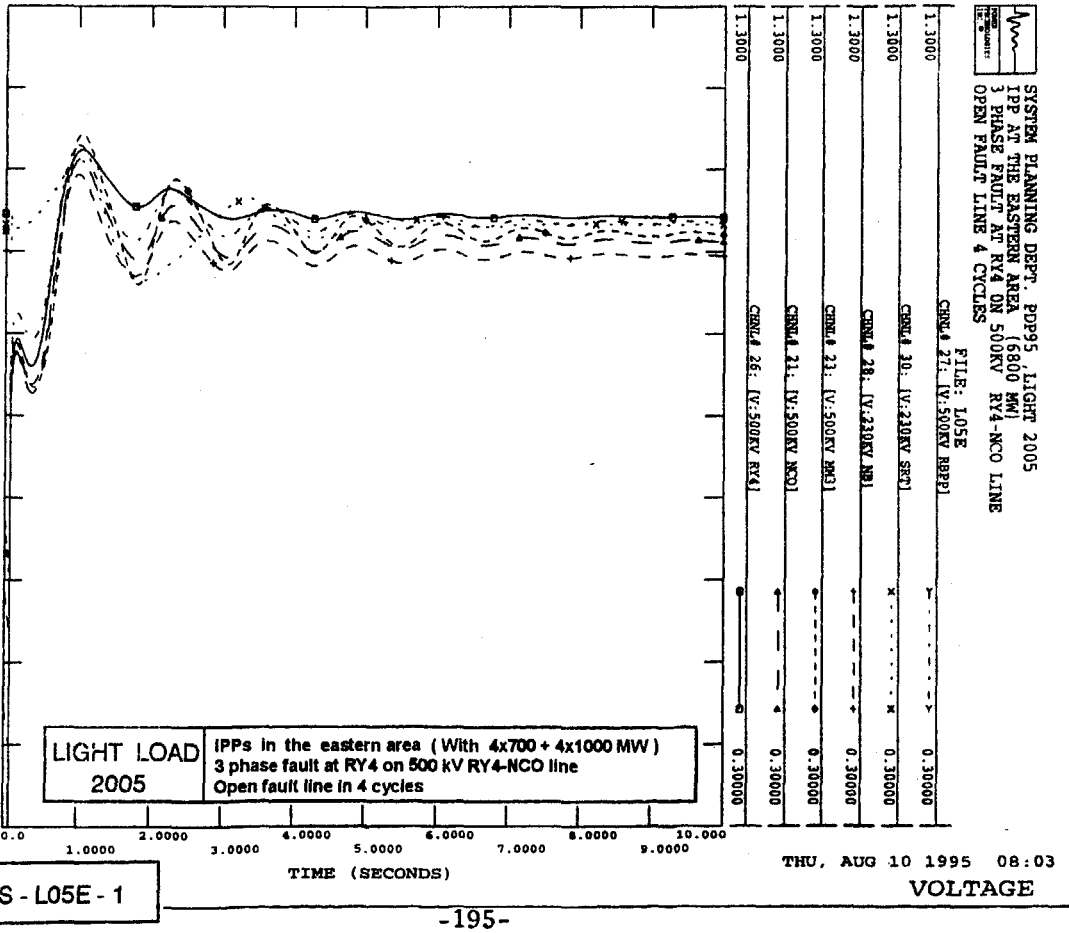

SYSTEM PLANNING DEPT. PDP95 ,PEAK 2005
IPP AT THE EASTERN AREA (6800 MW)
SINGLE LINE TO GROUND FAULT AT RY4 ON 500KV RY4-NCO 2 LINES
OPEN FAULT LINE 4 AND 6 CYCLES (CONTIGENCY N-2)
FILE: P05E2RY4-NCO
CHNL# 27: [V:500KV REPU]
CHNL# 30: [V:230KV SEC]
CHNL# 28: [V:230KV MM1]
CHNL# 23: [V:500KV MM3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
TUE, OCT 17 1995 13:54
VOLTAGE
PEAK LOAD 2005
IPPs in the eastern area (With 4x700 + 4x1000 MW)
Single line to ground fault at RY4 on 500 kV RY4-NCO lines
Open fault line in 4 and 6 cycles (contigency n-2)
CASE TS - P05E - 3



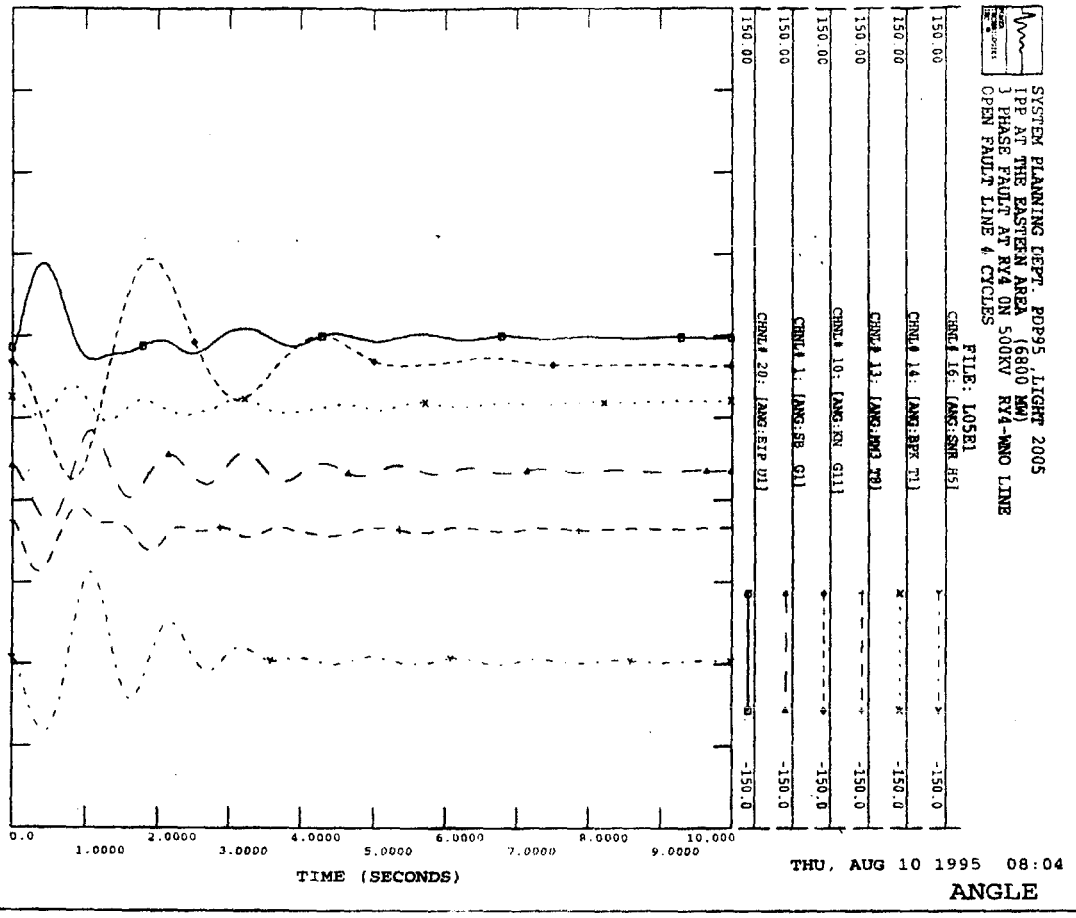


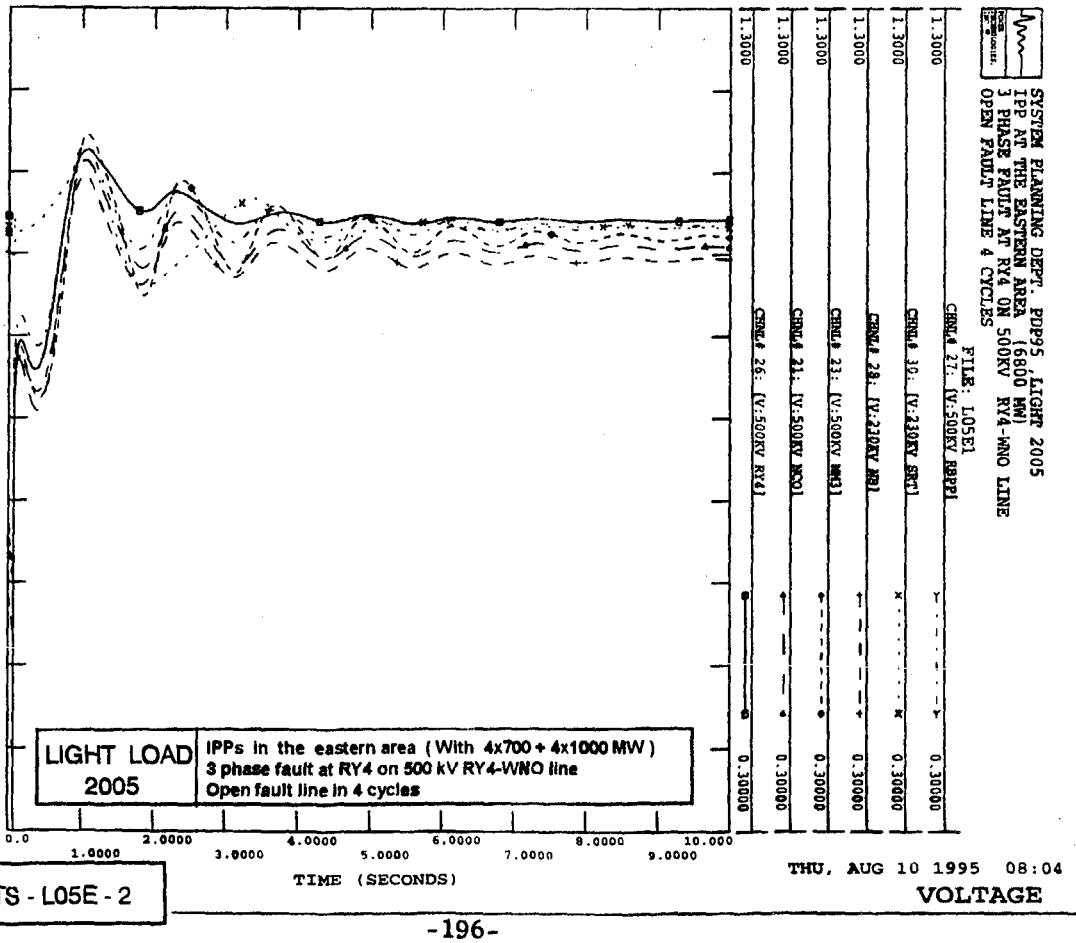
CASE TS - P05E - 4



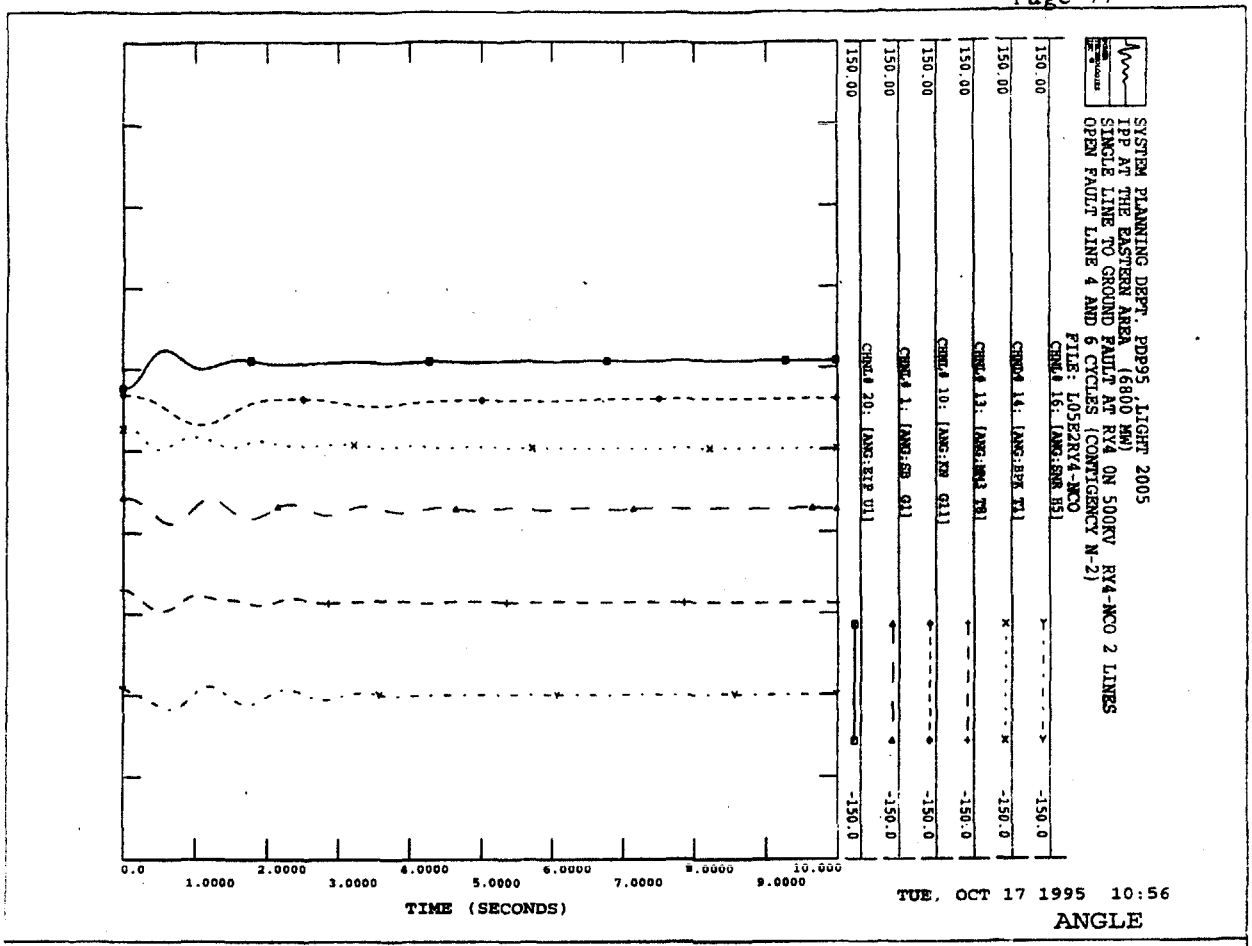


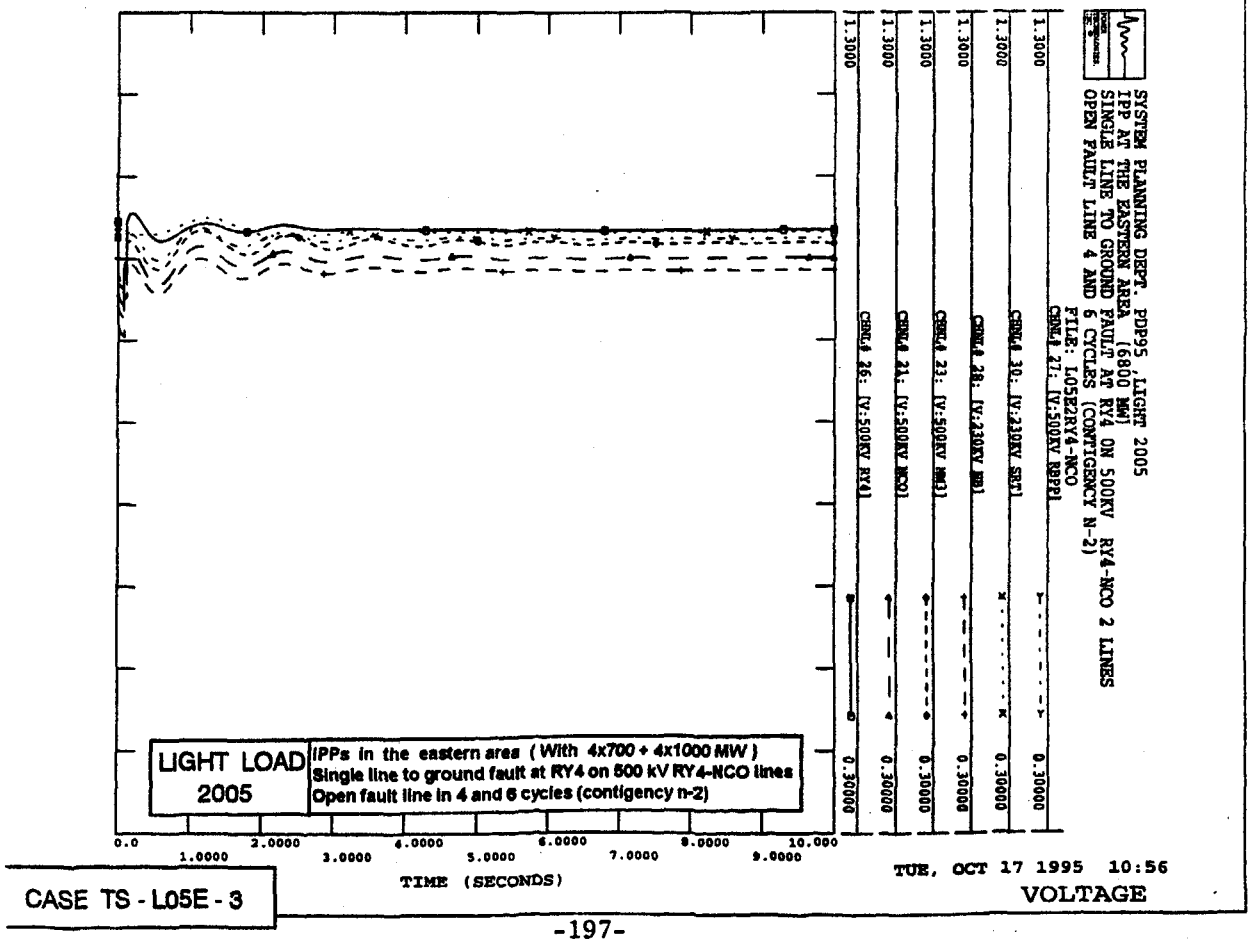
CASE TS - L05E - 1



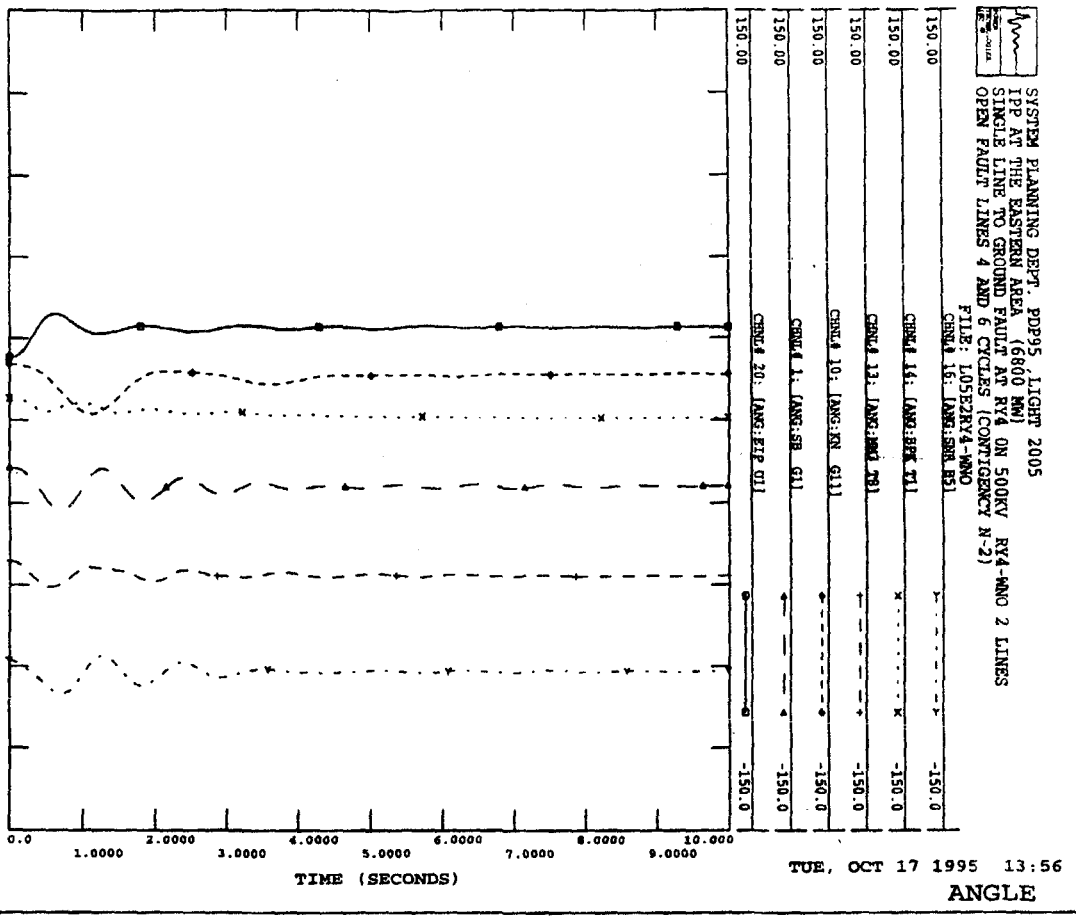


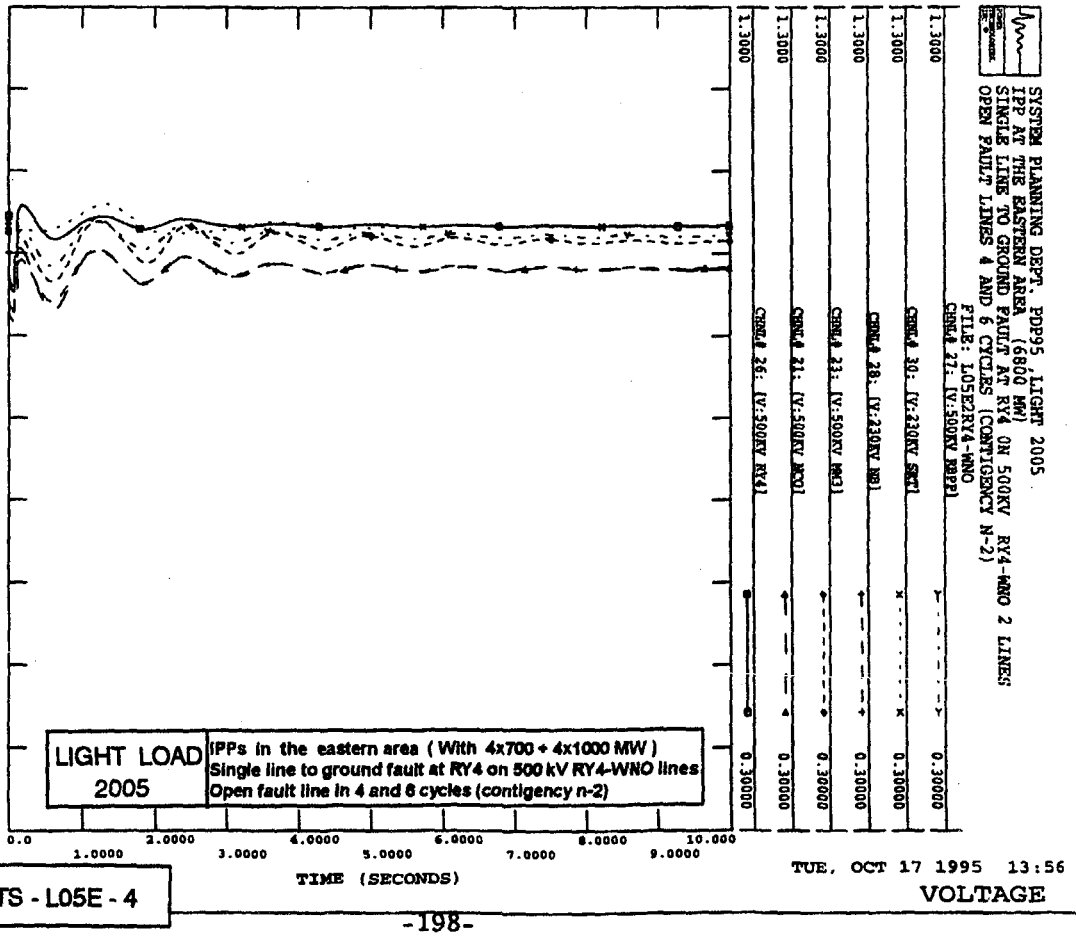
CASE TS - L05E - 2



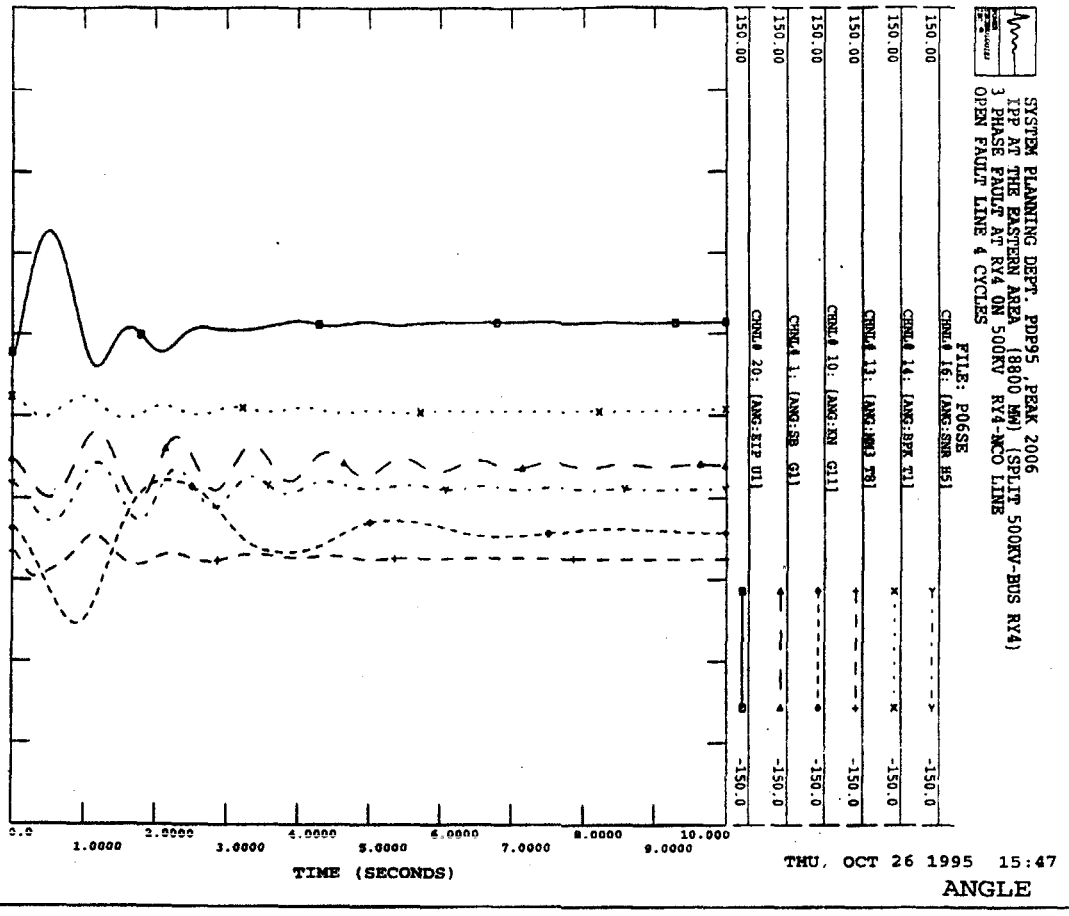


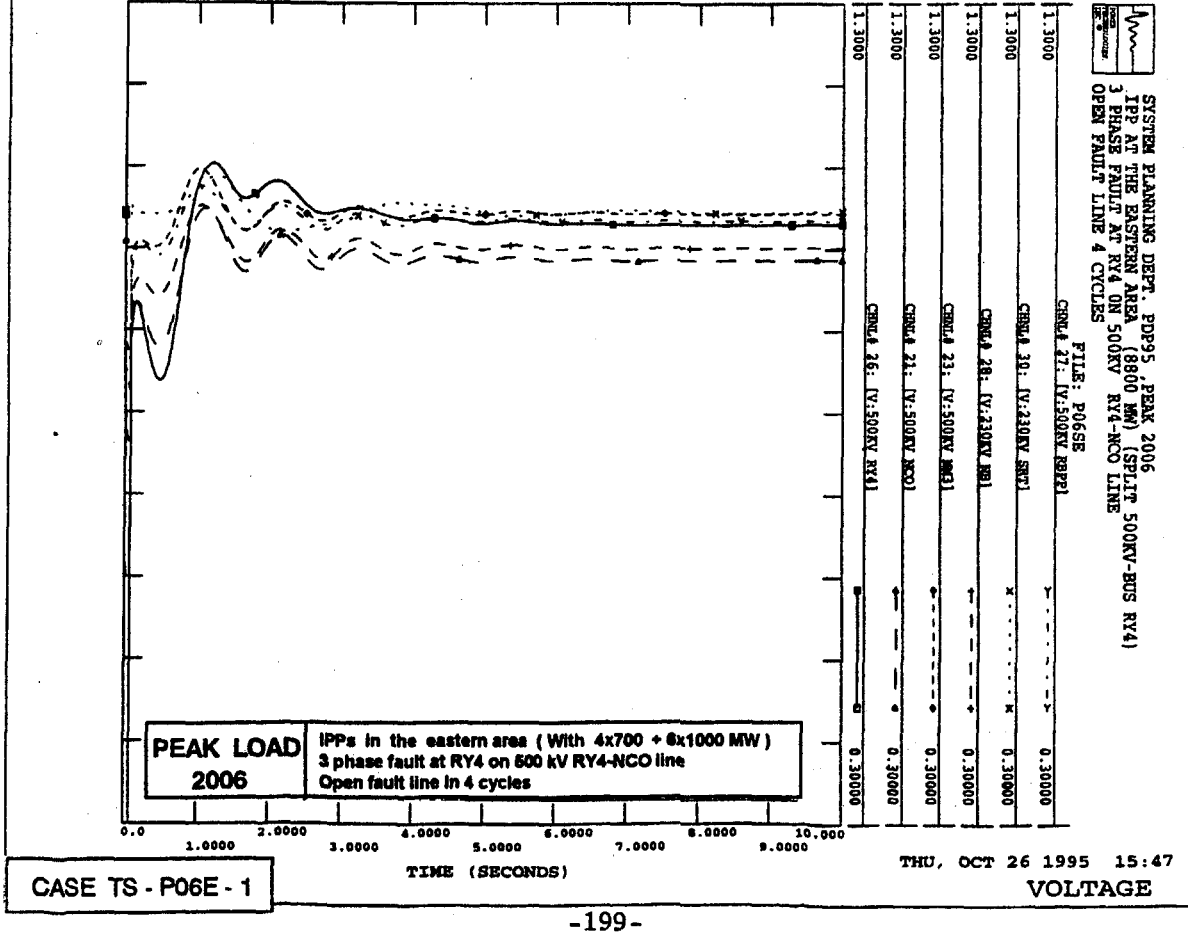
CASE TS - L05E - 3

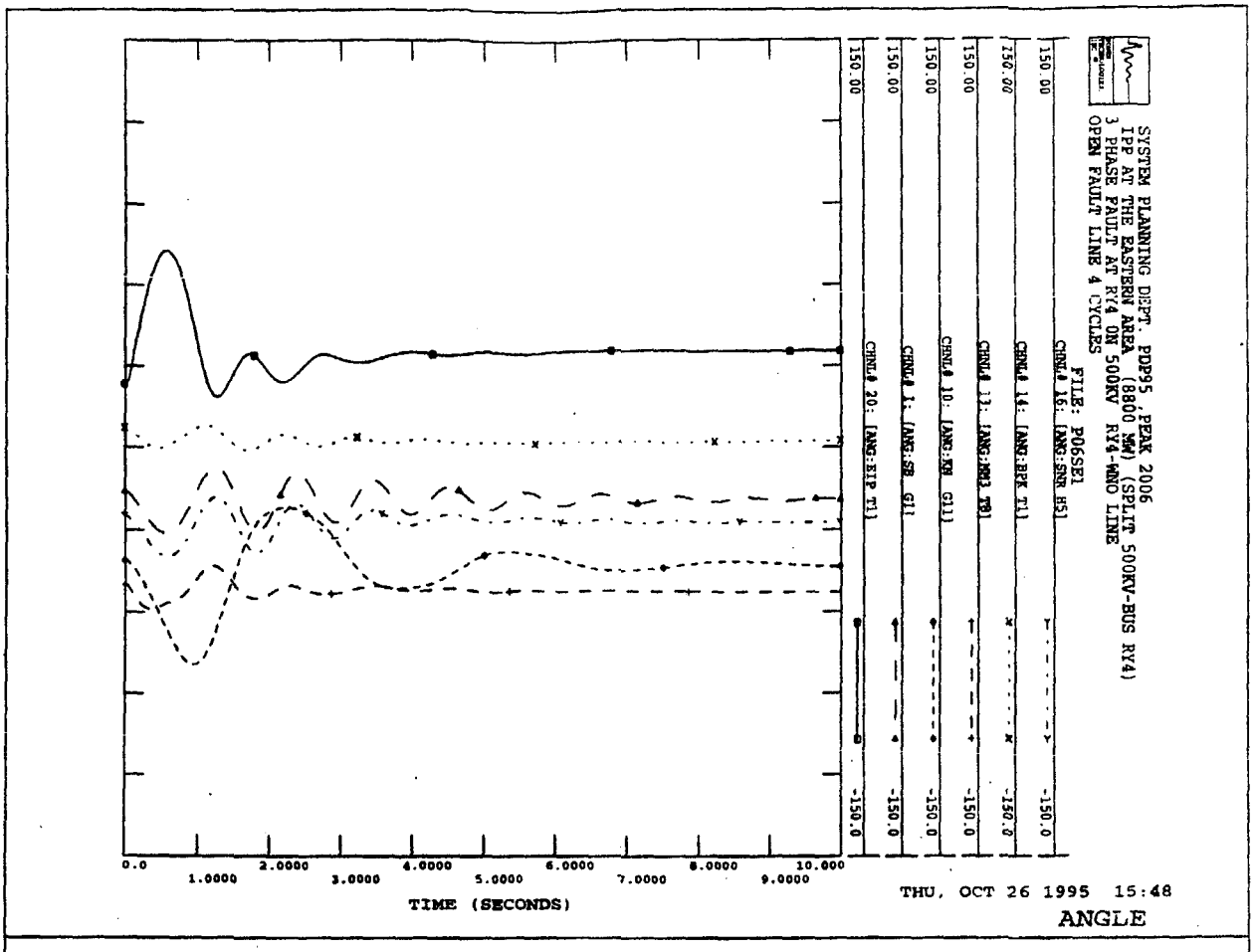


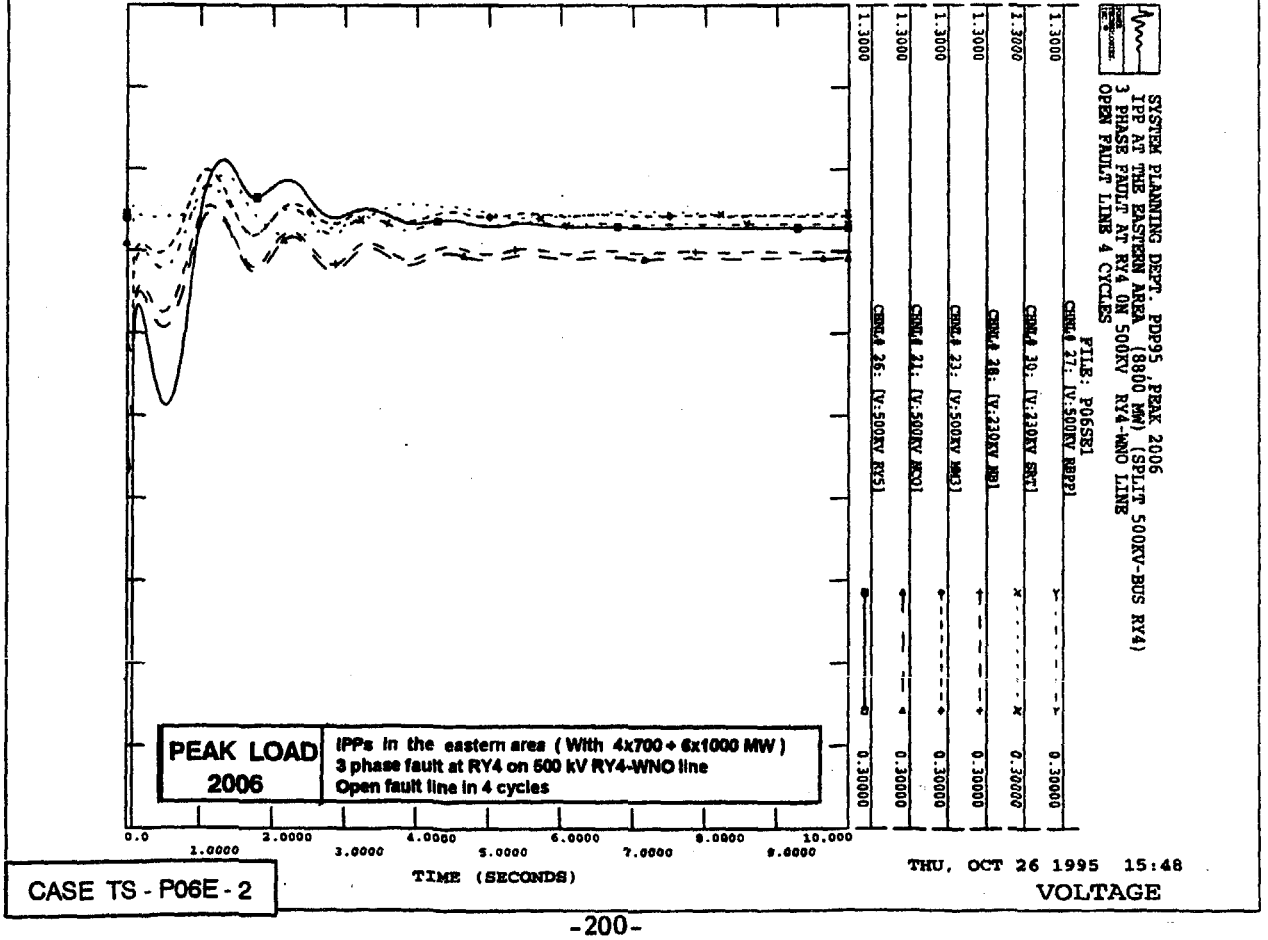


CASE TS - L05E - 4

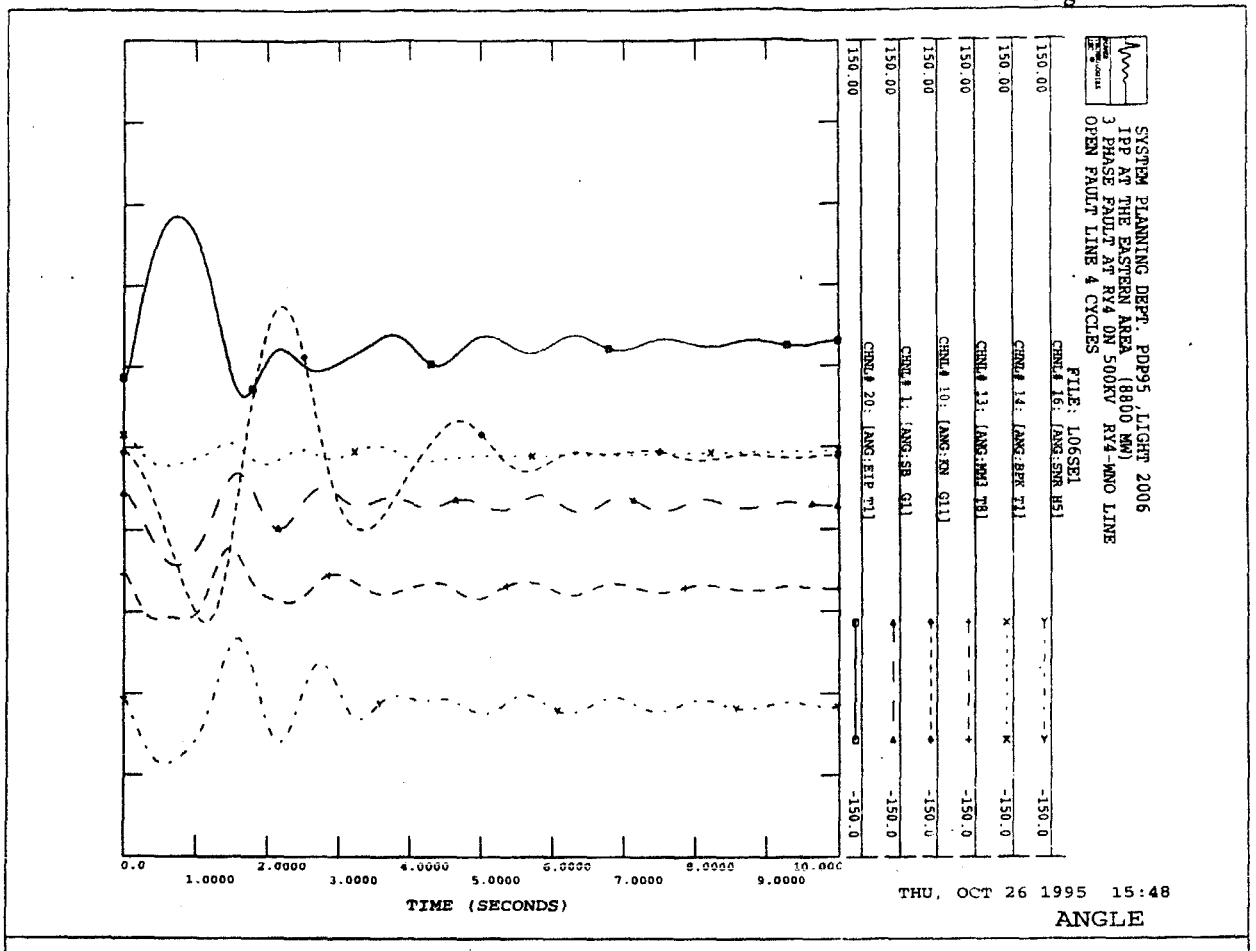

SYSTEM PLANNING DEPT. PDP95 PEAK 2006
IPP AT THE EASTERN AREA (8800 MW) (SPLIT 500KV-BUS RY4)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P06SE
CHNL# 16: [ANG:SNR H5]
CHNL# 14: [ANG:BPK T1]
CHNL# 11: [ANG:MM3 T8]
CHNL# 10: [ANG:RN G11]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:KIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 26 1995 15:47
ANGLE

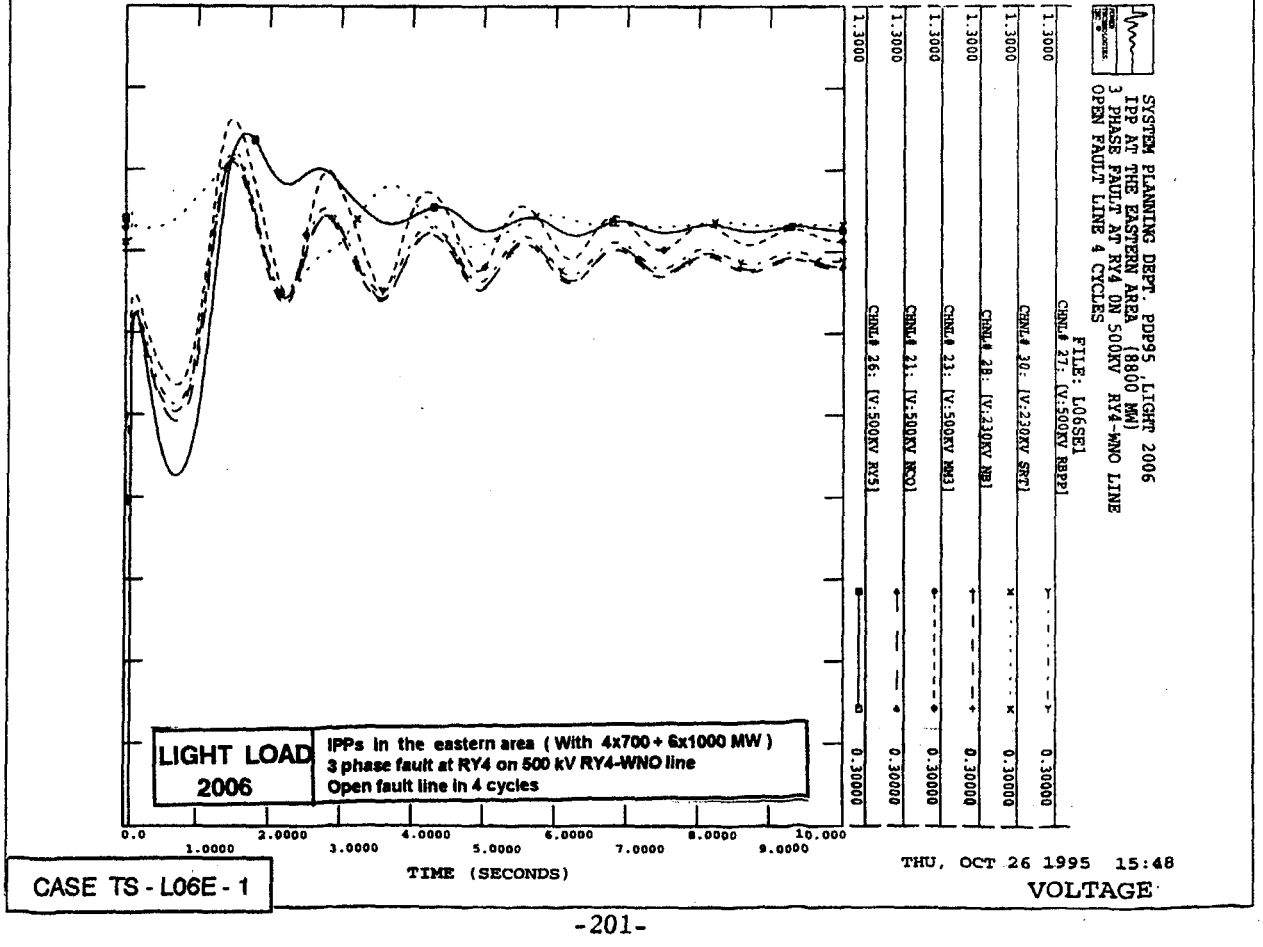

SYSTEM PLANNING DEPT. PDP95 PEAK 2006
IPP AT THE EASTERN AREA (8800 MW) (SPLIT 500KV-BUS RY4)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P06SE
CHNL# 27: [V:500KV RBPP]
CHNL# 30: [V:230KV SRT]
CHNL# 28: [V:230KV RB]
CHNL# 23: [V:500KV MM3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 26 1995 15:47
VOLTAGE
PEAK LOAD
2006
IPPs in the eastern area (With 4x700 + 6x1000 MW)
3 phase fault at RY4 on 500 kV RY4-NCO line
Open fault line in 4 cycles
CASE TS - P06E - 1

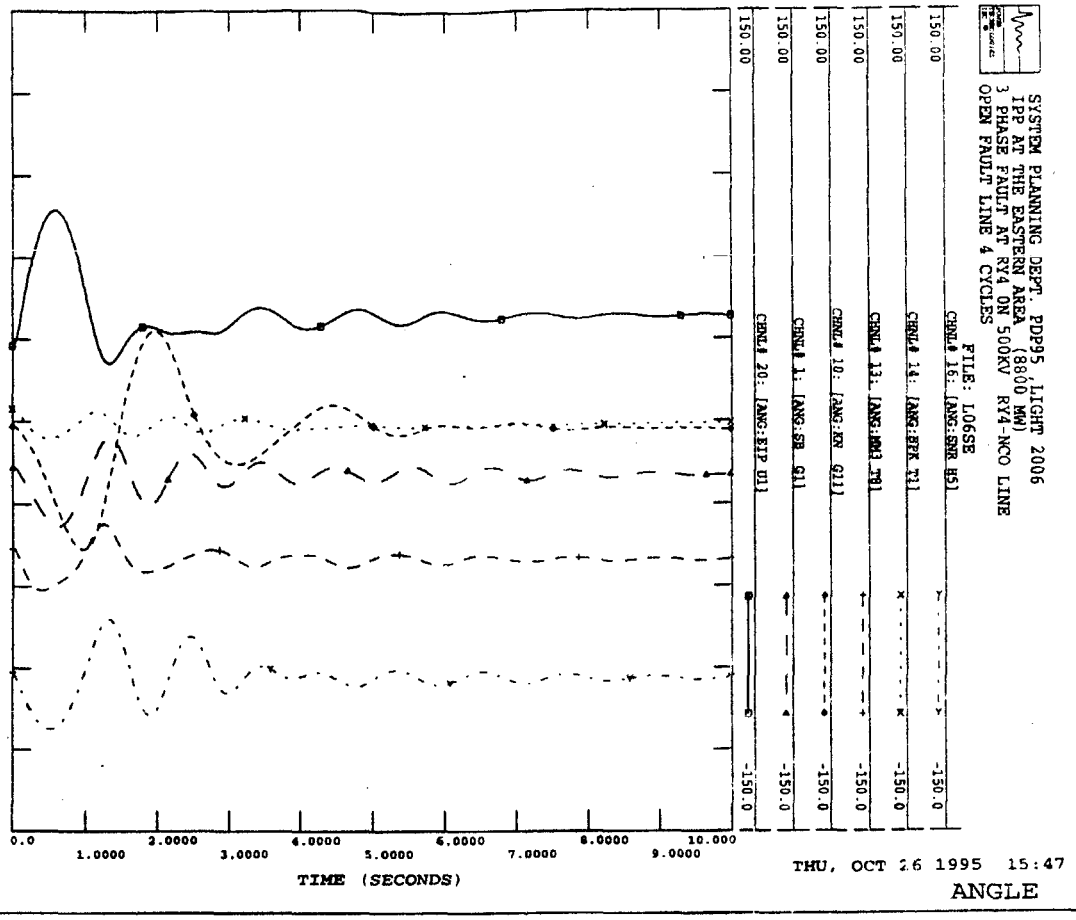


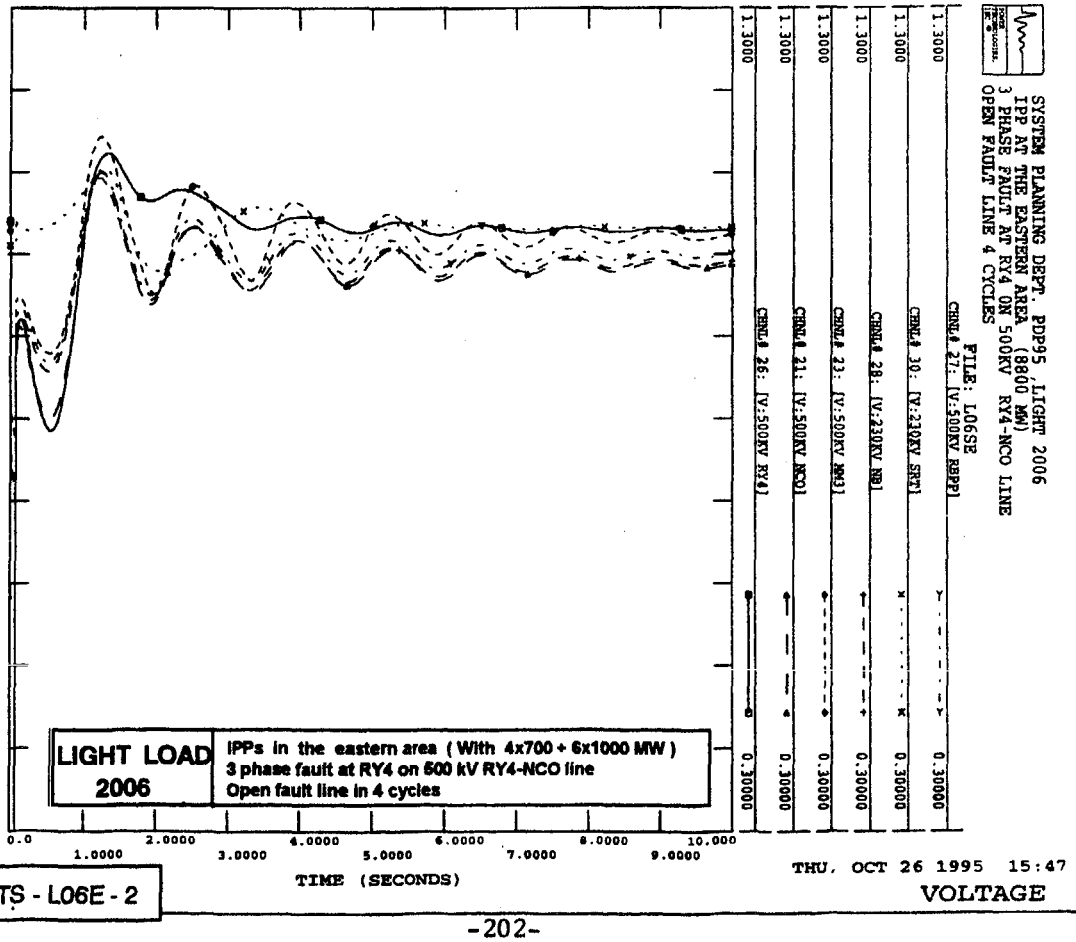


CASE TS - P06E - 2

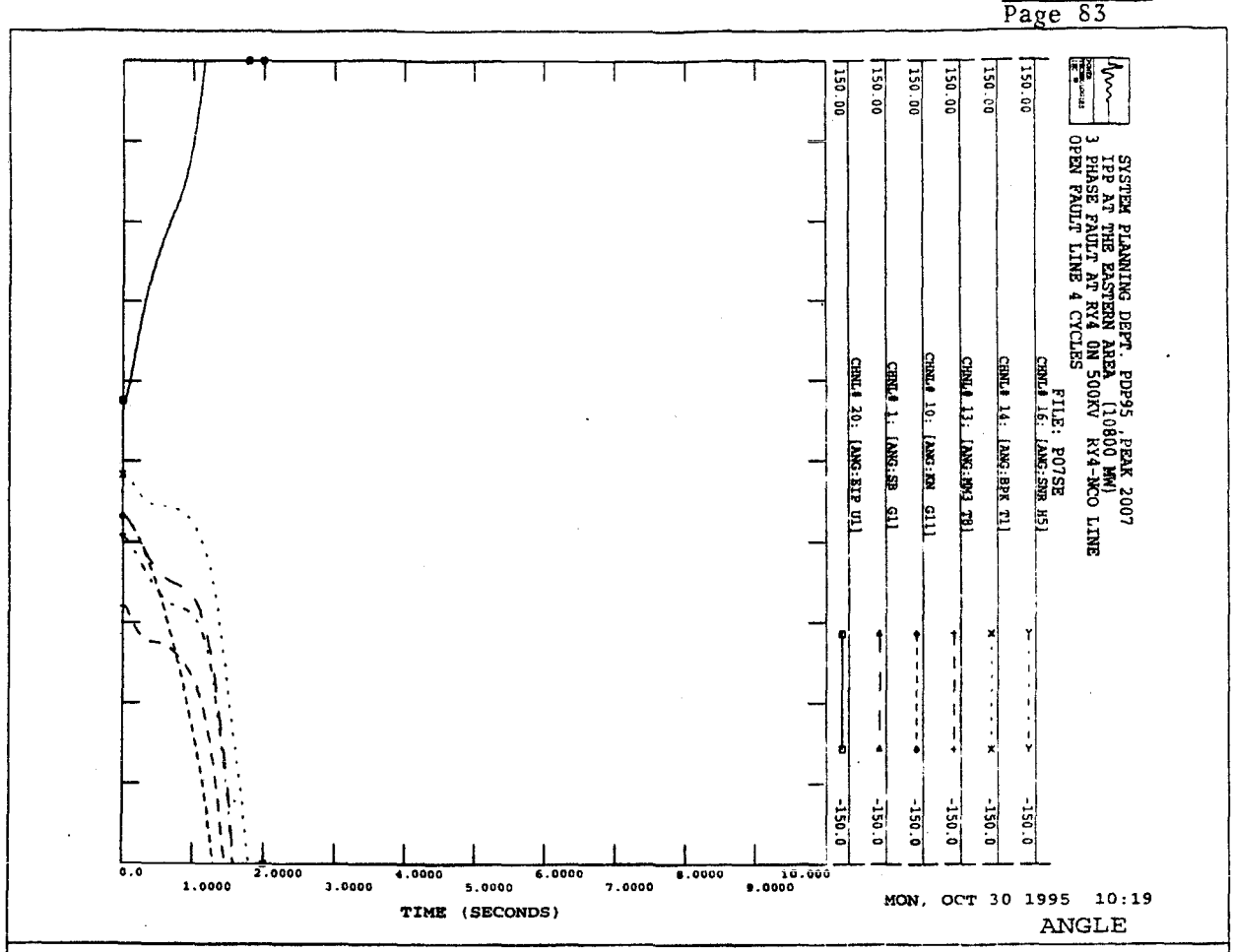

SYSTEM PLANNING DEPT. PDP95 LIGHT 2006
IPP AT THE EASTERN AREA (8800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-WNO LINE
OPEN FAULT LINE 4 CYCLES
FILE: L06SE1
CHNL# 16: [ANG:SWR H5]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:MM3 T8]
CHNL# 10: [ANG:KN G11]
CHNL# 1: [ANG:SR G1]
CHNL# 20: [ANG:EIP T1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 26 1995 15:48
ANGLE

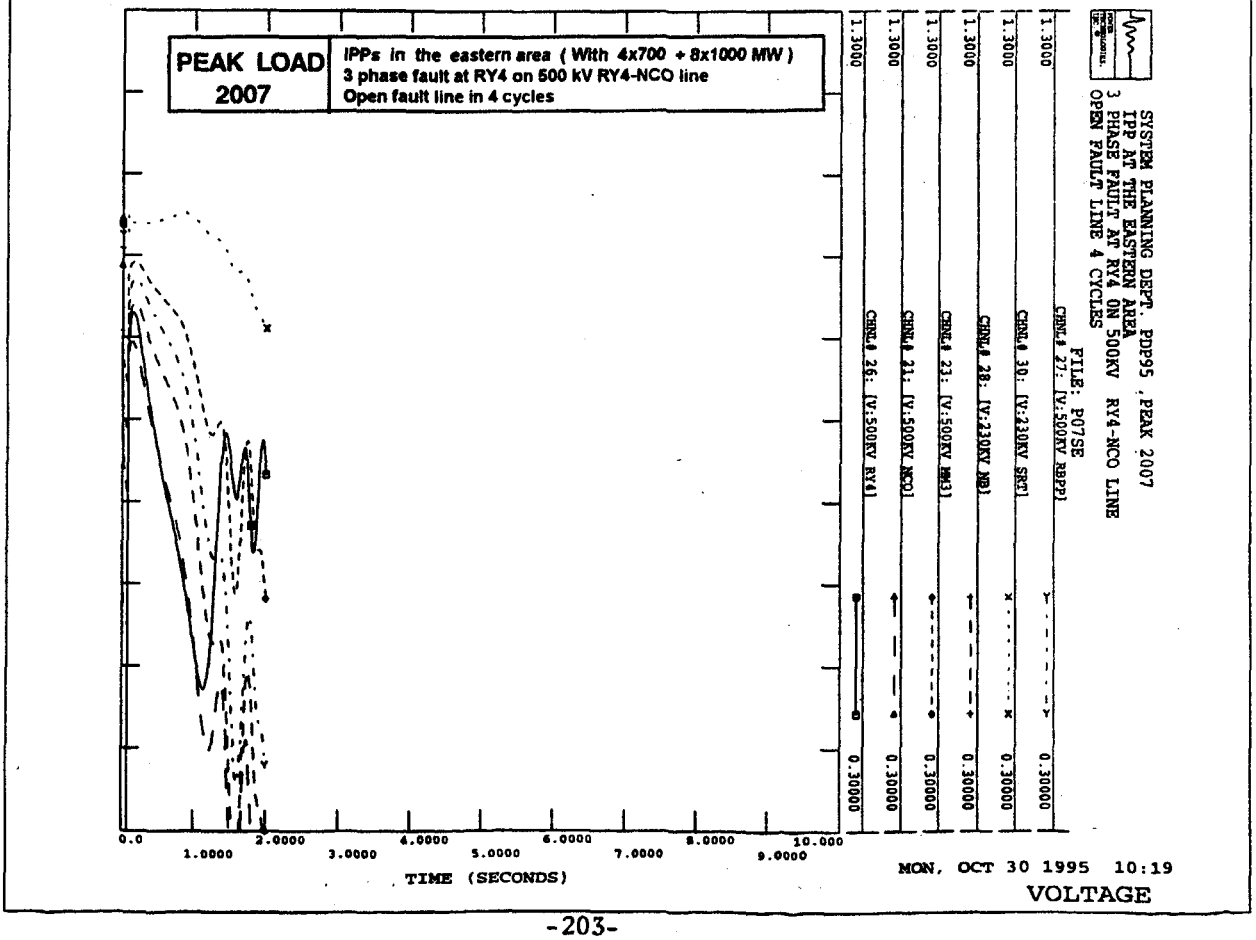

SYSTEM PLANNING DEPT. PDP95 LIGHT 2006
IPP AT THE EASTERN AREA (8800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-WNO LINE
OPEN FAULT LINE 4 CYCLES
FILE: L06SE1
CHNL# 27: [V:500KV RBPP]
CHNL# 30: [V:230KV SRT]
CHNL# 28: [V:230KV NB]
CHNL# 23: [V:500KV MM3]
CHNL# 21: [V:500KV MCQ]
CHNL# 26: [V:500KV RY5]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 26 1995 15:48
VOLTAGE
LIGHT LOAD
2006
IPPs in the eastern area (With 4x700 + 6x1000 MW)
3 phase fault at RY4 on 500 kV RY4-WNO line
Open fault line in 4 cycles
CASE TS - L06E - 1

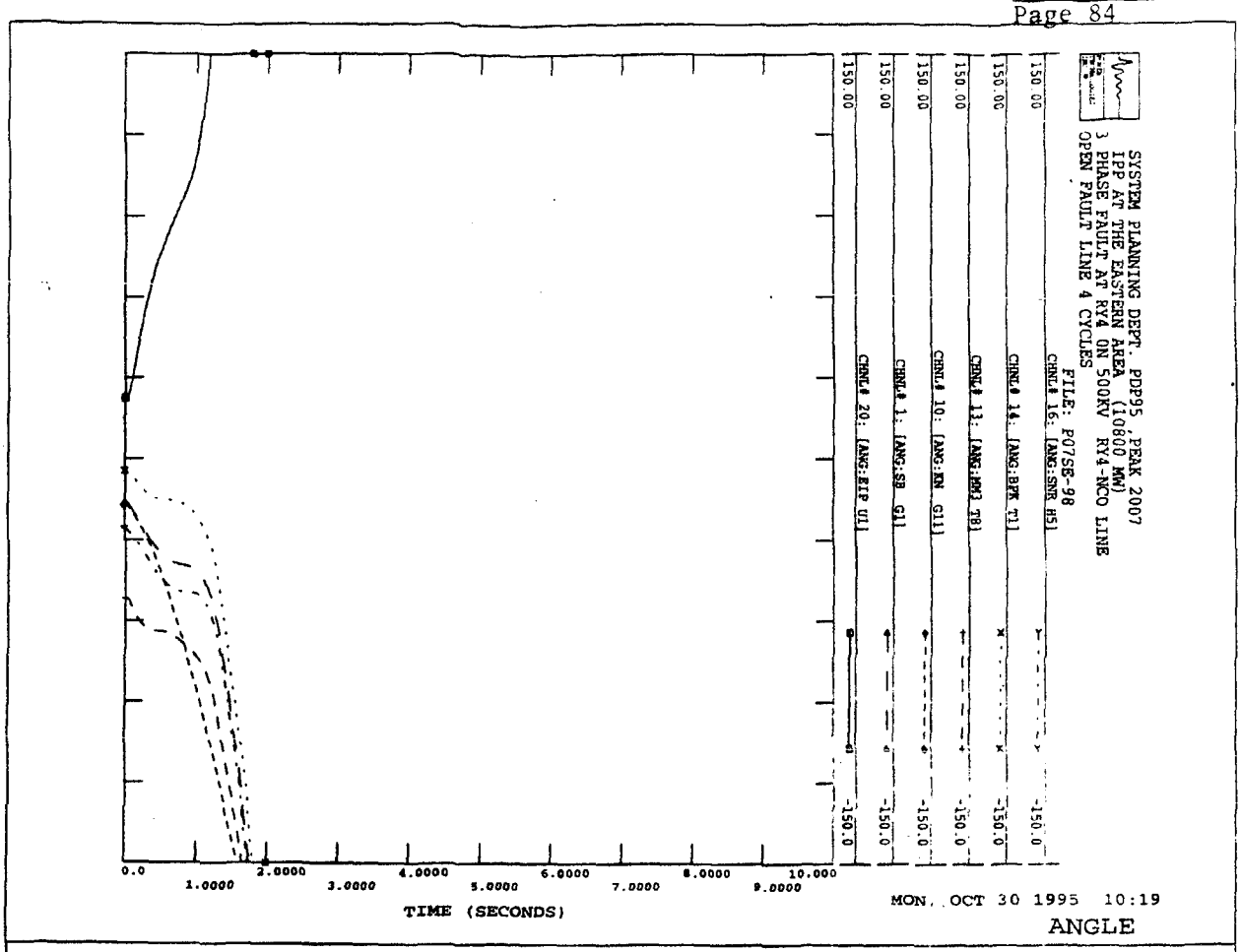


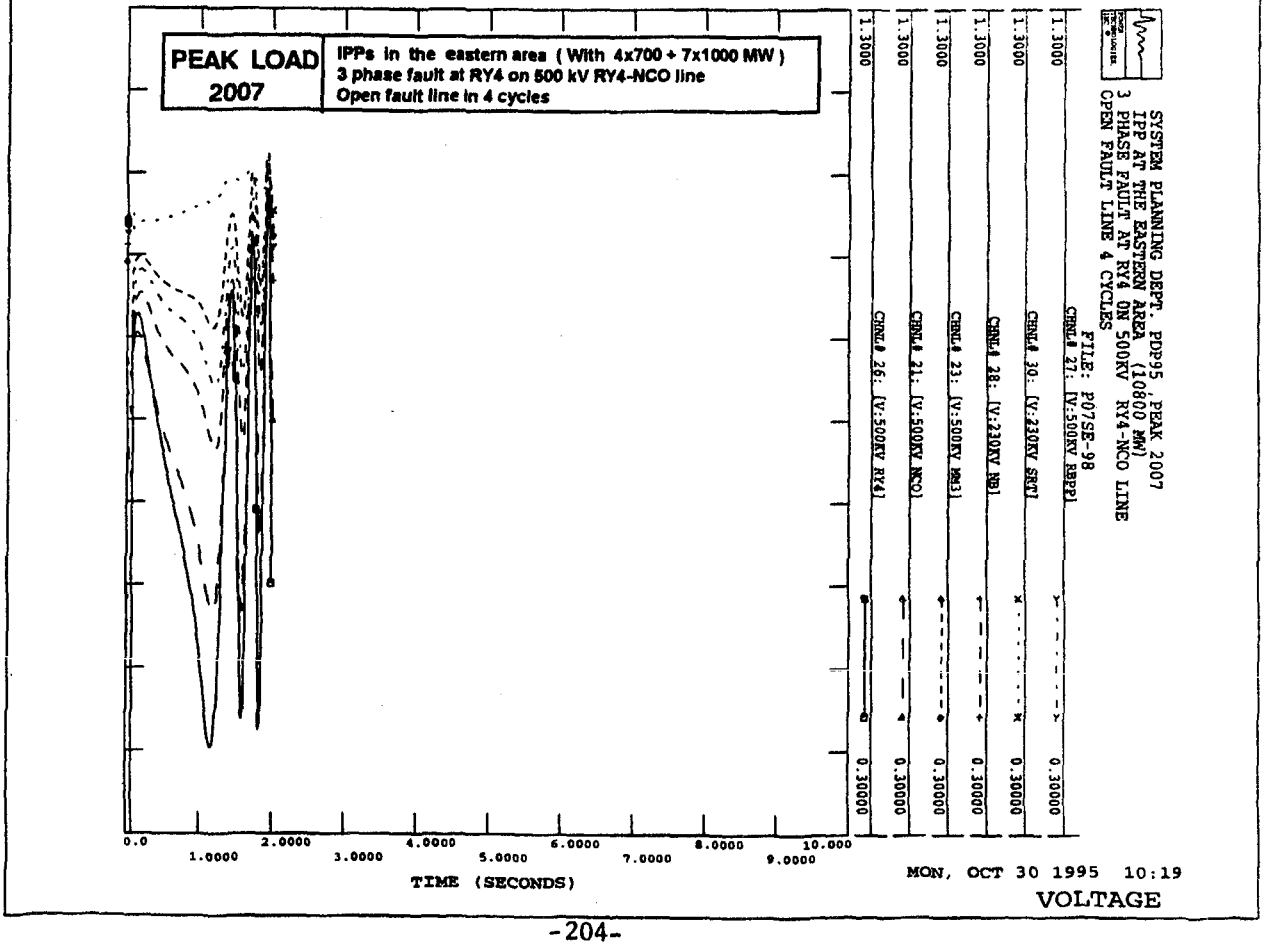


CASE TS - L06E - 2


SYSTEM PLANNING DEPT. PDP95 ,PEAK 2007
IPP AT THE EASTERN AREA (10800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P07SE
CHNL# 16: [ANG:SNR H5]
CHNL# 14: [ANG:BPK T1]
CHNL# 13: [ANG:BW3 T8]
CHNL# 10: [ANG:EN G111]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:EIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
MON, OCT 30 1995 10:19
ANGLE


PEAK LOAD
2007
IPPs in the eastern area (With 4x700 + 8x1000 MW)
3 phase fault at RY4 on 500 kV RY4-NCO line
Open fault line in 4 cycles
SYSTEM PLANNING DEPT. PDP95 ,PEAK 2007
IPP AT THE EASTERN AREA
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P07SE
CHNL# 27: [V:500KV RBPP]
CHNL# 30: [V:230KV SRT]
CHNL# 28: [V:230KV NB]
CHNL# 23: [V:500KV MW3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
MON, OCT 30 1995 10:19
VOLTAGE

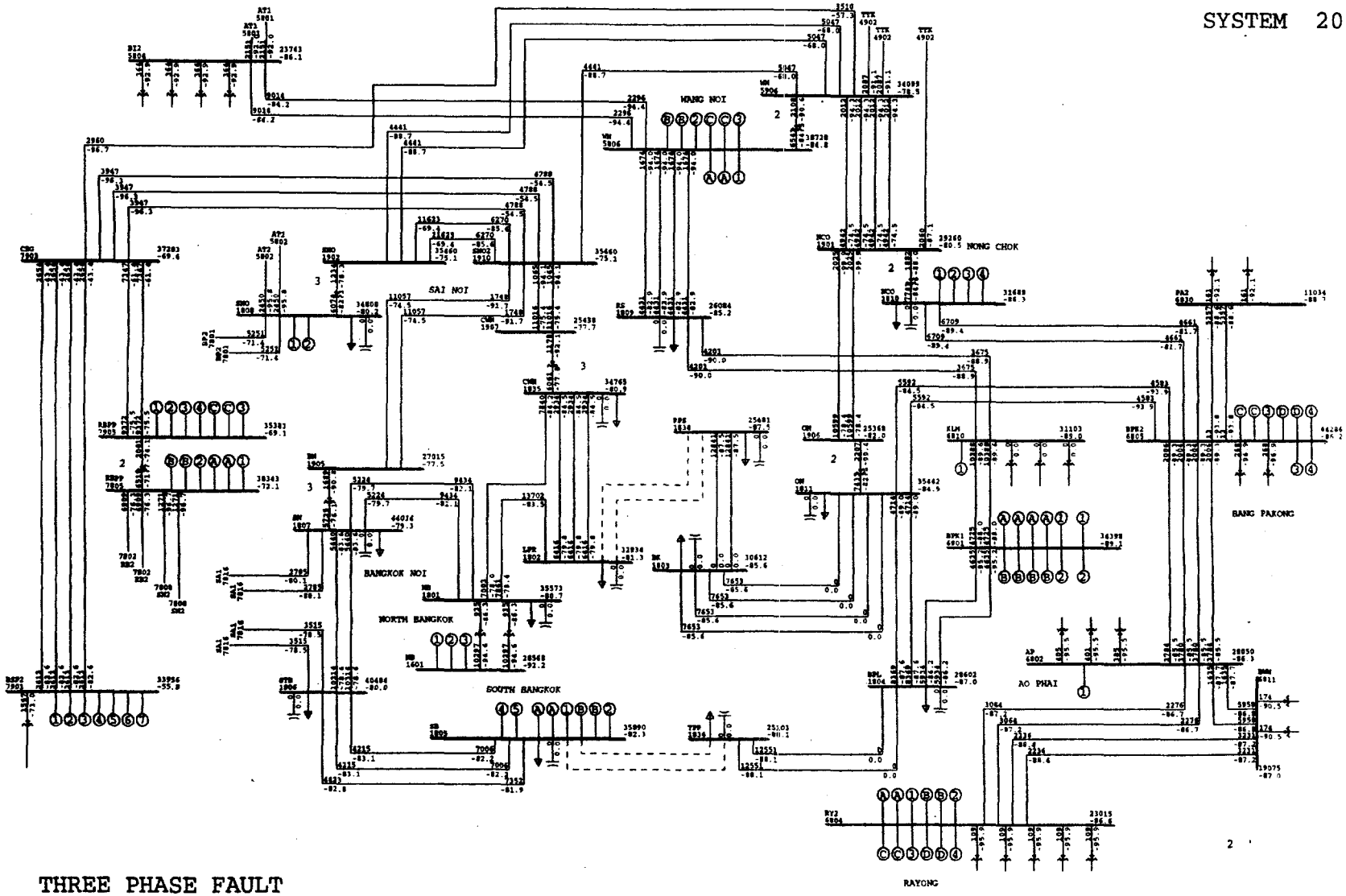

SYSTEM PLANNING DEPT. PDP95 ,PEAK 2007
IPP AT THE EASTERN AREA (10800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P07SE-98
CHNL# 16: [ANG:SNR #5]
CHNL# 14: [ANG:BPK T1]
CHNL# 12: [ANG:MM3 T8]
CHNL# 10: [ANG:EN G11]
CHNL# 1: [ANG:SB G1]
CHNL# 20: [ANG:BIP U1]
150.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
MON, OCT 30 1995 10:19
ANGLE


PEAK LOAD
2007
IPPs in the eastern area (With 4x700 + 7x1000 MW)
3 phase fault at RY4 on 500 kV RY4-NCO line
Open fault line in 4 cycles
SYSTEM PLANNING DEPT. PDP95 ,PEAK 2007
IPP AT THE EASTERN AREA (10800 MW)
3 PHASE FAULT AT RY4 ON 500KV RY4-NCO LINE
OPEN FAULT LINE 4 CYCLES
FILE: P07SE-98
CHNL# 27: [V:500KV REPP]
CHNL# 30: [V:230KV SRT]
CHNL# 28: [V:230KV NB]
CHNL# 23: [V:500KV MM3]
CHNL# 21: [V:500KV NCO]
CHNL# 26: [V:500KV RY4]
1.3000
0.30000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
MON, OCT 30 1995 10:19
VOLTAGE

APPENDIX 4

FAULT FLOW DIAGRAMS

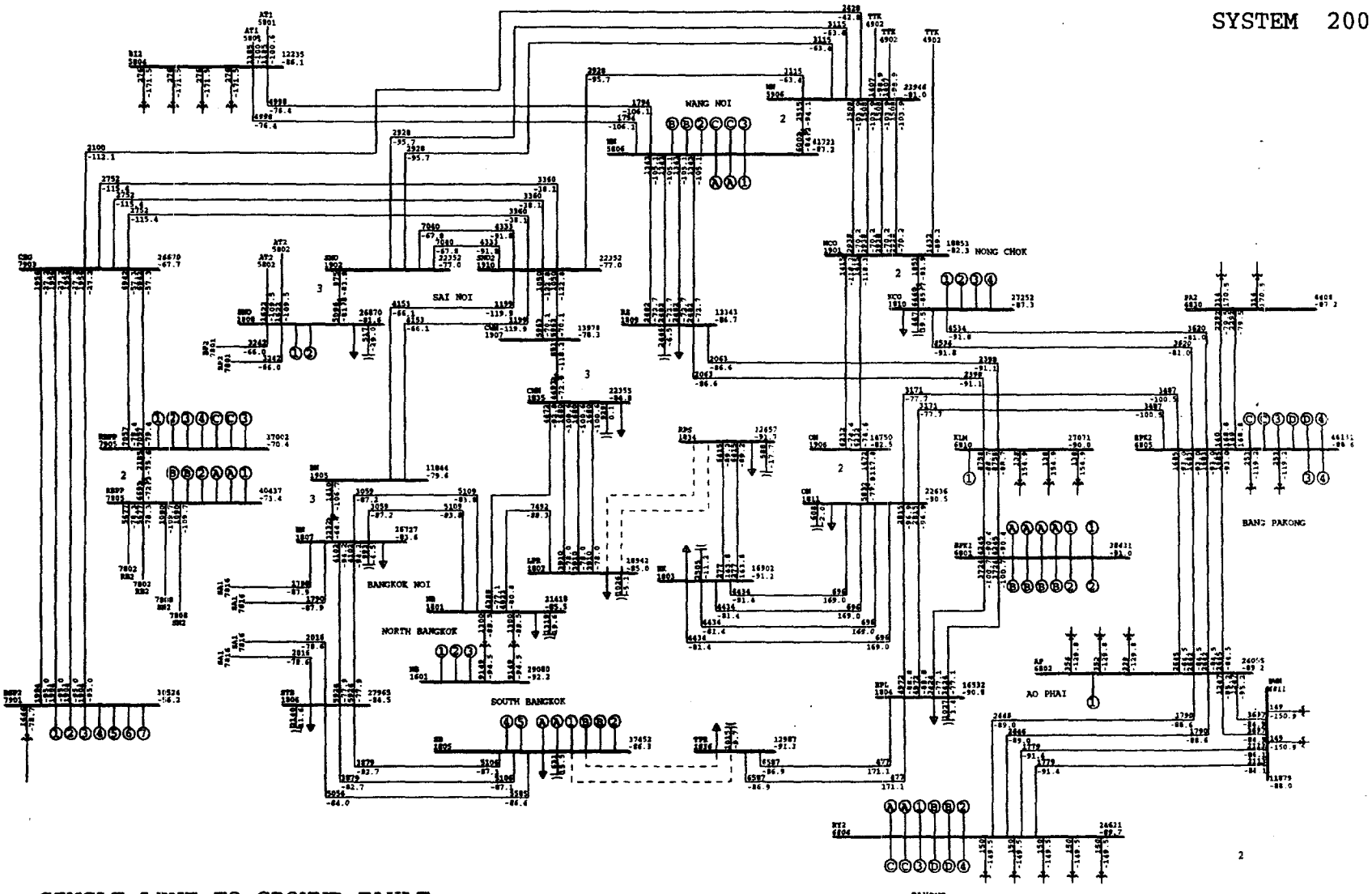
SYSTEM 2005



THREE PHASE FAULT

	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	3 - Phase Fault 2005	IPPs in the western area (With 4 x 700 + 3 x 1,000 MW at Bang Saphan 2 , 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE SC - P05W -1

SYSTEM 2005

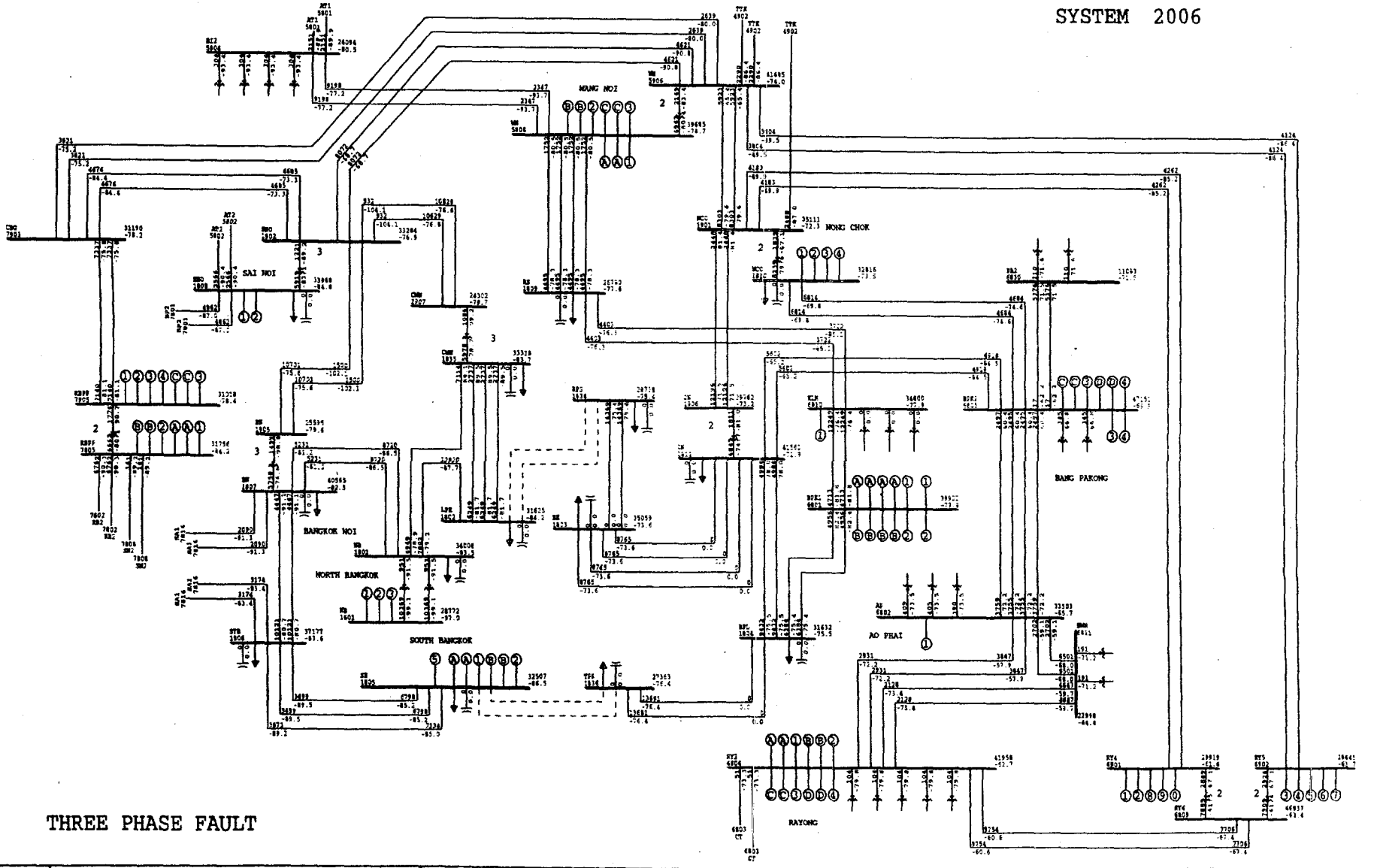


SINGLE LINE TO GROUND FAULT

System Planning Dept., Load Jun 94, PDP 95-01 500 KV Transmission System Project For IPPs	1 - Phase Fault 2005	IPPs in the western area (With 4 x 700 + 3 x 1,000 MW at Bang Saphan 2, 500 kv Bang Saphan 2 - Chom Bung 4 ccts. and spliting bus at Sai Noi)	CASE SC - P05W -2

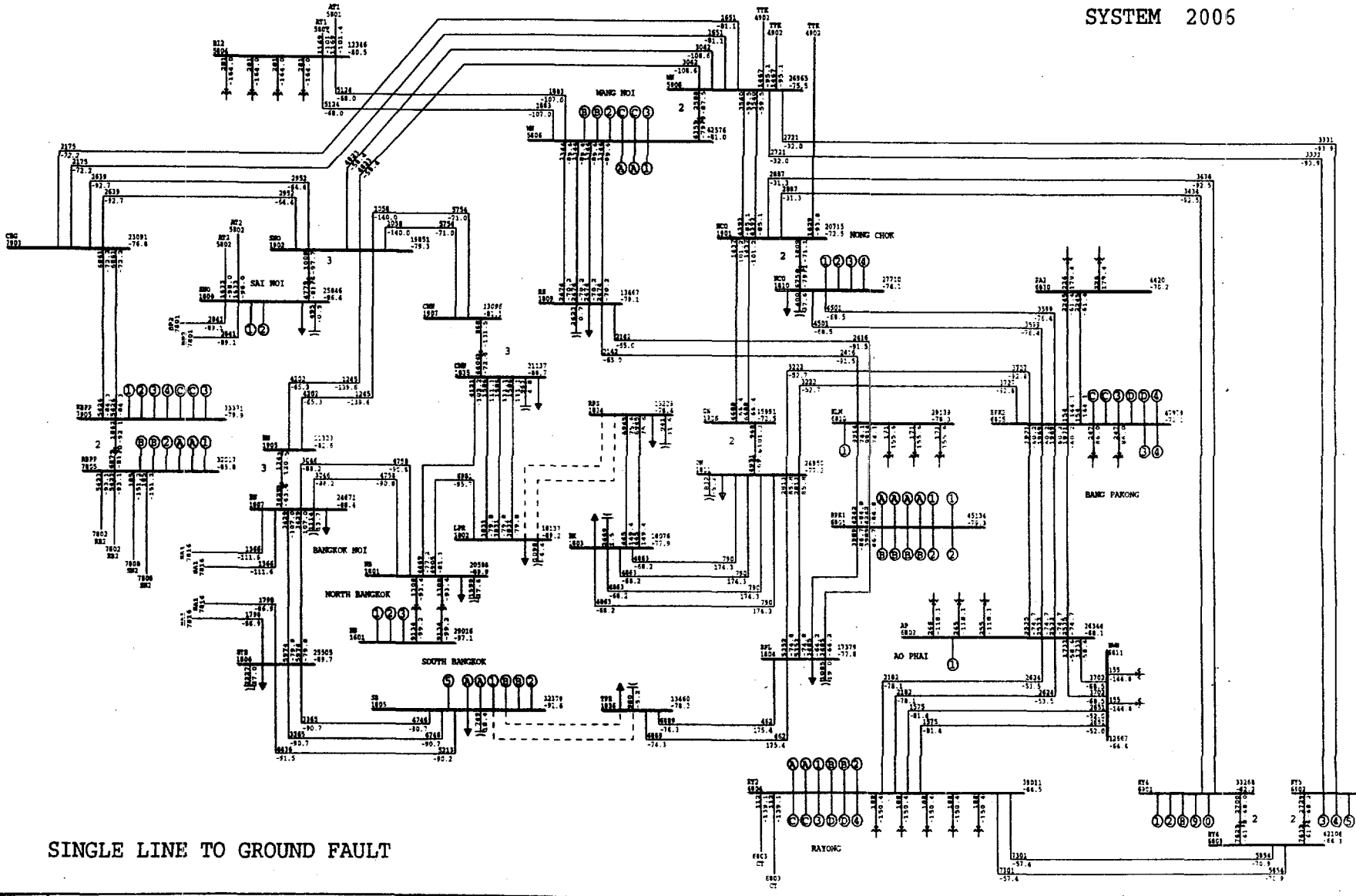
Page 2

SYSTEM 2006



THREE PHASE FAULT

	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	3 - PHASE FAULT 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE SC - P06E - 1



	System Planning Dept., Load Jun 94, PDP 95 - 01 500 KV Transmission System Project For IPPs	1 - PHASE FAULT 2006	IPPs in the eastern area (With 4 x 700 + 6 x 1,000 MW at Rayong 4 ; 500 kv Rayong 4 - Wang Noi 2 ccts. and 500 kv Rayong 4 - Nong Chok 2 ccts.)	CASE SC - P06E - 2

APPENDIX 5

FULL NAME AND ABBREVIATION OF SUBSTATION

FULL NAME AND ABBREVIATION OF SUBSTATION

NO.	SUBSTATIONS	ABBR.	NO.	SUBSTATIONS	ABBR.	NO.	SUBSTATIONS	ABBR.
1.	AMNAT CHAROEN	AN	85.	LAM POO RA	LR	169.	PHUKET 1&2	PK1&2
2.	ANG THONG 1&2	AT1&2	86.	LAM TAKHONG	LTK	170.	PHUNPHIN	PP
3.	AO PHAI 1&2	AP1&2*	87.	LAMPANG 1&2	LP1&2	171.	PONG BON	PBO
4.	AO UDOM	AU	88.	LAMPHUN 1&2	LN1&2	172.	PRACHIN BURI 1&2	PA1&2
5.	ARANYAPRATHET	AR	89.	LAN KRABU	LKB	173.	PRACHUAP KHIRI KHAN	PKK
6.	AYUTTHAYA 1&2	AY1&2	90.	LAT PHRAO	LPR	174.	PRAKHON CHAI	PKC
7.	BAMNET NARONG	BNN	91.	LANG SUAN	LSN	175.	PRAN BURI	PRB
8.	BAN BUNG	BBG	92.	LI	LI	176.	PRAN BURI POWER STATION	PRP
9.	BAN COK CHANG	BCC	93.	LOEI	LE	177.	RAJJAPRABHA (CHIEW LARN)	RPB
10.	BAN DON	BDN	94.	LOM SAK	LS	178.	RANGSIT	RS
11.	BAN DUNG	BDG	95.	LOP BURI 1&2	LB1&2	179.	RANONG	RN
12.	BAN KHUN KLANG	BKG	96.	LOWER MAE PING	LMP	180.	RANOT	RA
13.	BAN NA SAN	BNS	97.	MAE CHAEM	MC	181.	RATCHABURI 1.2&3	RB1.2&3
14.	BAN PHAI	BPI	98.	MAE CHAN	MCN	182.	RATCHABURI POWER PLANT	RBPP*
15.	BAN PONG 1&2	BP1&2	99.	MAE HONG SON	MH	183.	RATCHADAPHISEK	RPS
16.	BAN SANTI	BST	100.	MAE KHAM	MKH*	184.	RAYONG 1.2&3	RY1.2&3
17.	BAN YANG	BYG	101.	MAE KOK	MKK	185.	ROI ET	RE
18.	BANG KAPI	BK	102.	MAE KUM LUANG (NEA)	MKL	186.	SABA YOI	SBY
19.	BANG LAMUNG	BL	103.	MAE KUANG	MKG	187.	SADAO	SDO
20.	BANG LANG	BLG	104.	MAE LAMA LUANG	MLL	188.	SAI NOI	SNO
21.	BANG MUN NAK	BMN	105.	MAE MOH 1.2&3	MM1.2&3	189.	SAI BURI	SBR
22.	BANG PA-IN 1&2	BI1&2	106.	MAE MOH MINE	MMM*	190.	SAKON NAKHON 1&2	SO1&2*
23.	BANG PAKONG	BPK	107.	MAE NGAT	MNG	191.	SALOKBAT	SLB
24.	BANG PHLI	BPL	108.	MAE SA-NGA	MSN	192.	SAM PHRAN 1&2	SA1&2
25.	BANG SAPHAN	BSP	109.	MAE SARIANG	MSR	193.	SAMUT SAKHON 1.2&3	SN1.2&3
26.	BANGKOK NOI	BN	110.	MAE SOT	MS	194.	SAMUT SONGKHRAM	SM
27.	BETONG	BT	111.	MAE TAENG	MTG	195.	SAN KAMPHAENG	SKP
28.	BHUMIBOL	BB	112.	MAHA SARAKHAM	MK	196.	SANGKHA	SKA*
29.	BO WIN	BWN	113.	MANOROM	MR	197.	SARABURI 1&2	SR1&2
30.	BUNG KAN	BKN	114.	MAP TA PHUT	MTP	198.	SARABURI 3&4	SR3&4
31.	BUNG SAM PHAN	BGS	115.	MUKDAHAN 1&2	MD1&2*	199.	SATTAHIP 1&2	SH1&2
32.	BURI RAM	BR	116.	NA KAE (OUT OF SERVICE)	NE	200.	SATUN	STU
33.	CHA-AM	CA	117.	NAKHON CHAISI	NCS	201.	SAWANKHALOK	SL
34.	CHACHOENGSAO	CC	118.	NAKHON NAYOK	NY	202.	SAVANNAKHET	SVN*
35.	CHAENG WATTHANA	CHW	119.	NAKHON PATHOM	NPT	203.	SI RACHA	SC
36.	CHAI BADAN	CBD	120.	NAKHON PHANOM	NN	204.	SI SA KET	SS
37.	CHAIYAPHUM	CYP	121.	NAKHON RATCHASIMA 1&2	NR1&2	205.	SIKHIU	SKI
38.	CHANTHABURI	CT	122.	NAKHON SAWAN	NS	206.	SING BURI	SI
39.	CHIANG KAN	CKN	123.	NAKHON SI THAMMARAT	NT	207.	SIN PUN	SPU
40.	CHIANG MAI 1.2&3	CM1.2&3	124.	NAM CHOEN	NCE	208.	SIRIKIT	SK
41.	CHIANG RAI	CR	125.	NAM CHON	NCN	209.	SIRINDHORN	SRD
42.	CHOK CHAI	CCI	126.	NAM HAENG	NHA	210.	SOMDET	SD
43.	CHOM BUNG	CBG	127.	NAM KHEK	NAK	211.	SONGKHLA	SKL
44.	CHOM THONG	CTG	128.	NAM LOEI	NLE	212.	SOUTH BANGKOK	SB
45.	CHOM THIEN	CTN	129.	NAM MAN	NM	213.	SOUTH THON BURI	STB
46.	CHON BURI	CB	130.	NAM NGAO	NNA	214.	SRINAGARIND	SNR
47.	CHONG KLAM	CHK	131.	NAM NGUM	NNG	215.	SUKHOTHAI	ST
48.	CHONG MEK	CMK	132.	NAM PAI	NPI	216.	SUNGAI KOLOK	SUK
49.	CHULABHORN	CLB	133.	NAM PHONG 1&2	NPO1&2	217.	SUPHAN BURI	SP
50.	CHUM PHAE	CPA	134.	NAM PUNG	NP	218.	SURAT THANI	SRT
51.	CHUMPHON	CP	135.	NAM SAN	NSN	219.	SURIN	SU
52.	DET UDOM	DD	136.	NAM SU	NAS	220.	TAK 1&2	TA1&2
53.	DOEMBANG NANGBUAT	DBN	137.	NAM THEUN	NTN	221.	TAKHLI 1&2	TK1&2
54.	FANG	FA	138.	NAM THEUN 2	NTN2*	222.	TAKUA PA	TP
55.	GREATER BANGKOK	BKK	139.	NAM YUAM	NYU	223.	TA MOON	TMO
56.	HAT YAI 1&2	HY1&2	140.	NAN	NA	224.	THAKHEK	THK*
57.	HONG SA	HSA*	141.	NARATHIWAT	NW	225.	THA MUANG	TM
58.	HOUAY HO	HHO*	142.	NONG BUA LAM PHU	NBL	226.	THALAN 1.2&3	TL1.2&3
59.	HUA HIN	HH	143.	NONG CHOK	NCO	227.	THAP THAN	TTH
60.	HUAI KUM	HK	144.	NONG HAN	NH	228.	THA TAKO	TTK
61.	HUAI NGAED	HNG	145.	NONG KHAI	NK	229.	THA THUNG NA	TN
62.	HUAI PHUKHI	HPK	146.	NORTH BANGKOK	NB	230.	THAT PHANOM	TH
63.	HUAI SAK	HSK	147.	NUCLEAR	NC	231.	THA WUNG	TW*
64.	KABIN BURI	KBB	148.	ON NUCH	ON	232.	THEPHARAK	TPR
65.	KAENG KRUNG	KKU	149.	PAK CHONG	PCH	233.	THEUN-HINBOUN	THPP*
66.	KAENG SUA TEN	KST	150.	PAK MUN	PMN	234.	THI KHONG	TKH
67.	KALASIN	KL	151.	PAK SE	PSE	235.	THOEN	TE
68.	KAMPHAENGPHET	KP	152.	PATHUM THANI	PT	236.	THOENG	THG
69.	KAMPHAENG SAEN	KS	153.	PATTANI	PTN	237.	THUNG SONG	TS
70.	KANCHANABURI	KB	154.	PHACHI	PH	238.	TRANG	TG
71.	KAENG KRACHAN	KKC	155.	PHANAT NIKHOM	PNN	239.	TRAT	TR
72.	KANTANG	KT	156.	PHANG KHON	PHK	240.	UBOLRATANA	UR
73.	KANTHARALAK	KTL	157.	PHANGNGA	PN	241.	UBON RATCHATHANI 1&2	UB1&2
74.	KHANOM	KN	158.	PHATTHALUNG	PU	242.	UDON THANI 1&2	UD1&2
75.	KHAO LAEM	KHL	159.	PHAYAKKHAPHUM PHISAI	PYK	243.	UPPER MAE PING	UMP
76.	KHLONG MAI	KLM	160.	PHAYAO	PY	244.	UPPER PA SAK	UPS
77.	KHLONG NGAE	KNE*	161.	PHETCHABUN	PE	245.	U THONG	UTG
78.	KHOK KLOI	KKL*	162.	PHETCHABURI	PB	246.	UTTARADIT	UT
79.	KHON KAEN 1.2&3	KK1.2&3	163.	PHICHIT	PC	247.	WANG NOI	WN
80.	KHONG	KNG	164.	PHITSANULOK 1.2&3	PL1.2&3	248.	WATTHANA NAKHON	WNK
81.	KIRIDHARN (HUAI SAPHAN HIN)	KRD	165.	PHON	PO	249.	WIENG HAENG	WHG
82.	KLAENG	KLA	166.	PHON THONG	POT	250.	XESET	XSE
83.	KRABI	KA	167.	PHRA PHUTTHABAT	PTB	251.	YALA	YL
84.	KUD	KUD	168.	PHRAE	PR	252.	YASOTHON	YT