Report No. 7129-CH

Chile
Energy Sector Review

August 1, 1988

Energy Efficiency and Strategy Unit
Industry and Energy Department

FOR OFFICIAL USE ONLY

Document of the World Bank

OFFICIAL FISCAL YEAR

January 1 - December 31

CURRENCY EQUIVALENTS

Currency Unit: Chilean Peso (Ch$)

Exchange Rate of Chilean Peso (Ch$)
Annual Averages

Year	Peso
1980	39.00
1981	39.00
1982	50.91
1983	78.79
1984	98.48
1985	160.86
1986	193.02
1987	223.62
1988 (Jan. - Jun.)	243.40

ENERGY CONVERSION FACTORS

Energy Source	Density (M.T./m^3)	Calorific Values
Crude Oil	0.86	10,860 kcal/kg
Fuel Oil	0.95	10,500 kcal/kg
Naphtha	0.70	11,500 kcal/kg
Liquefied Petroleum Gas	0.55	12,100 kcal/kg
Gasoline	0.73	11,200 kcal/kg
Aviation Gasoline	0.70	11,400 kcal/kg
Kerosene/Jet Fuel	0.81	11,100 kcal/kg
Diesel Oil	0.84	10,900 kcal/kg
Gas Oil	0.92	10,120 kcal/kg
Coke		7,000 kcal/kg
Fuelwood	0.50	3,500 kcal/kg
Coal	1.45	7,000 kcal/kg
Natural Gas	-	9,341 kcal/m^3
City Gas	-	4,000 kcal/m^3
Furnace Gas	-	900 kcal/m^3
Electricity	n.a.	860 kcal/kWh

This report is based on the findings of an energy sector mission which visited Chile in April 1987. Its members were: Messrs Jochen Schmedtje (Mission Leader); Dale F. Gray (Energy Economist); Salvador Rivera (Coal Specialist), Richard W. Fetzner (Petroleum Consultant), and Uffe Bundguard-Jorgensen (Natural Gas Consultant). Mr. Joerg U. Richter (Senior Economist) completed the Report.

ABSTRACT

Chile's energy resources are significant but are concentrated in remote areas distant from the major energy consumption centers, involving high cost of energy production and transmission. Final energy consumption in Chile, 7.8 million tons of oil equivalent or 0.65 toe per capita in 1986, is moderate compared to other Latin American countries at a similar stage of economic development. Declining output of crude oil is bound to result in increasing petroleum imports to meet future energy requirements. This will exert a growing yet manageable burden on the balance of payments as the Government's strategy of pricing energy according to economic cost and shifting demand towards non-petroleum energy sources should keep future petroleum requirements in check.

As agreed with the Government, the present report focuses on selected priority issues in the energy sector. These are, in the hydrocarbon subsector, the rapid decline in domestic petroleum production and concomitant needs for energy imports, accelerated exploration, utilization of natural gas, improving petroleum product pricing and refinery management; in the coal subsector, the high cost of production and the marketing policy of the national coal enterprise ENACAR; and in the forestry subsector, the role of woodfuels within the overal energy sector strategy. The report makes recommendations on the development and production of remaining crude oil reserves, domestic exploration strategy and joint ventures envisaged by ENAP with foreign oil companies. Regarding natural gas, various supply and utilization options are identified. The report emphasizes the importance of addressing ENACAR's rehabilitation needs. The report further recommends that a fuelwood strategy be prepared and more emphasis be given to reconciling energy sector development with environmental conservation. The implications of the report's findings for the medium-term investment requirements of the hydrocarbon and coal subsectors are briefly discussed.

COMPENDIO

Los recursos de Chile en energía son significantes pero se encuentran concentrados en áreas remotas de los centros de consumo, lo que involucra altos costos de producción y transporte. El consumo final de energía en 1986, 7,8 millones de toneladas de petróleo equivalente, o 0,65 tep. por habitante, es moderado en comparación con otros países de América Latina al mismo nivel de desarrollo económico. La caída en la producción nacional de petróleo traerá consigo incrementos de gran escala en las importaciones de petróleo para cubrir los requerimientos energéticos futuros. Esto ejercerá una carga creciente, aunque manejable, sobre la balanza de pagos, ya que la estrategia del Gobierno basada en precios de energía según costos económicos y cambios en la estructura de la demanda hacia fuentes energéticas, fuera de las de petróleo, limitaría los requerimientos futuros de petróleo.

De acuerdo a lo convenido con el Gobierno, este informe enfoca aspectos prioritarios del sector energético. Estos son, en el subsector de hidrocarburos, la disminución acelerada del petróleo nacional y los requerimientos concomitantes para importaciones y para la aceleración de la exploración, la utilización del gas natural, mejoras en la fijación de precios de productos petrolíferos y requerimientos de modificación de las refinerías; en el subsector carbonífero, los altos costos de producción y la política comercial de ENACAR; y en el subsector forestal, el papel de combustibles leñosos dentro de la estrategia global para el sector energético. El informe presenta recomendaciones con respecto al desarrollo y la producción de las reservas restantes de petróleo, la estrategia para la exploración nacional y proyectos de operación conjunta con compañías internacionales de petróleo contempladas por ENAP. Con respecto al gas natural, el informe identifica distintas opciones de suministro y de utilización. El informe enfatiza la importancia de encarar las necesidades de rehabilitación de ENACAR. El informe recomienda la preparación de una estrategia de uso de recursos forestales para fines energéticos y un enfoque más pronunciado sobre la necesidad de reconciliar el desarrollo del sector energético con la conservación del medio ambiente. Las implicaciones de las recomendaciones del informe sobre los requerimientos de inversión a mediano plazo en los subsectores de hidrocarburos y carbón son brevemente analizados.

ABBREVIATIONS

API	American Petroleum Institute (crude gravity measurement)
bbl	barrel
B/D	barrel per day
cm^3	cubic centimeter
ft^3	cubic foot
ha	hectare
in	inch (2.4 cm)
kgoe	kilogram of oil equivalent
km	kilometer
l	liter
LPG	Liquefied Petroleum Gas
m	meter
m^2	square meter
m^3	cubic meter
Mcf	thousand cubic feet (natural gas)
M.T.	metric ton
NGL	Natural Gas Liquids
RON	Research Octane Number
SCF	Standard Cubic Feet (natural gas)
sec.	second
Tcals	Teracalories
toe	ton of oil equivalent
tpy	metric ton per year

ACRONYMS

CHILELECTRA	Empresa Chilena de Electricidad
CNE	Comisión Nacional de Energia
COCAR	Compañia de Carbones de Chile
CODELCO	Corporación del Cobre
CONAF	Corporación Nacional Forestal
COPEC	Compañia de Petroleos de Chile S.A.
CORFO	Corporacion de Fomento de la Produccion
ENACAR	Empresa Nacional del Carbon
ENAP	Empresa Nacional del Petroleo
ENDESA	Empresa Nacional de Electricidad S.A.
GASCO	Compañia de Consumidores de Gas de Santiago
IDB	Inter-American Development Bank
INFOR	Instituto Forestal
ODEPLAN	Oficina de Planificacion
SIC	Central Interconnected System
SOFREGAZ	Société Française d'Etudes et de Réalisations d'Equipments Gaziers
YPF	Yacimientos Petroliferos Fiscales (Argentina)

TABLE OF CONTENTS

ANNEXES

TABLES

MAPS

RESUMEN Y CONCLUSIONES

1. La economía chilena depende en grado considerable de las importaciones de energéticos, principalmente petróleo. Estas importaciones menos reexportaciones de energéticos, ascendieron en 1986 a un costo de US$354 millones, o sea el 6,4% de las exportaciones de bienes y servicios no atribuibles a factores. Ante la disminución de la producción interna de petróleo crudo, el Gobierno enfrenta decisiones difíciles para asegurar la disponibilidad a largo plazo de energía para el crecimiento económico. La tarea principal en el sector consistirá en contrabalancear, en el mediano a largo plazo, la disminución de la producción del petróleo. La base de recursos energéticos de Chile es diversificada, pero las alternativas viables a petróleo crudo, mayormente hidroelectricidad y gas natural, se encuentran a gran distancia de los centros de consumo de energía. Su desarrollo es costoso --incluyendo altas inversiones en transporte de energía-- y requiere de un tiempo considerable de preparación. Carbón de algunas minas nacionales no es competitivo con importaciones. Después de haber alcanzado una sustitución notable de productos del petróleo por carbón, la sustitución económica del petróleo por gas natural en la región central de Chile es viable pero tendría que basarse en su mayor parte en importaciones. Aún suponiendo progresos adicionales en conservación de energía, las importaciones de energéticos inevitablemente aumentarán en forma sustancial en el curso del próximo decenio. Se estima que podrían absorber hasta un 9% de los ingresos de exportación de bienes y servicios de no-factores a principio de los años 90, siempre y cuando que se materialice un auge razonable de las exportaciones.

2. Chile está bien preparado para enfrentar los desafíos que se presenten en el sector energético. Los objetivos del Gobierno están claramente definidos y guardan armonía con las exigencias del desarrollo del sector. Tales objetivos están dirigidos a: a) asegurar la asignación eficiente de los recursos e intensificar la eficiencia del uso final de la energía; b) alentar la competencia y la mayor participación del sector privado; y c) satisfacer las necesidades de energía principalmente mediante recursos autóctonos. Un marco jurídico coherente y estructuras institucionales efectivas han sido establecidos. En el centro de la formulación de políticas, la Comisión Nacional de Energía (CNE) tiene a su cargo la preparación y coordinación de los planes del sector y el asesoramiento al Gobierno sobre políticas y reglamentaciones en materia de energía. La Oficina de Planificacion Nacional (ODEPLAN) coordina las actividades de las entidades y empresas estatales dentro del Programa Nacional de Desarrollo. El Ministerio de Economía aprueba las tarifas de electricidad sobre la base de recomendaciones de la CNE. Al Ministerio de Minería le compete la representación del Estado para concertar y supervisar contratos con empresas para la exploración y producción de hidrocarburos. El Ministerio de Hacienda tiene última autoridad en las

decisiones sobre inversiones y el financiamiento de las mismas en las empresas del Estado. Las políticas de energía basadas en la fijación de precios de acuerdo a costos económicos y la aplicación de mecanismos de mercado para la asignación de recursos han sido medidas claves para asegurar abastecimientos suficientes y aumentar la eficiencia del uso final.

3. A nivel operativo, la estrategia del Gobierno es aplicada a través de empresas estatales y privadas, las cuales tienen plena autonomía y responsabilidad administrativa. La Empresa Nacional de Petróleo (ENAP) tiene a su cargo la exploración, producción y refinación de petróleo y gas natural, y está facultada para asociarse con empresas extranjeras a fines de desarrollar reservas petróliferas tanto en Chile como en el exterior. Cuatro corporaciones de energía eléctrica están encargadas de generación: Empresa Nacional de Electricidad, S.A. (ENDESA), Compañía Chilena de Generación Eléctrica, S.A. (CHILECTRA-GENERACION), Empresa Eléctrica Colbun S.A. (COLBUN, S.A.) y Empresa Eléctrica Pehuenche S.A. (PEHUENCHE, S.A.) la transmisión está principalmente bajo la responsabilidad de ENDESA. La distribución de electricidad se efectúa mayoritariamente por empresas privadas. La Empresa Nacional del Carbón (ENACAR) es el productor más importante de carbón, mientras que COCAR y Schwager son los productores principales del sector privado. La Corporación Nacional Forestal (CONAF) regula las actividades relacionadas con la leña que son dominadas por el sector privado. El Gobierno ha iniciado un programa de desregularización y descentralización de las empresas de energía estatales más importantes, con miras a su privatización gradual. Una presencia vigorosa del sector privado ha sido asegurada en la comercialización del petróleo, la generación y distribución de electricidad, y la producción y comercialización de carbón. Más reciente, el Gobierno ha tenido éxito en atraer compañías privadas extranjeras para la exploración de hidrocarburos. El Gobierno continuará desempeñando una función clave vigilando los precios de la energía y las inversiones en ese campo, evaluando los recursos y necesidades de energía, asegurando la transparencia del mercado, y fomentando el uso eficiente de la energía.

4. A fin de asegurar la capacidad productiva y manejo eficiente del sector de energía, y ante la disminución de las reservas de crudo, es preciso mantener una estrategia coherente cuyos elementos principales, en gran medida, ya se están llevando a cabo. Estos incluyen los siguientes:

(a) A corto plazo:

(i) eliminar las distorsiones menores que subsistan en la formación de precios en la energía y robustecer el manejo de la demanda de energía a través de medidas enfocadas a incentivar la transparencia del mercado, y a su vez, aumentar la eficiencia de las inversiones y del uso final de la energía;

(ii) mejorar la eficiencia de los abastecimientos de energía mediante la reducción de desgastes en la producción, y de pérdidas en la tranformación y distribución, especialmente de electricidad;

(iii) asegurar un esfuerzo sostenido para promover la exploración petrolífera por compañías foraneas en todas las áreas promisorias;

(iv) evaluar el potencial y las opciones para la utilización de gas natural, incluyendo la generación de energía termoeléctrica, y las opciones para la importación de gas y el trueque de gas con Argentina;

(v) desarrollar una estrategia con miras a optimizar el abastecimiento y uso de combustibles a base de madera;

(vi) identificar los requerimientos inmediatos y las opciones disponibles para la conservación del medio ambiente;

(b) De mediano a largo plazo:

(vii) expandir la participación de inversionistas privados nacionales y extranjeros en todas las etapas de las actividades de energía, aplicando modalidades apropiadas de financiamiento incluyendo la conversión de la deuda en capital accionario en la medida posible;

(viii) explotar en forma económicamente (vs. técnicamente) óptima las reservas de petróleo crudo, y aprovechar las nuevas reservas dentro del país como en el exterior;

(ix) aprovechar el potencial hidroeléctrico como componente clave del programa de expansión de electricidad a costo mínimo;

(x) rehabilitar y desarrollar aquellas minas de carbón que tienen el potencial de ser competitivas con las importaciones;

(xi) desarrollar la utilización de gas natural en la región central de Chile en aquellas actividades en que el combustible es de costo mínimo; y

(xii) reconciliar los objetivos del desarrollo del sector de energía con aquellos de la preservación del medio ambiente.

Mejorando el sistema de precios de la energía

5. En general, la política de precios de energía está bien desarrollada y se administra eficazmente, promoviendo la eficiencia de la asignación de recursos en la economía, los objetivos fiscales y la viabilidad financiera de las empresas de energía. Los precios de los productos del petróleo y de carbón se basan en los precios de frontera. Los precios de electricidad se determinan por negociación entre compañías generadoras y distribuidoras ajustados por los cobros de transmisión, y aquellos para usuarios de menos de 2,000 kW de potencia, se basan en los costos marginales a largo plazo como aproximación de precios de mercado. Aunque los precios ex-refinería de los productos del petróleo están ajustados regularmente por los abastecedores, han surgido algunas distorsiones en los precios al consumidor, como resultado de diferencias en la tributación. Si bien estas distorsiones plantean consecuencias negativas de menor índole, deben abordarse sin embargo en el interés de mejorar la utilización eficiente de los recursos. También es menester que se consideren las exigencias específicas que envuelve la fijación de precios de los productos del petróleo en el medio actual caracterizado por la inestabilidad de los precios internacionales de petróleo.

6. Precios de los productos del petróleo. Debido a las marcadas diferencias en los impuestos específicos, los precios del diesel automotriz son más bajos que aquellos de la gasolina, lo que ha creado un incentivo para el uso del diesel y la orientación del parque automotor hacia los vehículos impulsados con ese tipo de combustible. Mientras que el impuesto sobre el diesel en su nivel actual cubre adecuadamente el cargo variable por el uso de carreteras, el impuesto sobre la gasolina es mucho más alto que ese cargo. Este problema podría resolverse elevando el impuesto específico sobre el diesel, o bajando el impuesto sobre la gasolina, o con una combinación de las dos medidas, a fin de reflejar de una manera mejor los costos relativos para los usuarios de carreteras y colocar los precios relativos de la gasolina y el diesel más en armonía con sus precios relativos en frontera. La cuestión que se plantea es si el costo económico vinculado a la distorsión de los precios relativos de los combustibles es mayor que el costo económico de recaudar el mismo ingreso a través de impuestos diferentes, por ejemplo, sobre los vehículos. La justificación para estas diferencias en los precios deberá analizarse más a fondo a fin de determinar los medios óptimos para lograr los objetivos de las mismas.

7. Un problema potencial es causado por el precio más alto del diesel automotriz frente al diesel industrial ya que el impuesto específico se recauda solamente sobre el primero. Mientras los camioneros independientes pagan un precio más alto por el diesel automotriz, las industrias con fletes de camiones tienen la posibilidad de usar el diesel industrial de precio más bajo como combustible para el transporte, afectando así los márgenes de utilidad de los camioneros independientes. Sin embargo, el fisco otorga la exención de impuestos para el diesel industrial solamente ex-post, con verificación adecuada que el carburante estuvo usado para propósitos industriales. El precio

al consumidor del keroséne es apreciablemente inferior al del gas licuado de petróleo. La factibilidad de corregir estas relaciones de los precios mediante el ajuste del impuesto sobre el keroséne debe ser evaluada.

8. El ajuste a la inestabilidad de los precios del petróleo. Los precios internacionales del petróleo en los últimos años han sido particularmente inestables, y la probabilidad es alta que permanezcan así en el corto a mediano plazo. Surge la pregunta si las variaciones de precios a corto plazo deberán ser trasladados a los consumidores en su totalidad, o si los precios al consumidor deberán ser estabilizados por medio de mecanismos compensatorios, aunque esto podría afectar en forma negativa la competibilidad internacional de la economía. A veces se presenta el argumento según el cual los problemas de tipo fiscal y de balanza de pagos más la necesidad de mantener el empuje de conservación de energía, requieran que los precios internos de productos petrolíferos sean establecidos en forma fija, dada la rigidez del proceso de inversión, los repuntes de los precios internacionales de petróleo esperados a mediano y largo plazo, la disminución de reservas en crudo de Chile y la fragilidad resultante de la posición externa de la economía. Sin embargo, por razones de eficiencia de la economía, es necesario que los precios internos de productos petrolíferos sean establecidos en conformidad con las condiciones que rigen a los mercados internacionales para que se tomen las decisiones basadas sobre estas condiciones. Por lo tanto, los precios internos deben moverse paralelamente con los movimientos en los mercados internacionales tanto en el corto como en el largo plazo, reflejando así auges como bajas. Esto también es la posición del Gobierno. En el supuesto de que el Gobierno evaluara una vez la conveniencia de imponer un "impuesto para la conservación", una medida de esta índole debería basarse en un análisis cuidadoso del potencial de ahorros de energía en la economía y de los costos y beneficios para realizar este potencial. Sin embargo, un impuesto de este tipo debería ser aplicado a todos los productos petrolíferos y a todos los consumidores a través de una tasa fija, preferiblemente idéntica, para asegurar que los consumidores sean sujetos en forma igual a la incidencia de movimientos de precios internacionales.

9. Precios y costos comparativos de la energía. La comparación de los precios de mercado de los energéticos (ajustados en función de la eficiencia del uso final a los consumidores) indica que en los sectores residencial, comercial y administrativo la leña es el combustibles de cocina de más bajo costo, seguidos del gas licuado de petróleo, kerosene, y gas de cañería mientras que la electricidad es la fuente de energía más cara. En los sectores industrial y minero, carbón y fuel oil son los combustibles de más bajo costo para calderas, seguido del diesel, leña y electricidad. El kerosene y el gas licuado de petróleo son los combustibles más caros pero se usan poco. En el sector transporte, el diesel es el combustible de menor costo dado su precio más bajo y su más alta eficiencia en comparación con la gasolina.

10. El análisis de los precios de mercado es útil para explicar los factores relacionados con la demanda afectando la conservación y sustitución de la energía. Sin embargo, es preciso que se analicen también los costos económicos relativos de varias formas de energía, incluyendo los costos de equipo para conclusiones propias acerca de la factibilidad de usar o sustituir distintas fuentes de energía. Sobre esta base, en los sectores residencial, comercial y administrativo, el gas licuado de petróleo sigue siendo el combustible de costo mínimo, seguido del kerosène y la leña. El gas de cañería y la electricidad son mucho más costosos. En los sectores industrial y minero, salvo el advenimiento del gas natural, la leña, el carbón y el fuel oil son los combustibles más baratos, seguidos del diesel y el kerosène. La electricidad continúa siendo la fuente de energía más cara a pesar de la más alta eficiencia de las calderas de electrodos.

11. Algunas conclusiones importantes surgen de este análisis. Se minimizaría el costo de la energía mediante un esquema enfatizando el uso de leña en los sectores residencial, comercial y administrativo, y el uso de leña, carbón y fuel oil en los sectores industrial y minero. Es recomendable fortalecer la capacidad para producir y comercializar estos energéticos en la manera factible. La electricidad (en los sectores residencial, comercial y administrativo, así como en los sectores industrial y minero), y el diesel, kerosene y gas licuado de petróleo (en los sectores industrial y minero) son fuentes costosas de energía, aunque puede requerirse de electricidad por razones vinculadas a tecnologías de procesamiento (por ejemplo, en la refinación del cobre). En el sector transporte, el costo económico del diesel y el de la gasolina se aproximan en tal grado que no se puede llegar a una conclusión definitiva respecto de su preferencia relativa sobre esa base solamente. Los costos de la energía en la región central de Chile serían notablemente influídas si llega a disponerse de gas natural en esa región. Es probable que el gas natural sea el combustible de costo mínimo para la generación de energía termoeléctrica y muchos usos industriales aunque la conversión del equipo existente para adaptarlo al uso del gas podría ser no viable. Con el fin de promover la transferencia del mercado y de obtener una base firme para proyecciones de demanda, es preciso que se lleven a cabo estudios de costos económicos detallados y que se les actualice continuamente. Estos estudios deben incluir una evaluación a fondo de externalidades relacionadas a las distintas formas de energía, tal como su impacto sobre el medio ambiente.

Fortalecimiento del subsector del petróleo

12. Producción y exploración. La producción nacional de petróleo crudo suministra actualmente cerca del 33% de las necesidades de Chile. Sin embargo, este porcentaje podría descender a 5% para mediados de 1990, ya que las reservas probadas y la producción interna están disminuyendo pronunciadamente y la producción se vuelve más costosa. Incluso en base a supuestos optimistas en cuanto al aumento de reservas en áreas donde todavía no se ha descubierto depósitos comerciales, la producción incremental de esas áreas no sería suficiente para estabilizar la tasa de

declinación, a la que se pronostica un aceleramiento rápido a partir del principios de los años 90. Una cuestión importante es determinar el nivel y la tasa con que se debe producir el petróleo de alto costo todavía existente, lo que afectaría directamente la envergadura de las actividades de la ENAP. Una cuestión conexa es la estrategia de exploración de la ENAP, es decir, a) si en ausencia de inversiones extranjeras se debe seguir realizando exploraciones riesgosas en las zonas geologicamente difíciles, y b) cuál debe ser el grado y la índole de su nuevo énfasis en las operaciones internacionales. Los próximos años pueden ofrecer a la ENAP una oportunidad singular para adquirir por lo menos una participación limitada en las reservas de petróleo de costo relativamente bajo en el exterior, pero su falta de experiencia en las operaciones fuera de Chile y las graves limitaciones de divisas de la economía podrían restringir tal opción.

13. La estrategia del Gobierno de aprovechamiento de los recursos, que tiene por meta reducir los gastos públicos y los riesgos tanto para el Gobierno como para la ENAP, es apropiada y se debe aplicar vigorosamente. Debe hacer hincapié en los siguientes aspectos:

(a) Producción

(i) enfocar el desarrollo y la explotación a corto plazo de las reservas restantes de petróleo crudo a las "reservas básicas" que se puede producir a costos más bajos;

(ii) ofrecer las propiedades restantes, así como las zonas con potencial de recuperación secundaria, a empresas del sector privado en virtud de contratos de explotación; y

(iii) continuar asegurándose que las decisiones sobre explotación sean basadas sobre costos marginales de producción de cada yacimiento incluyendo tasas de declinación susceptible de maximizar el rendimiento económico más bien que la producción física;

(b) Exploración nacional

(i) asegurar la promoción contínua de las nuevas zonas ofrecidas, a fin de superar la percepción negativa de las empresas internacionales acerca del potencial de hidrocarburos de Chile, y atraer a aquellas empresas que tengan los conocimientos técnicos y el respaldo financiero requeridos;

(ii) poner en marcha la decisión del Gobierno de abrir todas las áreas a los inversionistas; y

(iii) realizar esfuerzos suplementarios de bajo costo para mejorar la base de datos sobre las zonas geológicas técnicamente difíciles y complejas. Aunque cierta

actividad de perforación por la ENAP podría estar justificada, se deben evitar gastos de gran magnitud en la exploración de esas zonas;

(c) Inversiones en el exterior

(i) fijar objetivos claros para la ENAP con respecto al grado y tipo de riesgo y a la magnitud de sus inversiones, y

(ii) mejorar la capacidad de la ENAP para evaluar las oportunidades en el exterior, particularmente las inversiones de bajo riesgo por realizar conjuntamente con empresas internacionales.

14. Utilización del gas natural. Actualmente el gas natural se produce y utiliza solamente en la zona de Magallanes. En el período actual son reinyectadas casi tres cuartas partes de la producción bruta principalmente para mantener la presión del reservorios, mejorar el recubrimiento del petróleo y eventualmente, producir de nuevo el gas reinyectado. El resto es usado en las operaciones de yacimientos, venteado o consumido en el pequeño mercado residencial. El gas producido en Magallanes no se puede transportar económicamente a las otras regiones del país, de modo que se ha decidido usarlo localmente para producir metanol y amoníaco/urea para exportación. Así, gas asociado al crudo, que anteriormente estaba reinyectado o venteado, será vendido por la ENAP a empresas privadas para la producción de metanol y de ammonia urea, a un precio de base suficiente para cubrir costos, más un precio suplementario para obtener un margen adecuado.

15. Aunque la demanda de energía en el centro de Chile es considerable, el abastecimiento de gas tendría que provenir de Argentina mediante la importación o el trueque con el gas de Magallanes o, potencialmente, de los yacimientos costa afuera de Valdivia que todavía tienen que explorarse más a fondo. De las dos opciones de imporcación, la del proyecto del valle de Maipo parece superior y seria marginalmente económica, a un precio en frontera del gas de alrededor de US$2 por millón de BTU. El plan de los yacimientos marítimos costa afuera de Valdivia no parece viable actualmente porque las posibles reservas tal vez no sean suficientes para justificar este proyecto de alto costo como una operación autónoma. No obstante, un enfoque de dos etapas podría ser considerado, es decir, importar primero el gas a través del valle de Maipo, y mas tarde, aprovechar los recursos costa afuera de Valdivia si las reservas disponibles fueran suficientes y si el mercado del gas se desarrolla. Además, el proyecto combinado podría reforzar la posición negociadora del país en que existiría otra fuente para el abastecimiento futuro.

16. Como una variante de la opción de la importación, el gas de Magallanes se podría proveer a Argentina a cambio del suministro de gas argentino a la región central de Chile. Esta alternativa reduciría considerablemente el costo de suministro de gas a Chile central. Su

viabilidad dependería, entre otras cosas, de los costos de oportunidad del gas de Magallanes y de los costos del transporte (y la disponibilidad de capacidad) por el gasoducto sur de la Argentina, en comparación con el costo de las importaciones lisa y llanas de gas argentino. La ENAP jugaría un papel importante en este esquema. El Gobierno ha indicado a Argentina su interés para iniciar negociaciones sobre importaciones tal como trueque de gas. Potencialmente, volumenes importantes de gas podrían también existir en el solar de Atacama cuyo desarrollo podría abrir una alternativa importante de energía para Chile central. Dada la complejidad de las cuestiones involucradas, se recomienda: a) que se actualicen los estudios ya hechos de optimización del suministro de gas al centro de Chile, basado en evaluaciones actualizadas del mercado y nueva información sobre las reservas de la cuenca marítima de Valdivia, y teniendo en cuenta la posibilidad de usar el gas para generar electricidad, por una parte, y la opción del trueque de gas con Argentina, por la otra, y b) en la manera que el resultado de esta evaluación lo aconseje, buscar acuerdos con Argentina sobre la ejecución de proyectos conjuntos como materia de alta prioridad.

17. Refinación del petróleo. Debido a la reorientación de la demanda de productos del petróleo hacia el uso mayor de diesel, el Gobierno enfrenta la decisión de si se justifica aumentar las instalaciones de craqueo o si se pueden atender los cambios en la composición de demanda más economicamente aumentando el volúmen de la producción de la refinería, modificando los insumos del crudo mediante un uso mayor de crudos más livianos o de crudos mezclados con destilados ("spiked crude"), importando los productos en posición deficitaria, o con una combinación de estas opciones. La modificación actualmente siendo considerada es un hidrocráquer moderado, muy probablemente en la refinería de Concón, con un costo estimado de US$22 millones, y un coquizador retardado en la refinería de Concepción para mejorar la producción de gasolina y diesel y reducir la producción de fuel oil convirtiéndolo en coque de petróleo, a un costo que se estima en forma preliminar a US$45 millones.

18. Aprovechando plenamente la capacidad refinadora existente de la ENAP, podría ser suficiente para cubrir la demanda nacional de casi todos los productos sin necesidad de inversión adicional. Sin embargo, se requeriría usar cantidades más grandes de crudo que en el caso de instalación de un hidrocraquer moderado y se debería exportar volumenes considerables de fuel oil a precios relativamente bajos. Un hidrocraquer moderado también contribuiría en aumentar la cualidad de productos y cumplir con los requerimientos de conservación del medio ambiente, pero los costos de capital y operacionales de refinación aumentarían en forma sustancial. Mientras que el hidrocraquer moderado contribuiría poco a reducir la producción de fuel oil; esto se alcanzaría a travéz de un coquizador retardado que convierte los residuos casi totalmente en coque de petróleo. Sin embargo, la viabilidad de la segunda alternativa queda por establecer. El analisis hecho por la ENAP sobre las diversas opciones de inversión se basaba inicialmente en varias restricciones, las cuales tendrán una gran influencia en los resultados del análisis,

especialmente las relativas a restringir la exportación de productos de petróleo en exceso y a limitar la proporción de crudo liviano de los insumos de la refinería. Aunque la eliminación de algunas de estas restricciones podría indicar que la instalación de un hidrocráquer moderado en Concón sea económicamente factible, los beneficios incrementales de este proyecto disminuyen significativamente una vez que se considere exportar productos en exceso. En el caso que los precios relativos de crudos livianos y pesados prevalezcan hacia los años 1990-91, se justificaría postergar el proyecto del hidrocráquer moderado por unos dos años incluso si después de esa época los precios de crudos livianos aumentaran más rápidamente que aquellos de crudos pesados. El Gobierno ha postergado la decisión correspondiente hasta fines de 1988. En vista de la complejidad de los problemas asociados, se deben evaluar más a fondo los costos y beneficios de las opciones del hidrocráquer moderado y coquizador retardado, conjuntamente con la opción de seguir la pauta actual. La armonía de las inversiones propuestas, con los requerimientos a largo plazo deben ser claramente establecidas antes de tomar una decisión al respecto. Este análisis tendría que clarificar la compatibilidad o, contrariamente, la competividad de estas dos opciones. Mientras tanto, se debería considerar las siguientes modificaciones en la evaluación de los proyectos de las refinerías; algunas de las cuales tendrían un impacto directo sobre mejoras de operaciones:

(a) reducir el diferencial entre el precio de crudos livianos y de crudos pesados;

(b) optimizar los insumos de crudos, particularmente mediante el "spiking" de insumos con diesel;

(c) eliminar la asignación fija (50% y 50%) de crudo nacional a las refinerías ; y

(d) eliminar la asignación fija de mercado para las refinerías, e iniciar la venta de productos en la Región I.

19. El Gobierno está en el proceso de evaluar la factibilidad de privatizar las dos refinerías o en forma alternativa, la ENAP en su totalidad. Las perspectivas financieras de refinación en Chile serán de primordial importancia para que estos esfuerzos sean exitosos. Cualquier medida de privatización se escogerá, la misma debe ser expuesta en estricta conformidad con un enfoque basado en la competencia de precios y mercados.

Reestructuración del subsector carbonífero

20. Chile está dotado de recursos carboníferos moderados, de calidad relativamente baja. La producción en Chile central se basa totalmente en la minería subterránea, en condiciones geológicas difíciles, realizada principalmente por la Empresa Nacional del Carbón (ENACAR), la entidad más grande del sector. Las importaciones son

reducidas y consisten básicamente en carbón coquizable. El Gobierno ha dado apoyo al desarrollo del subsector carbonífero mediante actividades de exploración, expansión de capacidad de las minas estatales y sustitución del carbón por productos del petróleo en los sectores de electricidad e industrial. Una nueva empresa privada, COCAR, comenzó la explotación de una mina a cielo abierto de 600.000 toneladas anuales en Magallanes a fines de 1987.

21. Costos del suministro. El problema fundamental en el subsector es determinar en qué proporción la capacidad minera nacional es o puede volverse competitiva con las importaciones. ENACAR está afectada por costos altos especialmente costos fijos de mano de obra en comparación con aquellos de importaciones y suministros de otros productores nacionales. Aunque ENACAR ha hecho grandes esfuerzos de racionalizar sus operaciones y de reducir la mano de obra ociosa, durante los años 1981-87, los costos operativos por unidad de producción aumentaron y la producción por empleado estaba virtualmente estancada por lo que la producción declinó. El precio en boca-mina que oscila entre US$43 y US$64 por tonelada métrica (de carbón lavado), es superior al costo de paridad de las importaciones, de alrededor de US$40 por tonelada métrica, y los precios de entrega para la mayor parte de la producción de ENACAR varían entre US$56 y US$75 por tonelada métrica. Un indicador mejor del precio económico del carbón es el costo marginal a corto plazo de la producción actual y el costo marginal a largo plazo de la producción futura. En algunas minas estos costos podrían aproximarse al costo de paridad de importación, sobre el supuesto de la reducción de la mano de obra y el aumento del grado de mecanización. Esto indica que la producción nacional de carbón podría ser marginalmente económica.

22. Por lo tanto, se plantea la pregunta si es aconsejable continuar la producción de las minas no económicas. Hay varios factores que considerar a este respecto. Primero, una proporción importante de los costos no son recuperables, y en la medida en que los costos monetarios de los despidos, las jubilaciones, cargas financieras, etc., sean mayores que la diferencia entre los costos monetarios de producción y de importación, no se obtendría ningún ahorro reemplazando la producción nacional por las importaciones. Segundo, no obstante de ser técnicamente difícil y costoso reponer en operación las minas cerradas, continuando la producción se justificaría solamente en la medida que haya un margen suficiente de reducción de costos para que la producción sea más competitiva. En caso contrario, el cierre de las minas sería la solución económicamente óptima. Tercero, una gran parte de los costos fijos se relaciona con el exceso de mano de obra, cuyo precio sombra probablemente sea relativamente bajo siempre y cuando exista falta de otras fuentes de trabajo. Los costos de mano de obra relativamente bajos, tienden a reducir el costo de bienestar de operaciones mineras contínuas (o a la inversa, resultan en costos de bienestar significativos en caso de cierre de las minas). El exceso de mano de obra en las minas de carbón podría ser el resultado, a lo menos en parte, de presiones del lado de autoridades regionales y locales de preservar el nivel de empleo. Este costo debería ser hecho explícito. En un sentido más amplio, se deberían estudiar medidas para aumentar la movilidad de la mano de obra en la manera que surjan otras fuentes de trabajo en las zonas afectadas.

23. Las consideraciones anteriormente mencionadas subrayan la urgencia de racionalizar las minas de costos elevados y de reestructurar ENACAR. Todas las opciones factibles, incluyendo la privatización, deberían ser evaluadas. Antes de considerar cualquier expansión de la producción es preciso reducir los altos costos fijos de sus minas, particularmente la de Lota, a través de mejoras de la eficiencia operativa. ENACAR ha contratado consultores para evaluar a fondo las opciones para aumentar la eficiencia, incluso por reducir la fuerza laboral. Cualquier consejo técnico a ENACAR debería enfocarse en las siguientes esferas:

(a) Reducción de los costos de operación: Se deberán evaluar las operaciones de cada mina con miras a determinar las posibilidades de reducir costos, especialmente los costos fijos, incluyendo mejoras en el manejo de inventarios y stocks, la reducción de los servicios en el exterior de la mina, el cierre de las minas o secciones de minas no rentables, y la reasignación o reducción de la fuerza de trabajo. Esta evaluación debería incluir las opciones para reorientar la producción de minas con costos elevados hacia aquellas con costos relativamente bajos;

(b) Examen del programa de inversiones: Se debe determinar si el programa de inversiones de ENAP es consistente con supuestos realistas acerca del alcance de las mejoras en eficiencia y el y el crecimiento del mercado futuro;

(c) Finanzas y la planificación: ENACAR deberá determinar:

(i) el nivel de producción financieramente óptimo --en vez de ser técnicamente factible-- de cada mina, y

(ii) el mejoramiento de la posición financiera que se puede obtener de la descentralización de las operaciones mineras, la contratación externa de servicios auxiliares y otras medidas aptas a reducir los costos de operación y los gastos generales;

(d) Estrategia de desarrollo: Se deberá preparar un plan empresarial a mediano plazo que abarque la producción, las inversiones, las ventas y las finanzas. En la medida en que ENACAR no pueda competir eficazmente con otros productores nacionales o con importaciones, se debe formular una estrategia que le permita reducir la escala de sus operaciones y volverse competitiva en un plazo de cinco años. El plan empresarial debería incluir una propuesta detallada para establecer un sistema de información para la gestión que ayude a integrar a todas las actividades de la entidad.

Fortaleciendo el rol de los combustibles leñosos

24. El crecimiento natural forestal se encuentra muy por encima de la demanda nacional combinada de leña y madera de construcción y cerca de un millón de hectáreas de plantaciones de arboles han sido establecidos en los últimos diez años. Sin embargo, estas plantaciones en su mayoría han sido para propósitos industriales mientras que plantaciones establecidas por CONAP para propósitos dentroenergéticos no eran suficientes para prevenir una escasez regional y de determinadas especies forestales, especialmente de eucalipto en la Región Metropolitana donde la demanda de leña es elevada y donde en años anteriores la deforestación ya ha causado problemas de erosión y ordenación de vertientes. Por ende, es necesario tomar medidas preventivas antes que la deforestación local alcance proporciones serias. La determinación de las necesidades concomitantes de reforestación requiere una evaluación detallada de suministro y demanda en cada región y para las especies específicas, para la cual es preciso ampliar la base estadística. Las zonas forestales que deben ser protejidas y aquellas aptas para uso intensivo deben ser cuidadosamente demarcadas. También se deben evaluar las opciones y necesidades con respecto a la participación de pequeños agricultores en la plantación de árboles, y de las necesidades financieras asociadas. En vista del potencial forestal de gran escala en de Chile, es conveniente establecer una estrategia para aumentar el rol de recursos forestales para enfrentar los requerimientos de energía. Eso deberá incluir fortalecer el marco institucional para poder controlar con más eficacia la evolución de la oferta, la demanda y la comercialización de leña. Como un paso positivo en esta dirección, CONAF estableció en 1986 la Red Nacional de Dendroenergía con el objetivo de a) facilitar la diseminación en el campo técnico y la acción conjunta de las instituciones pertinentes, b) formular recomendaciones sobre políticas, y c) preparar una base de información para facilitar el financiamiento de proyectos. La Red tiene programada procurar la participación activa de los grupos de población directamente afectados. Se recomienda que se incorpore a la Red aquellas entidades del sector privado que actúan en el campo del manejo forestal, las plantaciones y la comercialización de la leña.

Encarando aspectos del medio ambiente

25. Existen conflictos, tal como complementaridades, entre los objetivos de desarrollo energético y la conservación del medio ambiente. Por encima de deforestación causada por el uso de leña, la producción, mercadeo y uso de carbón y de productos petrolíferos contribuyen a la contaminación atmosférica y terrestre. Este problema tiene particular seriedad en la Región Metropolitana donde el impacto de la alta concentración de población y de actividades económicas aumenta debido a las condiciones topográficas y climatológicas locales.

26. El Gobierno está conciente de la necesidad de manejo ambiental en el sector energético y la CNE ha tomado la iniciativa de preparar medidas correctivas. Proyectos recientes de hidroelectricidad incluyen componentes dirigidos a aminorar los efectos negativos sobre el medio

ambiente. El Gobierno está en el proceso de preparar un manual para medir el impacto ambiental sobre proyectos de electricidad como parte del proyecto de gestión del sector público financiado por el Banco Mundial. Un proyecto de descontaminación ambiental está siendo llevado a cabo en Santiago financiado en parte por un préstamo del BID.

27. Los aspectos ambientales, a menudo complejos, deben ser mejor entendidos y los costos de degradación del medio ambiente y de la reducción de los mismos deben ser determinados más a fondo, para poder evaluar en que forma estos problemas deben ser encarados. Entre las opciones para mejorar y prevenir los efectos negativos sobre el medio ambiente, las más eficaces en función de costos deben ser evaluados a fondo. El manejo de recursos naturales debe dar énfasis a la conservación y sostener la base de esos recursos. El impacto ambiental de las distintas formas de energía debe ser evaluado, considerando debidamente aquellas formas que son más compatibles con la meta de conservación del medio ambiente. El análisis de proyectos de energía debe incluir una evaluación de posibilidades para reducir los efectos negativos sobre el medio ambiente, especialmente en zonas susceptibles a la degradación ecológica. Se debe establecer claramente el principio de cobrar los costos de daños ambientales a aquellos que los causan. La CNE y otras instituciones gubernamentales jugarán un papel importante para lograr un mejor entendimiento sobre las complementariedades e inconsistencias entre energía y preocupación ambiental y para definir conceptos de la política a seguir y proyectos aptos que reconcilien los objetivos de desarrollo de energía, protección del medio ambiente y crecimiento económico. La CNE y ODEPLAN deberían guiar la integración de información sobre el uso de recursos con datos macroeconómicos, y evaluar los costos y beneficios de ameliorar y prevenir la degradación ambiental como resultado de operaciones de energía.

Inversiones previstas en el sector energético, 1987-91

28. De acuerdo con la información suministrada por las empresas del sector, las inversiones en el sector de la energía para 1987-91 podrían alcanzar el equivalente de US$2.700 millones (a precios y tipos de cambio de 1986), el 75% del cual corresponde al sector público. La mayor proporción de éstas inversiones sigue siendo asignada al subsector de la electricidad. Hay cuestiones fundamentales con respecto a las inversiones en los subsectores de los hidrocarburos y del carbón. Se plantea la cuestión de si el programa de inversiones de ENAP, que prevé un volumen en el rango de US$460-675 millones, se justifica o si no se podría reducir este programa por medio de una selección de proyectos en forma más rigorosa, mayor eficiencia de los proyectos en función de los costos y mayor participación del sector privado. Los rubros que más preocupan son las exploraciones de petróleo y gas, pero también las inversiones en refinería, para los cuales las prioridades aún deben de ser definidas en forma más clara basándose en soluciones a costo mínimo. Por tanto, las inversiones en el subsector de hidrocarburos quedan por ser definidos más claramente, lo que incluye la intervención respectiva de los sectores público y privado.

29. En el subsector carbonífero, el programa de inversiones de ENACAR para 1987-91 asciende a casi US$47 millones. En vista del margen restringido de ENACAR para ampliar la producción y de sus dificultades financieras actuales, la magnitud y composición de este programa plantean preguntas con respecto a en qué medida las inversiones previstas le permitirán realizar las mejoras necesarias para poder competir con el carbón importado (cuyo precio está previsto de aumentar muy poco durante los próximos diez años). El programa de inversiones de ENACAR se debería reexaminar basándose en una evaluación de todas las alternativas al alcance para reducir los costos de producción, desglosados mina por mina, proponiendo a la vez medidas específicas para reforzar la capacidad en materia de planificación, finanzas y comercialización de la empresa. Inversiones en mejoras de la infraestructura deberían ser orientadas hacia una reducción de costos de suministro y un apoyo a las operaciones de minas de costos relativamente bajos.

SUMMARY AND CONCLUSIONS

1. Chile's economy depends to a considerable degree on energy imports, mainly petroleum, which in 1986 amounted to US$354 million (net of energy reexports) equivalent to 6.4% of exports of goods and non-factor services. With domestic production of crude oil declining, the decision makers face difficult choices to secure the long-term availability of energy for economic growth. Counterbalancing the decline in crude production will therefore be the principal task in the energy sector. Chile's energy resources are diversified but viable alternatives to crude oil, largely hydropower and natural gas, are located distant from the centers of energy consumption. Their development will be costly--including considerable investment in transport--and will involve long lead times. Coal from some domestic mines may not be competitive with imports. Significant substitution of woodfuels for petroleum products has been achieved in industry but a clear Government strategy is needed to utilize this potential more fully. Following significant conversion from fuel oil to coal, economic substitution of natural gas for petroleum in central Chile is feasible but may have to be based mainly on imports. Even assuming further gains in energy conservation, energy imports are bound to increase substantially over the next decade. They might absorb 7-9% of earnings from exports of goods and non-factor services by the early 1990s, provided that the export growth of the economy remains reasonably buoyant.

2. Chile is well-prepared to meet the challenges in the energy sector. The Government's objectives are clearly defined and in accordance with development requirements. They aim at (a) ensuring efficient resource allocation, and enhancing the efficiency of energy end-use; (b) encouraging competition and greater private sector involvement; and (c) meeting energy requirements primarily through indigenous resources. A coherent legal framework and effective organizational structures have been established. At the apex of policy formulation, the autonomous National Energy Commission (CNE) is responsible for preparing and coordinating sector plans, and for advising the Government on energy policies and regulations. The National Planning Office (ODEPLAN) coordinates the actions of state entities within the National Development Program. The Ministry of Economy approves electricity tariffs based on CNE's recommendations. The Ministry of Mining represents the State in concluding and supervising contracts with companies on hydrocarbon exploration and production. The Finance Ministry has ultimate authority in decisions on investment and the financing of investment in state-owned corporations. Energy policies based on pricing according to economic costs and the application of market mechanisms for resource allocation have been instrumental in securing adequate supplies, and in enhancing the efficiency of end-use.

3. At the operational level, the Government's strategy is implemented through state-owned and private companies which have full managerial autonomy and accountability. The National Petroleum Company

(ENAP) is charged with oil and gas exploration, production and refining, and is empowered to enter into partnership with foreign firms to develop hydrocarbon reserves both in Chile and abroad. Four major electricity corporations are in charge of generation, i.e. ENDESA, CHILECTRA-GENERACION, COLBUN, and PEHUENCHE. Transmission is primarily the responsibility of ENDESA. Electricity distribution is carried out mainly by private companies. The National Coal Company (ENACAR) is the major producer of coal whereas COCAR and Schwager are the principal private producers. The National Forestry Corporation (CONAF) monitors fuelwood-related activities dominated by the private sector. The Government has initiated a program of deregulating and decentralizing the major state energy corporations, in preparation for their gradual privatization. A strong private sector presence has been secured in petroleum marketing, electricity generation and distribution, and coal production and marketing. The Government has recently succeeded in attracting private foreign firms to hydrocarbon exploration. The Government will continue to have a key role in the energy sector through monitoring pricing and investment, evaluating resources and requirements, ensuring market transparency, and promoting efficient energy use.

4. To strengthen the productive capacity and management of the energy sector, in the face of declining crude reserves, a coherent strategy is called for whose main components to an important extent are already being implemented. They include:

(a) over the short term:

(i) removing the remaining minor distortions in energy pricing, and reinforcing energy demand management through measures to increase market transparency, to improve the efficiency of investment and energy use;

(ii) enhancing the efficiency of energy supplies through reducing wastage in production and losses in transformation and distribution, especially for electricity;

(iii) ensuring a determined effort to promote petroleum exploration by outside companies in all promising areas;

(iv) assessing the potential for natural gas utilization including for thermal power generation, and evaluating options for gas imports from, and gas swaps with Argentina;

(v) developing a strategy for optimizing the use of woodfuels;

(vi) identifying the immediate requirements and specific options for environmental conservation;

(b) over the medium to longer term:

(vii) expanding private sector involvement by means of participation by national and foreign investors in all stages of energy operations, applying suitable financing mechanisms including debt-equity conversion to the feasible extent;

(viii) exploiting crude oil reserves to the economically optimal (vs. technically feasible) degree, and developing new reserves both domestically and abroad;

(ix) developing the hydro potential as the key component of the least-cost electricity expansion program;

(x) rehabilitating and developing those coal mines that have the scope to become competitive with imports;

(xi) utilizing natural gas in cental Chile for those uses where it is the least-cost fuel; and

(xii) reconciling longer-term energy development strategies with environmental concerns.

Improving Energy Pricing

5. In general, energy pricing is well-developed and effectively administered, furthering allocative efficiency, fiscal objectives, and the financial viability of energy enterprises. Prices of petroleum products and coal are based on border prices. Electricity prices are based on negotiations between generating and distributing companies adjusted by transmission charges and those for consumers with less than 2,000 kW installed capacity, on long-run marginal costs of supply as a proxy of market prices. Although ex-refinery prices of petroleum products are regularly adjusted by the suppliers, some distortions in consumer prices have emerged. While of relatively limited negative consequences, these distortions should be addressed in the interest of allocative efficiency. Also, the specific requirements involving the pricing of petroleum products in the current environment of international petroleum price volatility need to be addressed.

6. Pricing of Petroleum Products. Marked differentials in specific taxes result in lower prices of automotive diesel relative to gasoline, which has created an incentive to use diesel and to shift the fleet toward diesel-powered vehicles. While the tax on diesel at its current level covers adequately the variable element of road user costs, the tax on gasoline is much higher than an appropriate road user charge. This problem could be resolved through raising the specific tax on diesel, or lowering the tax on gasoline, or a combination of the two, to better reflect the relative road user costs and to bring the relative prices of gasoline and diesel closer in line with their relative border

prices. The issue is whether any sub-optimal resource allocation resulting from the distortion in the relative fuel prices involves a greater economic cost than that of raising the same revenue through a different tax, e.g. on vehicles. The justification for these price differentials should be analyzed in more detail to determine optimal means for achieving their objectives.

7. A potential problem relates to the price differential between automotive and industrial diesel as the specific tax is levied only on the former. While independent truckers pay the higher price of automotive diesel, industries with truck fleets might have the possibility to use lower-priced industrial diesel as transport fuel, thus squeezing profit margins of independent truckers. However, the tax exemption for industrial diesel is granted ex-post only on proof that the fuel has been used for industrial purposes. The retail price of kerosene is substantially below that of LPG. The feasibility of correcting this through adjusting the taxation of kerosene should be evaluated.

8. Adjusting to Petroleum Price Volatility. International petroleum prices have been highly volatile in recent years and are likely to be so in the short-to medium term. This raises the issue whether short-term as well as long-term price variations should be passed on to consumers, or if consumer prices should be stabilized through some compensatory mechanism, even if this may impact adversely on the international competitiveness of the economy. It is sometimes argued that fiscal and balance of payments concerns and the need to maintain the momentum for energy conservation may call for stabilizing petroleum prices, in view of investment rigidities, the expected increases in international petroleum prices over the medium-to longer term, the decline in Chile's crude oil reserves, and the resulting fragility of the external position of the economy. However, on economic efficiency grounds, it is necessary that domestic prices of petroleum products are in conformity with international market conditions so that economic decisions are based on these conditions. Therefore, domestic petroleum prices need to fully reflect international price movements, short-term as well as long-term, upswings as well as down-swings. The Government shares this position. Should some form of "conservation tax" on petroleum products ever be considered, this would need to be based on a careful analysis of the energy savings potential in the economy and of the costs and benefits of mobilizing this potential. Such a tax would need to be levied on all petroleum products and all consumers, at a fixed preferably identical rate, so that the impact of international price movements is felt fully and equally by all consumers.

9. Comparative Energy Prices and Costs. The comparison of market prices of useful energy to consumers indicates that in the residential/ commercial/administrative sectors, fuelwood is the cheapest cooking fuel, followed by LPG, kerosene, and town gas, whereas electricity is the most expensive energy source. In the industrial/ mining sectors, coal and fuel oil remain the cheapest boiler fuels followed by diesel, fuelwood, and electricity. Kerosene and LPG are the most expensive fuels but are

little used. In the transport sector, diesel is lower-cost on account of its lower price and higher combustion efficiency compared to gasoline.

10. The analysis of market prices is useful for explaining the demand-related factors in energy conservation and substitution. However, the relative economic costs of the various energy options including equipment costs also need to be analyzed to draw correct conclusions on the feasibility of using or substituting various energy sources. On that basis, in the residential/commercial/ administrative sectors, LPG remains the cheapest fuel, followed by kerosene and fuelwood. Town gas and electricity are much more costly. In the industrial/mining sectors, barring the advent of natural gas, fuelwood, coal, and fuel oil are the cheapest fuels, followed by diesel and kerosene. Electricity remains the most expensive energy source despite the higher efficiency of electrode boilers.

11. Some important conclusions can be drawn from this analysis. Energy costs would be minimized through a use pattern emphasizing fuelwood in the residential/commercial/administrative sectors and fuelwood, coal and fuel oil in the industrial/mining sectors. The capacity for producing and marketing these fuels should be expanded to the feasible extent. Electricity (in the residential/ commercial/ administrative sectors and in the industry/mining sectors), and diesel, kerosene, and LPG (in the industrial/mining sectors) are expensive sources of energy, even though electricity may be required for reasons related to process technology (e.g. for copper smelting). In the transport sector, the economic cost of diesel vs. gasoline approximate each other closely so that no definitive conclusion on their relative preferability can be reached on that basis alone. Energy costs in central Chile would be significantly influenced if natural gas becomes available. Natural gas might be the least-cost fuel for thermal power generation and many industrial uses although it may not be economic to convert existing equipment to gas use. In order to improve market transparency and to provide a firmer basis for energy demand projections, detailed economic cost studies need to be carried out and be continously updated. This should include a careful evaluation of the environmental impact of different energy sources.

Strengthening the Petroleum Subsector

12. Production and Exploration. Crude oil production presently meets about 33% of Chile's requirements. However, this may fall to about 5% by the mid-1990s, as proven reserves and production decline sharply and production is becoming increasingly expensive. Even under optimistic assumptions regarding reserve additions from areas where no commercial deposits have as yet been discovered, incremental production from these areas would not be sufficient to stabilize the decline rate which is projected to sharply accelerate from the early 1990s onwards. A major issue is determining the most economic level and rate at which the remaining high-cost oil should be produced, which has a direct bearing on the size of ENAP's future operations. A related issue is the exploration strategy of ENAP, i.e. (a) whether it should go ahead with costly and

risky exploration in domestic marginal areas in the absence of foreign investment; and (b) what should be the level and nature of its new thrust into international operations. The next few years may offer a unique opportunity for ENAP to acquire at least a limited stake in relatively low-cost crude oil reserves abroad but its inexperience in operations outside Chile and foreign exchange constraints of the economy may restrict this option.

13. The Government's resource development strategy, which aims at reducing fiscal expenditures and risk for both the Government and ENAP, is appropriate and should be actively pursued. It should emphasize the following elements:

(a) Production: (i) limit the near-term development and exploitation of the remaining crude oil reserves to core properties whose production costs are lowest; (ii) offer the remaining properties, along with areas with secondary recovery potential, to private sector operators under exploitation contracts; and (iii) assure that decisions on development investments continue to be based on long-run marginal cost of production by field, with depletion rates consistent with maximizing economic return rather than physical output;

(b) Domestic exploration: (i) ensure a persistent effort to promote the newly offered areas, to overcome the negative perception among international companies about Chile's hydrocarbon potential, and to attract those companies with the required technical expertise and financial backing; (ii) implement the Government's decision to open all areas to outside investors; and (iii) undertake supplementary low-cost efforts to improve the information base on technically difficult and complex geological areas. While some limited drilling by ENAP may be justified, large expenditure for exploring frontier areas should be avoided;

(c) International ventures: (i) establish clear objectives for ENAP regarding the degree and type of risk and the extent of its investment; and (ii) improve ENAP's ability to evaluate international opportunities, particularly lower-risk joint ventures with international companies.

14. Natural Gas Utilization. At present, natural gas is produced and used only in Magallanes. Nearly three-quarters of total output is reinjected, mainly to maintain reservoir pressure, to improve oil recovery, and eventually, recover the reinjected gas. The remainder is used in field operations, flared or consumed in the small residential market. Gas produced in Magallanes cannot be economically transported to other parts of the country so plans are to use it locally to produce methanol and ammonia/urea for exports. Therefore, natural gas associated with crude, which previously was reinjected or flared, will be sold by ENAP to private firms for the production of methanol and ammonia/urea, at

a floor price sufficient to cover costs and a supplementary price to achieve an adequate margin. While a basic assumption of these projects is that gas has low opportunity cost, it needs to be ensured that gas-related investment is least cost and viable on its own, irrespective of any associated oil development.

15. While there is considerable energy demand in central Chile, gas supplies would have to be provided from Argentina either through imports or swaps with Magallanes gas or, potentially, from deposits offshore Valdivia yet to be more fully explored. Of the import alternatives, the Maipo valley scheme appears to be superior and would be marginally economic at a border price of about US$2/BTU million. The Valdivia offshore scheme does not appear viable at this time as the reserves likely to exist might not be large enough to support this high-cost scheme as a free-standing project. However, a two-stage supply approach might be considered, i.e. first importing gas via the Maipo valley and later, tapping the Valdivia offshore resources once sufficient reserves are proven and the market for natural gas develops. The combined project also would improve the country's bargaining position in that a future domestic supply alternative would exist.

16. As a variation to the importation option, gas from Magallanes could be supplied to Argentina in exchange for Argentine supplies to central Chile. This option could considerably reduce the cost of gas to central Chile. Its viability among others would depend on the opportunity costs for Magallanes gas, and transmission costs (and capacity) on the Argentine southern trunk pipeline, compared to the cost of straight gas imports from Argentina. While GASCO has taken the lead in discussions with Gas del Estado of Argentina, ENAP would have an important role to play in this venture. The Government has indicated to Argentina their interest in initiating negotiations on gas imports as well as gas swaps. Potentially, the Salar de Atacama structure could hold significant gas reserves whose development might provide an important energy supply option to central Chile. Given the complexity of the issues involved, it is recommended that (a) existing gas optimization studies for central Chile be updated, based on updated market evaluations and new information on domestic reserves, thereby taking into account the use of gas for power generation, on the one hand, and the option of gas swaps with Argentina, on the other; and (b) provided the outcome of this evaluation makes it advisable, agreements with Argentina on joint projects be sought as a matter of priority.

17. Petroleum Refining. Because of the changing pattern of petroleum product demand towards more diesel use, the Government faces the decision whether additional cracking facilities should be installed, or whether this increased demand should be accomodated by increases in refinery throughput, changes in the crude input mix through increasing the use of lighter or spiked crudes, importation of products in short supply, or a combination of these options. Under consideration are the installation of a mild hydrocracker at the Concon refinery to improve diesel runs, estimated by ENAP to cost US$22 million, and a delayed coker at the Concepcion refinery to improve gasoline and diesel output and

reduce the output of fuel oil by converting it into petroleum coke, whose cost are preliminarily estimated at US$45 million.

18. Used fully, ENAP's existing capacity would be sufficient to meet domestic demand for virtually all products without any additional investment. However, larger volumes of crude would be necessary than if a mild hydrocracker were to be installed, and considerable volumes of fuel oil would need to be exported at relatively low prices. A mild hydrocracker also would contribute to improving product quality and meeting environmental requirements, but the capital and operating cost of refining would considerably increase. While the mild hydrocracker would do little to reduce the surplus of fuel oil, this could be achieved through a delayed coker which converts virtually all residual fuel into petroleum coke. However, the economic viability of the latter option has yet to be established. ENAP's analysis of investment options initially was based on a number of constraints which were bound to have a strong impact on the results of the analysis, especially those restricting exports of refined products in excess supply, and restricting the light crude portion of refinery inputs. While the removal of some of these constraints may make a mild hydrocracker at Concon economically viable, the incremental benefits of this scheme decline significantly once exports of surplus products are assumed to take place. Should the present relative prices of light vs. heavy crude prevail until 1990-91, postponing the investment in the mild hydrocracker by about two years would be justified even if the prices of light crude would afterwards increase faster than those of heavy crude. The Government has postponed a decision until end-1988. Given the complexity of the issues involved, the comparative costs and benefits of the mild hydrocracker and delayed coker options, together with those of continuing present arrangements, need to be evaluated in more detail, and the consistency of these investments with longer-term optimization of refining operations clearly established before a decision can be taken. This analysis also would need to clarify the compatibility or competitiveness of the two options. In the meantime, the following modifications of the refining analysis should be considered, some of which would have a direct bearing on operational improvements:

(a) reducing the differential in the price of light vs. heavy crudes;

(b) optimizing the crude slate, particularly through increasing diesel spike inputs;

(c) eliminating the 50-50 allocation of domestic crude to the refineries; and

(d) eliminating fixed market allocations for the refineries, and initiating product sales to Region I.

19. The Government is evaluating the feasibility of privatizing ENAP's refining operations or alternatively, ENAP in its entirety. The

financial prospects of refining in Chile will be crucial for this effort to be successful. Whichever form of privatization would in the end be chosen, it would need to be in strict conformity with price and market competition.

Restructuring the Coal Subsector

20. Chile's coal resources are moderate and of relatively poor quality. Mining in central Chile is entirely underground, carried out under difficult geological conditions mainly by the state-owned company ENACAR, the largest enterprise. Imports are minor and essentially consist of coking coal. The Government has supported the development of the coal subsector through exploration, capacity expansion at the state-owned mines, and substituting coal for petroleum products in the electricity and industrial sectors. A new private company, COCAR, has started a 0.8 million tpy open pit mine in Magallanes in late 1987.

21. Costs of Supplies. The central issue facing the coal subsector is how much of domestic mining capacity is competitive with imports or likely to become so. ENACAR is affected by high costs especially fixed labor costs relative to those of coal imports and of other domestic producers. While ENACAR has taken strides to rationalize operations and to reduce excess labor, during the 1981-87 period operating costs per unit of output increased and output per employee remained virtually unchanged as output dropped. Mine-mouth costs varying between US$43-64/M.T. (washed coal) are above import parity cost of about US$40/M.T. and its delivery prices range from US$56-75/M.T. A better measure of the economic viability of coal production is given by the short-run marginal cost of existing production and the long-run marginal cost of future production. These costs in some mines come close to, or below, the import parity cost, assuming reduced manning levels combined with higher mechanization. This indicates that local coal production could be economic at the margin.

22. The question arises if production from uneconomic mines should be continued. There are various considerations to this. First, a significant proportion of costs are sunk and to the extent that the cash costs of lay-offs, pensions, financial charges, etc. exceed the differential between cash production costs and import costs, no savings materialize from replacing domestic production through imports. Second, even though the recommissioning of closed mines is technically difficult and costly, continuing production would be justifiable only if there is sufficient scope for reducing costs to make production competitive. Otherwise, mine closure would be economically superior. Third, a large share of fixed costs is related to excess labor whose shadow price may be relatively low as long as employment alternatives are lacking. Relatively low labor cost would tend to reduce the welfare cost of continuing mining operations (or, conversely, result in significant welfare cost in the case of mine closures). Excessive labor in coal mining may, at least in part, be the outcome of pressures from regional and local authorities to preserve employment and these related costs

should be made explicit. In a wider context, measures should be evaluated to increase labor mobility as employment alternatives in the affected areas are being developed.

23. The above considerations stress the urgency for further rationalizing high-cost mines and restructuring ENACAR. All feasible options, including privatization, should be evaluated. The high fixed costs of ENACAR, particularly Lota, need to be addressed through improvements in operational efficiency before any expansion is pursued. ENACAR has contracted consultants to conduct an in-depth evaluation of the scope for efficiency improvements including reductions in the labor force. Any technical advice to ENACAR should focus on the following areas:

(a) Reducing Operating Costs: Operations should be evaluated mine-by-mine with a view to determining the scope for reducing costs especially fixed costs, including through improved inventory/stocks management, reducing above-ground services, closure of non-profitable mines or mine sections, and redeployment or reduction of the labor force. This evaluation should include the options for shifting production from high-cost to lower-cost mines;

(b) Review of Investment Program: It needs to be determined whether ENACAR's proposed investment program is consistent with realistic assumptions about efficiency improvements and the growth of future markets;

(c) Finance and Planning: ENACAR should determine and pursue (i) financially optimal -- rather than technically feasible -- production levels for invididual mines and (ii) the financial improvements attainable from decentralizing mining operations, out-contracting supporting services, and other measures conducive to reducing operating costs and overheads;

(d) Development Strategy: A consistent medium-term corporate plan should be prepared comprising production, investment, sales, and finances. To the extent that ENACAR is unable to compete effectively with other domestic producers or imports, a strategy enabling ENACAR to downsize operations and to become competitive over a five-year period should be prepared. The corporate plan should include detailed proposals for improving the management information system linking all activities of the entity.

Enhancing the Role of Woodfuels

24. Natural growth of forests exceeds considerably the combined fuelwood and timber demand country-wide, and nearly 1 million ha of tree plantations have been established over the past 10 years or so. However, most of these have been for industrial purposes whereas plantations for fuelwood established by CONAF have failed to prevent the emergence of

regional and species-specific shortages, especially for eucalyptus in the Metropolitan Region where fuelwood demand is heavy and where deforestation in the past has led to erosion and watershed management problems. It therefore is necessary to take preventive action before local deforestation reaches serious proportions. The concomitant reforestation needs should be determined by detailed regional and species-specific supply and demand evaluations, for which the data base needs to be considerably improved. Forested areas to be protected and those open for intensive use should be clearly demarcated. The options for involving small-scale farmers more widely in tree planting and the related institutional and financing requirements also need be evaluated.

25. Given Chile's substantial forestry potential, a strategy to enhance the role of woodfuels in meeting energy requirements is appropriate and should be developed. This should include strengthening the institutional framework to monitor more closely the supply, demand, and marketing of fuelwood. As a positive step in this direction, CONAF in 1986 created the National Dendroenergy Network, aimed at (a) facilitating technical dissemination and joint action among the relevant institutions, (b) preparing policy recommendations, and (c) preparing an information base to facilitate project financing. The active participation of the directly affected population groups is being sought. It is recommended to incorporate into the Network those private sector entities which are active in forest management, plantations, and fuelwood marketing.

Addressing Environmental Concerns

26. There are trade-offs, as well as complementarities, between the objectives of energy development and environmental conservation. In addition to deforestation as a result of fuelwood use, the production, marketing and use of coal and petroleum products contribute to atmospheric and soil pollution. This problem is especially serious in the Metropolitan Region where the effects of heavy concentration of population and of economic activities is aggravated by local topographic and climatological conditions.

27. The Government is aware of the need for environmental management in the energy sector, and CNE has taken the initiative to prepare corrective action. Recent hydro projects have included components aimed at ameliorating adverse environmental effects. The Government is preparing a manual for measuring the environmental impact of electric power projects, as part of the World Bank financed Public Sector Management project. A US$4 million air pollution monitoring and diagnostic program is being implemented in Santiago supported through an IDB loan.

28. Requirements and Recommendations. The often complex environment-related issues need to be better understood and the costs of environmental damage and its abatement determined, to assess how these issues can best be addressed. Among the options to counter adverse environmental impacts, the most cost-effective ones should be more closely evaluated. In managing natural resources, a premium should be

put on efficiency, conservation and sustaining the resource base. The environmental impact of different energy forms should be evaluated, giving due consideration to those which are environmentally more benign. Energy project analysis should incorporate an evaluation of options to reduce adverse environmental effects, especially in ecologically sensitive zones. The principle of charging the pollutor for the costs of environmental damage should be clearly established and applied. CNE and other public sector institutions have an important role to play in achieving a better understanding of the complementarities and trade-offs between energy and environmental concerns, and in formulating policy and project concepts that reconcile the objectives of energy development, environmental conservation, and economic growth. CNE and ODEPLAN should take the lead in integrating information on resource use with macro-economic data, and evaluating costs and benefits of ameliorating and preventing damage to the environment as a result of energy operations.

Future Energy Sector Investment, 1987-91

29. According to information provided by the energy enterprises, energy-related investment for the 1987-91 period could be about US$2.7 billion (1986 prices and exchange rates), with the public sector accounting for more than three-quarters of the total. The largest share of energy investment would continue to be allocated to electricity. Critical issues relate to the investment plans in the hydrocarbons and coal subsectors. There are questions as to whether ENAP's investment program as envisaged -- ranging from US$460-675 million -- is justified, or whether it could be reduced through more discriminating project selection, improved cost effectiveness of individual projects, and larger involvement by the private sector. This primarily concerns the largest investment items, i.e. petroleum and gas exploration, but also refining where priorities still need to be more clearly defined based on least-cost solutions to meeting petroleum requirements. Future investment in hydrocarbons has yet to be more clearly defined, including the respective roles of the public and private sectors.

30. In the coal subsector, ENACAR's 1987-91 investment program amounts to nearly US$47 million. Given ENACAR's limited scope to expand production and its prevailing operational and financial difficulties, the size and composition of this program raises questions as to what extent the proposed investment will enable the entity to make needed improvements to become competitive with imported coal (whose price is expected to increase very little over the next ten years or so). ENACAR's investment program should be reviewed based on evaluating all feasible options to reduce production costs, disaggregated mine-by-mine, while proposing specific measures to enhance ENACAR's planning, financial and marketing capabilities. Infrastructure-related investment should be planned with a view towards reducing the costs of coal supplies and supporting the operations of low-cost mines.

I. ENERGY AND THE ECONOMY

Background

1.1 Structure of the Economy. With a per-capita GNP of US$1,320 in 1986, Chile is in the upper range of middle-income countries. Agriculture in 1986 generated 10% of GDP; industry and mining combined, 32%; and services both modern and traditional accounted for 52% of GDP. Copper mining and refining continues to be a pillar of the economy, accounting for about 8% of GDP and 50% of merchandise exports. Sharply fluctuating international prices of copper traditionally have subjected the overall economy to a high degree of instability.

1.2 Recent Economic Developments. Following the 1982-83 depression, which was caused by both external events and inappropriate domestic policies, the Chilean economy has entered a period of relatively steady growth. Led by a strong export expansion which produced trade surpluses of US$1.1 billion both in 1986 and 1987, GDP growth averaged 4.6% p.a. during 1984-85 and nearly 5.5% p.a. in 1986-87, with employment generation more than twice as high, despite the persistence of unfavorable terms of trade and high real international interest rates. The resolution of the financial crisis which had struck many highly indebted firms and banks in 1982-83, has resulted in a significant increase in private savings and an increase in gross domestic savings to 18.4% of GDP by 1986. This recovery, severe fiscal austerity, and continued foreign capital inflows have permitted a strong investment expansion amounting to about 10% p.a. in 1986-87. Nevertheless, the economic and social costs of the recovery have been considerable even though they were mitigated by responsive social programs: unemployment reached record levels and family incomes dropped almost one-third during the depths of the depression. Chile's interest payments on its public foreign debt in 1985-86 amounted to one-tenth of GDP and one-half of domestic savings, leaving little room for expansionary programs or marginal investments.

1.3 Government Policies. The Government is aware that the structural problems of the economy require a sustained medium-term adjustment program. Such a program has been in place since 1985 and has included measures to (a) strengthen incentives for non-copper exports; (b) increase public savings and the efficiency of public expenditures; (c) improve the mobilization and allocation of savings; and (d) improve public efforts in the social sectors. This program has been supported by three Structural Adjustment Loans from the World Bank of US$250 million each, an Extended Fund Facility from the IMF of SDR 750 million, and reschedulings from commercial banks and creditor governments totalling US$18.4 billion. Prudent management of the external debt has contributed to maintain a sustainable situation. This included a program of debt-equity swaps which by mid-1986 had facilitated conversions of US$1.9

billion of foreign debt, bringing about a decline in foreign debt -- by about US$230 million -- in 1987.

1.4 Outlook. Continued fiscal prudence, growing investment, and a stable if not improving international environment are necessary to enable the economy to continue to grow despite its heavy debt burden. It will take some years more of austerity in consumption and sustained investment growth if Chile is to both service its external debt and achieve satisfactory economic growth. Given the openness of the economy, Chile's long-term economic prospects are linked to the performance of the industrial economies, terms of trade, and international interest rates. In spite of the growth in non-traditional exports, copper still accounts for almost half of export earnings and its price prospects are volatile. The country's foreign debt is about equal to GDP. Debt service ratios while declining will remain substantial throughout the 1980s. However, over the 1988-92 period, under moderately optimistic assumptions--real copper prices increasing by 3% p.a. (from a base of US¢72/lb), non-copper exports increasing by 6% p.a. in real terms, international interest rates falling to 5%, and continued international financial support--GDP growth averaging 4.5-5.5% p.a. seems feasible. Such a continued recovery would improve Chile's external debt position considerably and strengthen its creditworthiness. Over the 1986-92 period, the ratio of total debt to GDP would decrease from over 98% to 67% and the interest-to-exports ratio, from 33% to 16%. The benefits of export-led growth could be spread throughout the economy. Social outlays could be increased to attend to social infrastructure needs deferred by the adjustment program. The expected employment generation would likely lead to an improvement in income distribution and living conditions for the majority of the population.

1.5 Nevertheless, there remain considerable risks centering on the Government's ability to generate the required domestic savings and investment, Chile's terms of trade, and access to foreign capital at affordable interest rates. In the case of adverse external developments, domestic savings may be insufficient to permit satisfactory growth and debt service payments. Uncertainty related to internal political developments also may affect private savings and investment.

Energy Resources, Supply and Demand

Energy Resources

1.6 Chile has limited crude oil resources yet substantial resources of natural gas, coal, hydropower, and forests. Proven reserves of crude oil in 1986 were 9.6 million m^3, less than 10 years of production at the 1986 rate, which implies that oil resources are dwindling and production will decline sharply during the next years until commercial deposits are exhausted. Proven and developed reserves of natural gas are estimated at nearly 56 billion m^3 (or 1.96 trillion SCF), equivalent to 35 years of

net production at present levels. Much of it was reinjected over the years to maintain reservoir pressure to produce crude, and for future uses. As reinjection requirements decline along with lower crude production, more gas will become available for other uses. In addition, proven but undeveloped reserves of natural gas in the Springhill area are estimated at 8.4 billion m^3 (of which three-quarters offshore) and probable and possible reserves outside the Springhill area, another 18 billion m^3. Since the bulk of reserves are located in the extreme southern Magallanes region, far from the energy consumption centers in central and northern Chile, their development thus far has been feasible for local use only.

Table 1.1: PRIMARY ENERGY RESERVES, 1986
(Physical Units and Tcal '000)

Physical Units	Proven			Inferred; Probable & Possible
	Developed	Undeveloped	Total	
Crude Oil and Condensate (m^3 millions)	5.2	4.4	9.6	17.1
Natural Gas (m^3 billions)	55.6	8.4	64.0	18.0
	Demonstrated			Inferred
	Measured	Indicated	Total	
Coal (M.T. millions)	194	439	633	5,120
Concepcion-Arauco a/	10	25	35	100
Valdivia-Chiloe b/	3	6	9	20
Magallanes c/	181	408	589	5,000
Wood (m^3 millions)		1,049		
Natural Forests		915		
Plantations		134		
Hydropower (TWh)		103		
Tcals '000				
Crude Oil and Condensate d/			85.7	
Natural Gas d/			597.8	
Coal e/			1,358.0	
Wood f/			3,496.6	
Hydropower			88.6	

a/ Bituminous and sub-bituminous coal, 6,500 kcal/kg
b/ Sub-bituminous coal, 3,500-5,800 kcal/kg.
c/ Sub-bituminous coal, 4,500-5,500 kcal/kg.
d/ Proven reserves only.
e/ Measured reserves only.
f/ Green wood; 1,050 kg/m^3.

Source: CNE; ENAP; ENACAR; INFOR/CORFO

1.7 Measured reserves of coal are estimated at 194 million M.T., with indicated and inferred reserves estimated to total 5.6 billion M.T.. The Magallanes region also holds the bulk of coal reserves which, however, consist of sub-bituminous coal with high sulfur and ash content.

1.8 The feasible hydro potential is estimated at 18,000 MW and 103 TWh. Only 2,262 MW had been developed by 1985, with an average energy of 11 TWh. The ongoing 500 MW, US $798 million Pehuenche project financed by the World Bank and IDB, which is planned to be completed by 1993, will contribute to mobilizing additional hydro potential. Project studies (including detailed design studies) for hydro development involving 9,400 MW and an average energy of 55.5 TWh have been completed. Forests cover about 8.9 million ha, or 14% of continental Chile, but 83% of natural forests amounting to 7.6 million ha are located in the three southernmost districts, whereas there is impending deforestation in the Santiago Metropolitan Region and in some areas in the north. Other biomass resources and renewable energy (wind and solar) are relatively insignificant and likely have a limited local potential only.

Energy Supply and Conversion

1.9 Gross energy supplies in 1986 totalled 95,094 Tcals (9.5 million toe) of which nearly three-quarters were domestically produced. In line with the resource endowment, fuelwood and other biomass provide the largest share of domestically produced energy, 28% in 1986, followed by crude oil and natural gas, 21% each 1/; coal, 15.6%; and hydropower, 13.4%. Energy imports in 1986 were equivalent to 3.1 million toe, a sharp increase from their 1985 level (2.5 million toe). They consisted of crude oil (2.6 million M.T., up from 2.1 million M.T. in 1985), petroleum products, chiefly diesel and jet fuel (totalling 0.7 million M.T.) and coal largely metallurgical-grade (0.4 million M.T.). Their costs in 1986 amounted to US$351 million, equivalent to 6.4% of exports of goods and non-factor services. Nine-tenths of the cost of energy imports is accounted for by crude oil and petroleum products, the balance by metallurgical coal and coke.

1/ Natural Gas net of reinjection amounting to 3.2 billion m^3 in 1986.

Table 1.2: ENERGY INDICATORS, 1976; 1986

I. COMPOSITE ENERGY SUPPLY/DEMAND BALANCE

	1976		1986	
	Tcal '000	Percent	Tcal '000	Percent
Primary Supplies	115.0	100.0	105.8	100.0
Production	(80.1)	(69.7)	(74.4)	(70.3)
Net Imports	(38.3)	(33.3)	(31.4)	(29.7)
Net Exports	(3.4)	(3.0)	(-)	(-)
Secondary Energy Imports	0.8	(0.7)	7.2	6.8
Conversion and Distribution Losses	47.5	41.3	27.8	26.3
Net Supply	68.3	59.4	85.2	80.5
Secondary Exports	1.1	1.0	0.1	0.1
Final Consumption	67.2	58.4	85.1	80.4

II. COMPOSITION OF FINAL CONSUMPTION
(Percent)

	1976									1986								
	Wood-fuels	Petr. Products	Nat. Gas	Coal	Coke	Town Gas	Furnace Gas	Electricity	Total	Wood-fuels	Petr. Products	Nat. Gas	Coal	Coke	Town Gas	Furnace Gas	Electricity	Total
Residential/Commercial/ Administrative Sectors	16.9	12.3	1.3	0.8	-	0.9	-	3.2	35.4	16.3	9.4	1.7	0.1	-	0.7	-	4.0	32.2
Agricultural/Industrial/ Mining Sectors	4.8	17.6	0.1	4.9	1.7	0.7	0.9	6.5	37.2	7.0	13.9	0.1	5.9	1.9	0.7	0.7	8.1	38.3
Transport Sector	-	27.1	-	-	-	-	-	0.3	27.4	-	29.2	-	-	-	-	-	0.3	29.5
Total	21.7	57.0	1.4	5.7	1.7	1.6	0.9	10.0	100.0	23.3	52.5	1.8	6.0	1.9	1.4	0.7	12.4	100.0

Source: CNE; ENAP; ENDESA; mission estimates

1.10 Energy Conversion. Crude oil refining (4.9 million m^3 in 1987) is carried out in ENAP's two refineries located near Concon and Concepcion in central Chile, whose capacity is 69,000 B/D and 72,000 B/D, respectively. Diesel is the most important refined product (32% of the refineries' combined output, on a volume basis) followed by gasoline (29%), fuel oil (21%), kerosene and jet fuel (7% combined), and LPG, naphtha, and minor products. Electricity generation is largely hydro-based (76% in 1986), followed by thermal generation based on coal (13%), fuel oil (6%), diesel (2.3%), wood, and natural gas (1.4% each). There is little production of charcoal from fuelwood. Processing of coal into coke is significant, absorbing 24% of coal output in 1986. Refinery own consumption and losses are low at about 3% of crude oil inputs, down from 6% in the early 1980s. There has been a substantial reduction in natural gas flaring (from 58% of output net of reinjection in 1976 to less than 18% in 1986). However, in the electricity subsector, own consumption and losses have increased, amounting to over 15% of generation in 1986. This is because of high transmission losses typical of a longitudinal system, as well as illicit electricity use.

Energy Demand

1.11 Woodfuels. Fuelwood including charcoal and sawmill residues accounted for some 23% of final energy consumption in 1986, reaching nearly 6 million M.T. in that year. Fuelwood consumption has increased since the mid-1970s at 3.5% on annual average, significantly faster than energy use overall, largely due to its expanded use as industrial fuel. There is now a well-established market in terms of steadily growing demand and identified regional suppliers. The residential and commercial sectors account for about 65% of fuelwood consumption and mining and industry, for 30% (compared to 77% and 21.5%, respectively in 1976). The remainder is used in electricity generation.

Table 1.3: FUELWOOD CONSUMPTION, 1976-86
(M.T. '000 AND PERCENT)

	1976		1980		1985		1986		Increase p.a.(%)	
	M.T.'000	%	M.T.'000	%	M.T.'000	%	M.T.'000	%	1977-80	1981-86
Total Consumption	4,230	100.0	5,050	100.0	5,806	100.0	5,953	100.0	4.5	2.3
Final Consumption	4,158	98.3	4,947	97.9	5,614	96.7	5,654	94.9	4.4	2.3
Residential/Commercial/ Admin. Sectors	3,247	76.7	3,512	69.5	3,873	66.7	3,960	66.5	2.0	2.0
Industry and Mining	911	21.5	1,436	28.4	1,741	29.9	1,704	28.5	12.1	2.9
Industry	(910)	(21.5)	(1,433)	(28.4)	(1,741)	(29.9)	(1,701)	(28.5)		
Mining	(1)	(.)	(3)	(.)	(-)	(-)	(3)	(.)		
Energy Transformation	72	1.7	103	2.0	192	3.3	298	5.1	9.3	17.8

Source: CNE

1.12 Coal and Coke. The use of coal both for processing into coke and in final energy consumption in 1986 reached 1.85 million M.T., below its peak of over 2 million tpy in the late 1960s. Consumption increases during 1977-86 averaged 3.6% p.a., interrupted by a steep decline in 1982. Energy transformation traditionally has accounted for 60-65% of total coal use. The remainder is largely absorbed by industries such as steel, mining, sugar refining, and cement production. Consumption by the residential/commercial/administrative sectors accounts for less than 1.5% and is confined to the coal-producing regions. Coal use in railway transport has been phased out. The consumption of coke primarily in the iron and steel industry has amounted to about 20% of coal consumption and has moved in parallel with the latter.

Table 1.4: Coal and Coke Consumption, 1976-86
(M.T. '000 and Percent)

	1976		1980		1985		1986		Increase p.a.(%)	
	M.T.'000	%	M.T.'000	%	M.T.'000	%	M.T.'000	%	1977-80	1981-86
Coal										
Total Consumption	1,307	100.0	1,677	100.0	1,792	100.0	1,858	100.0	6.4	1.7
Final Consumption	548	41.9	520	31.0	630	35.2	725	39.9	neg.	9.3
Residential/Commercial Administrative Sectors	73	5.6	25	1.5	17	0.9	10	0.5	neg.	9.3
Industry and Mining	350	26.7	419	25.0	613	34.2	715	38.5	4.9	9.3
Industry	(328)	(25.0)	(381)	(22.7)	(513)	(28.6)	(632)	(34.0)		
Mining	(22)	(1.7)	(38)	(2.3)	(100)	(5.6)	(83)	(4.5)		
Transportation	125	9.5	76	4.5	1	0.1	-	-	neg.	neg.
Energy Transformation	759	58.1	1,157	69.0	1,162	64.8	1,133	61.0	11.1	-0.4
Electric Generation	346	26.5	660	39.4	712	39.7	679	36.5	17.5	0.5
Coke, Town Gas, Furnace Gas Production	402	30.8	489	29.2	448	25.0	451	24.3	neg.	neg.
Other	11	0.8	8	0.4	2	0.1	3	0.2	neg.	neg.
Coke										
Total Consumption	293	100.0	399	100.0	334	100.0	347	100.0	8.0	-2.4
Final Consumption a/	145	49.5	178	44.6	197	59.0	209	60.2	5.3	2.7
Energy Transformation b/	148	50.5	221	55.4	137	41.0	138	39.8	10.5	-8.2

a/ Consists of consumption in industry and mining only.
b/ Consists of use in coke and town gas production only.

Source: CNE.

1.13 Petroleum Products. Consumption of petroleum products, 4.3 million M.T. or 86,000 B/D in 1986, is relatively limited for an economy of the size of Chile's. Demand for petroleum products has been subject

to pronounced swings. It grew rapidly between 1960 and 1972 when it reached its highest level ever (5 million M.T.) but fell during 1973-75 and again during 1981-85 in the wake of increasing international petroleum prices and the economic down-turn. However, following the reent recovery of the economy which coincided with declining petroleum prices, petroleum consumption increased again in 1986 (at 5.7%). There have been important changes in the composition of consumption during 1976-86. The share of diesel increased substantially (from 21% to 34%) spurred by low prices in relation to both gasoline and fuel oil. There also was an increase in the share of gasoline (from 20% to 23%, with a shift from regular to premium brands) and of jet fuel (from 2.6% to 4.2%). LPG's share remained unchanged (10%). In contrast, the share of fuel oil in petroleum products demand declined significantly (from 33% to 23%) primarily because of its replacement by coal and fuelwood in electricity generation and industry. Kerosene's share also declined (from 9% to 3.4%) due to its replacement by fuelwood, natural gas and LPG in the residential/commercial sectors. Imports of petroleum products cover nearly 20% of domestic demand; in turn, 63% of locally refined crude is imported.

Table 1.5: CONSUMPTION OF PETROLEUM PRODUCTS, 1976-86

	1976		1980		1985		1986		Increase p.a.(%)	
	M.T.'000	%	M.T.'000	%	M.T.'000	%	M.T.'000	%	1977-80	1981-86
Grand Total	4,430	100.0	5,148	100.0	4,394	100.0	4,645	100.0	3.8	-1.8
by Fuel										
Gasoline	871	19.7	1,081	21.0	998	22.7	1,038	22.3	5.6	-0.7
Aviation Gasoline	8	0.2	8	0.2	5	0.1	6	0.1	-	-4.9
LPG	432	9.7	485	9.4	426	9.7	444	9.6	2.9	0.7
Kerosene	369	8.3	240	4.7	115	2.6	148	3.2	-11.4	-8.4
Jet Fuel	109	2.5	166	3.2	151	3.4	191	4.1	11.1	2.4
Diesel	905	20.4	1,245	24.2	1,441	32.9	1,557	33.5	8.3	3.9
Fuel Oil	1,507	34.0	1,681	32.6	1,102	25.1	1,095	23.6	2.8	-7.4
Naphtha	58	1.3	37	0.7	32	0.7	32	0.7	-11.9	-2.5
Refinery Gas	171	3.9	205	4.0	124	2.8	134	2.9	4.6	-7.3
by Economic Activity										
Final Consumption	3,475	78.4	4,132	80.3	3,789	86.2	4,051	87.2	2.9	-0.3
Resid./Comm./Admin. Sectors	715	16.1	685	13.3	583	13.3	680	14.6	-1.1	-
Agric./Ind./Mining	1,187	26.8	1,266	24.6	1,064	24.2	1,116	24.0	1.1	-2.1
Transport	1,573	35.5	2,181	42.4	2,142	48.7	2,255	48.6	8.5	0.5
Energy Transformation	955	21.6	1,016	19.7	605	13.8	594	12.8	1.6	-9.4
Electricity Generation	539	12.2	612	11.9	290	6.6	282	6.1	3.2	-13.8
Town Gas & Coke Production	66	1.5	57	1.1	37	0.8	39	0.8	-3.7	-6.5
Crude Oil & Nat.Gas Prod.	350	7.9	347	6.7	278	6.4	273	5.9	-	-4.1

Source: CNE; ENAP

1.14 Natural Gas, Furnace Gas, and Town Gas. At present, the use of natural gas is restricted to the producing region of Magallanes, distant from major energy consumption centers. A substantial share of the 1986 production amounting to 1.2 billion m^3 (net of reinjection of 3.2 billion m^3) was for ENAP's own use (640 million m^3) or was burned (211 million m^3). Gas is mainly sold to the residential/commercial/administrative sectors and for electricity generation, whereas very little is consumed in industry. Consumption during 1977-86 increased at 1.8%, annual average, which is low given available resources and the energy substitution potential in the economy. Natural gas exports to Argentina had reached 750 million m^3 in 1978 but were discontinued after 1979 when that country accelerated the development of its own resources. The consumption of low-calorific furnace gas and town gas has stagnated over the past ten years.

Table 1.6: CONSUMPTION OF NATURAL GAS, FURNACE GAS, AND TOWN GAS, 1976-86
(m^3 millions and Percent)

	1976		1980		1985		1986		Increase p.a.(%)	
	m^3 million	%	m^3 million	%	m^3 million	%	m^3 million	%	1977-80	1981-86
Natural Gas										
Total Consumption	760	100.0	857	100.0	959	100.0	877	100.0	3.0	0.4
Final Consumption	104	13.7	118	13.8	153	16.0	168	19.2	3.2	6.1
Resid./Comm./Admin. Sectors	94	12.4	109	12.7	145	15.1	160	18.2	3.8	6.6
Industry and Mining	10	1.3	9	1.1	8	0.9	8	1.0	neg.	unch.
Energy Transformation	656	86.3	739	86.2	806	84.0	709	80.8	3.0	-0.7
Electricity Generation	28	3.7	47	5.5	66	6.9	68	7.8	13.8	6.4
Petroleum and Natural Gas Operations	486	63.9	555	64.8	589	61.4	504	57.4	3.4	-1.6
Liquids Extraction	142	18.7	137	15.9	151	15.7	137	15.6	-0.7	unch.
Furnace Gas										
Total Consumption	883	100.0	1,194	100.0	935	100.0	911	100.0	7.8	-4.6
Final Consumption a/	632	71.6	895	75.0	654	69.9	651	71.5	9.1	-5.4
Energy Transformation b/	251	28.4	299	25.0	281	30.1	260	28.5	4.5	-2.4
Town Gas										
Total Consumption	290	100.0	355	100.0	326	100.0	330	100.0	5.2	-1.2
Final Consumption	271	93.4	331	93.2	295	90.5	296	89.7	5.1	-2.3
Resid./Comm./Admin. Sectors	156	53.8	163	45.9	152	46.6	157	47.6	1.1	-0.6
Industry and Mining	115	39.6	168	47.3	143	43.9	139	42.1	8.0	-3.2
Energy Transformation	19	6.6	24	6.8	31	9.5	34	10.3	6.0	6.0
Electricity Generation	-	-	6	1.7	3	0.9	3	0.9		-12.3
Town Gas and Coke Production	19	6.6	18	5.1	28	8.6	31	9.4	1.4	9.5

a/ Industry and Mining (iron and steel industry) only.
b/ Gas and coke production only.

Source: CNE

1.15 Electricity. With a per-capita consumption of 1,051 kWh in 1986, Chile among Latin American countries ranks sixth, having one of the highest rates of access to electricity (87%, i.e. 96% of the urban population and 35% of the rural population). Industry and mining

combined accounted for 61% of 1986 consumption followed by the residential/commercial/administrative sectors (33%), energy transformation (4.3%) and transport (1.7%). Industry and mining are relatively electricity-intensive, due to the importance of copper and pulp and paper production. 2/ Given the relatively moderate growth of self-generation, the share of industrial consumption supplied by the public service has been growing significantly faster than that of total industrial consumption, especially in the Central Interconnected System which accounts for 74% of total installed capacity and 84% of generation and consumption. In the future, this difference should become less pronounced in view of the continued reduction of the share of self-generation.

Table 1.7: ELECTRICITY CONSUMPTION BY SECTOR, 1975-86
(GWh and Percent)

Consuming Sectors	----1975----		----1980----		----1985----		Preliminary ----1986----		Change p.a. (%) 1976-80	1981-86
	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)		
Total Consumption	7,962	100.0	10,526	100.0	12,262	100.0	12,795	100.0	5.9	3.7
Industry and Mining	5,129	64.4	6,954	66.1	8,101	66.0	8.407	65.7	5.8	3.2
Public Grid Supplied	(2,817)	(35.4)	(4,076)	(38.7)	(5,103)	(41.6)	(5,380)	(42.0)	(7.7)	(4.6)
Self Generation	(2,312)	(29.0)	(2,878)	(27.4)	(2,998)	(25.4)	(3,027)	(23.7)	(4.5)	(0.8)
Residential	1,393	17.5	1,805	17.1	1,996	16.3	2,109	16.5	5.3	2.6
Commercial and Others	1,264	15.9	1,569	14.9	1,945	15.9	2,056	16.1	4.4	7.2
Transport	176	2.2	198	1.9	220	1.8	223	1.7	2.4	2.0

Source: ENDESA.

1.16 Electricity growth was relatively high throughout the 1970s but slowed down during 1981-86 especially for residential consumption. Indeed, present consumption per customer is practically the same as that of 1960. It seems that until 1970, the rapid pace of connections of new customers with below-average consumption outweighed the growth of consumption of existing customers. In contrast, the stagnation of per-customer consumption since 1980 cannot be explained by rapid growth of the number of low-volume consumers: it probably is due to improvements in the efficiency of appliances and other conservation efforts, as well as the slight decline in disposable incomes. Neither can it be explained by a reduced competitiveness of electricity. In fact, the price of

2/ These two sectors in 1986 accounted for 40% and 13%, respectively, of industrial electricity consumption. Further, they accounted for 35% of the 1980-86 growth of total electricity consumption, and for 62% of the growth of industrial consumption alone.

electricity during 1975-84 has increased by a factor of 1.77 compared to 2.87 for kerosene and 3.91 for LPG.

Table 1.8: RESIDENTIAL ELECTRICITY CONSUMPTION INDICATORS, 1960-86

	1960-65	1965-70	1970-75	1975-80	1980-84
Number of Connections p.a.	40,326	56,200	70,293	47,576	45,295
Customer Growth (%)	7.7	7.3	6.8	3.7	3.0
Growth of Consumption per customer (%)	-1.4	-1.1	1.7	1.8	--

	1960	1965	1970	1975	1980	1984	1986
Consumption per Customer (kWh)	1,040	970	918	996	1,087	989	1,051

Source: ENDESA.

Energy End-Use for Major Economic Activities

1.17 Final energy consumption in 1986 totalled 8.5 million toe, or 0.69 toe per capita. 3/ Its growth during 1977-86 has been slow, 2.4% on annual average, compared to GDP growth averaging 3.7% over the same period, indicating that significant gains in energy efficiency have been achieved. Primarily as a result of energy conservation and substitution, important structural changes have taken place. Petroleum products while continuing to meet the largest share of final energy consumption have declined in 1976-86 from 57% to less than 53% whereas there were corresponding increases in the shares of fuelwood (from 21.6% to 23.3%) and electricity (from 10% to 12.4%). The use of wood has increased particularly in mining and the pulp and paper industries, where it has been replacing fuel oil and coal in heat generation. The share of the other fuels (coal and coke; natural, town, and furnace gases) have remained unchanged.

1.18 In the industrial sector, energy consumption during 1977-86 increased at 2.7% on annual average. The share of petroleum products over that period declined from 51% to 37%, with corresponding increases in the shares of electricity (from 18% to 21%), fuelwood (from 13% to 18%) and coal and coke (combined, from 14% to 17%). The shares of the remaining fuels (mainly town and furnace gas) have changed little. Fuel oil has remained the largest single energy source in industry (22.5% in

3/ This compares to per-capita energy consumption of 1.5 toe for Mexico, 1.3 toe for Brazil, and 0.7 toe for Colombia.

1986, down from 33% in 1976) which indicates that a substantial potential for fuel substitution still exists.

1.19 In the residential/commercial/administrative sectors, annual increases in energy consumption during 1977-86 averaged just 1.4%. Fuelwood has met 50% of energy requirements in 1986 followed by LPG (18%) and electricity (9%, vs. 13% in 1976). Town and natural gas increased their combined share slightly (from 6.3% to 7.6%). There were sharp increases in the use of fuelwood mirrored by declines in the use of kerosene (from 12.6% to 4.5%) and coal (from 2% to less than 0.5%) despite low relative prices for both fuels.

1.20 In the transport sector, energy consumption grew at 3.1% p.a. in 1977-86. There was a substantial increase in the shares of diesel (from 29% to 43%) and high-octane gasoline (from 9% to 37%) as a result of favorable relative prices of these fuels and concomitant shifts in the vehicle fleet. On the other hand, substantial declines occurred in the shares of low-octane gasoline (from 43% to 9%) and fuel oil for maritime and rail transport (from 5.5% to less than 2%). The small share of electricity principally for the Santiago Metro system remained unchanged (about 0.5%). The share of air transport fuels remained steady at 7.5 - 8.5% of energy use in transport.

Sector Policies and Institutions

Sector Objectives and Policies

1.21 The Government has set clear goals for the energy sector, consistent with its basic economic philosophy. These are: (a) ensuring efficient resource allocation to supply energy at least cost and enhance the efficiency of energy end-use throughout the economy; (b) encouraging competition and private sector activity; and (c) to the feasible degree, meeting energy demand primarily through indigenous resources. The application of economic cost principles to energy pricing and of market mechanisms for resource allocation have been key elements in the Government's energy strategy. Primarily because of economic-cost based pricing, important achievements have been made in energy conservation and substitution which have contributed to reducing gross energy requirements per GDP by 32% during 1976-86 4/ and energy imports by 18% (in energy terms) over the same period.

4/ Gross energy requirements fell from 0.44 Tcals/Ch$ million (1977 constant prices) of GDP in 1976 to 0.30 Tcals/Ch$ million of GDP in 1986. CODELO, the largest industrial corporation, reduced its energy requirements from

Table 1.9: ENERGY AND THE BALANCE OF PAYMENTS, 1976-86
(US$ millions and percent)

	1980	1982	1985	Prelim. 1986
(1) Energy Imports	911.2	589.0	491.5	351.3
Crude Petroleum	810.4	277.3	445.7	266.2
Petroleum Products	21.8	292.9	18.4	53.5
Coal	58.5	-	21.5	26.0
Coke	20.5	18.8	5.9	5.6
(2) Energy Reexports a/	60.3	69.3	34.3	31.5
(3) Net Energy Imports	850.9	519.7	457.2	319.8
Goods and Non-factor Service Imports	7,122.0	5,134.0	3,984.0	4,328.0
Goods and Non-factor Service Exports b/	5,908.7	4,572.7	4,461.7	5,008.5
(3) as Percent of (4)	11.9	11.4	11.5	7.4
(3) as Percent of (5)	14.4	10.1	10.2	6.4

a/ Mainly Petroleum Products
b/ Net of energy reexports and bunkers (mainly fuel oil and jet fuel).

Source: Central Bank of Chile.

1.22 The Government is carrying out a program to decentralize and deregulate the operations of the major state-owned energy companies, with a view towards enhancing competition, increasing managerial autonomy and accountability, and gradually transferring their ownership to the private sector. A Government presence is to be maintained only in those areas where private entities cannot meet the sectoral objectives. A strong private sector participation has been secured in petroleum products marketing, electricity generation and distribution, and coal production and marketing. Progress is being made in attracting private foreign firms to hydrocarbon exploration. Nevertheless, the Government continues to have a key role in the energy sector through (a) setting and/or monitoring energy prices; (b) deciding on the investment programs of the state energy enterprises; (c) evaluating energy resources and requirements; and (d) developing information systems to ensure market transparency and efficient use of energy resources.

Institutional Structure

1.23 To implement its energy strategy, the Government has established a coherent legal framework and effective organizational structures. At the apex of policy formulation is the National Energy Commission (Comision Nacional de Energía; CNE), an autonomous agency created in 1978, which is responsible for preparing and coordinating sector plans, policies and regulations, and for advising the Government on energy matters. CNE also is monitoring the electricity, hydrocarbons,

and coal subsectors and is responsible for preparing and updating the least-cost electricity investment program. 5/ The entity reports directly to the President of the Republic. A representative of the Presidency presides CNE and its Executive Board. This Board includes the Ministers of Defense, Economy, Finance, Mining, Planning, and the Chief of the Presidential Staff. CNE's Executive Secretary is in charge of the administrative and technical functions, assisted by a small but well-qualified staff. CNE also carries out energy studies for which it usually engages the services of consultants. The Ministry of Mining is responsible for negotiating and executing operating contracts in the hydrocarbons subsector on behalf of the State, with technical advice from CNE. (Contract signature requires the approval of CNE's Board.) The Ministry of Finance has ultimate authority in decisions on investment and investment financing of state-owned corporations. The National Planning Office (ODEPLAN) has an important role in the energy sector through coordinating the actions of state entities and enterprises within the National Development Program. ODEPLAN makes recommendations on public sector investment -- in close cooperation with CNE in matters pertaining to energy investment -- and through its handling the System of Basic Statistics for Investment, monitors Government-approved projects. The Ministry of Economy approves electricity tariffs based on CNE's recommendations, monitors the compliance with regulations and procedures regarding installations and services (through the Superintendent of Electricity and Fuels) , and attends to any customer complaints on matters related to service and tariffs.

1.24 On the operational level, the Government's strategy is implemented through state-owned or associated enterprises which are incorporated with the sole exception of ENAP, the National Petroleum Company, which is constituted as state company. All state-owned or controlled enterprises have full managerial autonomy and accountability. They operate strictly along market principles and are at differing stages of privatization. Corporation de Fomento de la Production (CORFO), the Government's holding company, controls the incorporated companies, i.e. National Coal Enterprise (ENACAR; 99.9% CORFO participation), ENDESA (about 60%, the remainder being owned by other power companies, municipalities, and small private investors), COLBUN S.A. (98%) and PEHUENCHE S.A. (about 70%) and Compañia Carbonifera Schwager S.A. (about 50%). Fully privately owned are meanwhile CHILECTRA-GENERATION, CHILECTRA-METROPOLITANA, and CHILECTRA-QUINTA REGION.

1.25 In the hydrocarbons subsector, ENAP carries out exploration, production, and refining, and is empowered to enter into association with foreign firms to develop petroleum reserves in Chile or abroad. ENAP

5/ For preparing the investment program, CNE uses a dynamic programming model taking into account hydrology factors and water storage systems, and determines the cost of demand not met.

owns and operates two refineries which are located at Concon and Conception in central Chile and which are operated as separate entities. The Government is studying the possible sale of these refineries to private investors such as ENAP employees, pension funds, and others.

1.26 In response to the Government's desire to use the natural gas reserves of Magallanes, private firms have been invited to develop projects to accelerate the economic utilization of these reserves. These projects are to be implemented without direct participation by public sector entities, i.e. ENAP, which would be responsible only for delivering gas to the respective plants.

1.27 In the electricity subsector, there are four major generating companies, i.e. ENDESA, CHILECTRA-GENERATION, COLBUN S.A., and PEHUENCHE S.A. (which will start operating in 1991). Transmission is primarily carried out by ENDESA, with other companies owning minor segments of the network. Distribution is the responsibility primarily of private companies which purchase electricity in bulk from the generating companies. 6/ Electricity operations are coordinated by the Economic Dispatch Center for the Central Interconnected System (CDEC-SIC) where the most important generation/transmission companies are represented. Its responsibilities are to preserve reliability of supply, ensure least-cost operation, establish access, and set wheeling charges for the users of this transmission system extending over 1,860 km. For these purposes, CDEC-SIC (a) determines energy dispatch and other operational parameters of the system on a daily basis and for the medium- and long-term; (b) calculates the marginal costs of the operation; (c) determines the transfer of energy among the generating companies and sets prices; and (d) coordinates major preventive maintenance of generating units.

1.28 In the coal subsector, ENACAR, COCAR, and Schwager are the main producers. The National Forestry Corporation (Corporación Nacional Forestal; CONAF) monitors fuelwood-related activities dominated by the private sector.

6/ A number of electricity generation/distribution companies such as EDELNOR, ELELAYSEN, and EDELMAG, are in the process of being privatized.

II. ENERGY PRICING AND TAXATION

Introduction

2.1 The system of energy prices is well-developed and effectively administered. Following a period during the mid-to late 1970s when their increases fell behind the increases in international energy prices and domestic inflation, in 1978 they were liberalized and allowed to find their market levels (kerosene and LPG prices in 1982 when subsidies were removed). Domestic price of energy without exception meet their opportunity cost, defined as border prices for tradeable goods, marginal cost for electricity and town gas, and replacement cost for fuelwood and natural gas. Thus, in setting or monitoring energy prices, the Government has succeeded in exerting the right signals to consumers and producers, furthering efficient allocation of energy resources, fiscal objectives, and the financial viability of the energy enterprises.

2.2 Prices of tradeables such as crude oil and petroleum products are based on international prices and are being adjusted by the suppliers in line with international price changes. In the same way, prices of fuelwood and coal are market-determined. For coal, large quantities are traded directly between producers and users, and import parity prices are used as a reference point. Fiscal levies take the form of import duties, value-added tax, and special taxes on transport fuels. The 15% import duty 7/ provides a margin of protection for domestic energy production. Otherwise, the Government has eliminated subsidies and resisted pressures to establish new ones. Nevertheless, some distortions in consumer prices have emerged mainly as a result of specific taxes on transport fuels. While these distortions are of relatively limited negative consequences, they should be addressed in the interest of allocative efficiency. Also, managing petroleum products pricing -- with participation by ENAP -- in the current environment of volatile international petroleum prices needs to be given careful attention.

Prices of Petroleum Products

Structure and Levels

2.3 Import parity prices are used by ENAP as a guide to set ex-refinery prices and there usually is only a small difference between the two. (Import parity prices for petroleum products are calculated weekly or bi-weekly based on Caribbean f.o.b. prices to which insurance and freight and the import duty are added.) As petroleum products can be

---

7/ This duty was reduced from 20% in early 1988.

Table 2.1: STRUCTURE OF PRICES OF PETROLEUM PRODUCTS, 1986; 1988
(Ch$/Unit)

	Premium Gasoline (93 RON)	Regular Gasoline (81 RON)	Kerosene	Automotive Diesel d/	Fuel Oil (FO5)	Fuel Oil (FO6)	LPG e/
	(Ch$/l)	(Ch$/l)	(Ch$/l)	(Ch$/l)	(Ch$/kg)	(Ch$/kg)	(Ch$/kg)
			December 1986				
C.i.f. Price	26.8	24.5	27.3	26.5	21.9	18.9	38.8
Import Duty	5.4	4.9	5.5	5.3	4.4	3.8	7.7
Import Parity Price a/	32.1	29.5	32.8	31.8	26.3	22.7	46.5
Ex-Refinery Price	30.2	27.4	30.4	29.3	24.9	22.5	47.0
Value Added Tax	6.8	6.5	7.5	6.6	5.3-5.8	4.8-5.5	12.7
Specific Tax	28.5	28.5	--	15.4	--	--	--
Distributor's Margin b/	3.6	4.9	7.0	3.7	1.6-4.0	1.6-4.8	16.8
Retail Price	69.10	67.3	44.9	55.0	31.8-34.7	28.9-32.8	76.5
Retail Price-- US¢/US gal equivalent c/	127.6	124.3	82.8	101.5	54.8-58.9	50.7-56.3	77.7
			April 1988				
C.i.f. Price	31.1	30.5	35.0	34.6	27.5	23.8	53.9
Import Duty	4.7	4.6	5.2	5.2	4.1	3.6	8.1
Import Parity Price a/	35.8	35.1	40.2	39.8	31.6	27.4	62.0
Ex-Refinery Price	38.8	36.3	40.6	37.0	29.2	25.0	60.6
Value-Added Tax	9.6	9.2	9.6	9.2	6.3-7.0	5.5-6.2	16.0
Special Tax	21.1	21.1	--	11.1	--	--	--
Distributor's Margin b/	9.3	9.7	7.6	9.2	2.5-5.8	2.5-5.8	19.2
Retail Price	78.8	76.3	57.8	66.5	38.0-42.0	33.0-37.0	95.8
Retail Price-- US¢/US gal equivalent c/	121.7	117.9	89.3	102.7	54.4-60.1	48.2-54.0	81.4

a/ The import parity price is defined here as the sum of the c.i.f. import price plus the import duty (20% in December 1986; 15% in February 1988).

b/ For gasolines, diesel and kerosene, the margin is the difference between the retail price and the cost to distributors; for other fuels, the margins were estimated from CNE 1984 data.

c/ Exchange rates used: Ch$205/US$ (December 1986); Ch$245/US$ (April 1988).

d/ The industrial diesel price structure is the same as for automotive diesel, except that the specific tax is excluded.

e/ 15 kg cylinders.

Source: CNE; Platt's Oilgram Price Report.

freely imported, ENAP is disciplined to frequently adjust ex-refinery prices because if the latter were to exceed import prices for any length of time, the private importers could undersell locally refined products. Retail prices to consumers are based on ex-refinery or c.i.f. import prices including import duty, increased by the value-added tax, special taxes on gasoline and automotive diesel, and the distributor's margin. Mainly because of differences in taxation, the ratio of retail prices to c.i.f. prices differs from product to product: it is 2.6 for gasoline, 2.0 for automotive diesel, 1.7 for kerosene, 1.6 for industrial diesel, and 1.4 for fuel oil.

2.4 Specific Taxes on Transport Fuels. As an important element of the pricing structure, specific taxes are imposed on gasoline and automotive diesel, imposed at the importation/ex-refinery stage, which in 1986 replaced a 27% tax on gasoline only. The specific diesel tax is levied only on the portion of that fuel used in transport. Other users, primarily in industry, initially pay the tax which subsequently is reimbursed. The specific taxes in 1986 were euqivalent to 42% of the gasoline retail price and 28% of the automotive diesel price. Value-added tax is imposed on all fuel sales but businesses deduct this levy -- as a prior-stage tax payment -- from their own value-added tax liability.

2.5 Taxes on gasoline and diesel originaly comprised a fixed component and a variable component (Table 2.2). The variable portion of the tax was established as a short-term device to smoothen the impact of the decline in international petroleum prices in 1986 and to appropriate part of the windfall caused by this decline to the Treasury. The variable portion was reduced from 70% to 60% in 1987 and was eliminated in April 1988.

Table 2.2: STRUCTURE OF SPECIFIC TAXES ON GASOLINE AND AUTOMOTIVE DIESEL, 1987-88

Product	Fixed Component			Variable Component
		March 1987		
Gasoline	3.0 UTM/m^3	+	70%	(US$233/exchange rate) - (wholesale price of 93 RON gasoline in Ch$/$m^3$)
Automotive Diesel	1.5 UTM/m^3	+	70%	(US$196/exchange rate) - (wholesale price in Ch$/$m^3$)
		May 1988		
Gasoline	3.0 UTM/m^3			--
Automotive Diesel	1.5 UTM/m^3			--

Note: UTM (Unidad Tributaria Mensual) is an index of domestic inflation.

Source: CNE.

Economic Implications of Petroleum Products Pricing

2.6 Fiscal Revenue. The contribution to Government revenue of the specific taxes on transport fuels has increased rapidly in recent years, i.e. during 1985-87 at 264% in current prices (130% in constant prices). They meanwhile constitute 8-10% of revenue from taxes from transactions of goods and services. It is estimated that in 1987, just under three-quarters of the total revenue was derived from the gasoline tax. One of the reasons for increasing the specific taxes on transport fuels has been to compensate for lower fiscal revenues elsewhere in the petroleum sector, primarily the decline in royalties on the production of crude oil and natural gas payable by ENAP ("derecho de explotacion") in line with the decline in international petroleum prices. Revenue from royalties during 1985-87 fell by 34% in nominal terms (50% in constant prices), due to lower oil prices, higher production costs and a change-over to a variable system of royalties instead of a fixed tax. 8/ However, because specific taxes on transport fuels were extended to include diesel, total petroleum-related fiscal revenue in 1985-87 increased in current prices while remaining roughly unchanged in constant prices.

Table 2.3: FISCAL REVENUE FROM THE PETROLEUM SUBSECTOR, 1984-87
(Ch$ billions)

	1984	1985	Jan-May 1986	Jun-Dec 1986	Jan-Dec 1986	Estimated 1987
Total Revenue	n.a.	111.95			109.12	132.02
Specific Taxes	10.00	15.02	6.39	32.62	39.01	54.67
Gasoline	10.00	15.02	6.39	23.40	29.79	39.45
Fixed Portion				(14.46)		(27.85)
Variable Portion				(8.94)		(11.60)
Automotive Diesel	--	--	--	9.22	9.22	15.22
Fixed Portion				(5.27)		(10.80)
Variable Portion				(3.95)		(4.42)
Royalties	n.a.	40.56			32.80	26.73
Import Duty; Value-added Tax; Other	n.a.	57.09			37.92	50.62

Source: Ministry of Finance.

8/ Under the new method, the royalty on crude oil production amounts to 17% of the parity c.i.f. price (in US$/m^3) - 15.1 based on current estimates of production and production costs.

2.7 Impact on Demand. The differentiation in taxation tends to distort relative prices to consumers of the various products, which thus differ from their relative c.i.f. prices adjusted for local marketing costs. This is most important in the transport sector where the ratio of retail prices of automotive diesel are about 15% below those of gasoline (81 RON) even though the c.i.f. price for diesel is close to and often exceeds that of gasoline. Lower taxes on automotive diesel have exerted an incentive to shift the public transport fleet toward diesel-powered vehicles, especially for busses, small trucks, etc.. While this would contribute to improving the efficiency of fuel use in the transport sector, 9/ the local refineries have been unable to meet the rapidly growing diesel demand and import requirements for diesel have significantly increased as a result. Also, since there are no specific taxes on kerosene, LPG, and fuel oil, the retail prices of these products are considerably lower than those of gasoline and diesel.

2.8 In many countries a road user charge is incorporated in the fuel price, normally in the form of specific taxes on transport fuels. In Chile, the specific tax on diesel is estimated to be in line with an appropriate road user charge whereas the specific tax on gasoline tends to be much higher than such a charge. (Since the--generally heavier--diesel-powered vehicles cause larger wear and tear on roads than gasoline-powered vehicles, road user charges for the former should be higher, not lower, than for the latter.) On grounds of allocative efficiency, it would seem to be advisable to either lower the specific tax on gasoline to more accurately reflect the road user charge, or to increase the tax on automotive diesel to levels closer to that of the gasoline tax. 10/ Either measure would bring the relative consumer prices of gasoline and diesel more closely in line with their relative border prices. However, fiscal and equity considerations might militate against a reduction of the gasoline tax, as the price elasticity of demand for gasoline is relatively low and revenue from such a tax correspondingly high, and gasoline-powered vehicles are used mainly for individual transport by higher income groups. On the other hand, an increase in the diesel tax would widen the price differential between automotive and industrial diesel (para 2.9). The issue is whether the distortion in relative fuel prices exerts a greater economic cost, in terms of affecting allocative efficiency and equity, than would result from raising the same revenue through other taxes. Therefore, the justification for the taxation-induced price differentials for transport fuels should be evaluated in more detail, possibly in the context of the

---

9/ Diesel engines are assumed to be at least 25% more efficient than gasoline engines.

10/ A third set of measures would consist of compensating for the difference in fuel taxes through license fees, km-based taxes etc.

study on fuel taxation and road user charges planned by the Ministry of Transport, to determine optimal means for achieving their objectives.

2.9 Another issue concerns the high price of automotive compared to industrial diesel, as the specific tax is levied only on the former. To the extent that truck fleets of industrial firms use lower-priced industrial diesel, they would gain an advantage over independent truckers who have access to higher-priced automotive diesel only. Any system where different prices for virtually the same products are established invites arbitrage. There is no easy solution to this problem, except, to a certain extent, stricter enforcement of the rules aimed at restricting the use of industrial diesel to industrial purposes, possibly by coloring the different diesel fuels.

2.10 The use of low-priced kerosene in diesel engines, which is in evidence in some countries, does not appear to be a problem in Chile and probably is limited to periods of the year/areas of the country with very low temperatures. However, the retail price of kerosene is well below that of diesel and LPG and does not reflect relative scarcities, considering that both these products need to be imported. The prevailing price relationship between kerosene and LPG tends to give the wrong signals to residential energy consumers and should be corrected through increasing the price of kerosene, in the interest of allocative efficiency.

Adjusting to Petroleum Price Volatility

2.11 International petroleum prices in recent years have shown a high degree of volatility. F.o.b. prices for crude averaged US$26/bbl in 1985, fell at times below US$10/bbl in 1986, and rose close to US$20/bbl in mid-1987, to fall again to about US$15/bbl by early 1988. Relatively low prices are projected for the period 1988-91 to be followed by substantial increases into the mid-1990s. The declining trend in Chile's crude oil production means that the economy will be even more vulnerable to price shocks in the 1990s than during the 1970s and 1980s. Given the importance of petroleum as the critical energy source, this raises the issue whether the short-term variations in international petroleum prices should be fully and promptly passed through to the consumers, or if part or all of these variations should be neutralized -- and prices be stabilized at relatively high levels -- through some compensatory mechanism, such as variable taxation, even if this impacts adversely on the international competitiveness of some energy users. So far, this compensatory mechanism was only applied for gasoline and automotive diesel, in the form of the variable portion of the specific tax. It can be argued that a variable tax applied evenly to all petroleum products would be the most efficient means to smooth swings as the volatility of all petroleum product prices is considered to be the problem.

2.12 It is sometimes argued that fiscal and balance of payments concerns call for stabilizing prices at relatively high levels even in situations of declining international prices, in view of the expected

increases in international petroleum prices over the medium-to longer term, the decline in Chile's crude oil reserves and the resulting fragility of the external position of the economy, which involve a high degree of risk for macroeconomic management. Also, because of investment rigidities, it might take relatively long to shift the productive structure in response to unanticipated price changes.

2.13 Nevertheless, on economic efficiency grounds, it is necessary that domestic prices of petroleum products -- like those of any other tradeables -- are set in conformity with international market conditions, to provide efficiency guideposts for the decisions of producers and consumers. Therefore, domestic petroleum prices need to reflect international price movements, short-term as well as long-term, downswings as well as upswings. There is no convincing economic argument why countercyclical tariff and taxation measures should be taken to cushion domestic consumers from international price movements. Considering that the price elasticity of demand for petroleum products tends to be low, any adverse effects of lowering prices on the incentive to improve the efficiency of energy use probably are minor. In addition, problems of a global nature such as fiscal and balance of payments problems would have to be addressed through global measures, e.g. exchange rate and fiscal reforms, and not just through changes in taxes on specific products. This also is the Government's position. Should the Government ever consider a "conservation tax" -- in preparation for increases in energy prices over the medium-to longer term -- this would need to be based on careful analysis of the energy savings potential in the economy and of the costs and benefits to mobilize this potential. Such a tax would need to be levied on all petroleum products and all consumers, at a fixed preferably identical rate, so that the impact of international price movements is felt fully and equally by all consumers.

Electricity Pricing

Principles of Tariff Setting

2.14 The Government's electricity pricing policy is in line with its economic philosophy of relying on market forces to establish prices of goods and services. Prices to major consumers and for exchanges among generating companies are set through bargaining with electricity suppliers who must compete for that portion of the market. Node prices and tariffs at the distribution level, where a natural monopoly exists, are set and regulated by the Ministry of Economy based on the structure and levels of marginal costs -- a proxy of market prices -- as calculated by CNE. This institutional separation combined with regular and automatic adjustments ensures that no political pressures come to bear in setting electricity prices.

2.15 Criteria and procedures for calculating electricity tariffs are laid down by the Electricity Law of 1982. The energy tariff reflects the

short-run marginal cost of energy and the capacity tariff, the long-run marginal cost of new generating capacity required to cover peak demand, calculated on the basis of a least-cost investment program. The legislation allows consumers to choose freely among alternative tariffs within their corresponding voltage range, and does not distinguish classes of consumers for tariff purposes.

Regulated Tariffs

2.16 Regulated electricity prices are established at two stages: i.e. the generation-transmission level (node prices) and the distribution level (aggregate values of distribution). The sum of both is the maximum price paid by the final consumer. The node prices are the prices of bulk electricity sold by the generation/transmission companies to the distribution companies. They are calculated for capacity and energy for those locations where electricity is supplied to distribution systems, including marginal transmission losses as a proxy for marginal costs of transmission and to account for locational differences. Node prices are recalculated by CNE twice each year and modified if necessary, through indexation formulae based on water reservoir levels 11/ and on cost components such as fuel (coal) and equipment. These formulae operate automatically every time there is a variation of at least 10% in the capacity or energy price. The average retail tariff in April 1988 was about US¢8.1/kWh equivalent. 12/

2.17 The aggregate values of distribution have three basic cost components, i.e. (a) costs of investment, operation, and maintenance; (b) administration, billing and other consumer-related costs; and (c) losses for model distribution components, with the optimum size and operational efficiency in concession areas classified according to their consumer density (high, medium and low). 13/ The aggregate values of distribution are calculated every four years and in the interim, are automatically adjusted through formulae which incorporate cost variations such as for materials, equipment, and labor. Distribution companies are authorized to adjust prices every time the node prices or the aggregate distribution values change. There are various tariff options among which

---

11/ This in view of the importance of water reservoir levels for the generating capacity of Chile's largely hydro-based system.

12/ BT 1 tariff, i.e. combined fixed charge and energy charge calculated for consumption of 100 kWh/month (as average household consumption); the fixed charge amounts to about US$1 equivalent/connection/month. See Annex 15 for the structure of electricity tariffs.

13/ Distribution costs incorporated into the tariffs are composed of (a) the cost of distributing 1 kWh at peak; (b) the cost of distributing 1 kWh off-peak; (c) costs of losses; and (d) fixed cost per customer, independent of consumption.

the consumers can freely choose the one that fits closest their particular circumstances (with the sole limitation of an upper maximum capacity for the simplest -- B1 -- tariff). By basing electricity tariffs on standard costs instead of actual costs, this system gives an incentive to distribution companies to achieve the highest possible efficiency levels, through reducing costs of operations and improving the utilization of the network.

Negotiated Tariffs for Major Consumers

2.18 Consumers with an installed capacity above 2,000 kW may freely negotiate electricity prices with any generation company. The resulting prices are within a range of the node prices and generally, do not diverge more than 10% from the latter. To facilitate the access of any electricity producer to any electricity consumer, the transmission system is freely accessible, by means of paying wheeling charges. 14/ These charges are based on short-run marginal costs or average incremental costs of transmission (as established by CNE) as their maximum level and otherwise are negotiated between the transmission company and the generating companies. This policy aims at (a) promoting competition among the generation companies; (b) stimulating major consumers to seek the least-cost sources of electricity including self-generation and cogeneration; (c) optimizing the use of transmission systems; and (d) utilizing the consumers' technical and entrepreneurial capacity to establish an effective independent system of monitoring electricity prices.

Comparative Energy Prices and Costs

2.19 The comparative costs of energy alternatives have a strong influence on consumer choices. In addition to the price paid by the consumers, the costs of these alternatives are determined by relative end-use efficiencies which vary according to the type of energy and of equipment used, specific applications, and the equipment's energy efficiency and power output. To provide appropriate signals to consumers, prices should reflect the economic cost of the energy form in question. Proper analysis should include the investment costs of the energy using equipment as these often are substantial and front-loaded and therefore can influence consumer decisions more than does the energy price itself.

2.20 The comparison of energy prices to consumers (market prices) adjusted by the end-use efficiency of energy-consuming appliances offers some important conclusions (Table 2.4). In the residential/commercial/

14/ In addition, there are no barriers to entry, and self-generation is encouraged, subject to certain technical regulations.

Table 2.4: PRICES TO CONSUMERS OF VARIOUS FORMS OF ENERGY, SANTIAGO, APRIL 1988
(Ch$/Useful kWh)

	Average Price		kWh/kg	Average Price/ Gross kWh	Current Utilization Efficiency	Average Price/ Useful kWh	Improved Utilization Efficiency	Average Price/ Useful kWh
	(Ch$/Unit)	(Ch$/kg)		(Ch$)	(%)	(Ch$)	(%)	(Ch$)
Residential, Commercial, Administrative Sectors								
(a) Cooking:								
Fuelwood	n.a.	11.0	4.07	2.7	35	7.7	60	4.5
Kerosene	57.8/l	71.4	12.91	5.5	70	13.8	45	12.2
LPG	n.a.	95.8	14.07	6.8	55	12.4	65	10.5
Town Gas	47.0/m^3	n.a.	4.65 b/	10.1	55	18.4	65	15.5
Electricity a/	21.6/kWh	n.a.	n.a.	21.6	60	36.0	80	27.0
(b) Heating:								
Fuelwood	n.a.	11.0	4.07	2.7	35	7.7	60	4.5
Kerosene	57.8/l	71.4	12.91	5.5	70	7.9	80	6.9
LPG	n.a.	95.8	14.07	6.8	70	9.7	80	8.5
Town Gas	47.0/m^3	n.a.	4.65/b	10.1	55	18.4	65	15.5
Electricity	21.6/kWh	n.a.	n.a.	21.6	90	24.0	100	21.6
Industrial Sector								
Fuelwood	n.a.	4.5	4.07	1.1	40	2.8	55	2.0
Coal	n.a.	14.7	7.56	1.9	56	3.4	65	2.9
Kerosene	48.2/l	59.5	12.91	4.6	65	7.0	75	6.1
LPG	n.a.	79.8	14.07	5.7	70	8.1	75	7.6
Diesel Oil	46.2/l	55.0	12.67	4.3	70	6.1	75	5.7
No.6 Fuel Oil	n.a.	35.0	2.21	2.9	70	4.1	75	3.9
Electricity c/	11.2/kWh	n.a.	n.a.	11.2	85	13.2	95	11.8
Transport Sector								
Gasoline (93 RON)	78.8/l	107.9	13.02	8.3	28	3.0		
Diesel Oil	66.5/l	79.2	12.67	6.3	35	1.8		

a/ BT-1 tariff; consumption of 100 kWh/month.
b/ kWh/m^3.
c/ Tariff for high-voltage consumers, 1,000 kW max./month; demand and energy charges combined.

Source: CNE; ENAP; ENACAR; ENDESA; mission estimates.

administrative sectors, fuelwood is the cheapest cooking fuel despite the relatively low efficiency of wood-burning stoves, followed by LPG and kerosene due to the high efficiency of the respective appliances, and town gas. Electricity is the most expensive energy source despite the high end-use efficiency of electrical appliances. In the industrial/ mining sectors, fuelwood, coal and fuel oil are the cheapest boiler fuels followed by diesel, kerosene, LPG, and electricity. For both the residential/commercial and industrial sectors, these relationships prevail even if the comparison is based on the use of more energy-efficient equipment since the inherent price and efficiency differentials are too large to be compensated through efficiency improvements. Finally, in the transport sector, diesel is lower-cost on account of its lower price and higher combustion efficiency compared to gasoline.

2.21 The analysis of comparative market prices is useful for explaining the demand-related factors in energy conservation and substitution. However, to fully assess the efficiency of energy use, the relative economic costs of the various energy forms including equipment costs also need to be analyzed. On this basis, in the residential/commercial/administrative sectors, fuelwood remains the least-cost fuel, followed by kerosene and LPG. Town gas and especially electricity are much more costly. In the industrial/mining sectors, fuelwood, coal and fuel oil are the cheapest boiler fuels, whose cost approximate each other very closely, followed by diesel, kerosene, and LPG. Electricity remains the most expensive energy source despite the higher efficiency of electrode boilers. Comparative costs would be significantly influenced if the wider use of natural gas were to become feasible. In transport, the combined energy and capital cost of diesel-powered vehicles are virtually the same as those of gasoline-powered vehicles as the formers' lower fuel costs are compensated by their higher equipment cost.

2.22 The foregoing analysis provides some important conclusions. First, relative prices to consumers of the various forms of energy are fairly closely in line with their relative economic costs (with the exception of transport fuels and to a lesser degree, kerosene and LPG) which indicates that in Chile, energy pricing according to economic efficiency principles has been largely accomplished. Second, costs of energy would be minimized through a use pattern emphasizing the use of fuelwood in the residential/ commercial/ administrative sectors and of fuelwood, coal, and fuel oil in the industrial/mining sectors. The capacity for producing and marketing these relatively cheaper fuels should be expanded, especially for fuelwood whose wider use might be limited by market imperfections, which should therefore be removed to the feasible extent. Kerosene, diesel, LPG and electricity are relatively expensive sources of energy in both sectors (although electricity often is required for reasons of process technology, e.g. for copper smelting). Third, in the transport sector, the economic cost of diesel vs. gasoline approximate each other closely so that no definitive

Table 2.5: ECONOMIC COST OF VARIOUS FORMS OF ENERGY, SANTIAGO, APRIL 1988
(US$ Equivalent)

	CIF Import/ Domestic Prod. Cost	Internal Marketing Cost a/	Total Cost	Total Energy Cost	Energy Cost/ Useful kWh	Energy Cost/Useful TOE	Energy Cost Year b/	Equipment Cost/Year b/	Energy plus Equipment Cost/Year b/
	(---------- US$/M.T.	----------	)	(US¢/kWh equiv.)	(US$)	(US$)	(---------- US$	----------	)
Residential, Commercial and Administrative Sectors									
Fuelwood	12.00	10.75	22.75	0.56	1.60	185.60	25.05	27.78	52.83
Kerosene	176.35	38.30	214.65	1.66	4.15	481.40	64.99	13.85	78.84
LPG	220.00	78.35	298.35	2.14	3.89	451.24	60.92	32.50	93.42
Town Gas				3.44	6.26	726.16	98.03	32.50	130.53
Electricity d/				7.35	12.25	1,421.00	191.84	40.35	232.19
Industrial Sector									
Fuelwood	12.00	6.35	18.35	0.46	1.15	133.40	1.02	1.91	2.93
Coal	42.00	8.50	50.50	0.67	1.20	139.20	1.07	1.91	2.98
Kerosene	176.35	28.75	205.10	1.59	2.45	284.20	2.21	1.91	4.12
LPG	220.00	58.75	278.75	1.99	2.84	329.44	2.51	1.91	4.42
Diesel Oil	168.10	33.52	201.62	1.59	2.27	263.32	2.04	1.91	3.95
No. 6 Fuel Oil	97.15	10.20	107.35	0.87	1.24	143.84	1.11	1.91	3.02
Electricity e/				4.57	5.38	624.08	4.15	2.91	7.06
Transport Sector									
Gasoline (93 RON)	175.55	52.00	227.55	1.75	6.25	725.00	943.80	2,168.00	3,111.80
Diesel	168.10	44.69	212.79	1.68	4.80	556.80	717.45	2,397.00	3,114.45

a/ Includes distributors margin. For industrial fuels, costs of internal marketing are assumed to be 75% of those for residential/commercial/administrative sectors.

b/ Capital recovery factor of 12%, for industrial sector, energy cost per M.T. of steam produced.

c/ Improved equipment.

d/ BT-1 tariff; consumption of 100 kWh/month.

e/ High-voltage tariff, 3,000 kW/max./month; demand and energy charges combined.

Source: CNE; ENDESA; ENAP; ENACAR; mission estimates.

conclusion about their preferability can be reached on the basis of current economic costs alone. However, the future price relationship of gasoline vs. diesel on international markets may be a potentially important consideration. Since the options for replacing middle distillates are relatively few, demand for diesel is likely to remain relatively strong and consequently, international prices of diesel over the medium term might increase relative to those of gasoline.

Economic Cost of Natural Gas

2.23 Natural gas, whose use presently is limited to Magallanes, could conceivably become available in central Chile by the early to mid-1990s (para 3.3). This fuel then would compete with town gas in the residential/commercial/administrative sectors, and with fuel oil and coal in industry (and, possibly, mining).

2.24 A preliminary evaluation of the economic costs of natural gas in central Chile for thermal power generation and industrial use has been carried out. This evaluation is based on the following assumptions:

(a) power generation in central Chile is to be expanded through the commissioning of a 300 MW thermal plant, to be on line by 1995;

(b) for power plant conversions to natural gas, a payback period (on a discounted cashflow basis) of up to ten years would be permissible but five years would be more desirable; and

(c) energy prices for 1995 are based on World Bank projections (September 1987).

2.25 For new installations of industrial boilers and boiler conversions to gas use, two cases have been analyzed, i.e. (i) large-sized high-pressure boilers (45 M.T./hr) and (ii) medium-sized low pressure boilers (15 M.T./hr). The results of this evaluation show that natural gas would be the cheapest fuel for new installations in thermal power generation and industries using at least medium-sized boilers. Conversion of existing installations from fuel oil to gas use also would be economic whereas coal-to-gas conversion would involve long pay-back periods which make this option largely uneconomic.

2.26 Specifically, the results of the evaluation are as follows:

(a) Electricity generation - central Chile: based on the 1995 energy price projections, gas/combined cycle plant would be cheaper than either fuel oil- or coal-fired steam plant at

virtually all plant factors. 15/ The border price of gas would have to rise to US$3.50/BTU million by 1995 for gas to become uncompetitive with coal-fired steam plant.

(b) Electricity generation - Magallanes region: based on the current opportunity cost for gas of US$0.60/BTU million, gas turbine plant would be the least-cost option but at higher gas prices, combined-cycle plant would be more attractive.

(c) Industrial boilers: for large-sized boilers, at 1987 fuel prices and US$2/BTU million for gas, the use of gas would be cheaper than fuel oil for all load factors, and cheaper than coal up to a 50% load factor. At 1995 prices, gas would be cheaper than coal for load factors up to 65%. For medium-sized boilers, gas is cheaper than coal up to 60% load factor (1987 prices, and US$2/BTU million for gas) whereas at 1995 prices and gas at US$2/BTU million, gas is cheaper than coal up to 90% load factor.

(d) Power plant conversion - central Chile: coal-to-gas conversion is not likely to be attractive for existing steam plant. The coal price would need to rise to US$70/M.T. with a gas price of US$2/BTU million or alternatively, the gas price should drop to US$1.45/BTU million with a US$50/M.T. coal price, to achieve a payback within ten years. However, a 50% reduction in capital cost in the latter case would shorten the payback period of the conversion to 3.5 years. In contrast, fuel oil-to-gas conversion appears feasible at current price levels and even more so at 1995 energy prices. At a gas price of US$2/BTU million and the 1987 fuel oil price (US$100/M.T.), the payback would be within four years. Assuming a fuel oil price of US$115/M.T. by 1995, the payback would be within 1.5 years. With US$100/ton fuel oil, the maximum gas price would be US$2.10/BTU million for a payback in ten years.

(e) Boiler conversions: coal-to-gas conversions are not feasible regardless of boiler size at a gas price above US$1.-/BTU million. In contrast, fuel oil-to-gas conversion for both medium-sized and large-sized boilers is feasible for gas prices in the range of US$2-2.20/BTU million and the cost of fuel oil at US$115/M.T.

15/ At a 70% load factor, the cost per kWh sent out would be US¢3.5 for combined cycle plant compared to US¢6.5/kWh for coal-fired steam plant and US¢6.7/kWh for fuel oil-fired steam plant. The advantage of combined cycle plant results from high thermal efficiency and relatively low capital cost per installed kW.

Conclusions and Recommendations

2.27 The results of this analysis have important implications for the efficiency of energy supply and end-use in the economy. To evaluate the specific requirements related to the optimal energy mix for the various sectors, more detailed studies of the economic costs of different energy forms need to be carried out and be continuously updated. This should include a careful evaluation of externalities related to the use of different forms of energy, especially their environmental impact.

III. ISSUES IN THE HYDROCARBONS SUBSECTOR

Introduction

3.1 Crude oil and natural gas resources are almost entirely located in Magallanes, far from energy consumption centers. Crude oil was discovered in Magallanes in 1945 but since 1983, proven reserves and production have been dwindling and are approaching the final stages of depletion. The degree of crude self-sufficiency, presently about 33%, thus may fall to about 5-10% by 1995. Also, crude production is becoming increasingly expensive as reservoirs are being depleted. A major issue therefore is determining the most economic level and rate at which the remaining high-cost oil should be produced, particularly in the present environment of international price volatility, which has a direct bearing on the size of ENAP's future operations.

3.2 The Government actively pursues a policy of attracting foreign oil companies to explore in Chile. All previously reserved areas in Magallanes have been opened up except for the producing Springhill area, and new risk association contracts have been offered. Although the coastal basins have been open to international exploration for a number of years, and some companies were exploring at one stage, no foreign companies are active there at present. Also, the industry's response to offering exploration areas in Magallanes thus far has been moderate but the Salar de Atacama area in the North has attracted interest by a number of companies. ENAP plans to explore in frontier areas on its own if foreign investment is not forthcoming, and also envisages exploration and development ventures outside Chile. The key issue is (a) whether ENAP should go ahead with costly and risky exploration in domestic frontier areas even in the absence of foreign participation, and (b) what should be the level and nature of its new thrust into international operations.

3.3 Natural gas in Magallanes, which habitually has been reinjected in large quantities or flared, is planned to be sold to private companies for production of methanol and ammonia/urea. These ventures are based on the assumption that gas in Magallanes has very low production cost and low opportunity cost in view of the absence of readily available options for transporting gas to Chile's major energy consumption centers. A number of other options exist to supply gas to the Santiago Metropolitan region, including importation from Argentina, and the development of offshore deposits near Valdivia, and, possibly, the development of any deposits to be found in the Salar de Atacama, but the viability of these options depends on providing gas to industrial consumers at less than US$3.50/BTU million. For petroleum refining, the economic viability of alternatives to meet supply-demand imbalances needs to be evaluated comprehensively and in more detail.

Alternative Production Strategies for Declining Crude Oil Reserves

Reserves and Production Declines

3.4 Despite extensive field development, crude oil production has declined from its peak in 1982 (2.5 million m^3) at 7.5% p.a., to reach 1.74 million m^3 in 1987. Proven reserves of crude oil remaining at end-1986 were less than 10 million m^3, indicating that production from existing reserves will cease within 12-15 years. The frontier areas outside the Magallanes Springhill district -- where no crude oil has yet been discovered -- are estimated to hold about 17 million m^3 of probable and possible reserves, with a large probability of lower and a small probability of higher reserves. Even under optimistic assumptions regarding reserve additions from areas where no commercial deposits have as yet been discovered, incremental production would not be sufficient to stabilize the decline rate which thus is projected to sharply accelerate from the early 1990s onwards.

Table 3.1: PRODUCTION AND IMPORTS OF CRUDE OIL AND PETROLEUM PRODUCTS, 1985-87 AND 1988 (PROJECTED)
(m^3'000)

	1985	1986	1987	Projected 1988
Production				
Crude Oil	1,924	1,798	1,593	
Natural Gasoline	150	142	143	
LPG	428	432	439	
Total	2,502	2,322	2,175	1,920
Imports				
Crude Petroleum	2,406	3,035	3,129	
Petroleum Products	389	667	290	
Total	2,795	3,702	3,419	3,900
Re-exports	-	-	32	
Degree of Petroleum Self-sufficiency	47%	39%	39%	33%

Source: CNE; ENAP.

3.5 ENAP in 1985-86 was seemingly able to stabilize crude oil reserves by developing relatively low-cost onshore rather than the more expensive offshore deposits, but reserves continued to fall in 1987. While low-cost development of onshore deposits represents the fastest way to sustain production and revenue, the onshore reserves remaining are

less than 20% of offshore reserves, i.e. 1.1 vs. 5.8 million m^3. Nearly two-thirds of output is already provided from offshore. The potential for low-cost reserve development is small and future additions to reserves will be increasingly costly since they must be derived largely from offshore, hitherto undeveloped deposits.

3.6 The decline in crude production coupled with rising domestic demand for consumption and inventory accumulation led to a 31% rise in imports of crude oil and petroleum products in 1986. However, the impact of increased import volumes on the balance of payments was mitigated by the decline in international petroleum prices in that year. Following a decline of about 9% (in volume terms) in 1987, petroleum imports have started to increase again in 1988.

Table 3.2: PROJECTED CRUDE OIL AND CONDENSATES PRODUCTION FROM THE SPRINGHILL AREA ('000 m^3)

Year	From Existing Wells	From New Wells a/		Total	Standard Deviation
		Onshore	Offshore		
1987	1,333	70	319	1,721	(19)
1990	330	199	791	1,321	(231)
1996	94	57	60	211	(45)

a/ For exploration and development.

Source: ENAP.

Planned Production From Undeveloped Reserves

3.7 ENAP has prepared production plans for crude and condensates from both developed and undeveloped reserves, through the year 2000. They are predicated on the assumption that remaining reserves will be produced at the "maximum efficient rate", implying a decline rate of 8.5% p.a. during 1987-90 and of 26% p.a. during 1991-96.

3.8 There are three different crude production streams, i.e. from existing wells, new onshore wells, and new offshore wells. For existing wells, production costs are low, typically less than US$5/bbl, because there are only operating costs and hardly any investment is needed beyond major maintenance and well work-over. However, output from these wells is projected to decline rapidly, at about 30% p.a. over the next ten years. To compensate for this decline, ENAP envisage that large-scale investments are necessary (US$430 million in the next 5 years alone) to develop production from new wells, both onshore and offshore. This is a tentative estimate with decisions to be made step-by-step.

3.9 Offshore Development. The largest portion of this investment, about US$360 million, is for developing offshore deposits. Offshore wells are projected to achieve their peak around 1989 at 0.89 million m^3 of crude and condensate (or 15,000 B/D). However, also this production stream would decline sharply to 0.14 million m^3 (2,400 B/D) by 1995. Production would be relatively high-cost: over the field production life estimated at 10-14 years, average incremental costs are calculated at US$16.50/bbl, of which about US$2.50/bbl is operating cost (1986 prices and exchange rates). This average cost may exceed international petroleum prices in some years, although the marginal cost of crude from some reservoirs is likely to be lower. However, the marginal cost is expected to increase sharply especially once cumulative offshore production exceeds 3-4 million m^3 for offshore and 1 million m^3 for onshore, respectively.

3.10 Onshore Development. The output from new onshore wells is planned to peak shortly after 1990 at 0.28 million m^3 (4,700 B/D), after which also this production stream would decline sharply. Associated investment is projected to total about US$70 million in the next five years, for an average incremental cost of production approximating US$13/bbl. 16/

3.11 Project Evaluation Methodology. ENAP uses a sophisticated production optimization model to evaluate rates of return for hydrocarbon development, which is of particular relevance in situations when marginal costs of productions are close to the international crude price. The internal rates of return and net present values are calculated based on individual reservoirs and wells (onshore) and individual platforms (offshore). This analysis indicates high returns for onshore crude oil development and offshore crude oil and gas development. Investment decisions are based on marginal cost of production. ENAP's project analysis is appropriate but could be further improved through the following refinements:

(a) The application of marginal cost analysis for individual fields/platforms should be further refined. This would make it clear that some reservoirs (or producing units) may have high marginal cost and that their development should be postponed or ruled out. However, this analysis might be difficult if reservoirs are "sandwiched" and/or use common facilities.

(b) There should be an analysis of the depletion rate at which the net present value -- based on marginal cost -- is maximized. International experience in managing high-cost reservoirs has

---

16/ See Annex 9 for a breakdown of investment and resulting production as projected by ENAP. The cost of LPG extraction is included in the calculations as this is a by-product of gas compression required to maintain reservoir pressure for crude production.

shown that optimal economic depletion may occur at a much slower than the maximum technical rate. 17/ Through reducing costs more than benefits, the net present value would be maximized at lower production levels. This approach should be tested to see if slower depletion may be optimal for some of the larger fields.

(c) There should be a clear separation of investment for crude production and for production of natural gas as petrochemical feedstock. If planned expenditures are to result in gas production only, they should be allocated to the cost of producing gas, not oil.

(d) The analysis should incorporate the assumption of equipment reuse to the feasible extent (which could possibly lower investment costs by at least 10-15%).

3.12 The above refinements are important because (a) the marginal production cost should not exceed the costs of petroleum imports or of other substitutable energy sources; (b) the optimal economic depletion might be lower than planned depletion; and (c) in the Chilean context, investment should be geared to optimal development and production of crude whereas gas as a byproduct is of lesser significance as energy source. The marginal production cost of crude oil can be reduced through (a) producing only those reservoirs in "core properties" whose cost are lowest, and/or (b) slowing down the composite depletion rate. However, the question of which reservoirs to produce, and how fast to produce them are inter-related. At the one extreme, a strategy of producing all, or nearly all, of the reservoirs at the fastest possible rate is likely to lead to high marginal cost of production. In contrast, producing all reservoirs at a slower rate may increase the net present value to the extent that marginal costs will be reduced more than marginal benefits. Nevertheless, during the final stages of depletion, the marginal costs need to be carefully evaluated because per-barrel production costs then are bound to rise sharply.

3.13 Risk Considerations. Planning petroleum operations contains an unusually high degree of risk, both in regard to technical (i.e. production) and cost/price risks. Standard deviations based on ENAP's offshore production data indicate a one-third probability that crude and condensate production will be just three-quarters of the planned level. On a conservative basis, the average incremental cost of offshore oil could be above US$21/bbl.

3.14 Price risk is particularly significant in planning high-cost production, given the degree of volatility in international petroleum prices in recent years. According to World Bank projections, a supply

---

17/ See Annex 10 for details of the methodology to determine this rate.

overhang will likely result in relatively low petroleum prices during the late 1980s but these prices would increase significantly after 1992 into the mid-and late 1990s. There is, therefore, a distinct possibility that ENAP's marginal production cost exceed international petroleum prices in the 1989-91 period (when production of high-cost crude from new offshore wells is projected to peak). Rules of thumb in the oil industry are that an internal rate of return of at least 15% should be achieved on the low production/low price forecast. To the extent that ENAP's production costs for some offshore schemes are above US$20/bbl -- i.e. substantially above conservative price forecasts of, say, US$15/bbl -- these schemes would be unviable under those conditions. However, it is of particular concern that the decline in Chile's crude production may gather momentum after 1992 precisely at the time when increases in international petroleum prices are projected to accelerate also.

3.15 This reinforces the conclusion that an appropriate strategy of producing crude would be to limit development to the least-cost "core properties" and deplete these properties at the optimal rate. The remaining properties could be produced in later years (when international petroleum prices are projected to be higher) or be offered to private investors under exploitation contracts. Especially the latter appraoch would provide significant benefits to the public sector by reducing expenditures for field development and shifting part of the price and production risk to the private sector. The "core properties" should be defined based on conservative forecasts of international petroleum prices and of domestic crude production, so as to minimize risk and avoid producing excessively high-cost oil.

3.16 In the short run, lower depletion will have a positive effect on ENAP's investment requirements but through increasing petroleum import requirements, it may affect negatively the balance of payments. Therefore, in addition to a conventional rate of return analysis, a detailed evaluation of optimal depletion is needed, based on marginal production cost by reservoir and production and price risk, to define the appropriate depletion profile. In deciding on a production strategy, a high premium should be placed on operational flexibility especially in regard to the cost structure, in order to respond quickly to changes in prices and other crucial parameters.

Prospects for Secondary and Enhanced Recovery

3.17 In addition to primary production, crude oil can be produced through secondary recovery (water and/or gas injection) or enhanced recovery, depending on the geology and reservoir behavior. While no detailed information was provided, ENAP consider the prospects for producing additional oil reserves through secondary recovery in the Springhill district to be non-economic in six out of the eight largest

fields because of insufficient remaining reserves and other technical factors. 18/

3.18 Both CNE and ENAP envisage secondary recovery as a prime area for private service contractors, following the Argentine model, in particular for relatively small fields. Two portions of Springhill are planned to be opened to private service contractors to test their suitability for secondary recovery. Nevertheless, a firm conclusion on the attendant potential cannot be made on the limited information provided. Therefore, it is recommended to complete an independent review of this potential before ENAP take firm investment and production decisions. In the meantime, efforts aimed at commissioning private contractors to produce primary and secondary oil under exploitation contracts inside and outside the "core properties" should be pursued, possibly through joint ventures with ENAP, given the need to attract additional capital and technological resources (new production concepts etc.) for these complex operations.

Petroleum Exploration Strategy

Hydrocarbon Potential

3.19 General. Favorable geologic conditions for hydrocarbon formation are limited to the Magallanes region east of the Andes, essentially the Springhill District which is the only part of the country where crude oil and natural gas has been found in commercial quantities. More than 90 oil, gas, and condensate fields have been developed in Magallanes since the mid-1940s. Most of the "easy discoveries" appear to have been made, leaving only relatively high-risk areas unexplored. Thus, future hydrocarbon exploration and production will likely be more costly and higher-risk than in the past.

3.20 Two groups of basins comprise the frontier areas where hydrocarbons might be discovered, i.e. Magallanes outside the producing Springhill District, and the Pacific coast. Most of the Pacific coast is not prospective for crude and only marginally favorable for natural gas. Nevertheless, a number of prerequisites for hydrocarbon accumulations are present in both basins. Adequate structures for trapping hydrocarbons as well as sedimentary sequences sufficiently thick for oil and gas development exist along the entire coast. The problem lies in identifying the right kind of sediments, and this should be the

---

18/ ENAP studied eight of the largest oil fields in the Springhill district to determine their susceptibility to secondary recovery. Of these, only the Calafante and Catalina fields are considered candidates for secondary recovery, as represented in the operating plan.

focus of Chile's exploration effort. Noncommercial accumulations of natural gas have been found offshore Valdivia, which is important in that it confirms that hydrocarbon source materials do exist, at least to some extent, in that area.

3.21 Given the extension of the sedimentary basins and the past concentration of the exploration effort on Magallanes, Chile clearly is underexplored. Of ENAP's 1980-84 exploration expenditures totalling US$164 million (for 23,000 km of seismic lines and 15% exploratory wells) 70% were allocated to the Magallanes Basin, with 90% of exploratory drilling in the Magallanes Straits area. In the rest of the country, within a period of approximately 30 years, only about 100 exploration wells have been drilled, and only 18 offshore wells along the 3,500-mile-long continental shelf. 19/ 1,200 miles of the southern shelf and 1,000 miles of the northern shelf are totally undrilled. ENAP in 1987 finished 14 exploration wells (of which ten were dry), exclusively in Magallanes. However, ENAP envisage substantial exploration and development expenditures in frontier areas, tentatively in the order of US$80 million in 1988-91 and up to US$380 million in 1992-96 (1986 prices and exchange rates), although a large part of this may in fact be carried out by outside companies associated with ENAP.

3.22 Magallanes Basin. The mature producing Springhill district in the eastern part has been thoroughly explored, and there appear to be few prospects of finding significant further oil reserves. Half of the prospects lie below 2,500 m depth so that the general expectation is predominantly for gas accumulations of reduced size. 20/ In the western part of Magallanes, which has been much less explored, three exploration objectives are present, i.e. (a) the Western Springhill, (b) the Tertiary District, and (c) the Pre-Cordillera (Foothills) District. In Western Springhill, target exploration objectives consistently occur at depths greater than 2,500 m. In the Tertiary District, multiple reservoirs of lower and upper tertiary age occur. Thus far, 89 wells have been drilled, resulting in eight discoveries totalling 50 BCF of dry gas and 7 million bbl of condensate. Additional gas reserves of 80 BCF have been estimated, and there is a high probability that gas rather than crude oil will be discovered. This is not considered a desirable exploration objective in view of market constraints (para 3.39). ENAP has included exploration expenditure for this area for the early period of its plan. The likelihood of this expenditure going ahead depends on favorable indications from geophysical surveys.

19/ Of these wells, 14 were drilled by ENAP, three by Atlantic Richfield (including the Valdivia offshore gas field) and one by Phillips. Total depth drilled was 36,500 meters.

20/ There is a relatively high geothermal gradient in the Magallanes Straits (5 degrees centigrade per 100 m.). The warmer the medium, the more likely it is that hydrocarbon deposits are gasiferous.

3.23 Pre-Cordillera District. This is an untested and complex area with the presence of large folded and faulted anticlinal structures that could provide traps for significant oil accumulations. Thirteen exploration wells drilled in this area proved up only minor oil shows. The main deficiency has been the lack of porous and permeable reservoir rocks within the structures. Technical problems are considerable in structural provinces of this nature. Given that this area holds several large structures, 21/ exploration carried out thus far falls short of what is needed for a thorough evaluation of the potential. ENAP consider that about 50 exploration wells and in case of discoveries, 100 development wells should be drilled in that area between 1989 and 2000, with the emphasis on the northern Ultima Esperanza sector. Obviously, any production after 1991 will depend on the outcome of the exploration effort. (Two other foothill areas, Central and Tierra del Fuego, are equally oil prospective, but are not included in ENAP's exploration program because of their structural complexity and difficult operating conditions.)

3.24 Pacific Coast. This area includes numerous offshore, onshore and intra-montain sedimentary basins. For the most part, geologic conditions are not favorable for oil accumulations and only marginally favorable for natural gas. However, the Jurassic Norte Grande Basin (which may be an extension of the Argentine Cuyana Basin) contains geologic criteria that should favor oil formation. Although nine exploration wells have been drilled without significant shows, ENAP consider an extensive drilling program in this area appropriate, consisting of 37 exploration wells and 87 development wells to be drilled during 1989-2000. The expected results of this drilling, and that in Ultima Esperanza, are to account for 75% of crude production expected for the second half of the plan period. These are very optimistic projections for two areas that have had no exploration success to-date. The Arauco-Valdivia offshore basin might hold a favorable potential but is primarily gas-prone.

Domestic Exploration Strategy

3.25 In response to declining crude oil production, the Government has aimed at accelerating exploration and reserve accumulation domestically, and more recently, at initiating a thrust to explore and develop deposits outside Chile. The Government is aware that it cannot command the substantial resources required to mount an adequate exploration effort, and that the participation of outside companies is therefore needed. The Government in 1981 opened all hydrocarbon-prospective areas, except the Magallanes Basin, to outside companies for exploration and exploitation under Petroleum Operations Contracts (Risk Contracts). The Magallanes Basin then remained reserved for ENAP. The Government in 1986 also opened up all prospective areas in the Magallanes

---

21/ The Parillar-1 structure covers an area of 70 km^2; the Vicuna-Cabo Nariz structure, 600 km^2.

region. Areas offered to date to risk contracts total 276,000 sq. km (Magallanes, 53,000 sq. km; prospective areas with improved geological information, 79,000 sq.km; other areas, 144,000 sq.km.).

3.26 Exploration and exploitation of hydrocarbon resources in Chile require risk contracts between companies and the State and in the case of activities in Magallanes, additional association contracts between outside companies and ENAP. In areas outside Magallanes, the contractors are at liberty to decide to associate with ENAP in exploration or exploitation programs. The regulations of the petroleum law and model contract governing work commitments, production sharing, valuation of output, taxation, and foreign exchange matters are at least as favorable as in other countries in the Region, and offer considerable flexibility. It is indeed important to offer conditions to international companies that allow Chile to compete successfully with other oil producing countries for scarce exploration funds. This is especially so in view of the highly speculative and costly nature of exploration in Chile's frontier areas, the relatively unfavorable geology which might limit the chances for discovering crude in significant quantities, the complex technological requirements, and the moderate success thus far in attracting foreign petroleum companies to Chile.

3.27 While the Government has engaged its best efforts to attract investment in exploration by international companies, the response thus far has been relatively slow in coming. This may have been because of the timing of these offers which coincided with the fall in international petroleum prices in 1986 and a cutback in exploration world-wide. Especially the Pacific Basin is considered high-risk and expensive to evaluate, and the limited exploration to date in that area has not produced any significant results. Although foreign companies have shown interest in the Magallanes area, and the coastal basins have been open for years to foreign investors, at present no foreign companies are exploring in Chile. However, in early 1988, two companis were negotiating risk contracts for exploration acreage in the Salar de Atacama, and a number of others have acquired the technical information.

3.28 Should there be no or not sufficient foreign investment, ENAP plans to carry out some exploration in frontier areas and field development in case of commercial discoveries. Based on probabilistic estimates of oil discovery and development, ENAP estimates its investment expenditures for exploration and development to total US$430 million during 1987-1996, which are expected to result in a production of 0.7 million m^3 p.a. of crude by 1996 (±0.4 million m^3). ENAP plans to approach any investment incrementally, with continuous review of plans based on new information.

3.29 Evaluation of Exploration Strategy. In general, lack of interest by foreign companies may be attributable to one of the following factors: (a) the most prospective areas have not been offered; (b) contract terms are unattractive; (c) the hydrocarbon-related geology is comparatively poor, and/or exploration is technically difficult; and

(d) petroleum price prospects are unfavorable. In the case of Chile, it appears that reasons (a) and (b) are not a problem but reasons (c) and (d) explain the lack of oil company interest.

3.30 Therefore, ENAP need to reassess their plans to go ahead with costly and risky exploration in frontier areas, in the absence of foreign investment. Exploration of frontier areas and evaluation of results almost always are technically difficult and foreign oil company expertise and financial back-up is required. Instead of large-scale capital expenditures solely by ENAP, the Government's and ENAP's priority should be to improve the information base and promote these areas to attract foreign companies. All feasible options should be pursued including joint exploration ventures with ENAP. Opening up the remaining Magallanes areas hitherto reserved for ENAP, possibly on condition of exploring other areas as well, might help to stimulate interest by outside investors. Even though ENAP has sufficient expertise and experience to explore and develop the few remaining prospects, opening up the hitherto reserved areas to outside companies would stimulate know-how transfer and application of new technical concepts, with long-term benefits for petroleum operations overall.

3.31 Certain clauses pertaining to taxation (i.e. the possibility of choice between corporate income tax and a fixed levy on gross revenues; provision for tax rebates) might need to be clarified to ensure the eligibility of U.S. based companies for the U.S. overseas tax credit. 22/ This is recognized by the Government, and the contract framework offers sufficient flexibility to resolve any possible ambiguities, in consultation with the affected companies. Also, there are special provisions with regard to production sharing for natural gas. Eliminating the mandatory association with ENAP in Magallanes probably would help to attract additional investor's interest.

3.32 Exploration Promotion Needs. The prevailing perception among international oil companies is that prospects for significant petroleum discoveries in Chile are relatively poor. It will be a major challenge to convince these companies to invest significant portions of their exploration budgets in Chile. To achieve this, a strong technical case needs to be made that good prospects do exist in the areas being offered. Indeed, in the view of some exploration specialists, several complex and relatively untested exploration plays hold good hydrocarbon potential. However, few international companies command the necessary technology, experience, and financial resources to undertake specialized

---

22/ In order for a tax to meet U.S. Internal Revenue Service criteria for creditability against U.S. income tax, it needs to (a) be levied on income, not gross revenue (in which case it would be treated as a -- non-creditable -- royalty; (b) be generally applicable, i.e. not be industry- or company-specific; and (c) remain unchanged during the period of its application.

exploration of this type. It is therefore recommended that exploration promotion focuses on these plays, and on companies capable to undertake the required specialized exploration. The promoted areas should be given broader international coverage than they have received to-date. To the extent that specialized advice for organizing this complex type of exploration promotion is needed, ENAP and the Government at large should be prepared to actively seek it.

3.33 Price Uncertainty. The fall in international petroleum prices in 1986 and subsequent price uncertainty has contributed to the lack of company interest in exploring in Chile. Prior to 1986, major oil companies were interested in operating in Magallanes but these areas were not open to foreign investors at that time. Since then there has been a major reduction in the companies' exploration budgets particularly for marginal and complex basins like those in Chile. This price uncertainty makes an adequate legal framework for hydrocarbon operations and a strong promotional effort even more important, supplemented by relatively low-cost efforts to improve the information base. Any decision on large-scale investment by ENAP to explore risky and complex frontier areas should be deferred until a clearer picture on price prospects and on the involvement of outside companies emerges.

International Exploration Strategy

3.34 In view of the limited hydrocarbon potential domestically, ENAP is interested in forming joint ventures for oil exploration and/or purchase of reserves outside Chile, with special focus on prospects in other Latin American countries. Two projects are under consideration.

3.35 ENAP has discussed with YPF of Argentina and Petrobras the possibility to jointly operate in the Argentine Magallanes offshore a field holding recoverable reserves of 20-30 million bbls of recoverable crude and 5 billion m^3 of natural gas, and has recently submitted a proposal to YPF. 23/ ENAP's share of this oil could amount to 8-10 million bbls. If the field can be developed and produced economically, there probably is no other reserve addition available to ENAP outside Springhill at such a low risk. However, the Argentine Government has yet to give the go-ahead for this arrangement. A second international project -- less advanced than the former -- involves a joint exploration venture with PetroCanada and the state oil company of Uruguay in the Ecuadorian Oriente where a certain portion of exploration acreage has been set aside by the Government of Ecuador for state-owned oil

---

23/ Petroleum Intelligence Weekly, July 11, 1988. The field was discovered by Shell Oil Co. which considered it to be marginal and which elected not to develop it, so the field reverted to the State. Since the discovery is within 12 km of ENAP's own operating area, the economics for ENAP are more favorable than for Shell, which has no operations in the area.

companies. 24/ The contract calls for a seismic option followed by a two-well work program in the range of US$10-20 million. The block in question is near producing fields holding reserves of at least 50 million bbls.

3.36 Evaluation of Foreign Exploration Strategy. The option of acquiring relatively low-cost, low-risk reserves outside Chile, in association with international companies, may indeed be superior to high-risk, low-return exploration ventures in the country. However, it needs to be established that production, or earnings from production, can be freely transferred to Chile under acceptable conditions (e.g. in the case of countries that are net importers of petroleum, such as Argentina.)

3.37 An international exploration strategy also involves a number of institutional issues. ENAP as a domestic company has little international expertise, notwithstanding its recent exposure to foreign firms in the context of negotiating association contracts for ventures in Chile. To be successful internationally, ENAP has yet to develop the capability to generate and exploit exploration prospects abroad, negotiate agreements with international companies and foreign governments, and operate on international markets. Without it, ENAP would always depend on someone else's venture, operated by others, for which it will have to pay a premium and receive a relatively minor share. The international strategy also raises the issue as to which extent ENAP as a government-owned company should spend public funds on foreign ventures. An alternative to ENAP's direct involvement would be to set up a privately owned or mixed company to attract domestic private capital to international petroleum operations (even though up to now, national private firms have not indicated much interest in petroleum exploration, domestic as well as foreign). The purpose of exploration abroad, from a national perspective, is to ensure future petroleum supplies in the event of international shortages. Therefore, a private or mixed company would need to be structured in such a way that (a) the domestic private sector considers it a worthwhile investment, and (b) the benefits of international operations return to the national economy and not escape through leakages. Otherwise, the benefits of this international strategy would be lost.

3.38 Provided a satisfactory solution to these issues is found, the international strategy provides an excellent vehicle to develop a private oil sector in Chile, which is an important Government objective. However, the petroleum-related expertise in the country resides entirely in ENAP. It needs to be determined how this expertise can be transferred to the private sector, and how a privately-owned petroleum industry can be developed. One option would be to follow the Argentine experience by opening up service opportunities to the private sector, e.g. in

---

24/ PetroCanada, the original bidder, has obtained permission to bring in partners.

Springhill, although there may be only few adequate opportunities remaining in producing areas. An international strategy as a means of securing and augmenting the country's future oil supply, whether by ENAP or private companies, is a worthwhile effort and should be encouraged. How this strategy can be best pursued to the maximum benefit of the national economy still requires considerable analysis and strategic planning.

Conclusion and Recommendations

3.39 The sector strategy aimed at reducing expenditures and risk for both the Government and ENAP in hydrocarbon exploration and production is appropriate and should be maintained. Such a strategy should emphasize the following elements:

(a) Production: The near-term development and production of remaining oil reserves should be limited to the lowest-cost "core properties". Properties should be offered to private sector operators under service contracts, along with areas which may have secondary recovery potential.

(b) Domestic Exploration: A sustained promotion effort should be carried out to attract those foreign companies which have the required technical expertise and financial resources to explore technically difficult and complex geologic areas. This should be supplemented by low-cost efforts by ENAP to improve the relevant information base. While it may be appropriate for ENAP to carry out a limited amount of exploration drilling, the entity should avoid large-scale drilling expenditure in complex and risky frontier areas.

(c) International Ventures: The next five years or so may be a uniquely favorable period to acquire a stake in relatively low-cost petroleum reserves abroad. However, clear objectives and guidelines for ENAP are needed regarding the acceptable type and degree of risk and the size of the investment. ENAP's ability to assess international opportunities should be improved, particularly options to lower the risk through association with international companies. Options and requirements for involving the domestic private sector in these ventures should be evaluated.

Natural Gas Utilization

Introduction

3.40 Natural gas is produced only in Magallanes. Of the gross output (about 4.35 billion m^3 in 1987, or some 420 million CF/D), nearly three-quarters are reinjected to maintain reservoir pressure, improve oil recovery, and eventually, be utilized again. The remainder is used in

crude production, flared or consumed in the small Punta Arenas market (0.15 billion m^3). Gas flaring has been considerably reduced and amounted in 1986 to 17.6% of output net of reinjection, down from 55% in 1980. 25/

3.41 There are two distinct and geographically separated markets for natural gas, i.e. Magallanes and the industrial centers further north dominated by the Santiago Metropolitan Region (which accounts for three-quarters of potential demand outside Magallanes). In Magallanes, where there are about 30,000 individual customers for natural gas, utilization is constrained by insufficient demand, whereas in the rest of the country supplies are presently unavailable. Natural gas from Magallanes cannot be economically transported to the energy demand centers so the gas is planned to be used locally for new ventures to produce methanol and fertilizer for exports. The Santiago Metropolitan Region would have to be supplied through imports or from deposits offshore Valdivia yet to be more fully explored. The market potential is assumed to be as follows:

Table 3.3: ACTUAL AND POTENTIAL DEMAND FOR NATURAL GAS, 1985; 1990; 1995 (m^3 millions)

		------1990------		------2000------	
Area	1985	Low a/	High b/	Low a/	High b/
Magallanes	150	200	850	200	1,700
Metropolitan Region	100 c/	160	218	282	762
Regions V-X	0	48	82	97	296

a/ GASCO estimate for Santiago Metropolitan Region; for Magallanes without methanol and urea plants; CNE low estimate for Regions V-X (price assumptions of US$17/bbl for crude oil, US$2/BTU millions for Valdivia gas).

b/ For Magallanes, including methanol and ammonia/urea plants; CNE high estimate for Santiago Metropolitan Region and Regions V-X (price assumptions of US$23/bbl for crude oil, US$1/BTU millions for Valdivia gas).

c/ Town gas.

Source: CNE; GASCO; ENAP.

25/ In terms of total output (i.e. prior to reinjection) the reduction in gas flaring was even more substantial, i.e. from 25% to less than 5% during 1980-86.

Natural Gas Utilization in Magallanes

3.42 Two petrochemical projects are being developed by private investors, i.e. a 750,000 tpy methanol plant and a similar-sized ammonia/urea plant. The output of both schemes is almost entirely for exports. The methanol plant is expected to come on stream by end-1988 while the ammonia project is less advanced as financing has yet to be arranged. These schemes, whose gas requirements would total 1.5 billion m^3 p.a., will make use of the area's abundant natural gas resources which otherwise are of little economic value. ENAP will be the seller of the gas, with the major investment in a collection and delivery system. 26/ The cost of this investment amounting to US$22 million is financed in part through a loan from IDB.

3.43 Take-or-pay supply contracts guaranteed by the Government have been concluded between ENAP and the industrial purchasers. These broadly similar contracts are based on a minimum sales price sufficient for ENAP to recover investment and operating costs. The agreed base price covers ENAP's costs of supplying the gas to the plant gate and is then escalated using an index of international inflation. The contract includes a profit/risk sharing clause which is advantageous to ENAP. 27/ On the other hand, ENAP has a firm delivery commitment and the pipeline load factor is deemed to be close to 90% (330 days/year).

3.44 The petrochemical schemes offer a market for natural gas in Magallanes nearly four times its present size and provide export outlets for this resource. While there are no supply constraints, it needs to be ensured that investments to supply gas to petrochemical plants are least-

---

26/ The Cabo Nego Methanol project is implemented by the Henley Group of the U.S. (the ammonia/urea plant would start operating by 1990-1991 at the earliest). Capital costs of the methanol plant approximate US$305 million, of which IFC is providing a US$50 million long-term loan and US$5 million equity capital. ENAP's investment mainly consists of a 18 in, 178 km pipeline, with a capacity of 6 million m^3/d to supply gas to the two petrochemical schemes and to its own fields and oil terminals.

27/ This clause for the methanol plant works as follows: The standard cost of the methanol production is defined between the two parties and is escalated according to the international price index. Differences between agreed standard costs and actual production costs are borne entirely by the methanol producer. The calculated profit from methanol sales (i.e. sales proceeds less standard costs) is divided between ENAP and the plant: for years 1-3, ENAP's share is 33% and thereafter 50%. If the actual sales price exceeds 10% of the projected and escalated sales price, ENAP receives 80% of this excess profit.

cost and viable on their own, irrespective of any associated crude oil (or condensate) development.

Natural Gas Utilization in Central Chile

3.45 The Santiago Metropolitan Region at present receives about 100 million m^3 p.a. of town gas produced from naphtha, LPG, and biogas (25-30%), whose calorific content is about one-half that of natural gas. Based on studies made by CNE and GASCO, a market several times that size might exist provided that prices for natural gas to consumers are competitive.

3.46 Natural Gas Prices and Market Size. The potential market for natural gas is largely determined by relative energy prices, in addition to overall energy demand growth and the technical scope for substitution. In the Metropolitan Region, town gas at present is the most expensive fuel, costing US$9-11/BTU million equivalent. Since there is a limited market for such expensive energy, any additions would have to come from cheaper imports or new domestic production, possibly the Valdivia Area. Evidently, the lower the price of natural gas, the larger would its potential market be, and the higher the crude oil price, the more competitive gas would become. However, even with relatively high projected international petroleum prices (US$23/bbl) and a low cost of gas (US$1/BTU million from Valdivia, for example) the market is estimated by CNE and GASCO to be only 200-300 million m^3 p.a. by 1990 and around 700 million m^3 p.a. by the year 2000. This is equivalent to 0.2-0.3 million toe and 0.7 million toe, respectively or 10-12% of projected energy end-use in the Santiago Metropolitan Region in the latter year.

Table 3.4: COMPARATIVE FUEL PRICES IN THE SANTIAGO METROPOLITAN REGION (February 1987)

Product	Market Price	Equivalent Natural Gas Price	
	(Ch$/10,000 kcal)	(Ch$/$m^3$)	(US$/BTU million equivalent) a/
Towngas, small quantities	89.83	84.90	10.98
Towngas, large quantities	72.00	68.04	8.80
Fixed Monthly Charge	appr Ch$300/month	--	--
LPG	58.31	55.10	7.13
Kerosene	42.70	40.35	5.22
Diesel	55.47	52.42	6.78
No. 5 Fuel Oil	33.82	31.96	4.13
No. 6 Fuel Oil	31.61	29.87	3.86

a/ Conversion rate Ch$206/US$.

Source: Mission estimates.

3.47 Based on GASCO's evaluations, an order-of-magnitude estimate indicates a price of US$2-3.50/BTU million to be required for natural gas to be competitive with coal in major industrial firms, if these are to recover conversion costs over three to five years. Since conversion costs to the plants are high, it will be difficult for natural gas to penetrate the industrial market as a fuel for existing installations (whereas gas-using new installations would be more economic than those using either fuel oil or coal; para. 2.26). The required payback period is short for such a conversion to be profitable (2-4 years), and efficiency advantages from natural gas are few. According to available information, large-scale industrial consumers with a potential for using natural gas are principally in metal refining, cement production, and electricity generation.

Table 3.5: PRELIMINARY ESTIMATES OF COMPETITIVE PRICES FOR NATURAL GAS, VARIOUS INDUSTRIES AND LOCATIONS

Industrial Consumer	Consumption	Distance to Santiago	Approx. Natural Gas Price to Compete
	(m^3 million p.a.)	(km)	(US$/BTU million)
Cemento Polpaico	43	40	1.60
Cemento Melon	54	140	1.60
Chilelectra	80	variable	0.70
ENAMI	50	150	1.70
El Teniente	70	80	3.67

Source: CNE; GASCO; mission estimates.

3.48 Natural Gas Supply Options. There are three possible gas supply options to central Chile, i.e.

(a) production from the offshore Valdivia basin and the Salar de Atacama provided that commercially-sized reserves exist;

(b) imports from Argentina's Neuquen region via the Pino Hachado pass; and

(c) imports from Argentina via the center-west trunk pipeline and the Maipo Valley.

3.49 There are indications that the Valdivia offshore basin might contain gas in commercial quantities. 28/ ENAP and CNE are in the process of evaluating whether detailed exploration and, possibly, field development is justified in view of the likely costs and the market size. In addition to the demand in the Metropolitan area, the market would consist of an estimated one-third of the potential energy demand in the Valdivia-Santiago corridor. While detailed exploration and field development costs are not yet available, those are roughly estimated to be in the US$400-700 million range (for some 70 production wells), in addition to about US$400 million for onshore facilities and a 800 km trunk pipeline. Resulting transmission costs alone might be in the order of US$1.20-1.50/BTU million, assuming investment costs of US$200 million and a 700 million m^3 p.a. throughput.

3.50 Quite apart from its incipient nature, the scheme on is own is not likely to be economically viable from several perspectives. First, any capital costs above US$300 million would be high, in view of projected gas demand and realistic oil price scenarios determining substitution price levels. Second, for the price of natural gas to be competitive with other fuels and for the project to achieve a reasonable return, gas reserves would have to be in the order of 24 billion m^3 (or nearly one trillion CF), to produce 1 billion m^3/year for some 20 years. Such large reserves are not likely to exist. Third, with the expected relatively small reserves and high investment costs for gas production and transmission, the unit cost would be very high.

3.51 The option of importing natural gas from Argentina via the Pino Hachado pass has similarities to the Valdivia offshore scheme inasmuch as the pipeline (110 km in Argentina and 830 km on the Chilean side) would traverse the Temuco-Santiago corridor, thus reaching energy markets south of Santiago. Argentina's natural gas resources are very large and have only recently become more fully accessible. Their marginal opportunity cost is low. If the cost of imported gas does not exceed US$2-3/BTU million, the project is superior to the Valdivia offshore scheme.

3.52 The option of importing natural gas from Argentina via the Maipo Valley appears superior to the Pino Hachado scheme, assuming the same border price. The Maipo Valley scheme requires a less costly pipeline investment, i.e. a 300 km pipeline on the Argentine side (whose cost are in the range of US$45-70 million) and a 150 km pipeline from the border to Santiago, and, possibly, a branch to the El Teniente copper mining and processing center (costing about US$20-30 million). Based on CNE's market assumptions, the Maipo Valley scheme may be marginally economic at a border price of US$2/BTU million (1986 prices and exchange rates). However, based on GASCO's demand projections (which are 20-50%

28/ This basin comprises 25 geologic structures, three of which could contain commercial accumulations of gas. They are located about 50 km offshore, in water depths of 80-140 m.

lower than CNE's), this scheme would be commercial only at a border price in the US$1.30-1.80/BTU million range, with a city-gate price of US$2-2.50/BTU million. It thus appears that gas imports via the Maipo Valley would be an interesting option for the residential/commercial market where natural gas would substitute for higher-priced fuels, i.e. town gas, LPG, and kerosene, but also for thermal power generation and for use at El Teniente, substituting for fuel oil. Supplying natural gas to central Chile might reduce the costs of energy imports by approximately US$50-55 million p.a. by the mid-1990s, compared to US$85-120 million of investment and US$6 million p.a. of operating cost. However, this scheme hinges on a realistic price agreement with Argentina and a contractual framework which reduces the risk to the parties involved to acceptable levels. Discussions have been held between the two Governments on the various possibilities for gas importation but little progress has been made so far. One of the problems is that Argentina is reluctant to export gas at a lower price than it is paying for gas imports from Bolivia. One way to resolve the pricing issue may be through applying a combined base price/profit sharing or netback arrangement.

3.53 As a variation of the Maipo Valley scheme, there might be a medium- to long-term option of adding supplies from future Valdivia offshore production if and when sufficient reserves are proven and the market for natural gas develops. If these conditions were met, a two-stage supply approach could be envisaged: during the first stage, gas would be imported via the Maipo Valley, and during the second stage, these supplies could be supplemented from the Valdivia offshore. This approach would provide some important if unquantifiable benefits, i.e.

(a) developing domestic resources instead of exclusively relying on gas imports may be economically sound provided that the long-term cost of domestic supplies do not exceed those of gas imports;

(b) the decision on when, if at all, to incur the heavy front-end costs of developing offshore gas deposits and constructing the trunk pipeline could be postponed until a clearer picture of the offshore gas resources and of the gas market emerges; and

(c) a domestic supply alternative would improve Chile's bargaining position.

3.54 Gas Swaps with Argentina. As another variation of the importation option, natural gas from Magallanes could be supplied to Argentina and swapped with Argentine supplies to central Chile. The viability of this option would depend on the ultimate reserves and opportunity cost of Magallanes gas, the existence of a market in southern Argentina for Magallanes gas, the transmission costs, and the availability of spare capacity on the Argentine southern trunk pipeline to accomodate sufficiently large volumes of Magallanes gas to make the scheme economic, compared to the cost of straight gas imports from

Argentina. While GASCO has taken the lead in discussions with Gas del Estado of Argentina, ENAP would have an important role to play in this venture. In the past, Argentina has declined this option because (a) there is no spare capacity on the southern trunk pipeline, and (b) there is no market in Argentina for dry or liquids-stripped gas from Magallanes (Argentina requires rich gas especially ethane for use at its Bahia Blanca petrochemical complex). These obstacles could be removed to the extent that the pipeline capacity is increased and Chile agrees to exporting gas rich in liquids to Argentina. 29/

3.55 Salar de Atacama Potential. Seismic results in that area about 1,000 km north of Santiago indicate the existence of important structures, which will be the object of forthcoming exploration by foreign companies. Any commercial gas deposits could be used either in central Chile for markets indicated above and in combination with gas imports, or in the northern mining centers both for mineral processing and power generation. No detailed evaluations can be undertaken before more is known about that area's gas potential.

3.56 Recommendations. In view of the complexity and wide-ranging importance of the related issues, it is recommended that (a) existing studies on optimizing natural gas supplies and utilization in central Chile be reviewed, based on updated market evaluations and exploration results for the Valdivia and Salar de Atacama basins; and (b) provided that the results of these updated evaluations make this advisable, agreements with Argentina on joint projects be pursued as a matter of high priority.

Petroleum Refining

Introduction

3.57 Changes in petroleum product demand towards enlarging the share of middle distillates and a declining share of fuel oil have required technical modifications in ENAP's two refineries located at Concon and Concepcion, primarily to produce more diesel from fuel oil (secondary processing). These modifications were made during 1984-87 by (a) adding a 10,000 B/D visbreaker to the Concon refinery to convert fuel oil, and (b) modernizing a visbreaker and fluid catalytic cracking units at the Concepcion refinery. The costs of these modifications were about US$25 million (US$14.5 million at Concon; US$9.5 million at Concepcion) of which US$8 million were financed by IDB.

29/ There also is interest in Chile to acquire LPG (which is in short supply) from Argentina's Neuquen Province, in exchange for natural gas rich in ethane. The feasibility of this scheme would depend on options to transport LPG economically to and within Chile.

3.58 ENAP consider that the present technical configuration of their refineries continues to impose rigidities. This is because the output of middle distillates remains less than demand and fuel oil is produced in excess of domestic requirements, making it necessary to either (a) reduce overall refinery output to a level in line with the limited domestic requirements for fuel oil, or increase output to meet domestic demand of middle distillates and export gasoline and fuel oil surpluses at distress prices, typically US$2/B below Caribbean f.o.b. prices. The most immediate investment under consideration is a mild hydrocracker at Concon, whose cost is estimated by ENAP at about US$21-23 million. A preliminary analysis has been carried out on an investment in a delayed coker at Concepcion, estimated to cost about US$45 million, to convert fuel oil into petroleum coke for use in the iron and steel industry. According to ENAP, the justification for the investments is (a) the impending shortage of middle distillates, especially diesel, and the expected increase in prices of light relative to heavy crudes on international markets, both of which would be countered by the operation of a hydrocracker; (b) the excess of fuel oil, which could be reduced if not eliminated with the operation of a delayed coker; and (c) the requirement to improve product quality to meet higher environmental standards, such as for lead-free gasoline and low-sulphur diesel. The hydrocracker also would provide high-quality feedstock for the catalytic cracker. Apart from technical modifications, the Government is considering a proposal to privatize the two refineries, which would add an important element for the investment decision making.

Table 3.6: PETROLEUM REFINING CONFIGURATION, 1986
(B'000/D)

	Primary Distillation	Visbreaking	Fluid Catalytic Cracking
Concepcion Refinery			
Existing Capacity	72.0	8.5	12.0
Capacity Utilization	52%	74%	96%
Capacity after Conversion Program	n.a.	8.5	18.2
Concon Refinery			
Existing Capacity	66.0	10.0	20.0
Capacity Utilization	52%	n.a.	n.a.
Capacity after Conversion Program	n.a.	10.0	20.0

Source: ENAP

Hydrocracker Option

3.59 The question at this point is whether further investment in conversion facilities is justified or whether the changing pattern of demand can be met more economically through increases in refinery throughput, changes in the refinery input mix through increasing the use of lighter or spiked crudes, importation of petroleum products in short supply, or a combination of the aforementioned options. There are a number of ways to improve the supply-demand balance for petroleum products. ENAP can maintain existing refining capacity and import products that cannot be produced economically, or add a mild hydrocracker and/or a delayed coker and import products that still cannot be produced economically.

3.60 Initial Analysis. The determinants of the viability of the mild hydrocracker are (a) availability of domestically produced crude; (b) availability and prices of gas oil spike; (c) price differentials between light and heavy crudes; (d) price differentials between crude and petroleum products, in particular diesel and LPG; and (e) prices for petroleum products in excess supply in Chile, i.e. gasoline and fuel oil. ENAP analyzed each alternative listed above using a linear programming model to maximize the joint benefits from the Concon and Concepcion refineries subject to a number of constraints (paras 3.61-3.62). The model determined the type and amount of products that should be produced at Concon and Concepcion to maximize joint benefits in the years 1990, 1995, 2000, and 2005. Demand projections were based on projected consumer prices and various GDP growth scenarios. ENAP then calculated both the economic and financial net present values of each alternative based on its investment cost and the incremental net benefits. The benefit and gross profit flows are identical in the economic analysis, adjusted by shadow-pricing of foreign exchange. The result of this analysis was that for the proposed project, the option consisting of the mild hydrocracker at Concon combined with an additional vacuum unit at Concepcion had the highest net present value (Table 3.7). Concon emerged as the superior location for the mild hydrocracker because (a) it is slightly closer to the principal crude sources, i.e. imports, so its cost of raw materials is slightly lower; (b) it is closer to the major markets, so transport costs are lower; and (c) it has a larger guaranteed supply of hydrogen and thus, can support a somewhat larger plant. 30/ Should the hydrocracker be installed in Concepcion and no vacuum unit be added, the hydrocracker would compete with the catalytic cracker for gas oil feedstock, and neither could operate at capacity. It is worth noting that ENAP may consider adding a vacuum unit at Concepcion

---

30/ The Concon refinery has a vacuum unit to produce vacuum gas oil to feed its catalytic cracker. In contrast, installing the mild hydrocracker at Concepcion would necessitate the installation of a vacuum unit also, to increase the production of high-quality gas oil feedstock.

even in the absence of a mild hydrocracker as the increased gas oil feed stock to the catalytic cracker would permit increasing the production of premium gasoline and diesel.

3.61 ENAP based this initial analysis on a number of important assumptions. These included:

(a) a decline in indigenous crude (1.3 million m^3 in 1990 and 0.7 million m^3 in 1995) reflecting a perceived lack of success of further exploration; 31/

(b) Chilean crude is to be divided equally between the Concon and Concepcion refineries; 32/

(c) not more than 55% of refinery feedstock may be light crudes (i.e. above 34°API);

(d) only the Concepcion refinery can supply the South, and only the Concon refinery can supply Region V. The two refineries will compete for the Santiago Metropolitan Region and the North;

(e) the refineries must operate at a capacity of at least 40%; and

(f) no exports of refined products are to take place.

3.62 Sensivity Analysis. The above assumptions were bound to have an important effect on the results of the analysis, especially the exclusion of refined products exports and the restriction on the use of light crude. These constraints, which were either policy-induced or related to economic factors such as limitations on exporting surplus

---

31/ This assumption is significant for refining operations since Chilean crude is light and paraffinic and yields more diesel than most imported crudes. It was, however, the direct outcome of ENAP's simulation model for evaluating field development projects. The projection horizon of these models is relatively short (i.e. not more than seven years).

32/ The results of the model indicate that this is not an economically optimal solution since delivery cost of crude from Magallanes to Concepcion would be lower than to Concon. In fact, the assumption of free allocation of national crude would favor the mild hydrocracker option. However, this parameter would become less significant for the results of refining as less domestic crude becomes available over time.

products 33/ made a correct decision on this project difficult. Also the substantial degree of risk of this project, mainly associated with prevailing price volatility, made it advisable that a number of price scenarios were tested. On CNE's suggestion, ENAP in the following modified the analysis to incorporate the assumptions that (a) larger volumes of national crude would be available than originaly assumed, i.e. 0.7 million m^3 in 1995 and 0.5 million m^3 in 2000; (b) the national crude will be used by the refineries in the most economic way without fixed allocation; (c) sales to the Northern-most Region I will take place; (d) limiting supplies from one individual source will be determined in terms of overall petroleum requirements (i.e. crude plus products) instead of crude only; (e) gas oil spike will be available in sufficient quantities and at acceptable prices; and (f) the refineries are allowed to export part of their production 34/ and compete for each other's market.

3.63 To calculate the net present value of the investment, the incremental benefit flows for each project alternative were compared. When exports are permitted, the incremental benefits of the projects decrease substantially, as indicated by the lower net present values and internal rates of return (Table 3.7). However, sales to Region I (which hitherto has met its petroleum product requirements through imports) could allow disposing of most of the surpluses, at prices considerably above those obtainable at international markets. For the export case, Concon would remain the best location for the mild hydrocracker as long as a vacuum tower is installed at Concepcion.

33/ This is because regional surpluses prevail for fuel oil and low-octane gasoline, which are the principal excess products of Chilean refineries. As these products are of relatively inferior quality, ENAP would have to sell these at distress prices.

34/ To estimate the attainable export price, ENAP (a) established the f.o.b. price of each product at Caribbean refineries; (b) discounted that price by 3-10%; (c) deducted the cost of freight, insurance, losses in transport, etc.; and (d) added back the import duty that is levied on ENAP's crude imports. The discount is to reflect quality differentials and the fact that ENAP would not sell a complete product line. For the price differential between light and heavy crude, US$0.15/B/API were assumed. The gas oil spike was valued at 90-95% of the price of diesel. For calculating the net present value of the project, a discount rate of 13% was used to reflect the relatively high risk of the investment.

Table 3.7: NET PRESENT VALUE AND INTERNAL RATES OF RETURN OF ALTERNATIVE PETROLEUM REFINING PROJECTS a/
(1985 US$ millions and Percent)

Project Options	Constraints Binding		Constraints Removed	
	NPV	IRR	NPV	IRR
	(1985 US$ mn)	(%)	(1985 US$ mn)	(%)
Mild Hydrocracker at Concon	14.21	26.3	0.60	13.7
Mild Hydrocracker at Concon and Vacuum Unit at Concepcion	20.32	30.6	12.50	23.2
Mild Hydrocracker and Vacuum Unit at Concepcion	19.77	27.6	8.60	20.4
Vacuum Unit at Concepcion only	5.92	83.2	11.90	-

a/ NPV was calculated with a discount rate of 13%.

Source: ENAP.

3.64 The results of this second-round sensitivity analysis also indicate that even in the exportation case, ENAP's present refining capacity is sufficient to meet domestic demand for all products except LPG without any additional investment. This is because the actual restriction on exporting products prevents the refineries from operating at full capacity and thus, producing diesel at (larger) quantities commensurate with existing capacity. Table 3.8 shows the quantity of exportable surpluses in case diesel production were increased to levels at which the domestic demand for this product can be met. However, in that case, larger volumes of crude would be required than if a mild hydrocracker is installed, and surplus fuel oil would need to be exported at prices below the cost of crude. If no exports were to take place, domestic consumption (plus storage capacity) of fuel oil would limit overall refining operations. In the case of a mild hydrocracker, diesel output would be increased with given crude inputs and the quality of products improved, but capital and operating costs of refining would increase considerably. Also, higher output of diesel would be accompanied by a decline in the output of LPG, which already is in short supply. Assuming that present price relationships continue until the

early 1990s, 35/ it would be economic to postpone the project by one-two years even if the price differentials between light and heavy crudes and between crude and products were to increase afterwards. The comparative costs and benefits of all available options need to be evaluated in more detail, including that of continuing present arrangements (i.e. no exports, meeting supply deficits through imports of petroleum products), to provide an appropriate base case for evaluating the "with" and "without" hydrocracker options, before a final decision on the refining investment options can be made.

Table 3.8: EXPORTABLE SURPLUSES OF REFINED PRODUCTS IF DOMESTIC DEMAND FOR DIESEL IS TO BE MET THROUGH DOMESTIC PRODUCTION (m^3 '000)

Product	1990	2000
Gasoline (93 RON; Leaded)	769.6	688.3
Jet Fuel	3.6	0.0
Fuel Oil (No. 6)	--	1,170.6

Source: ENAP.

3.65 Recommendations on Further Steps. To make the analysis more relevant to the available options, other constraints forming part of the present analysis should be removed or modified. This includes (a) removing the restriction on using light or heavy crudes to the technically feasible extent; and (b) optimizing the refinery input slate, e.g., through increasing the diesel-spiking of crude. (Removing these constraints has direct operational significance as it would result in improving refining efficiency.) Also, there should be agreed assumptions on the future relative price of light vs. heavy crude, which is one of the key parameters for the economic viability of the mild hydrocracker.

3.66 It is therefore recommended that the decision on the mild hydrocracker investment should be preceded by a full sensitivity analysis which incorporates the above modifications, and which will establish the

35/ This assumption appears to be quite realistic. As an indication, Venezuela (which is a major supplier of crude to Chile) has an ambitious program to develop reserves of light crude over the medium to longer term. Following recent significant discoveries, Venezuela plans to add during 1988-93 14.4 bn bbl of light to medium crude plus condensate to its 58 bn bbl of current reserves (all types of crude), and to be producing in the terminal year 2.2 mn B/D of crude, of which 1.9 B/D would be of the light to medium kind. See: Oil and Gas Journal, 6 June, 1988, pp. 13-16.

consistency of the proposed investment with longer-term requirements. This analysis should take into account the risk related to the current degree of price volatility but also the probability that over the next three-four years (which is the critical period in terms of project economics) the price differential between light and heavy crude is likely to change little. CNE have proposed to postpone a decision on the mild hydrocracker for about one year until a clearer picture on the petroleum price outlook emerges. The cost involved in postponing this decision is likely to be low.

Delayed Coker Option

3.67 ENAP also are evaluating the feasibility of installing a delayed coker at Conception, mainly to transform surplus fuel oil into petroleum coke and to improve the quality of middle distillates. A prefeasibility study analyzing the economic viability of this scheme, i.e. costs, markets, and attainable prices for petroleum coke, is expected to be completed by end-1988. This investment would contribute to reducing fuel oil surpluses (the mild hydrocracker would address mainly the problem of shortage of middle distillates). While the two schemes may be complementary in certain aspects by allowing the Concon and Concepcion refineries to specialize in production processes and output patterns, they might be competitive in others. It therefore needs to be evaluated how these two investment options compare, and how they could be jointly optimized. The production of petroleum coke may not be economic as substitute for fuel oil unless it is low sulphur, electrode-grade material. Also, the supply of hydrogen at the Concepcion refinery (which is needed for operating a delayed coker) may pose a problem and may have to be secured from outside.

Refinery Ownership Considerations

3.68 Future petroleum refining operations will be influenced considerably by a possible Government decision to transfer the refineries to private sector ownership. It seems that the Government does not want to take a decision on refining modification before the ownership issue is resolved.

3.69 The viability of the proposed refining modifications and the financial prospects of refining overall will be important for any efforts to privatize the two refineries to be successful, and measures to strengthen the economic viability of refining would be instrumental for improving the financial position of the refineries as well. The financial results of refining operations in Chile, as elsewhere, have been susceptible to changes in relative prices of crude vs. petroleum products, and are likely to remain so. At any rate, privatization would need to be in strict conformity with a market-oriented approach, i.e. no subsidies nor price or market guarantees should be envisaged irrespective of refinery ownership.

IV. COAL SUBSECTOR

Introduction

4.1 In view of Chile's limited and declining reserves of crude oil, substituting petroleum use by coal has attained particular significance. The Government has supported the development of the coal sector through exploration particularly in Magallanes, expansion of the productive capacity of the state-owned mining companies, and facilitating substitution of coal for petroleum products, e.g. for power generation at CODELCO. However, Chile's coal resources are moderate, given the high sulphur content of Arauco coal and the high ash content of the sub-bituminous Magallanes coal, which limits their use. Only about 14% is good-quality, low-cost coal with some coking properties, located close to consuming centers in the southern and central regions. Coal in central Chile is mined entirely underground, under difficult geological conditions. The government-owned Empresa Nacional del Carbon S. A. (ENACAR), the largest coal producer, operates the Lota, Lebu, and Colico/Trongol mines. Compañia Carbonifera Schwager S.A., a former ENACAR subsidiary and now owned 50% each by CORFO and private investors, operates the Schwager mine. ENACAR in 1986 met 54% of domestic coal consumption (i.e. 1.5 million M.T.), the balance was provided by Schwager, small mine operators (pirquineros), and imports, largely of coking coal. A new private company, COCAR, has started operating a 0.8 million tpy open pit mine in Magallanes for sub-bituminous coal in late 1987, representing an investment of about US$65 million. Its capacity is planned to be eventually expanded to 1.4 million tpy. This venture between COPEC and Northern Strip Mining of the U.K. is partly financed through a US$16.5 million loan and US$2.2 million equity participation from IFC.

Main Issues

Costs of Coal Supplies

4.2 While the subsector's capacity is large enough to meet domestic coal demand for the foreseeable future, the key issue is how much of this capacity is, or is likely to become, competitive with imports. ENACAR's costs of operations are very high, which tends to raise energy costs throughout the economy. COCAR's production costs are considerably lower -- in the order of US$35/M.T. -- but this advantage will be partly offset by the lower quality of the subbituminous Magallanes coal. It therefore needs to be evaluated (a) whether domestic coal production can be made part of a least-cost program to meet energy demand especially on a local level, giving due consideration to energy alternatives primarily imported coal and/or natural gas, and the need for thermal back-up in the electricity system; and (b) whether there is scope for cost reductions at ENACAR so that its production becomes more competitive with coal imports.

Table 4.1: PROJECTED COAL MINING PRODUCTION AND DEMAND, 1987-95
(Adjusted M.T. '000 of 6,350 kcal/kg Coal)

Year	ENACAR	Schwager	Small & Medium Mines	Tenth Region	COCAR	Total Mining Capacity	Imports a/	Potential Demand
1986	836	320	330	110	-	1,596	410	1,541
1987	750	323	400	120	130	1,723	420	1,978
1988	850	328	400	141	582	2,301	485	2,546
1989	875	328	405	155	609	2,372	501	2,863
1990	966	337	410	183	628	2,524	518	3,042
1991	1,056	342	415	183	728	2,724	518	3,242
1992	1,147	367	420	183	794	2,911	539	3,450
1995	1,117	391	420	183	959	3,070	561	3,631

a/ Metallurgical coal.

Source: CNE; ENACAR.

4.3 Production Costs. The opportunity cost of coal generally is its c.i.f. border price, suitably adjusted for quality differentials, the higher cost of relatively small shipments, and the like. 36/ Thus, the economic viability of each mine would be measured in light of the border price of coal. While costs of coal supply from domestic mines vary according to mining conditions and production capacities, ENACAR's mine-mouth costs range from US$43-53/M.T., with Lota being the highest-cost mine. Fixed costs account for over two-thirds of total cost, with fixed labor costs alone accounting for about 55%. They thus tend to be considerably above border prices and currently exceed import parity cost of about US$ 40/M.T. c.i.f. Ventanas by US$3-13/M.T. (Table 4.2). Even if the comparison were based on adding the import duty to the c.i.f. cost of coal imports, production from some domestic mines is not the least-cost supply option unless a significant proportion of costs is considered sunk (under this assumption, savings from mine closures might be less than the costs of coal imports).

36/ In determining the opportunity cost of domestically produced coal, it needs to be considered that (a) in addition to the c.i.f. prices prevailing on international markets, a premium of, say, 5-10% might be added to account for Chile's small import volumes (about 20,000 M.T. per shipment) and relatively high freight charges; and (b) domestic coal reserves are large relative to domestic demand but export prospects for coal are poor or non-existent, which tends to exert a bias in the opposite direction. On balance, actual import prices could be applied as reference to assess the value of coal to domestic producers and consumers.

Table 4.2: AVERAGE MINE-MOUTH COSTS, 1987
(US$/M.T.)

Mine	Fixed Cost a/	Variable Cost b/	Total Cost	Mining Capacity
				(M.T.'000) d/
Lota	37.82	14.86	64.50	600
Colico-Trongol	27.24	15.95	43.19	195
Lebu	33.53	15.35	48.87	105
COCAR	10.80 c/	23.30 c/	34.10	600
Schwager	30.00	16.00	46.00	360

a/ Includes cost of inventory/stocks and of capital.
b/ Includes cost of equipment replacement.
c/ Expected costs.
d/ Equivalent to 6,350 kcal/kg coal.

Source: ENACAR; CNE.

4.4 A better measure of the economic cost of coal is given by the short-run marginal cost of existing production and the long-run marginal cost (LRMC) of future production which indicates the cost of expanding coal production, be it viable or not. Total LRMC (defined as average incremental cost) in some mines are estimated to be about US$42/M.T. (Annex 16), i.e. just about equal to the import parity cost net of import duty and below actual cost of ENACAR mines, assuming reduced manning levels and increased mechanization. This indicates that production of coal from some ENACAR mines may be economic at the margin. It remains to be seen if the necessary rationalization measures can indeed be taken to reduce costs to the indicated levels.

4.5 Delivery Costs. Domestic freight rates from the mines to consumption centers range from US$3.50-7/M.T. for vessels of 20,000 dwt and coastal shipping over 500-1,000 km, to US$13-14/M.T. for truck transport to Santiago, plus unloading (about US$1.50/M.T.), and insurance charges. These rates and charges reflect domestic transport cost fairly accurately. Factoring in all components, ex-delivery prices for domestic coal range from US$48-75/M.T. depending on the source, destination, type of contract, and contracted volumes. At those prices, domestically produced coal evidently is uncompetitive with imported coal.

Table 4.3: REPRESENTATIVE DELIVERED PRICES FOR STEAM COAL, MAY 1988 (US$/M.T.)

Destination	Source			US$/BTU million equiv.
	ENACAR	Schwager	COCAR	
Santiago	62.27 - 75.--	62.61 - 68.65	--	2.25 - 2.82
Ventanas	68.74 - 75.--	--	--	2.48 - 2.87
Antofagasta/Tocopilla	56.60	56.60	56.60	1.73 - 2.72

Note: Prices have been adjusted to energy content of 6,350 kcal/kg.

Source: ENACAR; CNE.

4.6 In the final analysis, to determine the least-cost option for coal supplies -- be it domestic production, importation or a combination of the two -- the LRMC of production and the economic delivery cost need to be evaluated on a mine-by-mine basis. Equally important is the evaluation of the relevant substitution options, either into or out of coal, with hydropower, fuel oil, and natural gas being the principal competing energy sources.

4.7 Considerations for Mine Closure. Given that ENACAR's (and Schwager's) costs exceed the c.i.f. cost of coal imports, the question arises if production should be continued. Generally, the criterion for recommending continuation or discontinuation of mining operations is whether the net-of-tax cash operating costs (fixed plus variable) of mining and delivering coal to the markets, plus any investments needed to maintain production, are below or above the cost of imported coal. In the case of the mines in central Chile, there are various considerations to this. First, a significant proportion of production costs are sunk and to the extent that the cash costs of lay-offs, pensions, financial charges etc. are higher than the differential between cash production costs and import costs, no savings would materialize from replacing domestic production through imports. Second, even though the recommissioning of closed mines is technically difficult and costly, it would only be justifiable to continue production if there is sufficient scope for reducing costs to make production competitive. Otherwise, mine closure would be the economically optional solution. Third, a large share of fixed costs are related to excess labor whose shadow price may be relatively low as long as local employment alternatives are lacking. 37/ Relatively low labor cost would tend to reduce the welfare cost

37/ Lota in early 1987 employed 4,358 persons, for a production of 0.5 million tpy (by comparison, about 300 people are employed in the COCAR mine in Magallanes, for an output of 0.8 million tpy.). However, alternative employment opportunities have developed in the concerned region in irrigated agriculture.

of continued mining operations (or, conversely, result in significant welfare cost in the case of mine closures). Also, excessive labor in coal mining at least in part is the outcome of pressures by local and provincial authorities to preserve employment, causing ENACAR to share the cost of employment preservation. These costs should be made explicit and, if feasible, be reimbursed to the company. In a wider context, measures should be evaluated to increase labor mobility as alternative employment in the affected areas is being created, to address economic and social problems resulting from lay-offs by the mines.

4.8 Requirements for Efficiency Improvements. The above considerations stress the urgency for rationalizing high-cost mines and restructuring ENACAR. The high fixed costs in ENACAR's mines, particularly Lota, need to be reduced through improvements in operational efficiency before any expansion is undertaken. Efforts are ongoing at ENACAR to lower production costs to more competitive levels primarily through mechanizing mining operations, such as the introduction of longwall mining, for which during 1984-87 a total of nearly US$22 million were invested. While the enterprise made efforts to improve operating efficiency and to reduce excess labor, over the 1981-87 period unit operating costs have increased, and output per employee has remained virtually unchanged as output has dropped (Table 4.4). The entity has still a long way to go to achieve efficiency levels comparable to those of other domestic producers. Specifically, the following areas need to be addressed as a matter of urgency:

(a) Operations: While current investment plans are aimed at mechanizing mine operations thus reducing variable production costs, fixed costs also need to be reduced, particularly at Lota, through rationalization including improved inventory/stocks management, reducing above-ground services, closing non-profitable mines or mine sections, and redeploying or reducing the labor force. An in-depth technical and financial evaluation of ENACAR's operations, by mine and mine section, is needed to determine the scope left for operational improvements to reduce production costs, within the technical/geological constraints.

(b) Investment: It needs to be determined that ENACAR's proposed investment program is consistent with realistic assumptions about the scope for efficiency improvements and the domestic market for coal over the medium-to-longer term, given competition from domestic and imported coal and, possibly, natural gas. The options for shifting production from high-cost to lower-cost mines should also be evaluated based on a refined analysis of LRMC and an examination mine-by-mine of the scope for cost reductions. More cost-effective technologies should be evaluated and introduced.

(c) Finance and Planning: ENACAR should determine (i) financially optimal production levels for individual mines (vs. the current

policy of maximizing production by mine irrespective of costs) and (ii) the impact on costs of decentralizing mining operations, out-contracting supporting services, and other measures conducive to reducing operating costs and overheads.

(d) Marketing: In order to obtain a realistic perception about the energy needs in the economy which could be competitively met through coal, ENACAR should systematically monitor the developments related to international coal markets and competing energy sources including coal from other domestic producers, and their impact on the domestic market. ENACAR also should carry out more determined and better focused selling efforts. These improvements could help to strengthen ENACAR's market position, particularly vis-a-vis major consumers.

Coal Market Outlook

4.9 Coal demand will continue to be closely linked to the expansion of thermal electricity generation. COCAR has been awarded an eight-year contract to eventually supply 880,000 tpy of coal to CODELCO's thermal power plant at Tocopilla (northern Chile), which represents about 80% of that plant's fuel needs (the remaining 20% will be supplied by ENACAR and others). Also, CHILECTRA and ENACAR in 1987 concluded a one-year, renewable contract based on a delivered price of US$51/M.T. (US$56.60 in 1988) c.i.f. Ventanas, as CHILECTRA's coal demand is projected to increase to 0.8 million M.T. by 1988. 38/ For thermal power generation, then, coal is likely to continue to play an important role especially in the Northern Integrated System although imported coal would be an attractive option given ample supplies on international markets and limited prospects for price increases over the medium-to longer term. Natural gas also would be a serious competitor provided that its cost at the plant gate would not exceed US$3.50/BTU million, at a capital cost of

---

38/ Delivered volumes in 1988 amount to 0.4 million M.T. for ENACAR and 60,000 M.T. each for Schwager and other coal supplies. CNE carried out a sensitivity analysis to measure the impact on planned power expansion in the Central Interconnected System of alternative coal pricing scenarios (i.e. US$40/M.T.; US$45/M.T.; and US$48/M.T). According to this analysis, different coal prices would affect the expansion of generation only slightly, i.e. through delaying the 325 MW Cortaderal hydroplant by about one year (from 1996 to 1997) for US$40/M.T. and US$45/M.T. prices. For all the three pricing scenarios, the need for a 300 MW thermal power plant in 1995 located in central Chile was confirmed.

$645/net kW installed (for combined-cycle plants). 39/ The industrial sector still offers scope for substitution towards coal, to the extent that natural gas could not or not economically be supplied.

Finances

4.10 Financial issues in the subsector mainly concern ENACAR and are directly related to the entity's cost structure and levels. In the past, ENACAR has operated with losses but has managed to improve its financial position considerably during 1981-86. Losses, which exceeded US$18 million in 1981, were reduced and for the first time in many years, ENACAR in 1986 achieved after-tax profits of US$5 million equivalent. Sales per employee, 135.5 M.T. in 1987, were 8% higher than in 1981. However, this was largely brought about by increasing purchases from independent small mines as output per employee remained nearly unchanged at 114 M.T./year during this period. ENACAR in 1987 again sustained losses, of US$11.7 million equivalent, largely on account of below-cost sales to CHILECTRA (at US$42/M.T. for nearly 0.25 million M.T.).

39/ Spot export prices (f.o.b.) for thermal coal in 1987 ranged from US$23/M.T. for South African coal (11,300 BTU/lb, 15% ash) to US$37/M.T. for U.S. coal (12,000 BTU/lb, 12% ash). Increases in international coal prices during 1988-95 are projected to total 43% in current prices, and 22% in constant prices (World Bank, September 1987). Natural gas when used with new electricity-generating technology -- e.g. combined cycle generation -- can already compete with much cheaper coal. Based on 1976-86 international prices (when energy-equivalent costs of natural gas averaged 34% more than those of coal) the cost of gas-produced electricity was estimated to be 17% less than that produced from coal. Key attractions of combined cycle plant include high thermal efficiency, smaller capital costs, shorter lead times, and environmental advantages. It thus could promote decentralized power generation among relatively small producers. Petroleum Intelligence Weekly, December 14, 1987.

Table 4.4: ENACAR--PERFORMANCE INDICATORS, 1981; 1984-87
(1987 Ch$ millions)

	1981	1984	1985	1986	1987
Income from Sales	10,186	10,765	12,508	13,710	12,811
Earnings after Tax (Losses)	(1,938)	(425)	(249)	1,262	(2,694)
Total Assets	26,587	22,051	23,548	26,754	22,609
Working Capital	3,393	3,435	1,966	2,047	2,788
Short and Long-Term Liabilities	3,088	2,972	4,769	6,307	6,072
Operating Costs	8,011	7,911	8,269	9,830	9,445
Total Costs	9,582	9,383	9,709	11,649	11,926
Investment	-	54	1,010	1,968	2,085
Output (M.T.'000)	860	726	713	836	751
Employees	7,604	5,998	6,313	6,655	6,560
Operating Costs/M.T. (1987 Ch$)	9,315	10,899	11,597	11,758	14,397
M.T./Employee	113	121	113	126	114

Source: ENACAR.

4.11 ENACAR's future financial performance hinges on the company's ability to reduce production costs and to become competitive with coal imports. Should this not be achieved, ENACAR runs the risk of losing the market that the power subsector represents through the 1990s. ENACAR's financial projections show a profitable position through 1991. However, they are predicated on a volume of production nearly 50% above 1985-87 levels, which appears incompatible with the scope for economically viable increases in productive capacity. ENACAR's financial projections therefore should be reviewed in line with more conservative production and sales assumptions, as a basis for financial restructuring.

Rehabilitation Plan

4.12 An integrated approach to rehabilitation is needed to enable ENACAR to develop and implement a medium-term strategy comprising improvements in production, marketing, and finances. Thus, production, investment, sales, and financing plans should be integrated. ENACAR's corporate planning capabilities need to be considerably improved to make this feasible. The existing management information system should be strengthened so that it links production, sales, and finances. This would significally contribute to improving decision making in these three areas, as well as supporting corporate planning. All feasible options for rehabilitation should be considered, including privatizing ENACAR either wholly or in part, although the feasibility of this will largely depend on ENACAR's financial prospects. A forthcoming evaluation by British Mining Consultants Ltd. will address these options and related requirements, including the need for further staff reductions.

4.13 To the extent that these measures still prove insufficient for ENACAR to compete effectively with coal imports or supplies from COCAR, an alternative strategy focusing on downsizing operations and financial restructuring would need to be pursued.

V. FORESTRY AND WOODFUELS

Supply-Demand Balance

5.1 Forest growth--as measured by its mean annual increment--is estimated at 64 million m^3 p.a., which is considerably higher than the combined demand for fuelwood and industrial forest products of about 15.4 million m^3 p.a. (fuelwood demand amounts to about 6 million m^3 p.a). Also, forest plantations have been substantially expanded, especially of pinus radiata which reached about 1 million ha by the mid-1980s. 40/ However, these have been mainly industrial plantations contributing little to meeting fuelwood requirements: those have to be met by natural forests, which usually are distant from population centers, or fuelwood plantations which are relatively small. 41/ Regional and species-specific imbalances of fuelwood have emerged especially in the Metropolitan Region where demand is heavy and which has to be supplied by other regions, over distances at up to 300 km, but also in northern Chile, the Interior Secano, and around nearly all major cities of the country. The supply-demand balance is especially delicate for eucalyptus whose natural growth just about meets demand. Areas subject to deforestation are already being affected by erosion and watershed management problems.

5.2 While these problems are incipient, reforestation is required to bring them under control. The specific reforestation needs should be determined by detailed regional and species-specific evaluations, for which the data base has to be substantially improved. This should include evaluating the options and requirements for involving small-scale farmers more widely in tree planting, including the financing requirements related to it. Forested areas in need of protection and those to be opened for intensive use should be clearly demarcated.

5.3 Any pressures on natural forests also could be relieved through intensified use of forest residues. On the demand side, improving the

---

40/ This was stimulated by subsidies (established through decree-law No. 701, of 1974) amounting to 75% of the cost of establishing industrial plantations. The Government plans to continue these subsidies through 1994.

41/ Fuelwood plantations established by CONAF in conjunction with small- and medium-scale farmers have totalled about 12,000 ha (at a cost of US$1.8 million equivalent) in three years.

Table 5.1: FUELWOOD SUPPLY/DEMAND BALANCE, 1985

	Radiata Pine						Eucalyptus					Native Forest				
Region	MAI	Available Area	Potential MAI Supply	Fuelwood Demand	Industrial Forest	Net Balance	MAI	Aailable Area	Potential MAI Supply	Demand	Net Balance	MAI	Available Area	Potential MAI Supply	Demand	Net Balance
	(m^3/ha)	(ha'000)	(m^3 million)				(m^3/ha)	(ha'000)	(m^3 million)			(m^3/ha)	(ha'000)	(m^3 million)		
Total		1,039.2	21.7	3.7	12.3	5.7			1.016	0.980	0.035		7,612.5	41.218	9.7	31.5
I																
III																
IV							5	0.8	0.004							
RM							14	3.6	0.054			2	2.7	0.005		
V	12.4	23.4	0.3				16	17.8	0.285			-				
VI	16.8	60.9	1.0				13	5.1	0.066			2.5	41.2	0.103		
VII	19.2	205.6	3.9				19	2.0	0.038			3.9	196.4	0.766		
VIII	23.2	523.5	1.2				27	18.8	0.507			5.1	401.7	2.049		
IX	18.0	167.3	3.0				27	2.0	0.053			5.3	632.9	3.354		
X	22.0	58.4	1.3				13	0.8	0.10			6.2	3,592.6	22.274		
XI												5.0	1,686.0	8.430		
XII												4.0	1,059.0	4.236		

MAI = Mean Annual Increment.

Source: CONAF.

efficiency of wood-burning stoves would help to a certain degree to reduce local pressures on supplies. 42/

Policy and Institutional Issues

Cost and Price Structure

5.4 In Chile, costs of wood are lower than almost anywhere else. CONAF's plantation establishment costs are in the US$150-210/ha range and lower if voluntary labor participates (i.e. about US$100/ha). With a mean annual increment of 25-30 m^3/ha (15-18 M.T./ha), this would result in stumpage (i.e. cost of establishing plantations and maintaining them until the time of harvesting) in the order of US$6.15/M.T.. Cost of logging, storage and extraction to roadside may add US$6/M.T. and transport to consumption centers, US$6.50/M.T. (for an average of US¢10/M.T. and an average distance of 65 km). 43/ With additional costs of preparation, wholesale costs of firewood would be in the order of US$23/M.T.

5.5 Current fuelwood prices to residential consumers in Santiago, about Ch$10/kg in early 1988, are considerably above long-run marginal costs. They thus fully cover production and marketing costs and allow satisfactory returns on fuelwood from plantations insasfar as yields for clear-felling are in the 150-200 M.T./ha range. Industrial users normally purchase directly from the fuelwood producers in large quantities and acquire fuelwood at prices only marginally above wholesale cost. To the extent that there are market imperfections, measures are required to remove any impedements so that fuelwood can play its full part in meeting energy requirements. This issue should be approached in the context of a Government strategy to enhance the economic use of fuelwood as energy source.

42/ In Region VIII (where reforestation with pinus radiata is centered) current consumption of forest residues for energy purposes amounts to over 0.4 million tpy. According to CNE, these consumption volumes could be doubled. Regarding the efficiency of woodstoves, a study carried out by CNE and CONAF in 1985 concluded that fuel savings in the order of 2-10% could be achieved: this, however, was considered too small to justify a large-scale stove dissemination program.

43/ See Chile Forest Industries Sub-Sector Study, World Bank Report No. 6380-CH of August 8, 1986.

Table 5.2: INTERNAL RATE OF RETURN ON PLANTATION PROJECTS

Yield	With CONAF Subsidy	Without CONAF SUBSIDY
(M.T./ha)	(%)	(%)
200	17.7	12.9
150	15.7	10.8
100	12.9	8.0

Source: CNE.

Institutional Requirements

5.6 While increases in fuelwood consumption are not yet alarming, they point towards the need to strengthen the institutional framework to monitor the supply, demand, and marketing of fuelwood and to take preventive action before deforestation reaches serious proportions. This involves strengthening CONAF as the Government's principal forestry service whose scope of activities is wide given its relatively limited budget (about US$7 million equivalent/year) and staff (some 950). A positive step in this direction has been the creation of the National Dendroenergy Network by CONAF with cooperation from FAO. The Network's objectives are to strengthen joint action on energy forestry among the relevant subsector institutions, through

(a) promoting the dissemination of experiences, training, research of new uses, and technology transfer;

(b) preparing policy recommendations conducive to enhancing the contribution of dentroenergy to energy supplies, environmental conservation, and improving living conditions especially of those population groups which depend largely on fuelwood for energy; and

(c) preparing an information base and identifying projects suitable to attract national and international financing.

5.7 Nearly 25 institutions meanwhile are associated with the Network, which plans to seek the active participation of the directly affected population groups in implementing self-sustaining projects. The Network still is in its formative phase and it remains to be seen what measure of support it will receive and what leverage it can exert. It would be advisable to incorporate into the Network those private sector entities active in forest management, fuelwood plantations, and fuelwwood marketing.

VI. ENERGY AND ENVIRONMENT

Present Situation

6.1 The energy sector as a major user of natural resources has a direct impact on the environment and there are trade-offs, as well as complementaries, between the objectives of energy development and environmental conservation. Energy operations can have multiple adverse effects: while damage from deforestation in Chile is limited to certain areas and species (para 5.1), environmental problems may arise from the construction and operation of electric power installations, coal mines, and petroleum production and processing facilities. Through creating effluents and solid waste, energy production and use contribute to atmospheric, soil, and water pollution. The effects of environmental contamination often become discernible only after many years and in areas distant from the source of pollution.

6.2 The Santiago Metropolitan Region with its heavy concentration of population and economic activities might be the area in Chile worst affected by pollution. There is substantial emission of contaminants from vehicles, industries, and space heating, including the heavy use of fuelwood and the associated creation of particle matter (i.e. polycyclic aromatic hydrocarbons). This is aggravated by the peculiar geographic and climatological conditions of this region. The Lower Aconcagua Valley also is being adversely affected by emissions of sulphur dioxyde from the Ventanas thermal power plant and copper smelter.

Government Policies

General

6.3 The Government is aware of the need for environmental management in the energy sector. CNE has taken the initiative to prepare corrective and preventive action. The Pehuenche hydropower project has included components aimed at ameliorating adverse impacts on fauna and flora. CNE have commissioned studies aimed at identifying measures to reduce sulphur and other contaminants contained in hydrocarbons, such as increasing the use of filters in chimneys. Under the World Bank financed Public Sector Management project, the Government is preparing a manual for measuring the environmental impact of electric power projects. A US$4 million project is being implemented to (a) monitor atmospheric and water pollution in Santiago, including the environmental impact of different fuels used by busses; (b) identify the pollution sources and their contribution; (c) model pollutants dispersion; and (d) devise stricter environmental safeguards. This project is under the responsibility of the regional and local authorities and is supported by a US$2.5 million IDB loan. The National Ecological Commission (which

reports to the Ministry of National Patrimony) has not been very effective, mainly for lack of resources, and should be strengthened.

Requirements for Environmental Management

6.4 To develop a coherent strategy, the environmental concerns need to be better understood and the costs of environmental damage and its alleviation be more clearly identified. Only on this basis will it be possible to determine at what speed and level environmental issues can be addressed. There is normally a wide range of options to ameliorate and prevent adverse environmental impacts, and the most cost-effective ones should be evaluated. The approach to natural resource management should be one which puts a premium on efficiency, conservation, and sustaining the resource base. Economic policy interventions to improve environmental management should be assessed with a view to their conformity with market principles. Thus, instead of offering subsidies for environment-supporting investment, the approach should be to charge the pollutor for the environmental cost to the economy. It also needs to be considered that the beneficiaries of environmental actions often are not identical to those who bear the costs of these actions. Building the capability in the public and private sectors to handle complex environmental issues is itself a complex process for which specialists need to be trained, especially those capable to carry out integrated environmental analysis. Better coordination and political resolve among institutions handling these matters are needed to strengthen environmental safeguards.

6.5 Chile is beginning to develop the capacity to identify options for reducing adverse environmental effects of energy projects. This development should be strengthened. Reducing pollution from energy processes is important, especially in ecologically sensitive zones. The wider environmental impact of different sources of energy also should be evaluated. Certain forms of energy are environmentally more benign, e.g. hydroelectricity and natural gas compared to fuel oil and coal, especially of the high-sulphur type. This should be given due consideration in deciding on energy development alternatives. The management and disposal of waste from energy processes needs to be evaluated in more detail. Energy pricing should reflect the environmental cost of the use of different energy forms. This has been largely achieved for electricity but not for other forms of energy (especially fuelwood). Measures aimed at improving the efficiency of energy use -- which normally involve reducing emission of burned gases, heat, and steam -- also have favorable environmental effects and should therefore be pursued to achieve twin benefits.

Recommendations

6.6 The Government institutions involved in environmental matters i.e. CNE, CONADE, ODEPLAN, and CORFO should enhance their role in achieving a better understanding of the complementarities and trade-offs between energy and environmental concerns, and in a search for policy and project concepts that reconcile the objectives of energy development,

environmental conservation, and economic growth. They should also aim at closer cooperation with non-governmental organizations concerned about environmental issues. CNE and ODEPLAN should take the lead in integrating the information on resource use with macroeconomic data, and in evaluating costs and benefits of ameliorating or preventing environmental damage caused by energy development.

VII. ENERGY SECTOR OUTLOOK, 1988-97

Constraints and Strategy Reuirements

7.1 Meeting future energy requirements will pose difficult choices for the country's decision makers. The development of energy rcsources will oe high-cost, technologically difficult in some cases, and will involve considerable lead time. The major energy corporations are highly indebted so that increased reliance needs to be placed on the private sector to carry out the necessary investments. 44/ Declines in crude oil production and constraints on expanding economically viable coal production are bound to limit the sector's productive capacity. The resulting increases in energy imports will impose a growing though manageable burden on the foreign exchange position of the economy.

7.2 On the positive side, the sectoral institutions are well-suited to analyze and implement policies and strategies, and prepare investment programs. The operating agencies are equally well-equipped and competent to meet their tasks. In order to make the energy sector more resilient, a coherent strategy is called for which should be formulated and implemented in close consultation with the private sector. The main components of such a strategy are as follows:

(a) developing the hydropower potential as the key component of the least-cost expansion program for the electricity subsector;

(b) exploiting existing crude oil reserves to the economically optimal (vs. technically feasible) degree, and developing new reserves both domestically and abroad;

(c) rehabilitating those coal mines that have the scope to become competitive with imports, if necessary through down-sizing operations;

(d) assessing the potential for natural gas use in central Chile, including for electricity generation, and determining the least-cost options for gas supply, including imports from, and/or gas swaps with, Argentina;

(e) enhancing the efficiency of energy supplies through reduction of losses in production, transformation, and distribution;

44/ The end-1986 debt outstanding and disbursed of Chile's four largest energy corporations (ENDESA, ENAP, ENACAR and CHILECTRA GENERACION) amounted to US$1.8 billion, with a debt service of some US$150 million. See OLADE, The Foreign Debt and the Energy Sector of Latin America and the Caribbean, 1987 (quoting national sources).

(f) expanding the involvement of the private sector in energy operations;

(g) removing the remaining minor distortions in energy pricing, essentially those for petroleum products, and increase market transparency, to ensure allocative efficiency;

(h) reinforcing energy pricing through non-pricing measures to improve the efficiency of energy end-use, such as dissemination of energy-efficient technologies and training in their application; and

(i) reconciling energy sector development with the objective of environmental conservation.

Subsector Projections and Projection Methodology

Petroleum Products

7.3 ENAP have developed demand forecasts for refined petroleum products which are based on econometric models for each product except fuel oil (the latter is based on individual information from the relatively few large-volume consumers). The explanatory variables include GDP, population growth, lagged consumption, and the price of each fuel and its closest substitute. ENAP's demand forecast is based on the assumption of GDP growth of 4.5% in 1988 and 3% p.a. thereafter, and their projections of international prices of crude and products (Table 6.1). ENAP tested a number of different lagged models and functional forms. The resulting models fit the data well. The methodology used is appropriate and the resulting elasticity estimates are robust. 45/

7.4 To forecast demand in the domestic market, it is necessary to convert f.o.b. Caribbean prices into landed Chilean prices, by increasing the f.o.b. price by the costs of transportation and handling, insurance, losses due to evaporation, a charge for working capital and the import duty on the c.i.f. price. On that basis, ENAP in early 1988 has projected domestic demand of petroleum products as follows:

45/ See Annex 13 for income and price elasticities of demand estimates.

Table 7.1: ENAP PROJECTIONS OF DEMAND AND PRICES FOR PETROLEUM PRODUCTS, 1988-2000

Product	1985	1987	1988	1990	1995	2000	Annual Change (Percent) 1986-90	1991-95	1996-2000
				TOTAL DEMAND (m^3'000)					
	5,315	5,917	6,176	6,616	7,041	7,736	4.5	1.3	1.9
Gasoline	1,361	1,527	1,641	1,794	1,916	2,039	5.7	1.3	1.3
Aviation Gasoline	7	8	8	8	8	8	2.7	-	-
LPG	771	848	900	976	1,123	1,272	4.8	2.9	2.5
Kerosene	142	217	219	216	191	165	8.8	-2.5	-3.0
Jet Fuel	195	260	285	312	371	433	9.9	3.5	3.1
Diesel	1,686	1,918	1,969	2,051	2,322	2,711	4.0	2.5	3.1
Fuel Oil	957	920	901	1,000	841	839	0.9	-3.5	-
Naphtha	44	50	50	50	50	50	2.6	-	-
Ethylene	74	74	95	95	95	95	5.1	-	-
Asphalt; Pitch; Solvents	78	108	108	114	124	124	7.9	1.7	-

Product	Units	1986	1990	1995	2000
		PETROLEUM PRODUCTS PRICES (Constant '85 US$/Units)			
ENAP Forecast					
Arab Marker Crude	(US$/bbl)	15.45	19.82	20.55	20.75
Gasoline (93 RON)	(US$/gal)	0.49	0.60	0.61	0.62
Kerosene	(US$/gal)	0.52	0.63	0.65	0.65
Diesel	(US$/gal)	0.59	0.60	0.61	0.62
Fuel Oil	(US$/bbl)	13.03	16.20	16.61	16.90
LPG	(US$/gal)	0.25	0.32	0.32	0.32
World Bank Forecast a/					
Arab Marker Crude	(US$/bbl)	11.50	11.10	16.00	18.70

a/ Dated January 27, 1988.

Source: ENAP; World Bank.

Natural Gas

7.5 CNE use a computer model to simulate natural gas demand and distribution costs under various price scenarios. This model is based on studies by ENAP and SOFREGAZ of France, carried out to analyze the cost for establishing a pipeline network connecting and servicing four consumption centers (Santiago, Concepcion, Talca and Linares) corresponding to various demand scenarios. The assumptions about the substitability of natural gas for other fuels are based on conversion costs, price differentials, and possible consumption volumes. Penetration rates (in terms of number of customers and volume of consumption) for different cost and price levels have been estimated based on a normal log distribution for residential, commercial and public sector customers and on deterministic analysis for industrial customers. A demand curve was constructed based on these estimates, and corresponding prices and volumes and distribution costs were iterated. Independently, GASCO have studied the market potential for natural gas in the Santiago area, indicating demand levels substantially below those projected by CNE. (GASCO's primary interest in obtaining natural gas is to blend it with town gas to reduce the cost of town gas.) While it has not been possible to obtain all the detailed information on the CNE study, the methodology applied for estimating demand appears appropriate. However, in view of the proposed pricing policy for gas (i.e. substitution price) probably 60-75% only of the potential market might be attainable within each delimited area. These relatively lower average penetration rates are consistent with market experiences in other countries. 46/

7.6 The potential demand for natural gas of large-volume industrial customers has been analyzed separately by both GASCO and CNE. Of particular interest is the El Teniente copper mining and processing center situated 80 km southeast of Santiago, whose consumption potential is estimated at 70 million m^3/year. CODELCO is interested in converting El Teniente to natural gas use, provided the ex-delivery price is at least 5% below the price of No. 6 fuel oil. (This assumption may be conservative given the efficiency advantages of natural gas, and provided that the costs of converting to gas are amortized over a reasonable period, say 3-4 years).

Electricity

7.7 CNE's electricity demand forecast for the Interconnected System is based on econometric models, using sectoral and global approaches. Under the sectoral approach, projections of residential consumption are based on exogenous parameters, i.e. population growth and electrification ratio, while per-customer consumption is related to household incomes,

---

46/ Only the Netherlands have a much higher penetration rate (close to 95-98%), but natural gas in that country has been priced far below competing fuels.

kerosene and electricity prices, and lagged consumption. The growth of consumption by small-scale industries and irrigation is related to the growth of industrial production (log-log model, with a good correlation) and of irrigated agriculture, respectively. The projections of consumption growth for large-scale industries and mining are based on customer surveys. The global approach is based on a classical log-log model, with lagged consumption and GDP as explanatory variables. Two macroeconomic scenarios have been used, i.e. GDP growth of 3.5% p.a. and 5% p.a., respectively, over the 1986-95 period. For the growth of self-generation, two alternative assumptions have been made in the global model, i.e. (a) a growth of 1% p.a. (which corresponds to recent trends), and (b) a somewhat higher forecast based on customer surveys.

7.8 The results of the forecasts are shown in Annex 15 (Tables 1 and 2). Depending on the approach chosen and the projected GDP growth, annual average growth of electricity consumption through 1995 ranges from 3.8% to 5.3%, accelerating significantly in the second half of the projection period. Although these rates are in line with long-run trends, the pattern and structure of electricity growth that result from the models are more debatable. For, within the framework of relatively steady GDP growth, one would expect the rates of electricity growth to be decreasing slightly over time rather than increasing. 47/ Also, in view of the recent acceleration of electricity growth -- an increase of nearly 9% is expected for the whole of 1988 -- ENDESA has revised upwards the growth of electricity demand over the medium to longer term, to about 6% per year.

7.9 As regards the residential consumption growth, the two approaches result in differing growth rates, with the econometric model forecasting a significant reduction of per-customer consumption. An analytical approach to residential consumption based on surveys of appliance ownership as well as a detailed analysis of the evolution of consumption per customer -- i.e. evolution of the statistical distribution, and analysis by zone -- may prove useful to better understand the recent evolution of consumption, as well as to complement the econometric approach.

World Bank Projections, 1988-97

7.10 There are no comprehensive projections for the energy sector as a whole beyond the individual subsectoral forecasts discussed above. Therefore, sectoral and sub-sectoral energy supply/demand projections have been developed for the periods 1988-92 and 1993-97. They are based

---

47/ The pattern of increasing growth rates is a direct result of the structure of the global model which gives a significant weight to lagged consumption, and a relatively low weight to GDP growth.

on the assumption that (a) economic growth will average 5% p.a. during 1988-92, and 4% p.a. during 1993-97; (b) growth in the main productive sectors and in personal consumption will be related to GDP growth based on historical correlations; and (c) income elasticities of energy demand will be lower than historically observed, thus resulting in lower energy growth per given GDP and sectoral growth (Annex 7). Two scenarios are used to illustrate the possible impact of alternative strategies on future energy requirements. The scenarios differ in their assumptions about energy demand, management and the efficiency of energy production, transformation and use. The Action-Oriented Scenario indicates the improvements in energy supply and demand that could result from the continuation of appropriate pricing policies, the intensification of non-pricing measures aimed at increasing the efficiency of energy end-use, the speedy implementation of energy production and transformation projects and the reduction in energy conversion and distribution losses especially in electricity. It is assumed that natural gas will be supplied to central Chile by the early 1990s either through imports from, or gas swaps with, Argentina. Under the Trend-Based Scenario, few if any of these measures are assumed to take place, and consequently, demand growth would be relatively faster and increases in energy supplies lower. While the two scenarios represent a range of possible outcomes rather than precise projections, they do indicate important structural changes in the energy sector likely to occur over the medium to longer term, such as quantitative relationships and qualitative characteristics, capacity constraints, and changes in the efficiency of investments and of energy use.

7.11 It is assumed that by the mid-1990s, under the Action-Oriented Scenario, (a) crude-oil production will still meet about 10% of domestic petroleum requirements, through increases in production efficiency from existing fields and development of new discoveries; (b) coal production will be raised nearly 55% over its 1986 level; (c) natural gas lift and flaring combined will be reduced to 10% of production net of reinjection (compared to 17.6% in 1986); and (d) own consumption and losses in electricity transmission will be reduced to 10% (13% in 1986). Under the Trend-Based Scenario, less progress is assumed to be made in these areas, resulting in correspondingly higher import requirements to meet energy demand. Increases in final energy consumption during 1987-97, projected at 2.6% p.a. under the Action-Oriented Scenario, would be 3.0% p.a. under the Trend-Based Scenario. Accordingly, energy end-use in 1997 would be 1.1 million toe lower under the Action-Oriented than under the Trend-Based Scenario. This difference reflects the respective assumptions on conservation and substitution of petroleum products through natural gas in mining and industry (0.3 million toe), in the residential/commercial/administrative sectors (0.1 million toe), and in transport (0.6 million toe), as well as differences in losses in natural gas production (0.6 bn CF) and in electricity transmission and distribution (1,350 GWh; all in respect of 1997). Final consumption of petroleum products in 1987-97 is projected to increase at 2% p.a. under the Action-Oriented Scenario and at about 3% p.a. under the Trend-Based Scenario. Petroleum

Table 7.2: PROJECTED ENERGY INDICATORS, 1990, 1995

ACTION-ORIENTED SCENARIO

I. Composite Energy Supply/Demand Balance

	1992		1997	
	Toe '000	Percent	Toe '000	Percent
Primary Supplies	125.3	100.0	144.1	100.0
Production	(84.0)	(67.0)	(91.9)	(63.8)
Net Imports	(41.3)	(33.0)	(52.2)	(36.2)
Secondary Energy Imports	5.6	4.5	3.1	2.1
Conversion and Distribution Losses	21.7	17.3	20.3	14.0
Net Supply	109.2	87.2	126.9	88.1
Secondary Exports	6.8	5.4	11.1	7.7
Final Consumption	102.4	81.8	115.8	80.4

II. Composition of Final Consumption (Percent)

	1992									1997								
	Wood-fuels	Petr. Pro-ducts	Nat. Gas	Coal	Coke	Town Gas	Fur-nace Gas	Elect-ricity	Total	Wood-fuels	Petr. Pro-ducts	Nat. Gas	Coal	Coke	Town Gas	Fur-nace Gas	Elect-ricity	Total
Residential/Commercial/ Admin. Sectors	15.0	6.4	2.1	0.1	-	0.7	-	4.5	28.8	14.3	5.6	3.4	0.1	-	0.6	-	4.8	28.9
Agricultural/Industry/ Mining Sectors	8.2	11.8	0.1	7.0	2.0	0.5	0.5	9.3	39.5	9.3	7.4	2.2	8.1	2.1	0.4	0.4	10.2	40.1
Transport Sector	-	31.5	-	-	-	-	-	0.2	31.7	-	32.8	-	-	-	-	-	0.2	33.0
Total	23.2	49.7	2.2	7.1	2.0	1.2	0.5	14.1	100.0	23.7	45.8	5.6	8.2	2.1	1.0	0.4	15.2	100.0

TREND-BASED SCENARIO

I. Composite Energy Supply/Demand Balance

	1992		1997	
	Toe '000	Percent	Toe '000	Percent
Primary Supplies	128.9	100.0	148.0	100.0
Production	(82.1)	(64.1)	(85.6)	(57.8)
Net Imports	(45.9)	(35.9)	(62.4)	(42.2)
Secondary Energy Imports	10.8	8.4	16.6	11.2
Conversion and Distribution Losses	24.4	19.0	30.3	20.5
Net Supply	114.4	89.4	134.6	90.9
Secondary Exports	6.8	5.3	6.8	4.6
Final Consumption	107.6	84.1	127.8	86.3

II. Composition of Final Consumption (Percent)

	1992									1997								
	Wood-fuels	Petr. Pro-ducts	Nat. Gas	Coal	Coke	Town Gas	Fur-nace Gas	Elect-ricity	Total	Wood-fuels	Petr. Pro-ducts	Nat. Gas	Coal	Coke	Town Gas	Fur-nace Gas	Elect-ricity	Total
Residential/ Commercial/ Admin. Sectors	14.3	6.9	2.1	8.1	-	0.6	-	4.3	28.3	13.0	5.0	2.3	0.1	-	0.6	-	4.4	25.4
Agricultural/ Industry/ Mining Sectors	8.1	11.8	0.1	6.8	1.9	0.5	0.5	9.2	38.9	9.0	8.5	0.2	7.9	2.0	0.4	0.4	10.4	38.9
Transport Sector	-	32.9	-	-	-	-	-	0.2	32.7	-	35.4	-	-	-	-	-	0.3	35.7
Total	22.4	51.1	2.2	6.9	1.9	1.1	0.5	13.8	100.0	22.0	49.0	2.5	8.0	2.0	1.0	0.4	15.1	100.0

Sources: Annex 4; Annex 5

products would continue to account for the largest share of final energy consumption which, however, would decline from 53% in 1986 to 44% by 1997 under the Action-Oriented Scenario (49% under the Trend-Based Scenario). The corresponding shares would rise for electricity from 11.6% (1986) to 15% and for natural gas, from 1.8% to 5.6% under the Action-Oriented Scenario (2.5% under the Trend-Based Scenario). The share of coal and coke combined would increase from 8% to about 10% under both scenarios. Woodfuels are projected to remain a significant energy source, meeting some 22-23% of final consumption in 1997, as they did in 1986.

Energy Imports and Exports

7.12 Differences in domestic crude and coal production, energy substitution patterns, and the efficiency of energy end-use in the economy will have a considerable impact on future import requirements. The share of imports in energy supplies is projected to rise during 1986-97 from 12.6% to 16-17% under both scenarios. Energy imports by 1992 are projected to be eqivalent to 7.4% of goods and non-factor service exports under the Action-Oriented Scenario (9.2% under the Trend-Based Scenario) and to increase further to reach by 1997 US$1.1 billion under the Action-Oriented Scenario (US$1.6 billion under the Trend-Based Scenario; all in current prices). 48/ The composition of energy imports would differ

Table 7.3: PROJECTED ENERGY IMPORTS, 1990 1992; 1995; 1997
(Current US$ millions)

	Prelim.	Action-Oriented Scenario				Trend-Based Scenario			
	1986	1990	1992	1995	1997	1990	1992	1995	1997
(1) Total Energy Imports	384.1a/	530.0	677.5	846.3	1,108.1	631.6	839.9	1,158.9	1,607.0
Crude Petroleum	250.2	441.4	532.0	704.7	915.6	471.7	557.5	735.7	954.8
Petroleum Products	104.1	60.6	117.6	85.2	89.3	124.7	235.7	335.0	523.8
Coal and Coke	29.8	28.0	27.9	30.4	39.3	35.4	46.7	88.2	128.4
Natural Gas	-	-	-	26.0	63.9	-	-	-	-
(2) Goods and NFS Imports	4,328.0	6,915.0	8,233.0			6,915.0	8,233.0		
(3) Goods and NFS Exports	5,008.5a/	7,629.0	9,169.0			7,629.0	9,169.0		
(1) as percent of (2)	8.9	7.7	8.2			9.1	10.2		
(1) as percent of (3)	7.7	6.9	7.4			8.3	9.2		

a/ There were energy reexports amounting to US$31.5 million in 1986.

Source: Annex 6.

48/ Based on January 1988 World Bank price projections.

significantly under both Scenarios: the bulk would consist of crude oil but there would also be significant imports of natural gas (under the Action-Oriented Scenario) and of coal (under the Trend-Based Scenario). Exports of methanol and ammonia/urea under the Action-Oriented Scenario would balance energy import costs to about 30%. Under the Trend-Based Scenario, where only exports of methanol are assumed to take place, the latter would be the equivalent of 12-15% of energy imports.

Energy Sector Investment Strategy

7.13 According to information provided by the energy enterprises, investment in the energy sector over the 1987-1991 period was envisaged to total US$2.7 billion (1986 prices and exchange rates). Of this, three-quarters or US$2.1 billion were to be accounted for by state-owned or associated companies.

Table 7.4: PROJECTED PUBLIC INVESTMENT IN THE ENERGY SECTOR, 1987-1991
(1986 US$ millions and Percent)

	High Assumption		Low Assumption	
	(1986 US$ millions)	(Percent)	(1986 US$ millions)	(Percent)
Total	2,102.7	100.0	1,830.5	100.0
Hydrocarbons	696.9	33.1	464.0	25.3
Petroleum Exploration and Development	552.0	26.2	404.0	22.1
Springhill Area	(432.0)	(20.5)	(384.0)	(21.0)
Frontier Areas	(120.0)	(5.7)	(20.0)	(1.1)
Petroleum Refining	133.9	6.4	49.0	2.6
Natural Gas Development	11.0	0.5	11.0	0.6
Coal	97.5	4.6	58.2	3.2
ENACAR	47.1	2.2	20.0	1.1
COCAR	45.0	2.1	35.0	1.9
Schwager	5.4	0.3	3.2	0.2
Electric Power	1,308.3	62.3	1,308.3	71.5
Generation and Transmission	1,199.9	57.1	1,199.9	65.6
Distribution	108.4	5.2	108.4	5.9

Source: Annex 23.

7.14 The electricity subsector would continue to absorb the bulk of energy-related investment, i.e. 62-72% depending on the assumed size of the investment total. 49/ Regarding the hydrocarbons subsector, there are questions as to whether the envisaged investment in the range of US$460-700 million is justified in view of the relatively moderate prospects, or whether it could be reduced through more rigorous project selection and improved cost effectiveness of individual projects. This concerns primarily the largest investment item, petroleum and gas exploration, projected to amount to some US$550 million, but also refining investment, where the priorities and relevant options still need to be evaluated in more detail. ENAP has made no provision for private sector investment in either area which, however, should be attracted to the feasible extent.

7.15 Based on information provided by the companies in April 1988, an unconstrained investment program in the coal subsector over the 1987-1991 period would total nearly US$98 million, with ENACAR's portion amounting to US$47 million. ENACAR's planned investment is high relative to the expected increase in mine output, about 0.3 million tpy for the whole company, and averages nearly US$160/M.T. of planned annual production. Nearly one-half is allocated to Lota where operating costs are highest. ENACAR's investment program aims at increasing productive efficiency by lowering mine-mouth costs to US$46/M.T. However, this is still significantly above the bench-mark cost of about US$42/M.T. needed for domestic coal production to be competitive with imports. While planned investment in Lota would do much to increase production and reduce losses, this scheme is the most vulnerable to technical and price risks, and its return would be the lowest among ENACAR's investment options. 50/ Given the severity of the operational and financial difficulties facing ENACAR, and the fact that the costs of other domestic producers are significantly lower, there are questions as to what extent the proposed investments should be initiated before the problems of ENACAR's fixed costs especially labor are satisfactorily addressed. Before proceeding with the proposed program, alternative ways to reduce production costs should be evaluated, on a mine-by-mine basis, while preparing specific proposals to enhance ENACAR's planning, financial and marketing capabilities. Investments in coal-related infrastructure should be planned with a view to reducing handling and delivery costs, and to supporting lower-cost mines including small- to medium-sized private mines.

49/ Investment plans of the electricity subsector have already been reviewed by the Bank in the context of the 1987 appraisal of the Pehuenche hydroelectric project.

50/ The economic rate of return for the second phase of the Lota expansion is estimated by CNE at about 22%, compared to 54% for Colico-Trangol, applying a discount rate of 10%.

ENERGY BALANCE, 1986
(Terracalories)

	Primary Energy						Secondary Energy													
	Crude Oil	Natural Gas	Coal	Hydro	Wood	Total	Refinery Gas	Town Gas	Furnace Gas	Electricity	LPG	Gasoline	Av. Gasol. & Jet Fuel	Kerosene	Diesel Oil	Fuel Oil	Naphtha	Coke	Total	Grand Total
Gross Supply																				
Production	16,583	11,200	11,435	9,950	20,834	69,000													0	69,000
Imports	20,190		3,210			31,400					158	1,543	479	172	5,695	811		364	7,222	38,622
Exports																		(86)	(86)	(86)
Stock Variation	(3,046)	(4,386)c/	(1,639)	(256)		(9,247)		5	(106)	(1,676)	(125)	(67)	(368)	72	(1,054)	(705)	4	9	(3,096)	(13,242)
Total Available	41,527	6,804	13,004	9,694	20,834	91,953		5	(106)	(1,676)	33	1,476	111	244	2,064	106	4	289	3,141	95,094
Energy Conversion																				
Petroleum Refining	(41,527)	(4,708)				(46,235)	889			(153)a/	9,343	10,197	2,074	1,587	14,314	11,500	389		49,609	(550)a/
Electricity Generation		(638)	(4,755)	(9,694)	(1,043)	(16,130)		(10)		12,679					(654)	(2,520)			9,685	(6,444)a/
Gas & Coke Processing			(3,175)			(3,175)		1,512	926	(9)	(102)						(956)	(2,261)	10,052	(448)a/
Own Consumption & Losses							(884)a/	(126)	(234)	(222)	(9)				(263)a/	(1,285)a/		(985)	(3,824)	(3,824)
										(103)									(103)	
Net Supply Available		1,548	5,074		19,791	26,413	5	1,183	586	10,516	5,265	11,653	2,185	1,631	16,098	7,065	15	1,570	58,720	85,031
Statistical Adjustment		(23)	(1)		2	(22)	-					(1)			1				(102)	8
Consumption by Sectors																				
Residential, Commercial, Administrative		1,492	72		15,826	15,380		595		3,582	4,055			1,238	1,652	175			12,055	27,425
Agriculture, Industry and Mines																				
Copper			580		10	590				2,667				195	1,220	5,412		55	7,497	8,087
Nitrate			-		-					157				15	81	472		-	725	725
Iron			544			544				199					98	39		-	326	870
Paper			38		5,117	5,147				877					16	712		-	1,605	6,752
Steel			-					535	586	256					-	644		1,435	3,254	3,254
Petrochemicals			-							104					-			-	104	104
Cement			954			954				161					10	10		-	201	1,155
Sugar			1,142		56	1,198				73					-			42	95	1,293
Other		79	1,755		700	2,612	5	95		2,249	411			222	2,392	2,291	15	48	7,626	10,238
Transportation			-							192		11,654	2,185		10,620	470			25,118	25,118
Final Consumption		1,571	5,075		19,709	26,435		1,183	586	10,515	5,266	11,654	2,185	1,631	16,097	7,065	15	1,580	58,610	85,055

a/ Inputs for petroleum refining.
b/ Conversion Losses.
c/ Corresponding flared gas, diff gas, and absorbed gas.

Source: CNE; mission estimates.

ENERGY BALANCE, 1986
(Physical Units)

	Primary Energy					Secondary Energy												
	Crude Oil	Natural Gas	Coal	Hydro	Wood	Refinery Gas	Town Gas	Furnace Gas	Electricity	LPG	Gasoline	Av. Gasol. & Jet Fuel	Kerosene	Diesel Oil	Fuel Oil	Naphtha	Coke
	m^3'000	m^3mm	000'ton	GWh	M.T.'000	mm ltr	m^3mm	m^3mm	GWh	mm^3'000	m^3'000	m^3'000	m^3'000	m^3'000	m^3'000	m^3'000	M.T.'000
Gross Supply																		
Production	1,764	1,199	1,633	11,570	5,955	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	5,036	0	450	0	0	0	0	0	0	24	189	95	19	404	91	0	52
Exports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(12)
Stock Variation	(328)	(461)	(254)	(298)	0	0	1	0	(1,949)	(19)	(8)	(62)	0	(115)	(79)	0	1
Total Available	4,472	738	1,858	11,272	5,955	0	1	0	(1,949)	5	181	13	27	291	12	0	40
Energy Conversion																		
Petroleum Refining	(4,472)	(504)	0	0	0	190	0	0	(170)	883	1,242	259	154	1,563	1,276	45	0
Electricity Generation	0	(68)	(679)	(11,272)	(298)	0	(3)	0	14,783	0	0	0	0	(71)	(261)	0	0
Gas & Coke Processing	0	0	(454)	0	0	0	320	0	(18)	(15)	0	0	0	0	0	(44)	325
Own Consumption & Losses	0	0	0			(189)	(31)	0	(258)	(1)	0	0	0	(29)	(195)	0	(138)
									(120)								
Net Supply Available		166	725	0	5,655	1	296	0	12,548	791	1,423	252	181	1,754	802	2	226
Statistical Adjustment			(0)							0							
Consumption by Sectors																		
Residential, Commercial, Administrative		160	10		3,958	0	139	0	4,165	750	0	0	158	178	19	0	0
Agriculture, Industry and Mines		0	0		0	0	0	0	0	0	0	0	0	0	0	0	0
Copper		0	85		0	0	0	0	3,101	0	0	0	17	154	502	0	5
Nitrate		0	0		0	0	0	0	183	0	0	0	2	9	55	0	0
Iron		0	18		0	0	0	0	251	0	0	0	0	11	5	0	0
Paper		0	4		1,462	0	0	0	1,020	0	0	0	0	2	80	0	0
Steel		0	0		0	0	155	0	298	0	0	0	0	0	50	0	205
Petrochemicals		0	0		0	0	0	0	121	0	0	0	0	0	0	0	0
Cement		0	136		0	0	0	0	187	0	0	0	0	5	1	0	0
Sugar		0	163		16	0	0	0	85	0	0	0	0	0	0	0	9
Other		0	250		223	0	24	0	2,615	62	0	0	24	157	298	2	7
Transportation		0	0		0	0	0	0	223	0	1,423	252	0	1,160	54	0	0
Final consumption	0	160	725	0	5,654	1	296	0	12,229	791	1,423	252	181	1,754	802	2	226

Source: CNE

Annex 3

CONSUMPTION OF PETROLEUM PRODUCTS, 1976-86
(M.T. '000 and Percent)

	1976		1980		1985		1986		Increase p.a.(%)	
	M.T.'000	%	M.T.'000	%	M.T.'000	%	M.T.'000	%	1977-80	1981-86
Grand Total	4,235	100.0	4,930	100.0	4,202	100.0	4,392	100.0	3.9	-1.7
Final Consumption	3,291	77.7	3,927	79.7	3,601	85.7	3,856	87.8	4.5	-0.3
Residential/Commercial/ Administrative Sectors	540	12.8	492	10.0	408	9.7	500	11.4	-2.3	0.3
Fuel Oil	29		25		16		17			
Diesel	28		39		87		150			
Kerosene	270		191		92		112			
LPG	213		237		213		221			
Industry & Mining	1,178	27.8	1,254	25.4	1,051	25.0	1,101	25.1	1.6	-2.2
Fuel Oil	779		915		699		695			
Diesel	281		270		311		349			
Kerosene	96		49		23		36			
LPG	11		15		16		19			
Naphtha	10		4		1		1			
Ref. Gas	1		1		1		1			
Transport	1,573	37.1	2,181	44.3	2,142	51.0	2,255	51.3	8.5	0.5
Fuel Oil	96		88		29		46			
Diesel	486		838		959		974			
81 Gasoline	720		693		214		203			
93 Gasoline	151		388		784		835			
Av. Gasoline	8		8		5		6			
Jet Fuel	109		166		151		191			
Kerosene	3		-		-		-			
Energy Transformation	944	22.3	1,003	20.3	601	14.3	536	12.2	1.7	-11.0
Electricity Generation	538	12.7	611	12.4	290	6.9	228	5.2	3.2	-17.9
Fuel Oil	(438)		(520)		(230)		(222)			
Diesel	(99)		(90)		(60)		(6)			
LPG	(1)		(1)		(-)		(-)			
Gas & Coke Production	58	1.4	46	0.9	34	0.8	35	0.8	-6.0	-4.7
LPG	(10)		(13)		(3)		(4)			
Naphtha	(48)		(33)		(31)		(31)			
Crude Oil & Nat. Gas Production	348	8.2	346	7.0	277	6.6	273	6.2	--	-4.0
Fuel Oil	(165)		(133)		(128)		(115)			
Diesel	(11)		(8)		(24)		(24)			
LPG	(2)		(1)		(2)		(1)			
Ref. Gas	(170)		(204)		(123)		(133)			

Source: CNE; ENAP

PROJECTED SUMMARY ENERGY BALANCES, 1990; 1992; 1995; 1997
(Physical Units)

	Prelim. 1986	Action-Oriented Scenario 1990	1992	1995	1997	Trend-Based Scenario 1990	1992	1995	1997
Production									
Fuelwood (M.T.'000)	5,953	6,690	6,94[illegible]	7,479	7,867	6,763	7,184	7,879	8,394
Crude Oil (M.T.'000)	1,484	1,115	850	675	450	890	680	500	270
Coal (M.T.'000)	1,399	2,305	2,304	2,167	2,216	2,297	2,247	2,095	2,035
Natural Gas (m^3 mn)	1,199	2,256	2,298	2,922	[illegible]	2,295	2,343	2,411	2,563
Hydro Power (GWh)	11,273	12,734	14,978	17,100	[illegible]	12,734	13,978	16,100	17,690
Primary Energy Imports									
Crude Oil (M.T.'000)	2,596	3,278	3,543	3,977	[illegible]	3,503	3,713	4,152	4,382
Coal (M.T.'000)	459	445	395	367	420	569	800	1,632	2,126
Natural Gas (m^3 mn)	-	-	-	200	400	-	-	-	-
Energy Transformation									
Inputs									
Fuelwood (M.T.'000)	298	245	147	98	61	270	307	344	369
Crude Oil (")	4,080	4,393	4,393	4,652	4,652	4,393	4,393	4,652	4,652
Coal (")	1,133	1,907	1,658	1,312	1,276	1,913	1,983	2,434	2,695
Coke (")	138	145	148	185	190	145	149	190	195
Natural Gas (m^3 mn)	205	250	279	322	356	254	282	328	369
Furnace Gas (m^3 mn)	260	230	210	200	200	248	240	235	235
Outputs									
Petroleum Products (M.T.'000)	3,891	4,250	4,250	4,500	4,500	4,250	4,250	4,500	4,500
Coke (")	307	346	366	430	455	346	366	430	455
Electricity (GWh)	3,471	4,782	3,812	3,874	4,090	5,457	5,849	7,341	8,065
Own Use & Losses									
Petroleum Refining (M.T.'000)	131	143	143	152	152	143	143	152	152
Natural Gas Production (m^3 mn)	826	1,058	1,043	1,164	1,145	1,102	1,072	1,046	1,117
Electricity (GWh)	1,948	2,081	2,088	1,982	2,050	2,401	2,617	3,118	3,400
Secondary Energy Imports									
Petroleum Products (M.T.'000)	619	258	449	275	235	531	900	1,084	1,378
Coke (M.T.'000)	40	48	52	58	63	52	58	76	86
Secondary Energy Exports									
Natural Gas Products	-	730	730	1,190	1,190	730	730	730	730
Final Consumption									
Fuelwood (M.T.'000)	5,654	6,445	6,799	7,381	7,806	6,473	6,877	7,535	8,025
Electricity (GWh)	12,795	15,414	16,702	18,877	20,501	15,790	17,210	20,323	22,355
Petroleum Products (M.T.'000)	3,855	4,205	4,386	4,435	4,369	4,423	4,738	5,112	5,392
Coal (M.T.'000)	725	843	1,041	1,222	1,360	877	1,064	1,293	1,466
Coke (M.T.'000)	209	249	270	303	328	253	275	316	346
Natural Gas (m^3mn)	168	218	246	446	694	209	259	307	347
Furnace Gas (")	651	600	550	500	500	649	595	590	590
Town Gas (")	296	305	303	298	292	316	316	321	314

Source: CNE; ENAP; ENDESA, ENACAR; Mission estimates.

Annex 5

PROJECTED FINAL ENERGY CONSUMPTION, 1990; 1992; 1995; 1997
(Teracalories)

	Prelim.	Action- Oriented Scenario				Trend-Based Scenario			
	1986	1990	1992	1995	1997	1990	1992	1995	1997
Total	85,058	96,202	102,413	110,217	115,786	99,505	107,625	119,324	127,820
by Source:									
Petroleum Products	44,753	48,822	50,922	51,489	50,726	51,355	55,006	59,352	62,604
Woodfuels	19,790	22,558	23,797	25,834	27,321	22,726	24,070	26,373	28,087
Electricity	10,517	13,256	14,364	16,234	17,631	13,579	14,801	17,478	19,225
Coal	5,077	5,899	7,287	8,554	9,520	6,136	7,450	9,051	10,262
Coke	1,579	1,881	2,040	2,289	2,478	1,911	2,078	2,387	2,614
Natural Gas	1,571	2,026	2,296	4,175	6,492	1,950	2,420	2,868	3,241
Town Gas	1,185	1,220	1,212	1,192	1,168	1,264	1,264	1,284	1,256
Furnace Gas	586	540	495	450	450	584	536	531	531
by Consuming Sector:									
Residential/Commercial/ Admin. Sectors	27,428	28,766	29,460	30,444	31,116	29,571	30,552	31,733	32,520
Petroleum Products	7,899	6,941	6,548	5,319	4,206	7,742	7,407	6,899	6,434
Woodfuels	13,826	14,886	15,334	16,037	16,520	14,907	15,386	16,089	16,576
Electricity	3,582	4,230	4,585	5,135	5,538	4,288	4,673	5,234	5,643
Coal	72	105	119	140	154	112	126	147	161
Natural Gas	1,492	1,924	2,182	3,101	3,970	1,838	2,260	2,644	2,970
Town Gas	557	680	692	712	728	684	700	720	736
Agric./Industry/Mining Sectors	32,521	37,605	40,441	43,935	46,430	38,124	41,878	46,470	49,688
Petroleum Products	11,937	12,060	12,098	10,591	8,556	12,025	12,642	11,599	10,847
Woodfuels	5,964	7,672	8,463	9,797	10,801	7,819	8,684	10,284	11,511
Electricity	6,743	8,806	9,543	10,840	11,817	9,069	9,890	11,977	13,293
Coal	5,005	6,004	7,168	8,414	9,366	6,024	7,324	8,904	10,101
Coke	1,579	1,881	2,040	2,289	2,478	1,911	2,078	2,387	2,614
Natural Gas	79	102	114	1,074	2,522	112	160	224	271
Town Gas	628	540	520	480	440	580	564	564	520
Furnace Gas	586	540	495	450	450	584	536	531	531
Transport Sector	25,109	29,831	32,512	35,838	38,240	31,810	35,195	41,121	45,612
Petroleum Products	24,917	29,611	32,276	35,579	37,964	31,588	34,957	40,854	45,323
Electricity	192	220	236	259	276	222	238	267	289

Source: CNE; ENDESA; ENAP; GASCO; mission estimates.

Annex 6

PROJECTED ENERGY FOREIGN TRADE, 1990; 1992; 1995; 1997
(Current US$ millions)

	Prelim. 1986	Action-Oriented Scenario 1990	1992	1995	1997	Trend-Based Scenario 1990	1992	1995	1997
Imports	384.1	530.0	677.5	846.3	1,108.1	631.8	839.9	1,158.9	1,607.0
Crude Petroleum and Petroleum Products	354.3	502.0	649.6	789.9	1,004.9	596.4	793.2	1,070.7	1,478.6
Crude Petroleum	250.2	441.4	532.0	704.7	915.6	471.7	557.5	735.7	954.8
Volume (M.T.'000)	(2,596)	(3,278)	(3,543)	(3,977)	(4,202)	(3,503)	(3,713)	(4,152)	(4,382)
Unit Price (US$/M.T.)	(96.39)	(134.66)	(150.16)	(177.19)	(217.90)	(134.66)	(150.16)	(177.19)	(217.90)
Petroleum Products	104.1	60.6	117.6	85.2	89.3	124.7	235.7	335.0	523.8
Volume (M.T.'000)	(619)	(258)	(449)	(275)	(235)	(531)	(900)	(1,084)	(1,378)
Unit Price (US$/MT) a/	(168.14)	(234.90)	(261.94)	(309.08)	(380.14)	(234.90)	(261.94)	(309.08)	(380.14)
Coal and Coke	29.8	28.0	27.9	30.4	39.3	35.4	46.7	88.2	128.4
Coking Coal	22.9	20.3	18.6	18.6	24.9	27.3	32.7	42.3	52.0
Volume (M.T.'000)	(381)	(454)	(496)	(258)	(303)	(477)	(520)	(585)	(633)
Unit Price (US$/M.T.)	(60.-)	(57.27)	(62.90)	(72.27)	(82.17)	(57.27)	(62.90)	(72.27)	(82.17)
Steam Coal	3.9	4.3	5.2	6.6	8.0	4.4	9.4	39.0	67.6
Volume (M.T.'000)	(78)	(91)	(99)	(109)	(117)	(92)	(180)	(647)	(993)
Unit Price (US$/M.T.)	(50.-)	(47.73)	(52.42)	(60.23)	(68.06)	(47.73)	(52.42)	(60.23)	(68.06)
Coke (Net)	3.0	3.4	4.1	5.2	6.4	3.7	4.6	6.9	8.8
Volume (M.T.'000)	(40)	(48)	(52)	(58)	(63)	(52)	(58)	(76)	(86)
Unit Price (US$/M.T.)	(75.-)	(71.59)	(78.63)	(90.34)	(102.08)	(71.59)	(78.63)	(90.34)	(102.08)
Natural Gas	-	-	-	26.0	63.9	-	-	-	-
Volume (m^3 million)	(-)			(200)	(400)				
Unit Price (US$/$m^3$'000)	(70.62)			(129.82)	(159.68)				
Exports	-	134.7	150.2	269.1	326.2	134.7	150.2	158.7	195.1
Methanol		134.7	150.2	158.7	195.1	134.7	150.2	158.7	195.1
Volume (M.T.'000)		(730)	(730)	(730)	(730)				
Unit Price (US$/M.T.)	(132.09)	(184.55)	(205.79)	(217.33)	(267.29)				
Ammonia/Urea	-	-	-	110.4	131.1	-	-	-	-
Volume (MT.'000) b/	-	-	-	(460)	(460)				
Unit Price (US$/M.T.)	(107.0)			(240.-)	(285.-)				

a/ Weighted average.
b/ 80% of capacity assumed to be dedicated to exports.

Memorandum Item -- Action-Oriented Scenario

Based on the assumption of a transmission fee in Argentina of US$1/BTU million (i.e. US$35.31/m^3 '000) and escalation of this fee in line with international petroleum price increases, the cost to Chile for gas exchanges would be as follows:

	1995	1997
US$ millions	13.0	31.9
Volume (m^3 millions)	(200)	(400)
Unit Transmission Fee (US$/$m^3$ '000)	(64.91)	(79.84)

Source: ENAP; GASCO; IFC; mission estimates.

ENERGY DEMAND PROJECTIONS, 1987-1997
ASSUMPTIONS USED

1. Energy demand projections have been based on growth rates for GDP, sectoral value added and personal incomes, as projected by the World Bank. They reflect a scenario which assumes that a continued vigorous pursuit of structural changes in the economy results in a sustainable long term GDP growth of around 5% p.a. and hence, in annual increases of 2.5-3% in per-capita incomes.

Table 1: PROJECTED GDP AND SECTORAL GROWTH, 1987-1997
(1986 constant prices)

	1987-92	1993-97
GDP	5.0	4.0
Agriculture, Industry, Mining	4.9	4.0
Transport	4.9	4.0
Personal Consumption	4.1	3.5

Source: World Bank; mission estimates

2. The base year for both the Action-Oriented Scenario and the Trend-Based Scenario is 1986. Growth rates were applied to the 1986 final energy consumption for each energy consuming sector. Income elasticities of demand were incorporated to reflect the growth of sectoral energy demand relative to sectoral value added and in the case of residential energy consumption, relative to personal income (consumption) growth. These elasticities are based on (a) observations of relevant historical trends, and (b) elasticities of demand projected for comparable countries. The lower elasticities of the Action-Oriented Scenario essentially reflect the mission's assumptions about the potential for conservation and interfuel substitution through energy demand management policies outlined in the report. A crucial component of these policies would be the continued active pursuit of energy pricing based on economic cost, with emphasis on proper price relationships as well as levels of energy prices. The Trend-Based Scenario incorporates less optimistic assumptions about energy demand management. As discussed in the report, the two scenarios are intended to represent a range of possible outcomes rather than precise forecasts.

3. The two sets of growth rates and elasticities of energy demand are indicated below.

Table 2: PROJECTED OVERALL ENERGY DEMAND GROWTH AND UNDERLYING ELASTICITIES, 1987-1997

Sector	1987-1992 Energy Demand Growth %	1987-1992 Elasticity	1993-1997 Energy Demand Growth %	1993-1997 Elasticity
		Action-Oriented Scenario		
Residential/Commercial/ Administrative Sectors	1.2	(0.30)	1.1	(0.30)
Agricultural/Industry/ Mining Sectors	3.7	(0.76)	2.8	(0.72)
Transport Sector	4.4	(0.90)	3.3	(0.83)
		Trend-Based Scenario		
Residential/Commercial/ Administrative Sectors	1.8	(0.44)	1.3	(0.37)
Agricultural/Industry/ Mining Sectors	4.3	(0.88)	3.5	(0.88)
Transport Sector	5.8	(1.18)	5.3	(1.32)

Source: Mission estimates

Woodfuels

4. The projections of final energy consumption of woodfuels are based on the following assumptions:

- natural population growth rate for 1987-97 of 1.7% p.a.; and unchanged per-capita consumption of woodfuels throughout this period;
- for the Action-Oriented Scenario, it is assumed that the average efficiency of woodstoves will increase by about 10%, mainly through the dissemination of improved stoves among rural populations;
- The Trend-Based Scenario assumes that there is no significant increase in stove efficiency; and
- consumption in the industry/mining sectors would be above the average energy consumption for the sectors.

5. The resulting increases in woodfuels consumption during 1987-97 would be held at 2.5% p.a. under the Action-Oriented Scenario and to

3.2% p.a. under the Trend-Based Scenario. Woodfuels consumption by 1997 would be nearly one-third higher than in 1986.

Petroleum Products

6. The projections of the consumption of petroleum products are based on elasticities of demand for the different groups of energy-consuming sectors. Fuel consumption for electricity generation is estimated based on CNE's forecast of the expansion of electricity generating capacity. Under the Action-Oriented Scenario, the bulk of the fuel oil- and diesel-based power generation would be phased out and replaced by electricity generation based on coal and later, natural gas, with the exception of isolated load centers when this would not be economic. Under the Trend-Based Scenario, little further progress would be achieved, with natural gas-based generation projected to be little expanded. Refinery own consumption and losses are assumed to remain at their 1986 level of 3.2% of refinery throughout the 1987-97 period, for both Scenarios.

7. Final consumption of petroleum products under both Scenarios is projected during 1987-97 to rise relatively moderately i.e. 0.7% p.a. and 1.9% p.a., respectively. The difference in growth essentially is accounted for by conservation measures, as well as some efficiency effects as result of substitution. Under the Trend-Based Scenario, final consumption of petroleum products by 1997 would be about 23% higher than under the Action-Oriented Scenario.

Table 3: PROJECTED GROWTH OF FINAL CONSUMPTION OF PETROLEUM PRODUCTS AND UNDERLYING ELASTICITIES, 1987-1997

Sector	1987-1992		1993-1997	
	Petr. Prod. Demand Growth %	Elasticity	Pet. Prod. Demand Growth %	Elasticity
		Action-Oriented Scenario		
Residential/Commercial/Admin. Sectors	-3.2	(n.a.)	-9.3	(n.a.)
Agricultural/Industry/Mining Sectors	-0.2	(n.a.)	-7.2	(n.a.)
Transport Sector	4.4	(0.90)	3.3	(0.82)
		Trend-Based Scenario		
Residential/Commercial/Admin. Sectors	-1.1	(n.a.)	-2.9	(n.a.)
Agricultural/Industry/Mining Sectors	1.0	(0.20)	-3.1	(n.a.)
Transport Sector	5.8	(1.18)	5.3	(1.32)

a/ Energy basis
. Smaller than smallest unit shown

Source: Mission estimates.

Natural Gas

8. Natural gas requirements under the Action-Oriented Scenario are projected to be nearly 30% above those for the Trend-Based Scenario, i.e. 3.3 bn m^3 vs. 2.6 bn m^3 in 1997. This is because (a) both petrochemical schemes (i.e. methanol and ammonia/urea production) are projected to be operating by then; (b) natural gas is projected to be supplied to central Chile from the mid-1990s onwards which would account for 250-350 million m^3 of additional demand for power generation and final consumption by the mid-to late 1990s; and (c) higher requirements for NGL extraction would arise. In contrast, natural gas flaring is projected to be reduced during 1986-97 from 27% of output (net of reinjection) to 15% under the Action-Oriented Scenario and to 20% under the Trend-Based Scenario.

Electricity

9. The electricity demand projections are those made by the Pehuenche project appraisal mission 1/ as extended to 1997 and complemented by projections for self-generation. They incorporate the following specific assumptions:

- a loss reduction program is instituted under the Action-Oriented Scenario such that transmission and distribution losses as a proportion of generation decline from 13.2% estimated in 1986 to 10% from 1995 onwards. Under the Trend-Based Scenario, however, no such decline would be achieved;

- the load factor is assumed to remain unchanged.

10. Compared to past years, the growth of electricity consumption projected over 1987-97 would be relatively fast, averaging 4.8% p.a. under the Action-Oriented Scenario and 5.6% p.a. under the Trend-Based Scenario. Resulting electricity requirements by 1997 under the latter would be about 10% higher than those under the Action-Oriented Scenario (i.e. about 2,000 CWh). Under the Action-Oriented Scenario, electricity growth would be moderated through higher efficiency of end-use and in generation and distribution. Thus, electricity generation required to meet domestic demand by 1997 under the Action-Oriented Scenario would be 13% lower than under the Trend-Based Scenario.

1/ SAR No. 6687-CH of May 15, 1987

CRITERIA FOR CRUDE OIL AND NATURAL GAS RESERVE ESTIMATES

Standard U.S. oil industry reserve categories are used in this analysis. Proved and developed reserves (I, IIA) are those connected to producing wells. Proved but undeveloped reserves (IIB) are adjacent and require another well to be drilled in order to be produced, but their probability of success is high (80-90%). Such wells are called development wells, and their costs are referred to as development costs. The obvious fact in this data is that 86% of the IIB reserves stated are in offshore fields which are normally more costly to develop and produce than are the onshore IIB reserves. Possible and probable reserves (III, IV) are speculative and must be viewed with caution. Class III reserves are those expected to be produced from secondary recovery operations, as well as reserves assigned to offshore discoveries before the production platform is set. Both types could be present here, but in small amounts. Class IV refers to expected exploration reserves and is merely an indication of anticipated success. No differentiation is made in these figures between III and IV, but the mission's analysis indicated they are primarily Class IV exploration reserves. Therefore, they are not of significant value. All conventional methods of reserve appraisal emphasize only Class I and II reserves in their valuations and view Class III and IV reserves merely as indications of upside potential.

Table 1: CRUDE OIL, CONDENSATE, AND NATURAL GAS RESERVES, END-1986
(m^3 '000)

Type of Reserves	Class	m^3 '000
Proved and Developed Reserves	I, IIA	5,205
Crude Oil		3,642
LPG (Gas Condensate)		1,563
Natural Gas		55.6 a/
Proved but Undeveloped Reserves	IIB	4,402
Onshore		369
Crude Oil		327
LPG		42
Offshore		4,033
Crude Oil		3,148
LPG		885
Inferred Reserves	IIB	3,463
Onshore		1,794
Crude Oil		1,265
LPG		160
Offshore		1,669
Crude Oil		1,575
LPG		94
Probable and Possible Reserves	III, IV b/	13,603
Foothills District		2,679
Brunswick		1,731
Vicuna		2,110
Sub-Total		6,520
Tertiary District (all LPG)		372
Norte Grande		6,330
Secondary Recovery Reserves at Calafate and Catalina	III	381
Subtotal		7,083

a/ m^3 billions

b/ These are expected reserves added from exploration.

Source: ENAP.

Table 2: CRUDE OIL AND CONDENSATE RESERVES, END-1984

Type of Reserves	Class	Amount of Reserves	
		(m^3 '000)	(B millions)
Proved and Developed	I, IIA	5,224	32.86
Proved but Undeveloped	IIB		
Offshore		6,385	40.16
Onshore		1,069	6.72
Total		7,454	46.88
Total Proved	I, II	12,678	79.74
Probable and Possible	III, IV	10,322	64.93
Production for 1984 (Crude Oil and Condensate)		2,232	14.04
At a daily rate of		6,114 m^3	38,450 BPD

Source: ENAP.

The total Class III and IV reserves for 1986 exceeds the 1984 projection by 20.5 MM bbls and is composed of 97% Class IV exploration reserves. These numbers result primarily from probability estimates of geological parameters. They do not represent any actual increase in oil reserves. They only represent an increase in expectation and cannot be given a quantitative significance.

CRUDE OIL AND NATURAL GAS PROJECTIONS, 1987-96

Table 1: PROJECTED INVESTMENT PROGRAM FOR PETROLEUM DEVELOPMENT AND EXPLORATION, 1987-1996
(1986 US$ millions; Standard Deviation in Parentheses)

Year	Springhill District				Non-Producing Areas						Total	
	Onshore		Offshore		Tertiary		Piedmont a/		Grand North b/			
1987	34	(6)	79	(9)	0	(0)	1	(0)	4	(0)	117	(10)
1988	24	(6)	80	(8)	4	(1)	8	(2)	5	(0)	122	(11)
1989	5	(5)	85	(11)	2	(1)	11	(3)	10	(1)	116	(12)
1990	4	(4)	75	(19)	0	(0)	17	(3)	15	(2)	110	(20)
1991	1	(2)	41	(27)	0	(0)	24	(5)	19	(4)	85	(28)
1992	1	(1)	12	(23)	3	(2)	27	(8)	23	(8)	65	(25)
1993	1	(1)	2	(7)	13	(2)	29	(10)	27	(9)	72	(16)
1994	0	(1)	0	(2)	17	(6)	26	(12)	24	(10)	67	(17)
1995	2	(1)	0	(1)	5	(4)	24	(13)	21	(10)	53	(17)
1996	4	(2)	0	(2)	2	(2)	21	(14)	20	(12)	47	(19)

a/ Ultima Esperanza Sector.
b/ Salar de Atacama Sector.

Source: ENAP.

Table 2: PETROLEUM PRODUCTION FORECAST DURING THE PERIOD 1987-1996
(m^3 '000; Standard Deviation in Parenthesis)

Year	Springhill District: Developed Reserves Presently Producing	Springhill District: Estimated Onshore a/		Springhill District: Estimated Offshore a/		Non-Producing Areas: Tertiary		Non-Producing Areas: Piedmont b/		Non-Producing Areas: Grand North c/		Total	
1987	1,333	70	(15)	319	(11)	0	(0)	0	(0)	0	(0)	1,721	(19)
1988	821	172	(42)	617	(73)	0	(0)	0	(0)	0	(0)	1,610	(84)
1989	490	220	(49)	805	(123)	0	(0)	0	(0)	0	(0)	1,515	(132)
1990	330	199	(67)	791	(221)	0	(0)	0	(0)	0	(0)	1,321	(231)
1991	305	161	(76)	619	(279)	0	(0)	0	(0)	0	(0)	1,085	(289)
1992	242	132	(76)	422	(235)	0	(0)	56	(60)	62	(83)	914	(268)
1993	198	107	(73)	261	(166)	82	(149)	164	(126)	186	(187)	999	(325)
1994	157	92	(71)	150	(104)	63	(133)	214	(141)	278	(246)	954	(337)
1995	119	72	(53)	85	(48)	57	(110)	249	(163)	343	(270)	924	(342)
1996	94	57	(37)	60	(21)	41	(84)	271	(184)	387	(283)	910	(350)

a/ Estimated production resulting from planned exploration and development investment.

b/ Ultima Esperanza Sector.

c/ Salar de Atacama Sector.

Source: ENAP.

Table 3: PROJECTED CONDENSATE PRODUCTION FOR THE PERIOD 1987-1996
(M tons, Standard Deviation in Parenthesis)

Year	Springhill District: Developed Reserves Presently Producing	Springhill District: Estimated Onshore		Springhill District: Estimated Offshore		Non-Producing Areas: Tertiary	Non-Producing Areas: Piedmont a/		Non-Producing Areas: Grand North b/		Total	
1987	217	4	(1)	5	(1)	0	0	(0)	0	(0)	226	(1)
1988	197	20	(5)	26	(5)	0	0	(0)	0	(0)	243	(7)
1989	189	31	(8)	45	(9)	0	0	(0)	0	(0)	264	(12)
1990	175	29	(11)	48	(11)	0	0	(0)	0	(0)	252	(16)
1991	161	24	(13)	52	(12)	0	0	(0)	0	(0)	237	(17)
1992	155	20	(14)	49	(13)	0	1	(2)	1	(3)	226	(19)
1993	151	15	(14)	44	(12)	0	7	(9)	5	(9)	222	(22)
1994	129	13	(14)	39	(11)	0	13	(13)	12	(15)	206	(27)
1995	130	10	(10)	32	(6)	0	19	(16)	19	(20)	211	(28)
1996	133	7	(6)	31	(3)	0	24	(18)	26	(23)	222	(30)

a/ Sector Ultima Esperanza.

b/ Sector Salar de Atacama.

Source: ENAP.

Table 4: PROJECTED NATURAL GAS PRODUCTION AND SALES, 1987-1996
(m^3 millions; Standard Deviation in Parenthesis)

Year	Springhill District: Methanol Project	Springhill District: Ammonia/Urea Project	Springhill District: Domestic XII Reg.	Presently Non-Producing Areas: Tertiary		Presently Non-Producing Areas: Piedmont a/		Presently Non-Producing Areas: Grand North b/		Total	
1987	0	0	225	0	(0)	0	(0)	0	(0)	225	(0)
1988	0	0	225	0	(0)	0	(0)	0	(0)	225	(0)
1989	550	0	215	0	(0)	0	(0)	0	(0)	765	(0)
1990	732	174	215	0	(0)	0	(0)	0	(0)	1,121	(0)
1991	732	436	215	0	(0)	0	(0)	0	(0)	1,383	(0)
1992	732	457	215	0	(0)	0	(0)	0	(0)	1,404	(0)
1993	732	457	215	0	(0)	0	(0)	0	(0)	1,404	(0)
1994	732	457	215	0	(0)	0	(0)	0	(0)	1,404	(0)
1995	732	457	215	460	(201)	32	(67)	33	(93)	1,929	(231)
1996	732	457	215	470	(192)	56	(81)	61	(122)	1,991	(241)

a/ Sector Ultima Esperanza.
b/ Sector Salar de Atacama.

Source: ENAP.

FORMULA FOR ESTIMATING OPTIMAL PETROLEUM DEPLETION

Q = Peak production (million bbls/year)

P = Oil price ($/bbl)

a = Decline rate from peak production (e.g. 0.21 is 21%/year decline)

i = Discount rate

R = Producible reserves (million bbls), note Q/a = R

C = Present cost of new investment, both capital and operating

a_p = Presently planned decline rate, associated with cost "C"

K = C/a_p

$$NPV = \quad P\,Q\,e^{-at}\,e^{-it}\,dt - Ka$$

$$NPV = \frac{PQ}{(a+i)} - Ka = a[(PR/a+i) - K]$$

$$\frac{d\,NPV}{d\,a} = \frac{PR}{a+i} - K - \frac{PRa}{(a+i)^2}$$

At maximum NPV, dNPV/da = 0 and K = C/a_p, so:

$$0 = \frac{PR}{(a+i)} - \frac{C}{a_p} - \frac{PRa}{(a+i)^2}$$

Optimum Depletion Rate: $a^* = [(i\ PR\ a_p)/C]^{\frac{1}{2}} - i$

<u>Note</u>: For oil prices which are increasing (or decreasing), a* can be estimated by substituting i with discount rate minus growth rate of oil price per year, from base price P (since at time t price = Pe^{gt}, where g = percent annual growth rate of oil price).

Application to Petroleum Production in Chile

Present Production

25.7 million barrels of planned oil reserves produced over 9 years declining at about 25%/year with operating costs of only $3.20/barrel:

$$a^* = [i\ P(.104)]^{\frac{1}{2}} - i$$

New Offshore

31 million barrels of oil and LPG reserves produced between 1997 and 2004, declining at about 14%/year with present value of investment and operating costs of US$341 million:

$$a^* = [i\ P(0.013)]^{\frac{1}{2}} - i$$

New Onshore

10.24 million barrels of oil and LPG reserves produced between 1987 and 2004, declining at about 26%/year with present value of operating and capital costs of US$80 million:

$$a^* = [i\ P(0.034)]^{\frac{1}{2}} - i$$

Using the above formulas indicates that optimal depletion of the new onshore and new offshore areas could be at one half to two-thirds of the planned rate for a wide range of oil prices and discount rates. However, if wells are dispersed widely among many reservoirs, as apperas to be the case in Chile, disaggregated optional depletion values would be closer to the planned rates. This indicates that the question of optimal depletion should be investigated further using disaggregated field engineering data, not available to the mission. The depletion of present production appears to be optimal.

Table 1: PROJECTED CRUDE OIL AND CONDENSATE PRODUCTION, 1987-2000
(m^3 '000)

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Planned Production														
Presently Producing														
Crude	1,333	821	490	330	305	242	198	157	119	94	69	51	38	26
LPG	400	363	348	323	296	286	278	237	239	245	230	220	200	180
Subtotal	1,733	1,184	838	653	601	528	476	394	358	339	299	271	238	206
New Offshore														
Crude	319	617	805	791	619	422	261	150	85	60	49	46	45	39
LPG	9	49	83	89	96	90	81	71	59	57	66	72	76	76
Subtotal	328	665	888	880	715	512	342	222	144	117	115	118	121	114
New Onshore														
Crude	70	172	220	199	161	132	107	92	72	51	34	23	16	11
LPG	7	37	51	53	44	37	28	24	18	9	7	4	4	2
Subtotal	77	209	277	252	205	169	135	116	90	60	41	27	20	13

Note: Crude includes natural gasoline.

Source: ENAP.

RISK AND ASSOCIATION CONTRACTS FOR OIL EXPLORATION AND PRODUCTION

Introduction

1. The Government in 1981 opened all hydrocarbon-prospective areas, except the Magallanes Basin, to outside companies for exploration and exploitation under Petroleum Operations Contracts (Risk Contracts). The Magallanes Basin then remained reserved for the state company ENAP. However, in 1986, the Government also opened up all prospective areas in the Magallanes region, except the producing Springhill district. Exploration and exploitation of hydrocarbon resources in Chile require risk contracts between companies and the State and in the case of activities in the Magallan, association contracts between outside companies and ENAP. It is up to the contractors' decision whether they associate with ENAP in exploration or exploitation programs outside Magallanes.

2. The stipulations of the petroleum law and model contract governing work commitments, production sharing, valuation of output, taxation, and foreign exchange matters are at least as favorable as in other countries in the Region, and offer considerable flexibility. It is important to offer conditions to international companies that allow Chile to compete successfully with established oil producing countries for scarce exploration funds, in a situation where the international investment is adversely affected by relatively depressed petroleum prices. This is especially so in view of the highly speculative and costly nature of exploration in Chile's frontier areas, the relatively unfavorable geology which might limit the chances for discovering crude in significant quantities, the complex technological requirements, and the moderate success achieved thus far in attracting foreign petroleum companies to Chile.

3. As part of the generally favorable petroleum legislation, the clauses pertaining to taxation (i.e. the possibility of choice between corporate income tax and a fixed levy on gross revenues; provision for tax rebates) are sufficiently flexible to allow elegibility of U.S. based companies of the U.S. overseas tax credit. 1/ Also, no special provisions seem to exist with regard to production sharing for natural gas. These issues should be resolved in consultation with affected companies. Also, eliminating the mandatory association with ENAP in the Magallanes probably would help to attract additional investors'

1/ In order for a levy to meet U.S. Internal Revenue Service criteria for creditability against U.S. income tax, it needs to (a) be levied on income, not gross revenue (in which case it would be treated as a -- non-creditable -- royalty; (b) be generally applicable, i.e. not be industry- or company-specific and (c) remain unchanged during the period of its application.

interest. While reserving the producing Springhill district for ENAP is not considered to be a serious impediment to attracting foreign investment, know-how transfer and application of new technical concepts by different companies would be stimulated through opening up this area, with long-term benefits for petroleum operations.

Contract Terms

4. The exploration/exploitation agreement is a modified service contract following the Colombian model. The Contractor assumes the entire exploration risk, unless ENAP agrees to join in the exploration program. The Contractor is paid in convertible currency or a percentage of production, at the Government's option. Should ENAP share in the exploitation and exploration risk, the agreement becomes an association contract between the outside company and ENAP. Almost all aspects of the contract, including certain aspects of taxation, are negotiable, in part to make provisions for higher costs and more severe working conditions in certain areas. As a result, it is impossible to determine how favorable this agreement is from its terms and conditions. To-date, no agreements have been negotiated under this new law, and as a result, no good understanding exists as to the range within which many of the contract terms can be negotiated.

5. In order to enter into a contract for any of the operations areas in Chile, an interested party must pay a US$50,000 registration fee. This entitles the party to receive the technical information package, which includes seismic surveys, well reports and logs, geological reports and maps, base maps and geological background data. By early 1987, 22 companies have expressed some interest and nine have paid the registration fee. Five companies followed up by making specific proposals and/or visiting ENAP for discussions.

Exploration

6. The contract comprises two parts, exploration and exploitation. The size of explortion blocks onshore is not to exceed 3,000 sq.km in Magallanes, or 5,000 sq.km elsewhere. The size of offshore blocks are not to exceed 10,000 sq.km.

7. Exploration Period. The exploration phase is for 10 years, i.e. initially for five years and extendable for five additional years, provided the Contractor has discovered hydrocarbons in sizeable quantities and has fulfilled all contractural obligations. Exploration is broken into eight contractual periods (three during the first five years, five during the following five years). The first is a two-year geological and geophysical work period, with a minimum expenditure commitment of US$1 million, exploratory drilling being optional. During the remaining seven contractual periods, at least one exploratory well per period needs to be drilled. A seismic option exists since the contractor can leave at the end of any work period. The length of the periods, the amount of work and even the length of the exploration phase are all negotiable.

8. After the fifth year, the Contractor must return 50% of the original contract area. The Contractor will be free to select the area to be retained, subject to certain limitations. After the tenth year, the Contractor must return all but the field exploitation areas. If no exploitation area is declared, the contract terminates after ten years.

9. Under certain conditions, ENAP will join in association during work periods two through eight. ENAP's share of exploration expenses will normally be made through providing equipment, materials, and services such as transportation.

Exploitation

10. Exploitation Period. This period starts after the declaration of a commercial discovery by the Contractor, at any time during the exploration period, and extends for 35 years from the start of the exploration period. The Contractor is allowed, from the time of discovery, a term of two years in the case of crude oil, four years in the case of natural gas, to decide whether or not to exploit the field so discovered. (Longer terms can be negotiated for marginal fields). The Contractor is given three years, from the date of discovery, to put an oil field into production, and up to five years for a gas field, if onshore. For offshore fields, those terms are six and nine years, respectively.

11. The Contractor has the exclusive right to develop and exploit any field in the contract area. However, if exploitation occurs in the Magallanes, the contractor must join ENAP in association. If it occurs outside Magallanes, this association is negotiable. The Contractor is compensated for services rendered by means of a "remuneration" in kind (for oil) or U.S. dollars (for gas). All exploration and development costs are recovered by the Contractor with its gross remuneration. When associated with ENAP, costs and remuneration are shared on up to a 50/50 basis. Therefore, an operating agreement with ENAP must also be negotiated. In all associations with ENAP, the terms and conditions are negotiable.

12. General guidelines for the production split are as follows:

Table 1: PRODUCTION SPLITS BETWEEN CONTRACTORS AND THE GOVERNMENT
(Percent)

Production	Field Size	Contractor	Government
0-5,000 BPD	Small	83.5	16.5
5,000-Negotiated	Medium	75.0	25.0
Negotiated and Larger	Large	50.0	50.0

13. Although this is not very useful for profitability calculations, it does give an indication of how the Government views production splits. The contract is a negotiated agreement, and when signed, it becomes a decree law.

14. Taxation. Should the Contractor elect to organize a single agency or partnership in Chile, it shall be deemed a single taxpayer and taxed on the basis of the consolidated balance sheet covering its operations in Chile. The Contractor will then be subject to taxation under the prevailing income tax law and customs duties. (The income tax rate is currently 37% for corporations.) Alternatively, the Contractor may elect to be taxed at 50% on the remuneration. The tax rate so established will remain constant while the contract is in force, although the Government can grant tax rebates under specific circumstances, e.g. difficult working conditions and costly operations.

15. Pricing of Crude Oil and Natural Gas. For purposes of calculating the Contractor's income tax liability, crude oil will be valued at the price actually received for sales to third parties in the domestic or export markets, or at the price calculated for reacquisition of oil by the State, whichever is higher. (The latter price is the average of the basket composed of at least three crudes, f.o.b. original port of shipment, from three countries, agreed by the Parties.) For natural gas, calculation of the tax liability will be based on the market price actually received. The State and the Contractor will agree to take all steps necessary for the sale of the gas, with a view to attaining the best possible price.

16. Domestic Market Supply Obligations. The State will only be entitled to reacquire part of the Contractor's remuneration (and pay for it in cash) if domestic requirements for crude oil are not met by the

volumes received by the State under all operation contracts in force. 2/

17. Provisions on Natural Gas. The Contractor may freely use gas for petroleum operations, including reinjecting it as a means to store it or to increase the recovery of liquid hydrocarbons. Flaring or venting of gas is only possible with express State permission.

18. Foreign Exchange Regulations. The Contractor is guaranteed free disposal of the foreign currency earned from exporting hydrocarbons received in payment of the remuneration. The Contractor (and Subcontractor, as the case may be) also is guaranteed free access to foreign currency for remitting capital and profits earned under the contract, at the highest exchange rate in effect in the market.

19. Contract Termination. The contract is envisaged to terminate

(a) by Contractor decision at the end of any contractual period during the exploration phase;

(b) at the end of the initial exploration phase if the Contractor has failed to make a sizeable discovery;

(c) upon unwarrantable non-compliance by the Contractor of any of its obligations under the contract;

(d) thirty-five years from the effective date of the contract.

2/ The maximum quantity of petroleum that the State may reacquire in any given year for each Contractor's remuneration (including ENAP) is to be calculated as follows:

$$WR = \frac{R}{TCR} \times (D - TER) \qquad \text{if } D > TER$$

$$WR = 0 \qquad \text{if } D < TER$$

where

R = Contractor's Remuneration

WR = Fraction of Contractor's remuneration that may be reacquired by the State.

TCR = Sum of all Contractor's remunerations plus ENAP's production.

D = Domestic hydrocarbon demand.

TER = Sum of all Contractor's productions plus ENAP production, less the sum of all Contractor's Remunerations.

20. Should the contract terminate during the exploration phase, the Contractor is obliged to return to the State the entire contract area and shall be released from all rights and obligations except the contractual obligations for the period in effect. The Contractor can dispose freely of any equipment, materials, and facilities used for exploration. Should the contract termiante after the start of the exploitation phase, the Contractor shall transfer to the State, free of charge and in good working conditions, all wells and ancillary installations associated with field exploitation.

Association Agreement with ENAP

21. For exploration and production in the Magallan area, it is obligatory for outside investors -- domestic as well as foreign -- to associate with ENAP. ENAP and the outside investors -- the "Associate" -- will then jointly constitute the Contractor under a Petroleum Operation Contract with the State.

22. Exploration. In any contract area, exploration shall be performed by the Associate(s) at own risk and expense, and under own responsibility. ENAP is to be kept informed of all exploration operations.

23. Exploitation. Any commercial field discovered shall be exploited at the risk and expense of the Associate(s) and ENAP. To carry out field development and exploitation, ENAP and the Associate(s) shall designate an operator who shall determine the maximum production rate for each field, among others. ENAP and the Associate(s) share 50% each in the joint operation. Once ENAP has accepted a declaration by the Associate(s) of commercial exploitability of a field, the joint operation to exploit such field will begin, and ENAP will reimburse the Associate(s) for 50% of the costs of drilling and completing those wells that are put into production. (In the case of an offshore field, all potentially productive wells will be treated as above, even if not completed as producing wells.) ENAP will reimburse the Associate(s) in crude oil from its share in the remuneration or in cash, at its option. Each party may freely and separately sell, or otherwise dispose of, any oil received as its part of the remuneration.

GEOLOGIC FRAMEWORK FOR HYDROCARBON DEPOSITS IN CHILE

Background

1. In order to comprehend the current level of oil development in Chile, several basic geologic factors must be understood. The entire Pacific coastal area is a subduction zone of convergent crustal plates. As a result, the sedimentary basins are characterized by sedimentary sequences comprised mainly of volcanic clastics, or fore arc facies. Such a geologic environment is not condusive to oil accumulations and only marginally favorable for natural gas formation. It is only on the east side of the main orogenic belt (Andean Cordillera) that favorable geologic conditions for forming hydrocarbon accumulations exist. This is the back arc facies in which almost all the oil fields of South and Central America are found.

2. The Springhill district of the eastern Magallanes area, adjacent to Argentina and between the first and second narrows of the Magallan Straights, is the only part of Chile where commercial oil accumulations have been found. This is a maturely developed oil basin that comprises ENAP's main exploration and production operations. The main reason for these oil and gas fields is the presence of the basal Cretaceous Springhill sandstone which forms the only oil reservoir in the area. This reservoir is a transgressive marine sandstone that occurs in close association with underlying granitic, bedrock, depositional highs, at depths between 2,000 and 3,000 meters. In no other conditions have commercial oil accumulations been found in the country.

3. Going west and south of the shallow Springhill district, this formation is found at increasing depths, and when it occurs below 3,500 meters natural gas with contained condensate is the rule. At depths greater then 4,000 meters, only natural gas can be expected. Shallower sandstones in the Cretaceous and Tertiary sections offer moderate potential, but to date have only produced natural gas, very lean in condensate content. Because of these geological chracteristics, 40 years of exploration operations have resulted in commercial oil production in only a very limited part of the country, i.e. northeast Magallanes. Except for the foothills and Norte Grande, it is not likely that oil will be found elsewhere in Chile. With this background in place, the following discussion of ENAP's exploration strategies for adding new oil reserves is presented.

Magallanes--Springhill District

4. ENAP is presently completing exploration of the shallow Springhill district, where minimum new onshore fields remain and only moderate amounts of offshore oil are to be found. The operating plan indicates that over the next four years, 22 and 24 exploratory wells will be drilled onshore and offshore, respectively. Beyond 1990, no explor-

atory work is programmed on- or offshore in the Springhill district. Associated with these exploratory wells are 90 onshore development wells (approximately 4 well fields) and 200 offshore development wells (8 well fields). Beyond 1991, almost all development drilling in the Springhill district is expected to be terminated. The numbers of development wells are based on the success of exploration wells and expected size of the fields to be found. Beyond 1992, no more exploration wells are planned because by then all expected oil fields will have been discovered. Exploration in this basin will be completed within the first five years of the plan.

5. The plan expectations for the Springhill district should be very realistic because the area is a mature oil basin, and ENAP has a good understanding of its content and what remains. Further exploration in the deep Springhill (below 3,000 meters) is likely to result primarily in natural gas reserves. Additional natural gas is not desired because of market limitations.

Magallanes--Tertiary District

6. The Tertiary district comprises the area west and south of the Springhill district and east of the folded Foothills district. This area is characterized by a deep basin filled with thick sequences of Cretaceous and Tertiary sediments. If the basal Cretaceous sandstone is present, it is deeply buried. Even if it is present, there is no knowledge that it occurs in the optimal situation that exists in the shallow Springhill; e.g., associated with underlying granitic depositional highs. At depths greater than 3,500 meters, the Springhill reservoir produces mainly dry gas. In the younger sand reservoirs, only dry gas has been found. Consequently, additional exploration in the deep Springhill and Tertiary basin will only produce additional natural gas reserves. No oil has been found in this area. Thus, the area does not appear to be an appropriate exploration objective. However, ENAP's plan includes U.S.$6 million for exploration in 1988-89 (for aeromagnetic surveys and other geophysical studies to try to locate basal Cretaceous depositional highs, similar to the Springhill district), and US$40 million for 1992-96, for exploration wells. Because of the depths involved, it is questionable that liquids will be present, even if the correct geological conditions can be found. Consequently, it is doubtful that the latter expenditures will be made.

Magallanes--Pre-Cordillera (Foothills) District

7. A long narrow area of folded structures occurs between the Tertiary district and the east side of the Andean cordillera. Only a few drilling shows and one oil seep have been found in the area. However, because of the large structures present, the area has been of exploration interest for the past decade. The foothills are divided into three segments.

Ultima Esperanza (Northern Segment)

8. This area contains the least structural complexity of the three areas, which makes it an easier area to explore. To date, five exploration wells have been drilled without success and without significant hydrocarbon shows. The main problem is the lack of favorable reservoir rocks. (Where the Springhill sandstone was encountered, it was found to be indurated, impermeable and not a favorable reservoir rock). The operations plan indicates that ENAP will undertake an extensive exploration and development program in this area over the next decade. Forty-nine exploration and 100 development wells are programmed between 1989 and the year 2000. The majority of this drilling is planned to occur during the second five years of the plan. The larger part of potential future oil production from 1992 on is expected to come from this area and Norte Grande. Three new seismic surveys have been completed in 1986, and this exploration program is well underway.

9. This would appear to be a very optimistic expectation since no results have been found to date. There are numerous geological reasons to argue that the favorable Springhill conditions that exist further east are not present in the Ultima Esperanza area. It is therefore questionable that all of these exploration funds can be usefully spent.

Central Area (Brunswick Peninsula)

10. This segment contains more complex structures than Ultima Esperanza and is a more difficult operating area due to fjords and rugged topography. Five exploration wells have been drilled without producing hydrocarbon shows. Again, the absence of adequate reservoir rocks was the biggest problem. Large anticlinal structures are present and the potential for oil discoveries should be similar to Ultima Esperanza. However, no exploration program for the area is contained in the plan, probably because of the operating problems that would be encountered and the lack of favorable results in the past five attempts.

Tierra Del Fuego (Southeastern Segment)

11. This is the southernmost section of the Foothills district extending to the southeast into the Argentinian Magallanes. Three exploration wells have been drilled without success, although an oil seep was reported in one. The Vicuna well was drilled on an enormous structure that could be 75 kilometers in length and contain 1,000 feet of vertical closure. Since the area is structurally complex, its exploration will be difficult: not only has it been effected by compressional folding from the Andean cordillera, but also from lateral wrench faulting that has displaced the southern tip of South America to the east. Such intense folding and faulting tends to break up oil traps and allow their contents to escape. However, the fracture volume that may result in such a regime can produce oil reservoirs. The biggest question here is whether the tectonics have been so great as to preclude oil accumulations.

12. ENAP reports that AMOCO is interested in exploring this area. Furthermore, Occidental Oil Corporation has taken a similar exploration block directly adjacent in Argentina. Obviously there is some interest by international oil companies in this part of the Foothills district. ENAP has not included funds for exploring this area in their operating plan.

13. Of the three Foothills segments described, Ultima Esperanza is the least complex and the most accessible. Whether it is the best area in which to find oil is uncertain, but it is the easiest of the three to explore. Geophysical work is in progress and numerous exploration wells are planned.

14. The Foothills district is attractive because it contains large structures that theoretically could hold significant oil accumulations. The depositional environment should be favorable, back arc facies, and the Springhill could be found at shallow enough depths to be oil rather than gas productive. However, ENAP is aware that this is a high risk area where 13 dry holes have been drilled with minimal hydrocarbon shows and no reservoir rocks found.

Pacific Coast

15. This area, which is 2,500 miles in length, consists of numerous offshore, onshore and intro-montaine sedimentary basins that have undergone limited but unsuccessful oil exploration over the past 40 years. Aprpoximately 65 onshore and 18 offshore exploration wells have been drilled, but no commercial oil fields have been discovered. This area lies on the west side of the Andean Cordillera, is dominated by a fore arc depositional facies and for numerous geologic reasons is not favorable for hydrocarbon formation. However, within this vast area, two basins are considered to have relatively more poitential.

Norte Grande

16. This is the large onshore, intra-montaine area which occupies the northern coast, adjacent to Peru and Bolivia. The southern half, known as Las Salares, contains two basins, Salar de Atacama and Salar de Punta Negra. These basins are probably the most attractive oil exploration areas of the entire Pacific coastal area. This is because they contain many prerequisits for oil accumulation that are not known to be present elsewhere on the coast. These factors include active oil seeps, marine source rocks, fractured limestone reservoirs and a favorable depositional history. The Jurassic age sediments of interest pre-date the fore arc facies development.

17. Broken Hills Py. is reported to be interested in an exploration contract in Salar de Punta Negra in order to supply fuel for its nearby mining operations. To date, six exploration wells have been drilled in the northern half and three exploration wells in the Salares area without success.

18. ENAP has designed an extensive exploration and development program in the Norte Grande. Between 1989 and 2000, 37 exploration wells are planned, accompanied by at least 83 development wells within that period. ENAP assumes extremely low exploration and development costs for this area, projecting U.S.$1.76 per barrel well-head cost. This must be considered to be an extremely optimistic forecast in terms of oil production and associated cost. This area, along with Ultima Esperanza, plays a dominant role in ENAP's strategy. Seventy-five percent of crude oil production during the second five-year period of the plan is projected to come from these two areas, where no known oil accumulations exist today.

Arauco-Valdivia Basins (offshore)

19. This is primarily a natural gas area that could contain accumulations of commercial size. Because of their offshore location, with high development costs, and remoteness from the main gas market, this area is not likely to be developed for at least another decade.

ESTIMATED INCOME AND PRICE ELASTICITIES OF DEMAND FOR PETROLEUM PRODUCTS

Product	Income Elasticity		Price Elasticity		Coefficient of Lagged Consumption a/	Gross Price Elasticity	
	SR a/	LR a/	SR a/	LR a/ b/		SR a/	LR
Motor Gasoline	0.55 (7.2)	1.34	-0.16(-11)	-0.40	0.59(11.5)	--	--
Diesel	0.62 (4.6)	1.67	-0.21(-2)	-0.56	0.63(9.4)	0.29 (2.6) c/	0.78
LPG	0.38 (4.1)	1.50	-0.10(-5.8)	-0.40	0.75(17.6)	--	--
Kerosene (dom.)	--	1.00	--	-0.60 (-1.32)	--	--	--
Fuel Oil	0.56 (68)	--	--	--	-0.21	(-4.7) d/ --	

a/ T-statistics are in parenthesis.

b/ Long-run elasticities derived from dividing short-run elasticities by (1-C) where C = coefficient of lagged consumption; income is real GDP except for fuel oil where manufacturing value-added was used.

c/ With respect to gasoline.

d/ With respect to coal.

Source: ENAP-Pronostico dal Consumo Nacional de Combustibles Derivados del Petroleo, 1986.

COMPARATIVE DELIVERED PRICES OF COAL, 1986
(U.S.$/M.T.)

Origin	Export/Mine Price (f.o.b)	Freight	Import Duty	Unloading Charges	Delivered Price (c.i.f.)
Colombia	26	10	7.20	1.50	44.70
South Africa	26	10	7.20	1.50	44.70
Australia	24	10	6.80	1.50	42.30
ENACAR	51	6	--	1.50	58.50

Source: International Coal Report, February 1987; mission estimates.

ELECTRICITY DEMAND FORECASTS AND PRICING FOR THE PUBLIC SECTOR IN THE CENTRAL INTERCONNECTED SYSTEM

Table 1: SECTORAL FORECASTS
(GWh)

	1985	1990		1995	
		High	Low	High	Low
Small Industry & Irrigation	2,200	2,974	2,768	3,641	3,236
Large Industry & Transport	2,987	4,157	4,157	6,272	6,272
Sub-total Industry	5,187	7,131	6,925	9,913	9,508
Residential;	1,873	1,926	1,929	2,446	2,364
Commercial; Public Lighting	1,565	1,617	1,620	2,145	2,060
Total Sales	8,625	10,674	10,474	14,504	13,932
Own Use and Losses	1,912	2,018	1,995	2,640	2,654
Total Generation	10,537	12,693	12,469	17,144	16,586

Source: CNE: Proyeccion del consumo de electricidad.

Table 2: GLOBAL FORECASTS a/
(GWh)

	1985	1990		1995	
		High	Low	High	Low
Total Sales SIC 1	8,625	10,165	9,926	14,845	13,267
Total Sales SIC 2	8,625	9,854	8,815	14,116	12,536
Growth Rates (%)		1986-90		1991-95	
Total Sales SIC 1		3.3	2.9	7.9	6.0
Total Sales SIC 2		2.7	2.2	7.5	7.3

a/ The high- and low-growth scenarios correspond to the two economic forecasts; hypothesis 1 for the SIC corresponds to a 1% growth of self-generation, hypothesis 2 corresponds to the growth of self-generation as given by the customer survey.

Source: CNE: Proyeccion del consumo de electricidad.

TYPICAL ELECTRICITY TARIFFS CHARGED BY DISTRIBUTION COMPANIES, 1986; 1988 a/

Tariff Description	EDELNOR (Regions I & II) (December 1986)			CHILECTRA METROPOLITANA (Santiago) (May 1988)			
	Fixed Charge	Demand Charge	Energy Charge	Fixed Charge	Demand Charge	Energy Charge	Additional Energy Charge, Winter Months
	(Ch$/month)	(Ch$/kW/month)	(Ch$/kWh)	(Ch$/month)	(Ch$/kWh)	(Ch$/kWh)	(Ch$/kWh)
BT1 Metered Customers							
up to 90 kWh/month	143.26	--	17.17	(			
over 90 kWh/month	210.67	--	19.93	(212.40	--	19.47	38.99
BT2 Monthly Contracted Demand							
Without peak hour limits	210.67	2,048.90	11.40	212.40	2,431.21	11.21	n.a.
Partly peak hour use	210.67	1,365.90	11.40	212.40	1,562.92	11.21	
BT3 Monthly Maximum Demand Reading							
Without peak hour limits	335.30	2,048.90	11.40	390.69	2,431.21	11.21	n.a.
Partly peak hour use	335.30	1,365.90	11.40	390.69	1,562.92	11.21	
AT2 High Voltage Tariff with Monthly Contracted Demand							
Without Peak hour limits	210.67	1,314.90	10.00	212.40	1,477.28	9.64	n.a.
Partly peak hour use	210.67	845.30	10.00	212.40	955.88	9.64	
AT3 Montly Maximum Demand Reading							
Without peak hour limits	335.30	1,314.90	10.00	390.69	1,477.28	9.64	n.a.
Parly peak hour use	335.30	845.30	10.00	390.69	955.88	9.64	
AT4 Off-Peak Tariff	491.09	--	10.00	585.25	--	9.64	n.a.
Plus off-peak demand	--	184.90	--	--	185.79	--	
Plus peak demand	--	1,130.00	--	--	1,291.48	--	

a/ Exchange rates: Ch$195/US$ (December 1986); Ch$ 243/US$ (May 1988)

Source: CNE

PENHUENCHE HYDROELECTRIC PROJECT AND
ALTO JAHUEL-POLPAICO TRANSMISSION PROJECT
TYPICAL TARIFFS CHARGED BY ENDESA FOR HIGH VOLTAGE CUSTOMERS
(As of December 1986; exchange rate: US$1-Ch$195) a/

Customer Type and Location	Tariff		
	Voltage	Demand Charge	Energy Charge
	(kV)	(Ch$/kW max/month)	(Ch$/kWh)
Public Service Distribution Companies			
Taltal	110	965.50	6.78
Diego de Almagro	220	768.70	5.40
San Isidro, Alto Jahuel	220	620.30	4.01
Rancagua	154	571.10	3.91
Temuco	154	512.70	3.26
Valdivia	66	557.30	3.14
Osorno	66	592.70	3.15
Puerto Elviar	23	1,537.30	6.97
Industries over 2,000 MW			
Diego de Almagro	220	816.40	5.51
San Isidro, Alto Jahuel	220	620.30	4.09
Rancagua	154	571.10	3.99
Valdivia	66	557.30	3.21
Osorno	66	592.70	3.21

a/ Tariffs do not include the value added tax of 20%.

Note: Delivery points are ENDESA's substations. For other delivery points using ENDESA's lines, other charges are added to cover use of the line and transmission losses.

Note: Extra charges are added for reactive energy for power factors lower than 85%; during peak hours, these charges are higher.

LONG RUN MARGINAL COST FOR SELECTED COAL MINES

The calculation of LRMC is based on the average incremental cost (AIC). The AIC method estimates LRMC by discounting all incremental costs (capital and operating) that will be incurred in the future to provide the additional amounts of coal produced over a specified period, and dividing that by the discounted incremental output over that period:

$$AIC = \frac{\text{NPV of total costs}}{\text{NPV of production stream}}$$

LOTA EXPANSION PLAN
LRMC Calculation

INV. = $51,289,336, I = 12%

Year	Capital Cost	Operating Cost	Production Stream
	(US$)	(US$)	(M.T.)
1	2,072,671	23,215,268	543,600
2	17,066,583	24,606,753	600,000
3	3,153,076	26,036,739	720,000
4	2,776,217	26,757,232	720,000
5	2,624,461	26,652,733	720,000
6	2,616,859	26,537,234	720,000
7	2,292,689	26,427,235	720,000
8	2,495,299	26,317,236	720,000
9	2,346,705	26,201,737	720,000
10	2,381,331	26,097,239	720,000
11	2,292,689	25,981,740	720,000
12	2,292,689	25,871,741	720,000
13	2,292,689	25,761,742	720,000
14	2,292,689	25,646,243	720,000
15	2,292,689	25,541,744	720,000
16	0	25,541,744	720,000
17	0	25,541,744	720,000
18	0	25,541,744	720,000
19	0	25,541,744	720,000
20	0	25,541,744	720,000
21	0	25,541,744	720,000
22	0	25,541,744	720,000
23	0	25,541,744	720,000
24	0	25,541,744	720,000
25	0	25,541,744	720,000.
NPV =	US$28,598,445	US$201,17[illegible],020	5,393,897
	AIC =	US$42.60/M.T.	

Source: Cost and production figures provided by ENACAR, March 1987.

COLICO/TRONGOL EXPANSION PLAN
LRMC Calculation

INV. = $9,800,983, i = 12%.

Year	Capital Cost	Operating Cost	Production Stream
	(US$)	(US$)	(M.T.)
1	614,464	6,946,431	185,500
2	2,354,503	7,281,927	195,000
3	347,660	7,776,922	210,000
4	1,017,649	8,216,917	225,000
5	749,891	8,205,917	225,000
6	853,071	8,563,414	240,000
7	545,705	8,442,415	240,000
8	431,511	8,326,916	225,000
9	440,917	7,045,429	180,000
10	407,602	7,034,429	180,000
11	407,602	7,023,429	180,000
12	407,602	7,012,429	180,000
13	407,602	7,001,429	180,000
14	407,602	6,990,430	180,000
15	407,602	6,990,430	180,000
16	0	6,990,430	180,000
17	0	6,990,430	180,000
18	0	6,990,430	180,000
19	0	6,990,430	180,000
20	0	6,990,430	180,000
21	0	6,990,430	180,000
22	0	6,990,430	180,000
23	0	6,990,430	180,000
24	0	6,990,430	180,000
25	0	6,990,430	180,000
NPV =	$5,361,962	$59,080,773	1,579,833
		AIC = US$40.79/M.T.	

Source: Cost and production figures provided by ENACAR, March 1987.

LEBU EXPANSION PLAN
LRMC Calculation

INV. = $19,740,633, i = 12%

Year	Capital Cost	Operating Cost	Production Stream
	(US$)	(US$)	(M.T.)
1	$404,137	$4,460,455	111750
2	$1,044,509	$4,806,951	120000
3	$2,412,413	$5,136,948	135000
4	$3,444,411	$5,389,946	150000
5	$965,389	$5,670,443	165000
6	$1,137,442	$5,983,940	180000
7	$1,423,212	$6,396,436	195000
8	$851,697	$6,599,934	210000
9	$1,383,214	$6,555,934	210000
10	$1,439,387	$6,511,934	210000
11	$1,200,766	$6,467,935	210000
12	$902,755	$6,423,935	210000
13	$1,125,811	$6,379,936	210000
14	$1,002,745	$6,335,936	210000
15	$1,002,745	$6,291,937	210000
16	$0	$6,291,937	210000
17	$0	$6,291,937	210000
18	$0	$6,291,937	210000
19	$0	$6,291,937	210000
20	$0	$6,291,937	210000
21	$0	$6,291,937	210000
22	$0	$6,291,937	210000
23	$0	$6,291,937	210000
24	$0	$6,291,937	210000
25	$0	$6,291,937	210000
	NPV = $9,396,970	$38,581,777	1131778
		AIC = $42.39	

Source: Cost and production figures provided by ENACAR, March 1987.

ENACAR - FINANCIAL INDICATORS
(Constant 1986 Ch$ millions)

	1981	1982	1983	1984	1985	1986	1987
Income from Sales	10,156	7,146	7,838	10,765	12,508	13,710	12,811
Other Income	1,338	1,400	1,648	1,865	1,057	1,266	480
Cost of Coal Purchases	-	-	-	390	1,350	1,938	980
Operating Costs	8,011	7,060	7,157	7,911	8,269	9,830	9,445
Wages and Salaries	(5,003)	(4,475)	(4,046)	(4,236)	(4,109)	(4,541)	(4,576)
Materials and Supplies	(1,218)	(937)	(1,117)	(1,275)	(1,561)	(2,100)	(1,730)
Third-party Services	(1,018)	(876)	(1,076)	(1,227)	(1,472)	(1,758)	(1,521)
Depreciation	(772)	(736)	(918)	((1,173)	(1,127)	(1,431)	(1,618)
Overheads	1,386	1,095	1,060	1,182	1,224	1,445	1,507
Final Charges	185	728	445	290	216	374	976
Earnings before Tax	(1,895)	2,003	1,278	419	210	1,284	2,691
Earnings after Tax	1,938	1,632	1,287	425	249	1,262	2,694
Short- and Long-term Liabilities	3,088	4,467	3,460	2,972	4,769	6,307	6,072
Working Capital	3,393	2,686	3,226	3,435	1,966	2,047	2,788
Total Assets	26,587	26,426	23,989	22,051	23,548	26,764	22,609
Investment	-	-	-	54	1,010	1,968	2,085
Mine				(54)	(1,010)	(1,919)	(2,029)
Above Mine				(-)	(_)	(49)	(56)
Total Output (M.T.'000)	859.7	683.2	670.4	725.8	713.3	836.1	750.9
Coal Purchases (")	-	-	-	41.5	143.9	203.6	107.4
Total Sales (")	952.8	612.3	652.4	854.3	811.4	881.6	888.9
Labor Force	7,604	6,591	5,918	5,998	6,313	6,655	6,500

Source: ENACAR.

PROJECTED COAL DEMAND FOR ELECTRICITY GENERATION IN THE CENTRAL INTERCONNECTED SYSTEM, 1987-91
(M.T. '000)

Year	Base Price (US$/ton) 40	45	48
1987	363	337	320
1988	605	587	577
1989	796	784	779
1990	851	844	835
1991	840	826	810

Source: CNE.

FUELWOOD PRICES AND COSTS

Table 1: TYPICAL FUELWOOD PRICES IN THE SANTIAGO AREA, OCTOBER 1985 (Ch$/kg)

Fuelwood Type	Price
Eucalyptus	7.40
Espino	9.04
Pine	4.65 a/

a/ For individual use.

Source: CNE.

Table 2: SUPPLY COSTS OF EUCALYPTUS a/ (Ch$/M.T.)

Activity	Yields (M.T./ha)		
	100	150	200
Standing Wood	1,162	1,107	831
Exploitation	856	856	856
Storage	252	196	169
Transport	1,183	1,183	1,183
Total	3,453	3,342	3,039
Preparation	750	750	750
Wholesale Cost	4,703	4,092	3,789

a/ It considers capital cost of 10%, and does not include subsidy.

Source: CNE.

FORECAST DEMAND FOR PETROLEUM PRODUCTS
USED IN ENAP REFINERY ANALYSIS
(m^3 '000)

Product	1985	1990	1995	Annual Change (Percent) 1986-90	1991-95	1986-95
Total	5,315	5,876	6,576	2.0	2.3	2.2
Gasoline						
93 Octane	1,073	1,281	1,464	3.6	2.7	3.2
87 Octane	288	226	219	-5.0	-0.1	-2.9
Aviation Gasoline	7	7	7	-	-	-
LPG	771	898	1,039	3.1	3.0	3.0
Kerosene	142	161	168	3.5	0.1	1.7
Jet Fuel	195	255	281	5.5	2.0	3.7
Diesel	1,686	1,988	2,373	3.4	3.6	3.5
No. 5 Fuel Oil	61	40	40	-8.8	-	-4.3
No. 6 Fuel Oil	896	797	760	-2.4	-0.1	-1.7
Naphtha	44	50	50	2.6	-	1.3
Asphalt	7	6	6	-3.1	-	-1.6
Ethylene	74	74	74	-	-	-
Pitch	45	60	60	5.9	-	2.9
Solvents	26	34	35	5.5	0.1	3.0

Source: ENAP, Gerencia de Desarrollo. Departamento de Estudios, "Pronóstico del Consumo Nacional de Combustibles Derivados de Petróleo," Septiembre de 1986.

SUMMARY OF ECONOMIC CALCULATIONS OF THE COMBINED
VALDIVIA/MAIPO VALLEY NATURAL GAS SCHEME
(Net/capital values of different schedulings of
the combined projects; 1986 US$ millions) a/

Offshore Costs	MP-1990 1986-2010	VP 1990 1986-2010	MP-1990 VP-1995 1986-2017	MP-1990 VP-1997 1986-2017	MP-1990 VP-2000 1986-2017	MP-1990 VP-2003 1986-2017
US$23/bbl Scenario						
US$800 million	--	-427	-137	-74	-5	43
US$500 million	192	-127	50	80	105	125
US$300 million	--	73	174	182	182	182
US$17/bbl Scenario						
US$800 million	--	-556	-265	-190	-75	-44
US$500 million	141	-256	-83	-36	10	43
US$300 million	--	-55	41	67	87	100

a/ MP-Maipo Valley Project; VP-Valdivia Project.

Note: Maipo Valley Project: The construction period is assumed to start two years before the natural gas market is developed. In the alternative where the Maipo project runs without combination of the Valdivia project until 2010, US$10 million are added for extra costs of repair and replacement. It is assumed that off-shore resources of at least 17-25 Billion m^3 exist. It is assumed that the gas c.i.f. Argentine/Chilean border equals a price of US$2/BTU million (which is similar to the assumed price possible to pay at the Valdivia shore.

Source: Mission Estimates.

ECONOMIC COST OF NATURAL GAS FOR ELECTRICITY GENERATION

1. Summary and Conclusions

1. Natural gas, whose use presently is limited to Magallanes, could conceivably become available in central Chile by the early to mid-1990s. This fuel then would compete with town gas in the residential/commercial/administrative sectors, and with fuel oil and coal in industry (and, possibly, mining).

2. The mission has carried out a preliminary evaluation of the economic costs in central Chile and Magallanes of using natural gas for thermal power generation and as a boiler fuel. This evaluation is based on the following assumptions:

(a) power generation in central Chile is to be expanded through the commissioning of a 300 MW thermal plant, to be on line by 1995;

(b) power generation in Magallanes is to be expanded with a 100 MW plant. The average kWh-cost for smaller plant sizes would be relatively high for plant additions much less than 100 MW because of higher unit capital costs. The price of the gas is to be based on its opportunity cost, estimated at US$0.60/BTU million;

(c) for power plant conversions to natural gas, it is assumed that a payback period (on a discounted cashflow basis) of up to ten years would be permissible but five years would be more desirable;

(d) new installations of industrial boilers and boiler conversions to gas use have been analyzed for two cases, i.e. (i) for large-sized high-pressure boilers (45 M.T./hr) and (ii) medium-sized low pressure boilers (15 M.T./hr); and

(e) energy prices for 1995 are based on World Bank projections (September 1987);

(f) equipment costs are based on January 1987 prices; and

(g) a discount rate of 13% has been used for all cases.

3. The results of this evaluation show that natural gas would be the cheapest energy source for new installations in thermal power generation and industries using at least medium-sized boilers. Conversion of existing installations from fuel oil to gas use also would be economic whereas coal-to-gas conversions would involve long pay-back periods which make this option largely uneconomic.

2. Metropolitan Region - Electricity Generation
300 MW Net Capacity New Plant

Price Assumptions (1987 US$)

	1987			1995		
	Border Price	Transport Cost	Total	Border Price	Transport Cost	Total
Base Case						
Natural Gas (BTU millions) 1/	2.-	0.30	2.30	2.-	0.30	2.30
Coal (M.T.)	45.-	5.-	50.-	50.-	5.-	55.-
Fuel Oil (M.T.)	100.-	5.-	105.-	115.-	5.-	120.-

Sensitivity Analysis
Natural Gas (BTU millions) 3.20
All Other Assumptions as per Base Case

		Steam Plant Fuel Oil/Gas	Steam Plant Coal	Combined Cycle Plant Gas fired
Capital Cost (US$/net kW)		937	1,104	645
		% of Total		
Disbursement Profile				
Year	-4		7%	
	-3	7%	20%	
	-2	33%	35%	30%
	-1	42%	25%	50%
On line	0	18%	13%	20%
Plant Service Life (Years)		25	25	20
Gross Heat Rate for 75% Daily Plant Factor 2/	kj/kWh	10,100	10,400	8,900
(kJ/kcal = 4.187)	kcal/kWh	2,412	2,484	2,126

Fuel Cost (US$)		Fuel Oil	Coal	Natural Gas
Natural Gas (US$/million BTU)				2.-
Border Price (per Physical Unit)		M.T.	M.T.	'000 m3
		115.-	50.-	74.13
Inland Transport & Handling		5.-	5.-	10.70
Total Fuel Cost		120.-	55.-	84.83
Higher Heating Value	kcal/kg	10,500	7,000 2/	
kcal/m3		9,341		
Cost/10,000 kcal (US¢)		11.43	7.86	9.08

1/ Based on 700 million m^3 throughout p.a. (i.e. average CNE/GASCO assumptions plus 400 million m^3 p.a. for termal power station).

2/ As regards these specific assumptions, CNE have pointed out that (a) the daily plant factor would be closer to 50% than 75%; and (b) the heating value of coal would be 6,700 kcal/kg rather than 7,000 kcal/kg. Based on CNE's assumptions, the case for natural gas-based electricity generation would in fact be strengthened.

Fuel Cost/kWh by Plant Type		Fuel Oil Steam	Coal Steam	Nat.Gas Comb. Cycle	Nat. Gas Steam
Fuel consumption	gr./kWh	230	355		
m3/kWh	0.228	0.258			
Cost/kWh generated (US¢)		2.76	1.95	1.93	2.19

Total Costs for 300 MW Plant

		Fuel Oil Steam	Coal Steam	Nat.Gas Comb.Cycle	Nat.Gas Steam
Annual Generation at Load Factor 70.0%	(GWh)	---------- 1,839.6 ----------			
Capital Cost Total (US$ millions)		281.1	331.2	193.5	281.1
Assume Year-end Disbursement	-4	0.0	23.2	0.0	0.0
-3	19.7	66.2	0.0	19.7	
-2	92.8	115.9	58.1	92.8	
-1	118.1	82.8	96.8	118.1	
Annual Capital Cost	0	50.6	43.1	38.7	50.6
Discounted Value at t=0 a/		330.8	418.0	222.2	330.8
Annual Capital Cost over Service Life		45.1	57.0	31.6	45.1
Operation and Maintenance Costs					
Fixed O&M per kW Installed Capacity (US$)		8.29	9.84	12.43	8.29
Variable O&M per kWh Generated (US¢)		0.186	0.218	0.249	0.186
Total O&M Costs (US$ millions)					
Fixed		2.5	3.0	3.7	2.5
Variable		3.4	4.0	4.6	3.4
Total		5.9	7.0	8.3	5.9
Fuel Costs (US$ millions)		50.7	35.9	35.5	40.3
Fuel Consumption (M.T.'000s or m3 million)		422.6	652.8	418.6	475.1
Total Costs of Generation		101.8	99.9	75.4	91.3
Cost per kWh sent out (US¢/kWh)		5.53	5.43	4.10	4.97

a/ Discount rate at 13%.

Combined Cycle Generating Plant - Cost per kWh Sent Out (US¢/kWh)

	Natural Gas Cost (US$/BTU million)							
	2.00	2.20	2.40	2.60	2.80	3.00	3.20	
0.0	1,347.43	1,347.60	1,347.76	1,347.93	1,348.10	1,348.27	1348.44	
Annual	0.1	15.50	15.67	15.84	16.00	16.17	16.34	16.51
0.2	8.87	9.04	9.21	9.38	9.55	9.72	9.88	
Plant	0.3	6.65	6.82	6.99	7.15	7.32	7.49	7.66
0.4	5.53	5.70	5.87	6.04	6.21	6.38	6.55	
Factor	0.5	4.86	5.03	5.20	5.37	5.54	5.71	5.88
0.6	4.42	4.59	4.76	4.92	5.09	5.26	5.43	
0.7	4.10	4.27	4.44	4.60	4.77	4.94	5.11	
0.8	3.86	4.03	4.20	4.36	4.53	4.70	4.87	
0.9	3.67	3.84	4.01	4.18	4.35	4.52	4.68	
1.0	3.52	3.69	3.86	4.03	4.20	4.37	4.54	

Oil-Fired Steam Plant - Cost per kWh Sent Out (US¢/kWh)

	Fuel Oil Cost (US$/M.T.)							
	95.-	100.-	105	110.-	115.-	120.-	125.-	
0.0	1,814.64	1,814.75	1,814.87	1,814.98	1,815.10	1,815.21	1,815.33	
0.1	20.43	20.54	20.66	20.77	20.88	21.00	21.11	
0.2	11.50	11.61	11.73	11.84	11.96	12.07	12.19	
Annual	0.3	8.50	8.62	8.73	8.85	8.96	9.08	9.19
0.4	7.00	7.12	7.23	7.35	7.46	7.58	7.69	
Plant	0.5	6.10	6.22	6.33	6.45	6.56	6.67	6.79
0.6	5.50	5.61	5.73	5.84	5.96	6.07	6.19	
Factor	0.7	5.07	5.18	5.30	5.41	5.53	5.64	5.76
0.8	4.75	4.86	4.98	5.09	5.21	5.32	5.43	
0.9	4.49	4.61	4.72	4.84	4.95	5.07	5.18	
1.0	4.29	4.41	4.52	4.64	4.75	4.87	4.98	

Coal-Fired Steam Plant - Cost per kWh Sent Out (US¢/kWh)

Coal Cost (US$/M.T.)

		40.-	42.50	45.-	47.50	50.-	52.50	55.-	
	0.0	2284.17	2284.26	2284.35	2284.44	2284.53	2284.61	2284.70	
	0.1	24.41	24.50	24.59	24.68	24.77	24.86	24.94	
	0.2	13.17	13.26	13.35	13.44	13.52	13.61	13.70	
Annual		0.3	9.40	9.49	9.57	9.66	9.75	9.84	9.93
	0.4	7.51	7.60	7.68	7.77	7.86	7.95	8.04	
Plant		0.5	6.37	6.46	6.55	6.64	6.73	6.81	6.90
	0.6	5.61	5.70	5.79	5.88	5.97	6.06	6.14	
F.	0.7	5.07	5.16	5.25	5.34	5.43	5.51	5.60	
	0.8	4.66	4.75	4.84	4.93	5.02	5.11	5.20	
	0.9	4.35	4.44	4.53	4.61	4.70	4.79	4.88	
	1.0	4.09	4.18	4.27	4.36	4.45	4.54	4.63	

Gas-fired Steam Plant - Cost per kWh Sent Out (US¢/kWh)

Fuel Cost

		2.00	2.20	2.40	2.60	2.80	3.00	3.20	
	0.0	1,814.53	1,814.72	1,814.91	1,815.10	1,815.30	1,815.49	1,815.68	
	0.1	20.32	20.51	20.70	20.89	21.08	21.28	21.47	
	0.2	11.39	11.58	11.78	11.97	12.16	12.35	12.54	
Annual		0.3	8.40	8.59	8.78	8.97	9.16	9.35	9.55
	0.4	6.90	7.09	7.28	7.47	7.66	7.85	8.04	
Plant		0.5	5.99	6.19	6.38	6.57	6.76	6.95	7.14
	0.6	5.39	5.58	5.77	5.97	6.16	6.35	6.54	
Factor		0.7	4.96	5.15	5.34	5.54	5.73	5.92	6.11
	0.8	4.64	4.83	5.02	5.21	5.40	5.60	5.79	
	0.9	4.39	4.58	4.77	4.96	5.15	5.35	5.54	
	1.0	4.19	4.38	4.57	4.76	4.95	5.14	5.34	

3. Metropolitan Region - Electricity Generation Cost Comparison
300 MW Net Capacity Plant

Coal-to-Natural Gas Conversion

		Coal Steam to Nat. Gas Conversion	Coal	Nat. Gas	
Capital Cost (US$/net kW, Jan. 87 Prices)			100	0	0
		% of total			
Disbursement Profile					
	Year	-4			
-3					
-2					
-1					
	Online	0	100%		
Plant Service Life (Years)			2	25	
Gross Heat Rate for 75% daily Plant Factor		kJ/kWh	10,100	10,400	8,900
kcal/kWh a/		2,412	2,484	2,126	
Fuel Cost			Fuel Oil	Coal	Nat.Gas
Natural Gas (US$/BTU million)					1.60
Border Price/Physical Unit (US$)			M.T.	M.T.	m3'000
		120.-	45.-	59.30	
Inland Transport & Handling (US$)				5.-	10.70
Total Fuel Cost			120.-	50.-	70.-
Higher Heating Value		kcal/kg	10,500	7,000	
kcal/m3				9,341	
Cost/10,000 kcal (US¢)			11.43	7.14	7.49

a/ 4.187 kJ/kcal.

Fuel cost/kWh, by Plant Type		Fuel Oil	Coal Steam	Nat. Gas Steam	Nat. Gas Comb.Cyc	Nat. Gas Steam
Specific Fuel Consumption	gm/kWh		230	355		
	m3/kWh				0.228	0.258
Cost/kWh generated (US ¢)			2.76		1.77 1.59	1.81

Total Costs (300 MW Net Capacity Plant)

		Coal Steam	Coal-to Nat. Gas Steam	
Annual Generation Load Factor 70.0%	(GWh)	1,839.6	1,839.6	
Capital cost (US$ millions)		0.0	33.0	
Assume Year-end Disbursement	-4	0.0	0.0	
-3	0.0	0.0		
-2	0.0	0.0		
-1	0.0	0.0		
0	0.0	33.0		
Discounted Value at t-0 (US$ million) a/		0.0	33.0	
Annual Capital Cost over Service Life		0.0	19.8	

Operation and Maintenance Costs

Fixed O&M per kW installed Capacity (US$)		9.84	8.29		
Variable O&M per kWh generated (US¢)		0.218	0.186		
			Cost/kWh Sent Out (US¢/kWh)		
Total O&M Cost (US$ millions)					
Fixed		3.0	2.5	Capital Recovery Period (Years)	Coal/ Nat. Gas Conversion	Coal Steam
Variable		4.0	3.4			
Total		7.0	5.9			
Fuel Costs		32.6	33.26	1	4.16	2.15
Fuel Consumption				2	3.20	2.15
(M.T.'000 or m3 million)		652.8	475.1	3	2.89	2.15
			4	2.73	2.15	
Total Generation Cost		39.6	58.9	5	2.64	2.15
			6	2.58	2.15	
Cost per kWh Sent Out (US¢/kWh)		2.15	3.20	7	2.53	2.15
			8	2.50	2.15	
			9	2.48	2.15	
			10	2.46	2.15	

a/ Discount rate at 13%.

Fuel Oil - to- Natural Gas Conversion/Base Case

Net Plant Size to equal 300 MW	Fuel Oil to Steam Gas Conversion	Coal	
Capital Cost (US$/net kW)	42.3	00	

Disbursement Profile	Year	-4	% of total
-3			
-2			
-1			
	Online	0	100%

Plant Service Life (Years)		2	0	
Gross Heat Rate for 75% daily Plant Factor	kJ/kWh	10,100	10,400	8,900
kJ/kWh 1/	2,412	2,484	2,126	

Fuel Cost		Fuel Oil	Nat. Coal	Gas
Natural Gas (US$/BTU million				2.00
Border Price/Physical Unit (US$)		M.T.	M.T.	m3'000
Inland Transport & Handling (US$)		5	5	10.70
Total Fuel Cost		105	50	84.83
Higher heating value	kcal/kg	10,500	7,000	
kcal/m3		9,341		
Cost/10,000 kcal (US ¢)		10.00	7.14	9.08

Fuel Cost/kWh, by Plant Type		Fuel Oil	Coal Steam	Nat. Gas Steam	Nat. Gas Comb.cyc	Steam
Specific Fuel Consumption	gm/kWh		230	355		
	m3/kWh				0.228	0.258
Cost/kWh generated (US ¢)		2.41	1.77	1.93	2.19	

1/ 4.187 kJ/kcal

Total Costs (300 MW Net Capacity Plant)

		Fuel Oil Steam	Coal Steam	Nat.Gas Com.cyc	Nat.Gas Steam
Annual Generation at Load Factor 70.0%	(GWh)	1,839.6	1,839.6	1,839.6	1,839.6
Capital Cost (US$ millions)		0.0	0.0	0.0	12.69
Assume Year-end Disbursement	-4	0.0	0.0	0.0	0.0
	-3	0.0	0.0	0.0	0.0
	-2	0.0	0.0	0.0	0.0
	-1	0.0	0.0	0.0	0.0
Annual Capital Cost	0	0.0	0.0	0.0	12.7
Discounted Value at t=0 (US$ millions) 2/		0.0	ERR	ERR	7.6
Operation and Maintenance Costs					
Fixed O&M per kW Installed Capacity (US$)		8.29	9.84	12.43	8.29
Variable O&M per kWh Generated (US$)		0.186	0.218	0.249	0.186
Total O&M Costs (US$ millions)					
Fixed		2.5	3.0	3.7	2.5
Variable		3.4	4.0	4.6	3.4
Total		5.9	7.0	8.3	5.9
Fuel Costs (US$ millions)		44.4	32.6	35.5	40.30
Fuel Consumption (M.T.'000 or m3 million)		422.6	652.8	418.6	475.1
Total Costs of Generation (US$ millions)		50.3	ERR	ERR	53.8
Cost per kWh Sent Out (US ¢/kWh)		2.73	ERR	ERR	2.93

Cost/kWh Sent Out
US¢/kWh

Capital Recovery Period (Years)	Fuel Oil/ Nat.Gas Conv.	Fuel Oil Steam
1	3.29	2.73
2	2.93	2.73
3	2.80	2.73
4	2.74	2.73
5	2.71	2.73
6	2.68	2.73
7	2.67	2.73
8	2.66	2.73
9	2.65	2.73
10	2.64	2.73

2/ Discount rate at 13%

Fuel Oil-to-Natural Gas Conversion/Modified Case 1/

Fuel Oil Steam-to-Gas Conversion				
		Coal		
Capital Costs (US$/net kW)		31.725	0	0
Disbursement Profile	**% of total**			
	year -4			
-3				
-2				
-1				
0	100%			
Plant Service Life (Years)		2	0	
Gross Heat Rate for 75% daily Plant Factor	kJ/kWh	10,100	10,400	8,900
	kcal/kWh 2/	2,142	2,484	2,126

Fuel Cost (US$)		Fuel Oil	Coal	Nat. Gas
Natural Gas (US$/BTU million)				2.50
Border Price/Physical Unit		115	45	92.66
Inland Transport & Handling		5	5	10.70
Total Fuel Cost		120	50	103.36
Higher Heating Value	kcal/kg	10,500	7,000	
kcal/m3			9,341	
Cost/10,000 (US¢)		11.43	7.14	11.07

Fuel Cost/kWh, by Plant Type		Fuel Oil	Coal	Nat.Gas	Nat. Gas
	Steam	Steam	Comb. Cyc	Steam	
Fuel Consumption	gr/kWh	230	355		
m3/kWh			0.228	0.258	
Cost/kWh generated (US¢)		2.76	1.27	2.35	2.67

1/ Capital cost assumed at 75% of those of base case; natural gas price at US$2.50/BTU million.

2/ 4.187 kJ/kcal.

Total Costs (300 MW Net Capacity Plant)

	Fuel Oil Steam	Coal Steam	Nat. Gas Comb. Cyc.		Nat. Gas Steam
Annual Generation at Load Factor 70.0% (GWh)	1,839.6	1,839.6	1,839.6		1,839.6
Capital Cost (US$ millions)		0.0	0.0	0.0	9.52
Assume Year-end Disbursement	-4	0.0	0.0	0.0	0.0
-3	0.0	0.0	0.0	0.0	
-2	0.0	0.0	0.0	0.0	
-1	0.0	0.0	0.0	0.0	
Annual Capital Cost (US$ million)	0	0.0	0.0	0.0	9.52
Discounted value at t=0 1/		0.0	0.0	0.0	9.52
Annual Capital Cost over Service Life (US$ million)		0.0	ERR	ERR	5.7

Operation and Maintenance Costs

Fixed O&M per kW Installed Capacity (US$)	8.29	9.84	12.43	8.29	Cost/kWh Sent Out (US¢/kWh)		
				Capital Fuel	Oil/ Continue		
Variable O&M per kWh Generated (US¢)	0.186	0.218	0.249	0.186	Recovery Period (Years)	Nat. Gas Conv.	Existing Fuel Oil
Total O&M Cost (US$ millions)							
Fixed	2.5	3.0	3.7	2.5	1	3.58	3.08
Variable	3.4	4.0	4.6	3.4	2	3.30	3.08
Total	5.9	7.0	8.3	5.9	3	3.21	3.08
				4	3.16	3.08	
Fuel Costs (US$ million)	50.7	32.6	43.3	49.10	5	3.14	3.08
Fuel Consumption					6	3.12	3.08
(M.T.'000 or m3 million)	422.6	652.8	418.6	475.1	7	3.11	3.08
				8	3.10	3.08	
Total Costs Generation					9	3.09	3.08
(US$ millions)	56.6	ERR	ERR	60.7	10	3.09	3.08
Cost per kWh Sent Out (US¢/kWh)	3.08	ERR	ERR	3.30			

1/ Discount rate at 13%.

Fuel Oil-to-Natural Gas Conversion/1995 Base Case 1/

		Fuel Oil Steam/Nat. Gas Conversion	Coal	
Capital Cost (US$/net kW)		42.3	0	0
			% of total	
Disbursement Profile				
Year	-4			
-3				
-2				
-1				
Online	0		100.0	
Capital Recovery Period		2	0	
Gross Heat Rate for 75% Daily Plant Factor	kJ/kWh	10,100	10,400	8,900
(kJ/kcal = 4.187)	kcal/kWh	2,412	2,484	2,126

Fuel Cost (US$)		Fuel Oil	Coal	Nat. Gas
Natural Gas Cost (US$/BTU million)				2.00
Border price/Physical Unit		M.T	M.T.	m3 '000
	115	45	74.13	
Inland Transport & Handling		5	5	10.7
Total Fuel Cost		120	50	84.83
Higher Heating Value	kcal/kg	10,500	7,000	
kcal/m3			9,341	
Cost/10,000 kcal (US¢)		11.43	7.14	9.08

Fuel Cost/kWh, by Plant Type		Fuel Oil Steam	Coal Steam	Nat. Gas Steam	Nat. Gas Comb. Cyc.	Nat. Gas Steam
Fuel Consumption	gr/kWh	230	355			
m3/kWh				0.228	0.258	
Cost/kWh generated (US¢)		2.76	1.77	1.93		2.19

1/ Fuel Oil at US$115/M.T.; Natural Gas at US$2/BTU million.

Total Costs (300 MW Net Capacity Plant)

	Fuel Oil Steam	Coal Steam	Nat. Gas Comb.cyc.		Nat. Gas Steam
Annual Generation at Load Factor 70% (GWh)		1,839.6	1,839.6	1,839.6	1,839.6
Capital Cost (US$ millions)		0.0	0.0	0.0	12.69
Assume Year-end Disbursement -4		0.0	0.0	0.0	0.0
-3	0.0	0.0	0.0	0.0	
-2	0.0	0.0	0.0	0.0	
-1	0.0	0.0	0.0	0.0	
Annual Capital Cost (US$ millions)	0	0.0	0.0	0.0	12.69
Discounted Value at t=0 a/		0.0	0.0	0.0	12.69
Annual CapitalCost Over Service Life		0.0	ERR	ERR	7.6

Operation and Maintenance Costs

Fixed O&M per kW Installed Capacity (US$)	8.29	9.84	12.43	8.29
Variable O&M per kWh Generated (US¢)	0.186	0.218	0.249	0.186
Total O&M Costs (US$ millions)				
Fixed	2.5	3.0	3.7	2.5
Variable	3.4	4.0	4.6	3.4
Total	5.9	7.0	8.3	5.9
Fuel Costs (US$ millions)	50.7	32.6	35.5	40.3
Fuel Consumption (M.T.'000 or m3 millions)	422.6	652.8	418.6	475.1
Total Costs of Generation (US$ millions)	56.6	ERR	ERR	53.8
Cost per kWh Sent Out (US¢/kWh)	3.08	ERR	ERR	2.93

Cost/kWh Sent Out (US¢/kWh)

	Capital Recovery Period	Avg. Cost/kWh (US¢) Fuel Oil/Gas Conversion	Continue Existing Fuel Oil
		3.29	3.08
	2	2.93	3.08
	3	2.80	3.08
	4	2.74	3.08
	5	2.71	3.08
	6	2.68	3.08
	7	2.67	3.08
	8	2.66	3.08
	9	2.65	3.08
	10	2.64	3.08

a/ Discount rate at 13%.

4. Metropolitan Region - Industrial Boiler Cost Comparison: New Boilers

Large Size Boilers - 45 M.T./hr, High Pressure (250 psi)

Fuel Oil		Coal	Nat. Gas	
Capital Cost (US$ per kg/hr Steam Output)		26.62	68.97	26.62
Disbursement Profile		**% of total**		
Year	-4			
-3				
-2				
-1				
Online	0	100%	100%	100%
Plant Service Life (Years)		20	20	20
Boiler Efficiency		0.85	0.88	0.82
Heat Rate	BTU/lb Steam	1,000	1,000	1,000
kcal/kg Steam 554	554	554		
Fueling Rate to Boiler (kcal/kg Steam)		652	630	676

Fuel Cost (US$)		Fuel Oil	Coal	Nat. Gas
Natural Gas (US$/BTU million)				2.00
Border Price/Physical Unit		M.T.	M.T.	m^3 '000
	115	50	74.13	
Inland Transport & Handling		5	5	10.70
Total Fuel Cost		120	55	84.83
Higher Heating Value	kcal/kg	10,500	7,000	
kcal/m3			9,341	
Cost/10,000 kcal (US¢)		11.43	7.86	9.08

Fuel Cost/kg Steam, by Boiler Type		Fuel Oil	Coal	Nat. Gas
Fuel Consumption	gm/kg Steam	62	90	
m3/kg Seam			0.072	
Cost/kg steam produced (US¢)		0.74	0.49	0.61

	Fuel Oil	Coal	Nat. Gas	
Steam Production ('000 M.T./yr) (Annual Load Factor at 70.0%)		275.9	275.9	275.9
Total Capital Cost (US$ '000)		1,197.9	3,103.7	1,197.9
Assume Year-end Disbursement	-4	0.0	0.0	0.0
-3	0.0	0.0	0.0	
-2	0.0	0.0	0.0	
-1	0.0	0.0	0.0	
Annual Capital Cost	0	1,197.9	3,103.7	1,197.9
Discounted Value at t-0 a/		1,197.9	3,103.7	1,197.0
Annual Capital Cost over Service Life		170.5	441.8	170.5
Operation and Maintenance Costs				
Fixed O&M per kg Capacity ($/kg/hr) 2% of Capital Cost)		0.53	1.38	0.53
Total O&M Cost (US$ '000)		24.0	62.1	24.0
Fuel Costs ('000 US$)		2,055.4	1,364.9	1,693.0
Fuel Consumption ('000 tonnes or m3)		17.1	24.8	20.0
Total Costs of Steam ('000 US$)		2,249.9	1,868.8	1,887.5
Cost per M.T. Steam (US$)		8.15	6.77	6.84

a/ Discount rate of 13%.

Senisitivity Analysis for Varying Plant Factors and Fuel Costs

Natural Gas-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Natural Gas Cost (US$/BTU million) a/							
	2.00	2.20	2.40	2.60	2.80	3.00	3.20	
0.0	499.50	500.03	500.57	501.11	501.64	502.18	502.72	
Annual	0.1	11.02	11.56	12.09	12.63	13.16	13.70	14.24
0.2	8.59	9.13	9.66	10.20	10.73	11.27	11.81	
Plant	0.3	7.77	8.31	8.85	9.38	9.92	10.45	10.99
0.4	7.37	7.90	8.44	8.97	9.51	10.05	10.58	
Factor	0.5	7.12	7.66	8.19	8.73	9.26	9.80	10.34
0.6	6.96	7.49	8.03	8.56	9.10	9.64	10.17	
0.7	6.84	7.38	7.91	8.45	8.98	9.52	10.06	
0.8	6.75	7.29	7.82	8.36	8.90	9.43	9.97	
0.9	6.68	7.22	7.76	8.29	8.83	9.36	9.90	
1.0	6.63	7.16	7.70	8.24	8.77	9.31	9.85	

Fuel Oil-fired Boiler - Cost of Steam Produced (US$/tonne)

	Fuel Oil a/ Cost (US$/M.T.)							
	95	100	105	110 a/	115	120	125	
0.0	499.57	499.88	500.19	500.50	500.81	501.12	501.43	
0.1	11.09	11.40	11.71	12.02	12.33	12.64	12.95	
0.2	8.66	8.97	9.28	9.59	9.90	10.21	10.52	
Annual	0.3	7.85	8.16	8.47	8.78	9.09	9.40	9.71
0.4	7.44	7.75	8.06	8.37	8.68	8.99	9.30	
Plant	0.5	7.19	7.50	7.81	8.12	8.43	8.74	9.05
0.6	7.03	7.34	7.65	7.96	8.27	8.58	8.89	
Factor	0.7	6.91	7.22	7.53	7.84	8.15	8.46	8.77
0.8	6.82	7.13	7.44	7.75	8.06	8.38	8.69	
0.9	6.75	7.07	7.38	7.69	8.00	8.31	8.62	
1.0	6.70	7.01	7.32	7.63	7.94	8.25	8.56	

Coal-fired Boiler - Cost of Steam Produced (US$/tonne)

	Coal Cost (US$/M.T.) a/							
	40.-	42.5.-	45.-	47.50	50.-	52.50	55.-	
0.0	1,282.31	1,282.53	1,282.75	1,2.82.98	1,283.20	1,283.43	1,283.65	
0.1	16.70	16.93	17.15	17.38	17.60	17.83	18.05	
0.2	10.41	10.63	10.86	11.08	11.31	11.53	11.76	
Annual	0.3	8.29	8.52	8.74	8.97	9.19	9.42	9.64
0.4	7.23	7.46	7.68	7.91	8.13	8.36	8.58	
Plant	0.5	6.60	6.82	7.05	7.27	7.50	7.72	7.95
0.6	6.17	6.40	6.62	6.85	7.07	7.30	7.52	
Factor	0.7	5.87	6.10	6.32	6.55	6.77	6.99	7.22
0.8	5.64	5.87	6.09	6.32	6.54	6.77	6.99	
0.9	5.47	5.69	5.92	6.14	6.37	6.59	6.81	
1.0	5.32	5.55	5.77	6.00	6.22	6.45	6.67	

---

a/ Border Price.

Medium-Sized/Low Pressure Boilers - 15 M.T./hr, 100 psig

		Fuel Oil	Coal	Nat. Gas	
Capital Cost (US$ per kg/hr Steam Output)			23.4	77.2	23.4
			% of total		
Disbursement Profile					
year		-4			
-3					
-2					
-1					
on line		0	100%	100%	100%
Plan Service Life (Years)			20	20	20
Boiler Efficiency			0.85	0.88	0.82
Heat Rate	BTU/lb steam		1,000	1,000	1,000
kcal/kg steam		554	554	554	
Fueling Rate to Boiler (kcal/kg Steam)			652	630	676
Fuel Cost (US$)			Fuel		Nat.
		Oil	Coal	Gas	
Natural Gas (US$/BTU million)				2.00	
Border Price/Physical Unit			M.T.	M.T.	m3 '000
		115	50	74.13	
Inland Transport & Handling			5	5	10.70
Total Fuel Cost			120	55	84.33
Higher Heating Value	kcal/kg		10,500	7,000	
kcal/m3				9,341	
Cost/10,000 kcal (US¢)			11.43	7.86	9.08
Fuel Cost/kg Steam, by Boiler Type					
Fuel Consumption	gm/kg Steam		62	90	
m3/kg Steam				0.072	
Cost/kg Steam Produced (US¢)			0.74	0.49	0.61

	Fuel Oil	Coal	Nat. Gas	
Steam Production ('000 M.T./yr) (Annual Load Factor at 70.0%)		92.0	92.0	92.0
Total Capital Cost (US$ '000)		351.0	1,158.0	351.0
Assume Year-end Disbursement	-4	0.0	0.0	0.0
-3	0.0	0.0	0.0	
-2	0.0	0.0	0.0	
-1	0.0	0.0	0.0	
Annual Capital Cost	0	351.0	1,158.0	351.0
Discounted value at t-0 a/		351.0	1,158.0	351.0
Annual Capital Cost Over Service Life		50.0	164.8	50.0
Operation and Maintenance Costs				
Annual O&M per kg Capacity (US$/kg/hr) (2% of capital cost)		0.47	1.54	0.47
Total O&M Costs (US$ '000)		7.0	23.2	7.0
Fuel Costs ('000 US$)		685.1	455.0	564.3
Fuel Consumption ('000 M.T. or m3)		5.7	8.3	6.7
Total Costs of Steam ('000 US$)	742.1	643.0	621.3	
Cost per M.T. Steam (US$)	8.07	6.99	6.76	

a/ Discount rate at 13%.

Sensitivity Analyses for Varying Plant Factors and Fuel Costs

Natural Gas-Fired Boiler - Cost of Steam Produced (US$/M.T.)

	Natural Gas Cost (US$/BTU million) a/						
	2.00	2.20	2.40	2.60	2.80	3.00	3.20
0.0	439.82	440.36	440.80	441.43	441.96	442.50	443.04
0.1	10.43	10.97	11.50	12.04	12.57	13.11	13.65
0.2	8.29	8.83	9.37	9.90	10.44	10.97	11.51
0.3	7.58	8.11	8.65	9.18	9.72	10.26	10.79
0.4	7.22	7.75	8.29	8.83	9.36	9.90	10.43
0.5	7.00	7.54	8.07	8.61	9.15	9.68	10.22
0.6	6.86	7.39	7.93	8.47	9.00	9.54	10.07
0.7	6.75	7.29	7.83	8.36	8.90	9.44	9.97
0.8	6.88	7.21	7.75	8.29	8.82	9.36	9.89
0.9	6.62	7.15	7.69	8.23	8.76	9.30	9.83
1.0	6.57	7.10	7.64	8.18	8.71	9.25	9.79

Fuel Oil-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Fuel Oil Cost (US$/M.T.) a/							
	95	100	105	110	115	120	125	
0.0	439.89	440.20	440.51	440.82	441.13	441.44	441.75	
0.1	10.50	10.81	11.12	11.43	11.74	12.05	12.36	
0.2	8.36	8.68	8.99	9.30	9.61	9.92	10.23	
Annual	0.3	7.65	7.96	8.27	8.58	8.89	9.20	9.51
0.4	7.29	7.60	7.91	8.22	8.53	8.84	9.15	
Plant	0.5	7.07	7.38	7.69	8.00	8.31	8.62	8.94
0.6	6.93	7.24	7.55	7.86	8.17	8.48	8.79	
Factor	0.7	6.83	7.14	7.45	7.76	8.07	8.38	8.69
0.8	6.75	7.06	7.37	7.68	7.99	8.30	8.61	
0.9	6.69	7.00	7.31	7.62	7.93	8.24	8.55	
1.0	6.64	6.95	7.26	7.57	7.88	8.19	8.50	

Coal-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Coal Cost (US$/M.T.) a/							
	40.-	42.50	45.-	47.50	50.-	52.50	55.-	
0.0	1,434.84	1,435.06	1,435.29	1,435.51	1,435.74	1,435.96	1,435.19	
0.1	18.21	18.44	18.66	18.89	19.11	19.34	19.56	
0.2	11.17	11.39	11.62	11.84	12.06	12.29	12.51	
Annual	0.3	8.80	9.03	9.25	9.48	9.70	9.92	10.15
0.4	7.62	7.84	8.06	8.29	8.51	8.74	8.96	
Plant	0.5	6.90	7.13	7.35	7.58	7.80	8.03	8.25
0.6	6.43	6.65	6.88	7.10	7.33	7.55	7.78	
Factor	0.7	6.09	6.31	6.54	6.76	6.99	7.21	7.44
0.8	5.83	6.06	6.28	6.51	6.73	6.96	7.18	
0.9	5.64	5.86	6.08	6.31	6.53	6.76	6.98	
1.0	5.48	5.70	5.93	6.15	6.38	6.60	6.83	

---

a/ Border Price.

5. Metropolitan Region - Industrial Boiler Cost Comparison: Boiler Conversions

Coal-to-Natural Gas Conversion - Large Size Boilers

		Fuel Oil	Coal	Nat. Gas
Capital Cost (US$ per kg/hr Steam Output)		0.0	0.0	23.0
			% of total	
Disbursement Profile				
Year	-4			
-3				
-2				
-1				
On-line	0	100%	100%	100%
Plan Service Life (Years)		20	5	5
Boiler Efficiency			0.88	0.82
Heat Rate BTU/lb steam			1,000	1,000
kcal/kg steam	554	554	554	
Fueling Rate to Boiler (kcal/kg Steam)		ERR	630	676
Fuel Cost (US$)		Fuel		Nat.
	Oil	Coal	Gas	
Natural Gas (US$/BTU million)				2.00
Border Price/Physical Unit		M.T.	M.T.	m3 '000
	115	50	74.13	
Inland Transport & Handling		5	5	10.70
Total Fuel Cost		120	55	84.33
Higher Heating Value kcal/kg		10,500	7,000	
kcal/m3			9,341	
Cost/10,000 kcal (US¢)		11.43	7.86	9.08
Fuel Cost/kg Steam, by Boiler Type		Fuel Oil	Coal	Nat. Gas
Fuel Consumption gm/kg Steam		ERR	90	
m3/kg Steam			0.072	
Cost/kg Steam Produced (US¢)		ERR	0.49	0.61

	Fuel Oil	Coal	Nat. Gas
Steam Production ('000 M.T./yr) (Annual Load Factor at 70.0%)		275.9	275.9	275.9
Total Capital Cost (US$ '000)		0.0	0.0	1,035.0
Assume Year-end Disbursement -4		0.0	0.0	0.0
-3	0.0	0.0	0.0	
-2	0.0	0.0	0.0	
-1	0.0	0.0	0.0	
Annual Capital Cost	0	0.0	0.0	1,035.0
Discounted Value at t-0 a/		0.0	0.0	1,035.0
Annual Capital Cost Over Service Life		0.0	0.0	249.3
Operation and Maintenance Costs				
Annual O&M per kg Capacity ($/kg/hr) (2% of Capital Cost)		0.0	0.0	0.46
Total O&M Costs (US$ '000)		0.0	0.0	20.7
Fuel Costs ('000 US$)		ERR	1,364.9	1,693.0
Fuel Consumption ('000 M.T. or m3)		ERR	24.8	20.0
Total Costs of Steam ('000 US$)		ERR	1364.9	2008.0
Cost per M.T. Steam (US$)		ERR	4.95	7.28

a/ Discount rate at 13%.

Sensitivity Analyses for Varying Plant Factors and Fuel Costs

Coal-to-Natural Gas-fired Conversion - Cost of Steam Produced (US$/M.T.)

	Natural Gas Cost (US$/BTU million) a/							
	1.00	1.20	1.40	1.60	1.80	2.00	2.20	
0.0	802.45	802.99	803.53	804.06	804.60	805.13	805.67	
Annual	0.1	11.37	11.90	12.44	12.97	13.51	14.05	14.58
0.2	7.43	7.97	8.50	9.04	9.57	10.11	10.65	
Plant	0.3	6.11	6.85	7.18	7.72	8.25	8.79	9.33
0.4	5.45	5.98	6.52	7.06	7.59	8.13	8.66	
Factor	0.5	5.05	5.59	6.12	6.66	7.19	7.73	8.27
0.6	4.78	5.32	5.86	6.39	6.93	7.56	8.00	
0.7	4.59	5.13	5.67	6.20	6.74	7.28	7.81	
0.8	4.45	4.99	5.52	6.06	6.60	7.13	7.67	
0.9	4.34	4.88	5.41	5.95	6.49	7.02	7.56	

Use Existing Coal-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Coal Cost (US$/M.T.) a/							
		42.5	45	47.5	50	52.5	55	
0.0	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
0.1	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
0.2	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
Annual	0.3	4.05	4.27	4.50	4.72	4.95	5.17	5.40
0.4	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
Plant	0.5	4.05	4.27	4.50	4.72	4.95	5.17	5.40
0.6	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
Factor	0.7	4.05	4.27	4.50	4.72	4.95	5.17	5.40
0.8	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
0.9	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
104	4.05	4.27	4.50	4.72	4.95	5.17	5.40	

---

a/ Border Price.

Coal-to-Natural Gas Conversion - Medium Sized Boilers

		Fuel Oil	Coal	Nat. Gas
Capital Cost (US$ per kg/hr Steam Output)			0.0	0.0	25.7
				% of total	
Disbursement Profile					
year	-4				
-3					
-2					
-1					
On-line	0		100%	100%	100%
Plan Service Life (Years)			0	5	5
Boiler Efficiency			0.85	0.88	0.82
Heat Rate	BTU/lb Steam		1,000	1,000	1,000
kcal/kg Steam		554	554	554	
Fueling Rate to Boiler (kcal/kg Steam)		652	630	676	
Fuel Cost (US$)		Oil	Fuel Coal	Gas	Nat.
Natural Gas (US$/BTU million)					2.00
Border Price/Physical Unit			M.T. 50	M.T. 74.13	m3 '000
Inland Transport & Handling				5	10.7
Total Fuel Cost				55	84.33
Higher Heating Value	kcal/kg		10,500	7,000	
kcal/m3				9,341	
Cost/10,000 kcal (US¢)			0.0	7.86	9.08
Fuel Cost/kg Steam, by Boiler Type			Fuel Oil	Coal	Nat. Gas
Fuel consumption	gm/kg Steam		62	90	
m3/kg Steam				0.072	
Cost/kg Steam Produced (US¢)			0.0	0.49	0.61

	Fuel Oil	Coal	Nat. Gas	
Steam production ('000 tpy) (Annual Load Factor at 70.0%)		92.0	92.0	92.0
Total Capital Cost (US$ '000)		0.0	0.0	386.0
Assume Year-end Disbursement -4		0.0	0.0	0.0
-3	0.0	0.0	0.0	
-2	0.0	0.0	0.0	
-1	0.0	0.0	0.0	
Annual Capital Cost	0	0.0	0.0	386.0
Discounted value at t-0 a/		0.0	0.0	386.0
Annual Capital Cost Over Service Life		ERR	0.0	109.7
Operation and Maintenance Costs				
Annual O&M per kg Capacity (US$/kg/hr)	0.00	0.00	0.51	
(2% of Capital Cost)				
Total O&M Costs (US$ '000)		0.0	0.0	7.7
Fuel Costs ('000 US$)		0.0	455.0	564.3
Fuel Consumption ('000 M.T. or m3)		5.7	8.3	6.7
Total Costs of Steam ('000 US$)		ERR	455.0	681.8
Cost per M.T. of Steam (US$)		ERR	4.95	7.41

a/ Discount rate at 13%.

Sensitivity Analyses for Varying Plant Factors and Fuel Costs

Coal-to-Natural Gas-fired Conversion - Cost of Steam Produced (US$/M.T.)

	Natural Gas Cost (US$/BTU million) a/							
	1.00	1.20	1.40	1.60	1.80	2.00	2.20	
0.0	897.41	897.94	898.48	899.02	899.55	900.09	900.62	
Annual	0.1	12.31	12.84	13.38	13.91	14.45	14.99	15.52
0.2	7.90	8.44	8.97	9.51	10.05	10.58	11.12	
Plant	0.3	6.42	6.96	7.50	8.03	8.57	9.11	9.64
0.4	5.68	6.22	6.76	7.29	7.83	8.36	8.90	
Factor	0.5	5.24	5.78	6.31	6.85	7.38	7.92	8.46
0.6	4.94	5.48	6.01	6.55	7.09	7.62	8.16	
0.7	4.73	5.27	5.80	6.34	6.87	7.41	7.95	
0.8	4.57	5.11	5.64	6.18	6.72	7.25	7.79	
0.9	4.45	4.98	5.52	6.06	6.59	7.13	7.66	
1.0	4.35	4.88	5.42	5.96	6.49	7.03	7.56	

Use Existing Coal-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Coal Cost (US$/M.T.) a/							
	40.-	42.50	45.-	47.50	50.-	52.50	55.-	
0.0	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
0.1	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
0.2	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
Annual	0.3	4.05	4.27	4.50	4.72	4.95	5.17	5.40
0.4	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
Plant	0.5	4.05	4.27	4.50	4.72	4.95	5.17	5.40
0.6	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
Factor	0.7	4.05	4.27	4.50	4.72	4.95	5.17	5.40
0.8	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
0.9	4.05	4.27	4.50	4.72	4.95	5.17	5.40	
1.0	4.05	4.27	4.50	4.72	4.95	5.17	5.40	

a/ Border Price.

Fuel Oil-to-Natural Gas Conversion - Large Size Boilers

		Existing Fuel Oil		Fuel Oil to Nat.Gas
Capital Cost (US$ per kg/hr Steam Output)		0.0	0.0	8.9
Disbursement Profile		% of total		
Year	-4			
-3				
-2				
-1				
Online	0	100%	100%	100%
Plant Service Life (Years)		5	5	5
Boiler Efficiency		0.85		0.82
Heat Rate	BTU/lb Steam	1,000		1,000
kcal/kg Steam	554	554	554	
Fueling Rate to Boiler	kcal/kg Steam	652	ERR	676
Fuel Cost (US$)		Fuel Oil	Coal	Nat.Gas
Natural Gas US$/BTU million				2.00
Border Price/Physical Unit		M.T.	M.T.	m3'000
	115	50	74.13	
Inland Transport & Handling		5	5	10.70
Total Fuel Cost		120	55	84.83
Higher Heating Value	kcal/kg	10,500	7,000	
kcal/m3			9,341	
Cost/10,000 kcal (US ¢)		11.43	7.86	9.08
Fuel Cost/kg Steam, by Boiler Type		Fuel Oil	Coal	Nat. Gas
Fuel Consumption	gr/kg Steam	62	ERR	
m3/kg Steam			0.072	
Cost/kg Steam Produced (US¢)		0.74	ERR	0.61

	Fuel Oil	Coal	Nat.Gas	
Steam Production ('000 tpy) (Annual Load Factor 70.0%)		275.9	275.9	275.9
Total Capital Cost (US$'000)		0.0	0.0	399.0
Assume Year-end Disbursement	-4	0.0	0.0	0.0
-3	0.0	0.0	0.0	
-2	0.0	0.0	0.0	
-1	0.0	0.0	0.0	
Annual Capital Cost	0	0.0	0.0	0.0
Discounted Value at t=0 a/		0.0	0.0	399.0
Annual Capital Cost over Service Life		0.0	0.0	113.4
Operation and Maintenance Costs				
Annual O&M per kg Capacity (US$/kg/hr) (2% of Capital Cost)		0.00	0.00	0.18
Total O&M Costs (US$ '000)		0.0	0.0	8.0
Fuel Costs ('000 US$)		2,055.4	ERR	1,693.0
Fuel Consumption ('000 M.T. or m3)		17.1	ERR	20.0
Total Costs of Steam ('000 US$)		2,055.4	ERR	1,814.5
Cost per M.T. Steam (US$)		7.45	ERR	6.58

a/ Discount rate at 13%.

Sensitivity Analyses for Varying Plant Factors and Fuel Costs

Fuel Oil-to-Gas-fired Conversion - Cost of Steam Produced (US$/M.T.)

	Natural Gas Cost (US$/BTU million) a/							
	2.00	2.20	2.40	2.60	2.80	3.00	3.20	
0.0	314.16	314.69	315.23	315.76	316.30	316.84	317.37	
Annual	0.1	9.19	9.72	10.26	10.79	11.33	11.87	12.40
0.2	7.67	8.20	8.74	9.28	9.81	10.35	10.88	
Plant	0.3	7.16	7.70	8.23	8.77	9.30	9.84	10.38
0.4	6.90	7.44	7.98	8.51	9.05	9.58	10.12	
Factor	0.5	6.75	7.29	7.82	8.36	8.90	9.43	9.97
0.6	6.65	7.18	7.72	8.26	8.79	9.33	9.87	
0.7	6.57	7.11	7.65	8.18	8.72	9.26	9.79	
0.8	6.52	7.06	7.59	8.13	8.66	9.20	9.74	
0.9	6.48	7.01	7.55	8.09	8.62	9.16	9.69	
1.0	6.44	6.98	7.52	8.05	8.59	9.12	9.66	

Fuel Oil-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Fuel oil cost (US$/M.T.) a/							
	95	100	105	110	115	120	125	
0.0	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
0.1	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
0.2	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
Annual	0.3	6.21	6.52	6.83	7.14	7.45	7.76	8.07
0.4	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
Plant	0.5	6.21	6.52	6.83	7.14	7.45	7.76	8.07
0.6	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
Factor	0.7	6.21	6.52	6.83	7.14	7.45	7.76	8.07
0.8	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
0.9	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
1.0	6.21	6.52	6.83	7.14	7.45	7.76	8.07	

---

a/ Border Price.

Fuel Oil-to-Natural Gas Conversion - Medium Size Boilers

		Existing Fuel Oil		Fuel Oil to Nat.Gas
Capital Cost (US$ per kg/hr Steam Output)		0.0	0.0	7.8
		% of total		
Disbursement Profile				
Year	-4			
-3				
-2				
-1				
Online	0	100%	100%	100%
Plant Service Life (Years)		5	20	5
Boiler Efficiency		0.85		0.82
Heat Rate	BTU/lb Steam	1,000		1,000
kcal/kg Steam	554	554	554	
Fueling Rate to Boiler (kcal/kg Steam)		652	ERR	676
Fuel Cost (US$)		Fuel Oil	Coal	Nat.Gas
Natural Gas (US$/BTU million)				2.00
	M.T.	M.T.	(m3 '000)	
Border Price/Physical Unit		115	0	74.13
Inland Transport & Handling		5	5	10.7
Total Fuel Cost		120	5	84.83
Higher Heating Value	kcal/kg	10,500	7,000	
kcal/m3			9,341	
Cost/10,000 kcal (US ¢)		11.43	0.71	9.08
Fuel Cost/kg Steam, by Boiler Type				
Fuel Consumption gm/kg Steam		62	ERR	
m3/kg Steam				0.072
Cost/kg Steam Produced (US ¢)		0.74	ERR	0.61

	Fuel Oil	Coal	Nat.Gas	
Steam Production ('000 tpy)				
(Annual Load Factor 70.0%)		70.0	92.0	92.0
Total Capital Cost (US$ '000)		0.0	0.0	117.0
Assume Year-end Disbursement	-4	0.0	0.0	0.0
-3	0.0	0.0	0.0	
-2	0.0	0.0	0.0	
-1	0.0	0.0	0.0	
Annual Capital Cost	0	0.0	0.0	117.0
Discounted Value at t=0 a/		0.0	0.0	117.0
Annual Capital Cost over Service Life		n.a.	n.a.	33.3
Operation and Maintenance Costs				
Annual O&M per kg Capacity (US$/kg/hr) (2% of Capital Cost)		0.00	0.00	0.16
Total O&M Costs (US$ '000)		0.00	0.0	2.3
Fuel Costs ('000 US$)		685.1	ERR	564.3
Fuel Consumption ('000 M.T. or m3)		5.7	ERR	6.7
Total Costs of Steam ('000 US$)		685.1	ERR	600.0
Cost per M.T. Steam (US$)		7.45	ERR	5.52

a/ Discount rate at 13%.

Sensitivity Analyses for Varying Plant Factors and Fuel Costs

Gas-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Natural Gas Cost (US$/BTU million) a/							
	2.00	2.20	2.40	2.60	2.80	3.00	3.20	
0.0	277.10	277.64	278.17	278.71	279.25	279.78	280.32	
Annual	0.1	8.82	9.35	9.89	10.43	10.96	11.50	12.04
0.2	7.48	8.02	8.56	9.09	9.63	10.16	10.70	
Plant	0.3	7.04	7.57	8.11	8.64	9.18	9.72	10.25
0.4	6.81	7.35	7.88	8.42	8.96	9.49	10.03	
Factor	0.5	6.68	7.21	7.75	8.28	8.82	9.36	9.89
0.6	6.59	7.12	7.66	8.19	8.73	9.27	9.80	
0.7	6.52	7.06	7.59	8.13	8.67	9.20	9.74	
0.8	6.47	7.01	7.55	8.08	8.62	9.15	9.69	
0.9	6.44	6.97	7.51	8.04	8.58	9.12	9.65	
1.0	6.41	6.94	7.48	8.01	8.55	9.09	9.62	

Fuel Oil-fired Boiler - Cost of Steam Produced (US$/M.T.)

	Fuel Oil Cost (US$/M.T.) a/							
	95	100	105	110	115	120	125	
0.0	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
0.1	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
0.2	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
Annual	0.3	6.21	6.52	6.83	7.14	7.45	7.76	8.07
0.4	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
Plant	0.5	6.21	6.52	6.83	7.14	7.45	7.76	8.07
0.6	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
Factor	0.7	6.21	6.52	6.83	7.14	7.45	7.76	8.07
0.8	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
0.9	6.21	6.52	6.83	7.14	7.45	7.76	8.07	
1.0	6.21	6.52	6.83	7.14	7.45	7.76	8.07	

a/ Border Price.

Table 1: PROJECTED ENERGY SECTOR INVESTMENT, 1987-1991
(1986 US$ millions equivalent)

	Actual 1986	Prelim. 1987	1988	1989	1990	1991	Total 1987-91
Grand Total a/	422.5	652.2	612.1	623.8	497.3	352.6	2,738.0 a/
Electric Power	209.4	319.9	287.3	307.7	263.1	205.3	1,383.3
Generation and Transmission							
Public	177.2	274.2	250.9	273.2	230.7	170.9	1,199.9
Private	10.0	10.0	10.0	10.0	10.0	10.0	50.0
Distribution							
Public	17.2	30.7	21.4	19.5	17.4	19.4	108.4
Private	5.0	5.0	5.0	5.0	5.0	5.0	25.0
Petroleum-ENAP	101.0	148.9	151.0	149.0	139.0	109.0	696.9
Exploration and Development	81.0	96.0	121.0	117.0	112.0	82.0	528.0
Onshore-Springhill	.	(	24.0	9.0	5.0	1.0	(
Offshore-Springhill	.	(96.0	80.0	85.0	75.0	41.0	(528.0
Frontier Areas	.	(--	17.0	23.0	32.0	40.0	(
Refining	20.1	19.1	22.0	31.0	26.0	32.0	130.1
RPC	15.7	4.0	11.0	11.0	9.0	14.0	59.0
PETROX	4.4	15.1	11.0	20.0	17.0	18.0	81.1
Natural Gas	9.0	9.0	2.0	25.0	60.0	50.0	146.0
Field Development	9.0	9.0	2.0	--	--	--	11.0
Pipelines	--	--	--	25.0	60.0	50.0	135.0
Natural Gas Based Projects b/	73.0	149.0	142.0	158.0	88.0	34.0	571.0
Methanol	73.0	149.0	72.0	-	-	-	221.0
Amonia-Urea	-	-	70.00	158.0	88.0	34.0	350.0
Coal	39.0	34.0	28.0	12.1	14.6	8.8	97.5
ENACAR	12.0	8.0	19.9	8.0	8.5	2.7	47.1
Lota	(5.5)	(0.7)	(16.2)	(3.4)	(1.1)	(2.9)	22.3
Colico-Trongol	(n.a)	(0.6)	(3.1)	(0.4)	(0.2)	(0.3)	(4.6)
Lebu	(n.a)	(0.4)	(0.5)	(0.7)	(1.4)	1.1	(4.1)
New Mine; Other	(n.a)	(6.3)	(0.1)	(3.5)	(5.8)	(0.4)	(16.1)
COCAR	27.0	25.0	7.0	3.0	5.0	5.0	45.0
Schwager	n.a.	1.0	1.1	1.1	1.1	1.1	5.4

a/ Nearly 78% of total projected investment is attributable to the public sector which includes power (public), petroleum-ENAP, and coal-ENACAR.

b/ Private Sector.

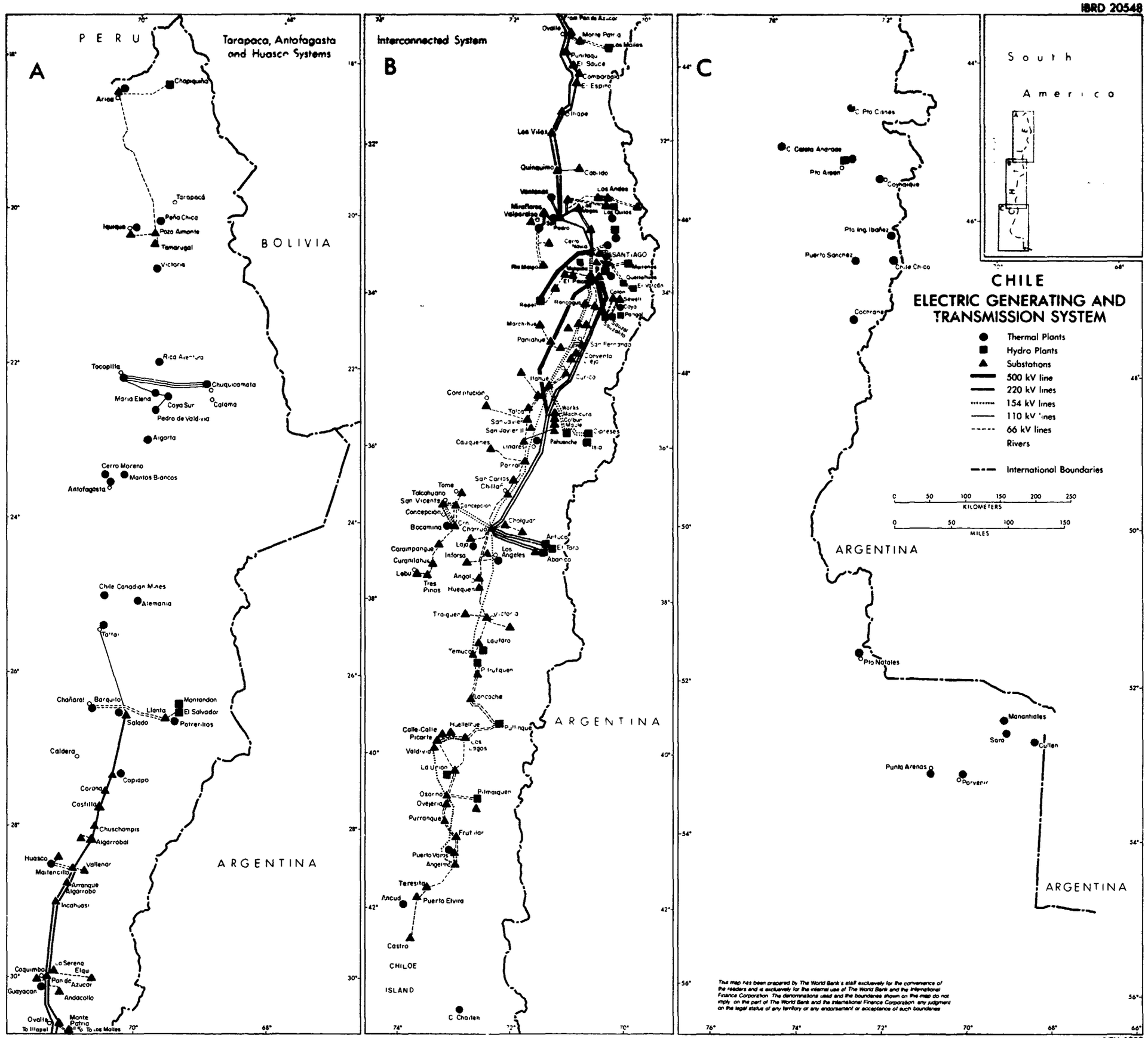
Source: CNE.

Table 2: PROJECTED INVESTMENT IN THE HYDROCARBONS SUBSECTOR, 1987-1991
(1986 US$ millions equivalent)

	1987	1988	1989	1990	1991	Total 1987-91
Grand Total	123-127	109-145	105-173	131-194	83-172	541-820
Exploration and Development	96	85-121	85-117	80-112	47-98	393-544
Springhill	96	80-104	80-94	75-80	42-58	384-432
Frontier Areas- Exploration/Promotion	--	5-10	5-10	5-10	5-10	20-40
Possible Additional Exploration/Development	--	0-7	0-13	0-22	0-30	0-72
Natural Gas	9	2	15-25	45-62	30-50	101-146
Field Development	9	2	--	--	--	11
Pipelines	--	--	15-25	45-60	30-50	90-135
Refining	18	11-22	5-31	7-26	6-32	47-130
RPC (Concon)						
Mild Hydrocracker	--	0-8	0-9	0-5	--	0-22
Additional Modifications	--	--	--	1	0-11	1-12
Misc. Inv. & Repairs	4	3	2	3	3	15
PETROX (Concepcion)						
New Conv/ Delayed Coker	1	--	0-16	0-14	0-15	1-46
Etilene Unit Modif.	--	0-3	0-1	--	--	0-4
Misc. Inv. & Repair	14	8	3	3	3	31

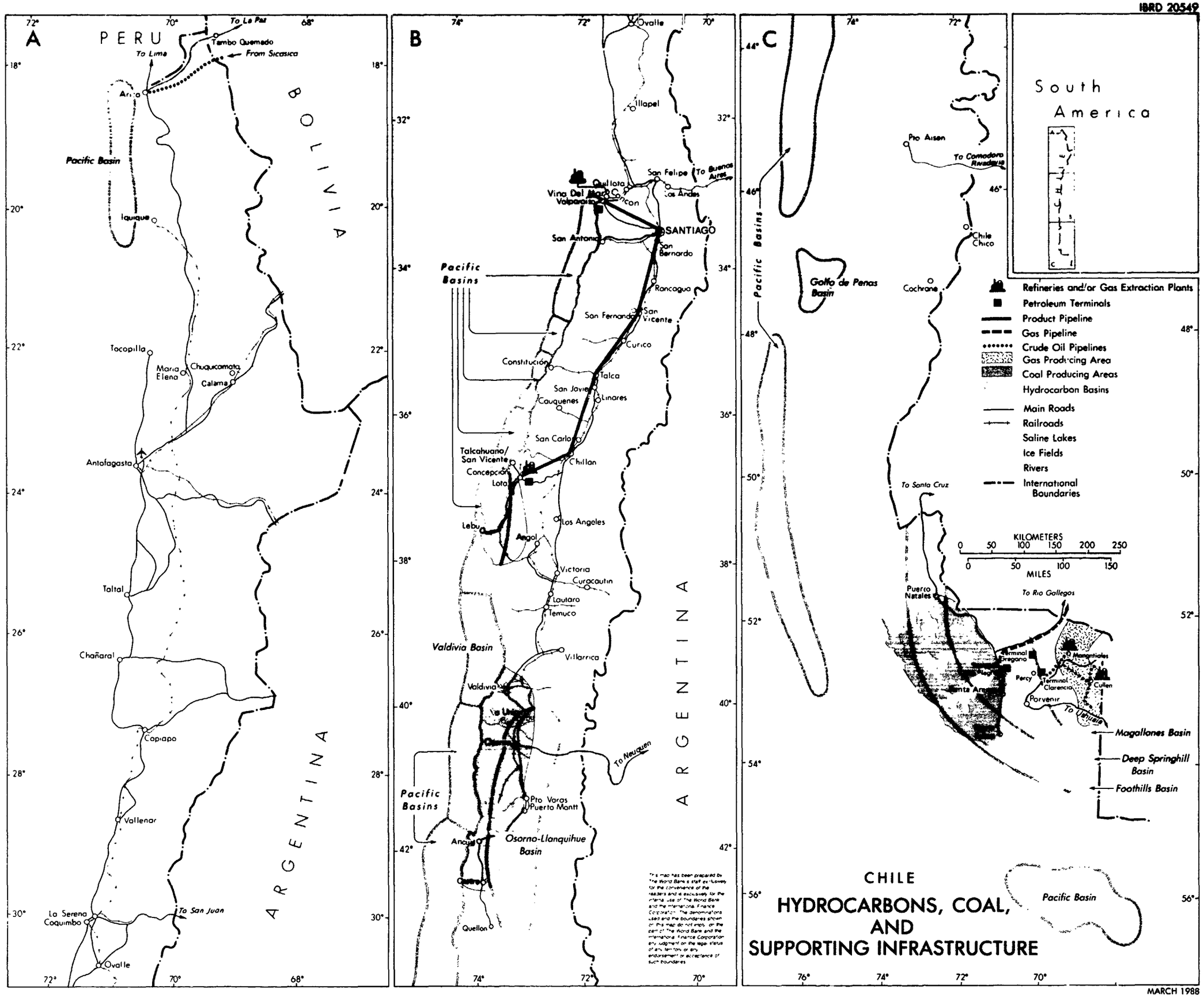
Source: ENAP; GASCO; mission estimates.

IBRD 20548



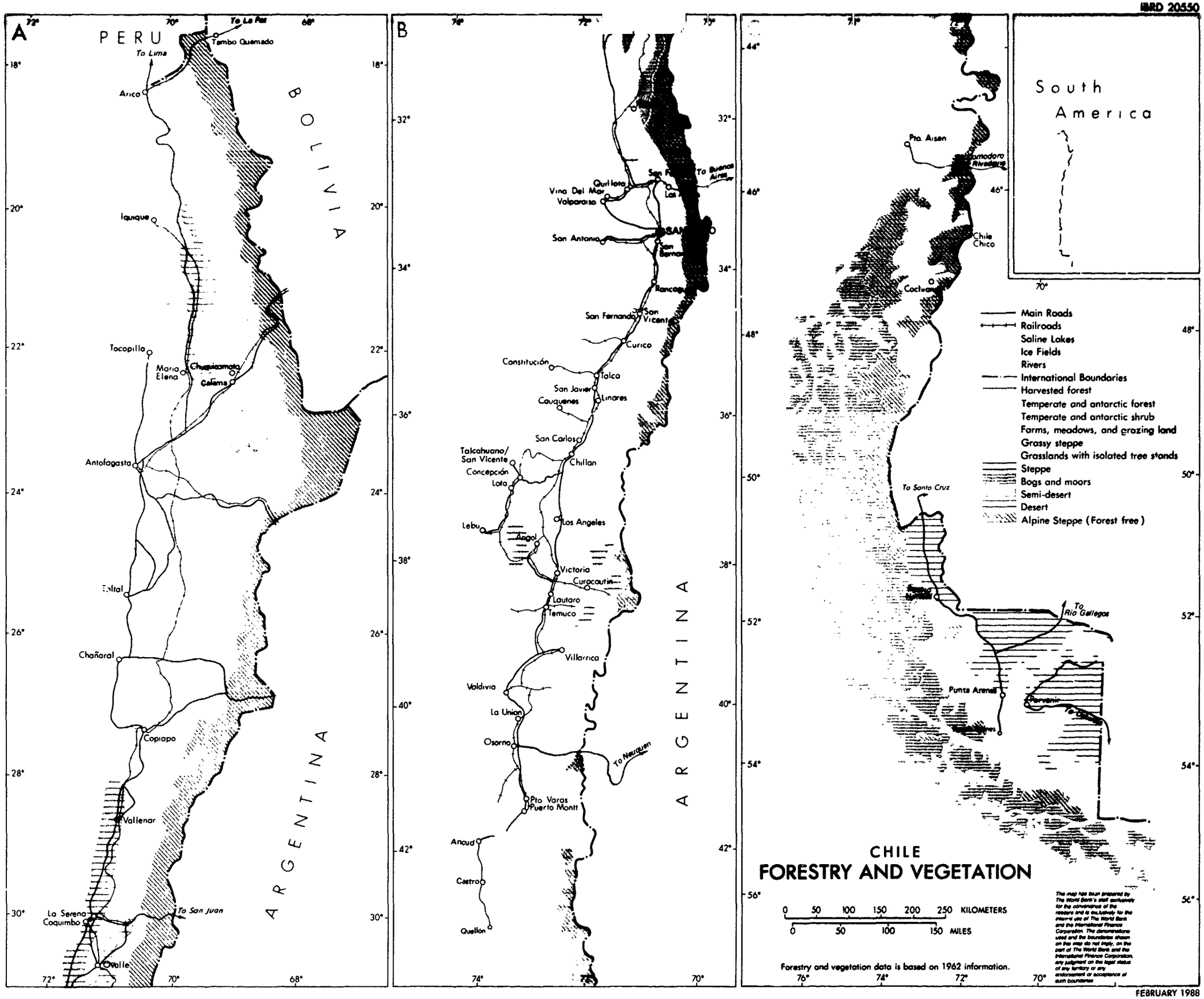
MARCH 1988

IBRD 20549



MARCH 1988

IBRD 20550



CHILE
FORESTRY AND VEGETATION

FEBRUARY 1988