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MEMO

To: New Mexico Energy Supply TWG

From: CCS analysis support team (Bill Dougherty, Michael Lazarus, David White, Tim Woolf, Eric Williams)

Re: Draft Plan for Revised ES Quantitative Analysis

Date: September 22, 2006

Per discussions on our August 30 TWG call, we are undertaking a revised analysis for several of the ES policy options. This memo describes the key elements of our proposed analysis approach. It draws from the outcomes of the August 30 call, as described in the call summary, and is guided by the time constraints of the process. It begins by outlining the principal proposed revisions to the analysis of each individual option, and is followed by a listing of key assumptions for capital, fuel, and other costs. We recognize that there are many uncertainties surrounding these assumptions; such uncertainties may be addressed through sensitivity analysis, time permitting, and/or through narrative explanation of how results might vary using different assumptions. The goal is to provide the TWG with draft revised analyses in advance of the October 6 TWG meeting, with a final version available for review prior to the October 20 TWG meeting.

ES-1 Mandate(s) for Renewable Energy (RPS, etc.)

General Comments: None.

Data Sources, Methods and Assumptions:

- **Data Sources:** CDEAC, WECC, EIA, EPA, NREL.
- **Quantification Methods:** The analysis uses a spreadsheet tool to compare the costs and CO₂ emissions of RPS scenarios with the costs and CO₂ emissions of the reference case. It involves the following steps: (1) identify the type of renewable generation that would most likely be used to meet the RPS in 2012 and 2020; (2) estimate the costs associated with each

type of renewable technology; (3) estimate the extent to which the cost of the renewables exceed the cost of conventional generation; and (4) estimate the amount of CO₂ emissions that are expected to be avoided by the renewables, relative to the reference case. The primary scenario assumes that the current New Mexico RPS is increased by 1% per year. Two sensitivity scenarios investigate the effect of increasing the New Mexico RPS by 0.5% and 2% per year. An additional sensitivity will assess how the primary scenario would be affected if it were implemented in conjunction with the financial incentives for centralized renewables (described below as ES-4).

- **Key Assumptions:** It is assumed that the NM RPS would be met with a combination of wind, geothermal and concentrating solar power (CSP). Wind provides a large majority of the resources, with CSP increasing in later years as the economics of that technology improve. It is assumed that in 2012 the renewable mix is made up of 87% wind, 10% geothermal, and 3% CSP; and that by 2020 the renewable mix is made up of 75% wind, 10% geothermal, and 15% CSP. These renewables mixes are roughly based on the results of the NEMS runs used in the initial draft of this analysis, combined with an assessment of renewable potential and cost identified in the 2006 CDEAC study. The costs of the new renewable systems are based on those used in the EIA Annual Energy Outlook for 2006, except where better (e.g., updated or more local) data are available. The cost of renewable generation include costs associated with connecting renewable technologies to the electric grid, and transmitting the renewable generation to loads, based on information from the 2006 CDEAC study. The cost of wind generation also includes costs associated with integrating large amounts of wind onto the system, where integration costs increase with increasing amounts of wind capacity. These wind integration costs are based on a review of the relevant literature, including a recent study by Xcel Energy. The benefits of this policy are the avoided costs of generation as estimated based on past avoided cost studies. Additional detail on key assumptions is provided in Attachment A below.

ES-2 Financial Incentives for Distributed Renewables

General Comments: To simplify and clarify the analysis, the TWG agreed to focus on the 10-year payback scenario. Payback periods of 3 and 25 years will also be calculated as part of sensitivity analyses. Two service areas will be considered, one for all utilities serving the entire state, the other just for PNM. The focus of the analysis will be on solar photovoltaic systems installed in new and existing residential and commercial buildings.

Data Sources, Methods and Assumptions:

- **Data Sources:** The Southwest Energy Efficiency Project's Report *Increasing Energy Efficiency in New Buildings in the Southwest: Energy Codes and Best Practices* for residential housing units and commercial floor space data and projections for NM; AEO2006 for solar PV capital cost and O&M costs projections, as well as R/C electricity costs and marginal CO₂ emission factor for the NERC region where NM is located.

- **Quantification Methods:** We use a simple spreadsheet analysis in which the magnitude of the incentive required to yield positive cash flow for the consumer post 10 years (and the other payback periods) is calculated. The incentive is the percentage of the capital cost that is subsidized by a funding source. The size of the incentive diminishes over time consistent with projected capital cost reduction assumptions. Final results are reported in terms of total PV capacity installed and annual generation avoided.
- **Key Assumptions:** Avoided electricity costs are assumed consistent with ES-1 above, also accounting for avoided transmission and distribution costs. Average capacity factor of PV systems conservatively assumed to be 25%.

ES-3 Renewable Energy Transmission and Storage

General Comments: The TWG agreed to forego separate quantification of this option, and view this as an enabling strategy for achieving reductions estimated for other options.

ES-4 Financial Incentives for Centralized Renewables

General Comments:

Data Sources, Methods and Assumptions:

- **Data Sources:** CDEAC, WECC, EIA, EPA, NREL.
- **Quantification Methods:** The analysis uses a spreadsheet tool to assess the impact that financial incentives for centralized renewables would have on the Renewable Performance Standard (described above as ES-1). We expect that the introduction of these financial incentives will (a) alter the mix of renewable resources used to meet the RPS, and (b) result in additional renewable generation that would be sold either in New Mexico or in neighboring states. The analysis involves the following steps: (1) identify the type of renewable generation that would most likely be developed as a result of the RPS combined with the financial incentives; (2) estimate the costs associated with each type of renewable technology; (3) estimate the extent to which the cost of the renewables exceed the cost of conventional generation; and (4) estimate the amount of CO₂ emissions that are expected to be avoided by the renewables, relative to the reference case.
- **Key Assumptions:** Where applicable, the key assumptions are the same as those used in assessing the RPS (ES-1). Ideally, we would undertake a full economic modeling exercise to assess how the proposed incentive amounts might alter the mix and amount of renewable energy generation; however, such a modeling exercise would be both time-consuming and subject to very large uncertainties. Instead, we make some indicative assumptions. For example, given the incentive structure proposed, it is assumed that biomass and solar would play a greater role in providing renewable generation under the RPS than would be the case without incentives. It is assumed that the renewables mixes developed above for the RPS (ES-1), would be modified such that in 2012 the renewables mix is made up of 85% wind,

5% biomass, 5% geothermal, and 5% CSP; and that by 2020 the renewables mix is made up of 60% wind, 5% biomass, 5% geothermal, and 30% CSP. The increase in total renewable generation will depend upon the cost-competitiveness of these resources after the subsidies, which will be assessed under ES-2 (i.e., to be determined later). The costs of the new renewable systems are based on those used in the EIA Annual Energy Outlook for 2006, except where better data are available. The costs for new renewable systems include incremental transmission costs, as well as costs associated with integrating large portions of wind into the New Mexico electricity grid.

ES-5 R&D including Energy Storage

General Comments: The TWG agreed to forego separate quantification of this option, and view this as an enabling strategy for achieving reductions estimated for other options.

ES-6 Advanced Coal/Fossil Technologies (e.g., IGCC with carbon capture)

General Comments:

Data Sources, Methods and Assumptions:

- **Data Sources:** EIA, EPA, EPRI, MIT, Princeton (Williams), and IPCC Special Report on Carbon Dioxide Capture and Storage.
- **Quantification Methods:** We assume that all new coal generation in the reference case projections in the reference case would be provided by IGCC with CCSR instead of pulverized coal plants with no CO₂ controls. We estimate the incremental cost of IGCC with CCSR relative to pulverized coal, and the difference in emissions using a simple spreadsheet analysis, which accounts for the additional energy needed to power the capture and storage processes. We estimate costs from two perspectives: a) a bottom-up assessment of estimated CO₂ pipeline, storage, and monitoring costs assuming the use of depleted natural gas reservoirs (to err on the side of being conservative, this includes the full cost of well drilling for storage purposes, even though existing wells may be used at potentially a lower cost); b) comparison with widely-reviewed CCS analyses by the IPCC and Princeton University on a cost per ton basis.
- **Key Assumptions:** For the bottom-up analysis, costs of IGCC and pulverized coal plants are drawn from AEO 2006, and assumptions for capture and storage are drawn from EPRI, MIT and others. For the top-down comparison, IPCC estimates are shown in Attachment B.

ES-7 Nuclear Power

General Comments: No further analysis needed.

ES-8 Incentives and Barrier Reductions for Combined Heat & Power (CHP)

General Comments:

Data Sources, Methods and Assumptions:

- **Data Sources:** The *Combined Heat and Power White Paper*, dated January, 2006, to the Clean and Diversified Energy Initiative of the Western Governors Association; and the *2003 Commercial Buildings Energy Consumption Survey Detailed Tables*, published by the US Department of Energy's Energy Information Administration.
- **Quantification Methods:** Starting with an estimate for New Mexico's share of CHP potential in the West, as provided in the "CHP White Paper" referenced above, assumptions regarding the penetration of and fuel shares for new CHP systems, and estimates of future capacity of CHP developed under the policy, are generated. Estimates of CHP cost and performance for different kinds of systems are then used to estimate the overall net GHG emissions reduction and net cost of the policy.
- **Key Assumptions:** Gas-fired systems are assumed to dominate new CHP in New Mexico, but some biomass- and coal-fired capacity is also included. Systems are assumed to operate an average of 5000 hours per year (at full capacity), and 90 percent of co-generated heat is assumed to be usable (and displaces heat from purchased fuels). See Attachment C for detailed assumptions.

ES-9 Demand-Side Management, Energy Efficiency, and Integrated Resource Planning (IRP)

General Comments: Being quantified by RCI TWG, no further ES TWG analysis needed.

ES-10 Transmission Capacity and Corridors

ES-11 CO2 Capture and Storage or Reuse (CCSR)

ES-12 Methane Reduction in Oil & Gas Operations: BMPs & PROs

ES-14 GHG Cap & Trade

General Comments: No further analysis needed.

ES-15 Generation Performance Standard

General Comments:

Data Sources, Methods and Assumptions:

- **Data Sources:** CDEAC, WECC, EIA, EPA, NREL.
- **Quantification Methods:** The analysis uses a spreadsheet tool to compare the costs and CO₂ emissions of compliance with the GPS with the costs and CO₂ emissions of the reference case. It involves the following steps: (1) estimate the amount of new coal generation expected in the reference case; (2) calculate the amount of CO₂ emissions from the new coal generation that would exceed the generation performance standard; (3) identify the type and amount of gas and renewable generation that would be needed to offset those coal CO₂ emissions; and (4) estimate the extent to which the cost of the gas and renewable generation exceeds the cost of conventional generation.
- **Key Assumptions:** Where applicable, the key assumptions are the same as those used in assessing the RPS (ES-1). The type of replacement resources needed to comply with the GPS are based on the mix of renewable generation that is assumed for the RPS analysis, modified to account for the role that gas can play in meeting the GPS. It is assumed that in 2012 the replacement resource mix is made up of 50% gas, 40% wind, 7% geothermal, and 3% CSP; and that by 2020 the replacement resource mix is made up of 50% gas, 25% wind, 10% geothermal, and 15% CSP. The costs of the new renewable systems are based on those used in the EIA Annual Energy Outlook for 2006, except where better data are available. The costs for new renewable systems include incremental transmission costs, as well as costs associated with integrating large portions of wind into the New Mexico electricity grid.

ES-16 Regulatory Reform for Electric Cooperatives

General Comments: No further analysis needed.

Attachment A
Key Assumptions for ES-1 Mandate(s) for Renewable Energy
and ES-4 Financial Incentives for Centralized Renewables

Reference Technology Costs

For overall consistency we propose using technology costs based on those used in EIA’s Annual Energy Outlook (AEO) for 2006.¹ Although current prices are higher for wind and coal because of tight markets, longer term prices are expected to return to these levels.

Technology Parameters							
	2010			2020			
	Total Overnight Cost	Variable O&M	Fixed O	Total Overht Cost	Variable	Fixed O&M	Project Life
	\$/kW	m Wh	\$/	\$/kW	Wh	\$/kW	Years
s	1,780		48.6	1,696	3.13	46.2	30
	2,205	0	75.0	2,005	0	68.2	30
Wind	1,171	0	27.6	1,159	0	27.3	25
Solar Thermal	2,779	0	51.7	2,315	0	43.1	25
Photovoltaic	4,193	0	10.6	3,494	0	8.9	20

All costs are expressed in year 2004 dollars.

Resource Potential

Wind: There is substantial wind potential in New Mexico. The 2000 NREL study² identified potential capacity of 31,990 MW after land use and environmental exclusions, with a generation potential of 57 billion kWh/year. The Western Governor’s Association CDEAC taskforce³ in 2006 identified over 10,000 MW from wind class 5 and above sites. That lower number is quite adequate for the current purpose.

Solar: The potential is essentially unlimited for the present analysis. The Renewable Energy Atlas of the West in 2002 identified the NM electric generation potential of 104 billion kWh/year (about 60,000 MW).⁴ The more recent 2006 CDEAC study identified a potential CSP

¹ Electric Market Module, EIA Assumptions to the Annual Energy Outlook 2006.

² NREL Wind Powering America – New Mexico, April 2000.

³ Clean and Diversified Energy Advisory Committee (CDEAC) Final Report, Western Governors’ Association, June 2006.

⁴ Renewable Energy Atlas of the West, p 53, by the Land and Water Fund of the Rockies, 2002.

deployment of 300 MW in NM by 2015. But the actual amount could be greater, especially with effective storage technologies.

Geothermal: There are currently no utility-scale installations, but numerous direct use applications. The 2004 Energy Atlas identified a electric generation potential of 3 billion kWh/year (about 350 MW).⁵ The CDEAC study identified the near-term potential of 80 MW, with a longer-term (20 year) potential of 170 MW.⁶

Renewable Capacity Components

The nature of many renewable resources limit their availability and generation.

Technology	Capacity Factor	Comment
Wind	35%	Intermittent – depends on location and technology. ⁷
Solar	25% ⁸	Diurnal – may be extended with storage.
Geothermal	90%	Baseload
Source – Synapse and CDEAC.		

⁵ Renewable Energy Atlas of the West, p 54, by the Land and Water Fund of the Rockies, 2002.

⁶ CDEAC Geothermal Task Force Report, p 65, WGA, 2006.

⁷ The better wind sites will be used first, but technology will also improve over time. The CDEAC report shows a fairly flat wind supply curve to over 10,000 MW. Thus for purposes of simplicity we propose a constant capacity factor over the time span of this analysis.

⁸ From “PV Grid Connected Grid Potential Under A Cost Breakthrough Scenario”, Navigant, September 2004.

System Integration Costs

As wind increases as a fraction of the total generating capacity, additional system costs are incurred (regulation, spinning reserves, ...) because of wind's intermittent nature. Based on an analysis of the wind integration literature carried by Synapse in 2005 we propose an additional system-related wind cost of \$3/MWh for each 10% increase in the wind penetration level up to 30%. This value is supported by the wind integration cost estimates presented in the CDEAC report.^{9 10}

Wind Capacity Fraction	Additional Wind Integration Cost (\$/MWh of Wind Generation)
0%	0
10%	3.0
20%	6.0
30%	9.0

Transmission Expansion Costs

Since many wind resources are located away from existing transmission lines additional transmission would be needed to get it to the grid. Also additional generation in general (whether conventional or renewable) would require upgrades to the existing transmission system. Taking the reference case from the CDEAC study, generation above those levels would have additional costs. Since the precise nature of those additional costs would require calculations beyond the scope of the current analysis, we propose using an average cost from that study.

Resource	Cost (\$/kW)	Explanation
All new resources	80	For total installed capacity above baseline levels. ¹¹

Production Tax Credit

For Wind & Solar technologies: Federal tax credit of \$19/MWh (inflated) for the first ten years of operation for new facilities in operation through 2010. We may wish to consider alternative scenarios for this.

⁹ See Table 7 on p35 of the CDEAC Wind Report. Exclusion of the two extreme data points (PJM/Hirst and We Energies II) produces a regression value of \$2.92 per 10% wind penetration.

¹⁰ The Xcel MN DOC study reported in Table 7 above has an integration cost of \$4.6/MWh at a 15% level, which is \$3.07 per 10% penetration.

¹¹ CDEAC Transmission Report in the High Renewables case has an average incremental transmission cost of 80 \$/kW compared to the reference case, i.e. 84,641 MW incremental capacity with additional transmission expansion costs of \$6,786 million.

Financial Parameters

Recommend common financial assumptions for all project investments. There is of course substantial future uncertainty and we propose the middle of the road consensus values below.

Financial Parameters for Energy Supply Analysis		
Annual Inflation	%	2.5%
Project Financial Structure		Regulated
Debt Fraction	%	50.0%
Equity Fraction	%	50.0%
Cost of Debt		8.00%
Cost of Equity		12.00%
State Income Tax Rate	%	7.6%
Federal Income Tax Rate	%	35.0%
Effective Tax Rate	%	39.9%
WACC Pre-Tax	%	10.00%
WACC Post-Tax	%	8.40%

Fuel and Energy Costs

Consistent with the previous analyses using NEMS we recommend the use of the fuel and energy prices from the AEO 2006 Reference case for the WECC Rocky Mountain Power Area and Arizona-New Mexico-Southern Nevada Power Area. The average electricity costs are provided for comparison purposes, but the marginal values need to be determined for evaluating the incremental cost savings from renewables.

Energy Costs		
	2012	2020
Electric Generation Fuel Costs - (2004\$/Million Btu)		
Coal	1.23	1.28
Natural Gas	5.61	5.40
Distillate Fuel	10.43	10.55
Residual Fuel	6.90	14.90
Biomass	1.58	1.61
Average Electricity Costs - (2004\$/MWh)		
Generation	49.7	49.9
Transmission	6.6	7.7
Distribution	18.9	18.3
Source – AEO 2006 WECC		

Avoided Costs

The various renewable options avoid fuel and new capacity costs from resources that would otherwise be constructed. An analysis carried out by PNM in 2001¹² came up with the following equivalent avoided costs. The prices from this analysis are a bit below the regional prices from AEO 2006 and may need to be updated and increased.

Avoided Generation Costs (2005\$/MWh)				
Year	Residential	Commercial	Industrial	Average
2005-20	47.7	46.8	44.4	46.4

¹² PNM's 2001S Marginal Cost Study & 2003 FERC Form 1 (MC Rates Described in Terms of Energy)

Attachment B IPCC (2006) Estimates for Power Plant CO₂ Capture and Storage

For ES-6: Advanced Coal/Fossil Technologies (e.g., IGCC with carbon capture)

Table 8.1 Summary of new plant performance and CO₂ capture cost based on current technology.

Performance and Cost Measures	New NGCC Plant				New PC Plant				New IGCC Plant				New Hydrogen Plant				(Units for H ₂ Plant)
	Range			Rep. Value	Range			Rep. Value	Range			Rep. Value	Range			Rep. Value	
	low	-	high		low	-	high		low	-	high		low	-	high		
Emission rate without capture (kg CO ₂ MWh ⁻¹)	344	-	379	367	736	-	811	762	682	-	846	773	78	-	174	137	kg CO ₂ GJ ⁻¹ (without capture)
Emission rate with capture (kg CO ₂ MWh ⁻¹)	40	-	66	52	92	-	145	112	65	-	152	108	7	-	28	17	kg CO ₂ GJ ⁻¹ (with capture)
Percent CO ₂ reduction per kWh (%)	83	-	88	86	81	-	88	85	81	-	91	86	72	-	96	86	% reduction/unit of product
Plant efficiency with capture, LHV basis (%)	47	-	50	48	30	-	35	33	31	-	40	35	52	-	68	60	Capture plant efficiency (% LHV)
Capture energy requirement (% more input MWh ⁻¹)	11	-	22	16	24	-	40	31	14	-	25	19	4	-	22	8	% more energy input per GJ product
Total capital requirement without capture (US\$ kW ⁻¹)	515	-	724	568	1161	-	1486	1286	1169	-	1565	1326	[No unique normalization for multi-product plants]				Capital requirement without capture
Total capital requirement with capture (US\$ kW ⁻¹)	909	-	1261	998	1894	-	2578	2096	1414	-	2270	1825					Capital requirement with capture
Percent increase in capital cost with capture (%)	64	-	100	76	44	-	74	63	19	-	66	37	-2	-	54	18	% increase in capital cost
COE without capture (US\$ MWh ⁻¹)	31	-	50	37	43	-	52	46	41	-	61	47	6.5	-	10.0	7.8	H ₂ cost without capture (US\$ GJ ⁻¹)
COE with capture only (US\$ MWh ⁻¹)	43	-	72	54	62	-	86	73	54	-	79	62	7.5	-	13.3	9.1	H ₂ cost with capture (US\$ GJ ⁻¹)
Increase in COE with capture (US\$ MWh ⁻¹)	12	-	24	17	18	-	34	27	9	-	22	16	0.3	-	3.3	1.3	Increase in H ₂ cost (US\$ GJ ⁻¹)
Percent increase in COE with capture (%)	37	-	69	46	42	-	66	57	20	-	55	33	5	-	33	15	% increase in H ₂ cost
Cost of CO ₂ captured (US\$/tCO ₂)	33	-	57	44	23	-	35	29	11	-	32	20	2	-	39	12	US\$/tCO ₂ captured
Cost of CO ₂ avoided (US\$/tCO ₂)	37	-	74	53	29	-	51	41	13	-	37	23	2	-	56	15	US\$/tCO ₂ avoided
Capture cost confidence Level (see Table 3.7)	moderate				moderate				moderate				moderate to high				Confidence Level (see Table 3.7)

COE = Cost of electricity

Notes: [a] Ranges and representative values are based on data from Tables 3.7, 3.9, 3.10 and 3.11. All costs in this table are for capture only and do not include the costs of CO₂ transport and storage; see Chapter 8 for total CCS costs. [b] All PC and IGCC data are for bituminous coals only at costs of 1.0-1.5 US\$ GJ⁻¹ (LHV); all PC plants are supercritical units. [c] NGCC data based on natural gas prices of 2.8-4.4 US\$ GJ⁻¹ (LHV basis). [d] Costs are in constant US\$ (approx. year 2002 basis). [e] Power plant sizes range from approximately 400-800 MW without capture and 300-700 MW with capture. [f] Capacity factors vary from 65-85% for coal plants and 50-95% for gas plants (average for each=80%). [g] Hydrogen plant feedstocks are natural gas (4.7-5.3 US\$ GJ⁻¹) or coal (0.9-1.3 US\$ GJ⁻¹); some plants in dataset produce electricity in addition to hydrogen. [h] Fixed charge factors vary from 11-16% for power plants and 13-20% for hydrogen plants. [i] All costs include CO₂ compression but not additional CO₂ transport and storage costs.

Attachment C

ES-8 Incentives and Barrier Reductions for Combined Heat & Power (CHP)				
<i>Date Last Modified:</i>		9/19/2006 M.Lazarus		
Key Data and Assumptions		2012	2020/all	Units
First Year Results Accrue			2008	
Electricity		2012	2020/all	Units
Avoided Electricity Cost				\$/MWh
<i>TBD</i>				
Avoided Natural Gas Cost				\$/MMBtu
<i>TBD</i>				
Other Data, Assumptions, Calculations		2010	2020/all	Units
Fraction of New Mexico's Remaining Existing CHP Potential Tapped per Year		2.0%	3.0%	
<i>Rough estimate to be refined in consultation with TWG. Fractions of remaining potential tapped in each year are assumed to be beyond "baseline plus existing policies" levels, and thus due to CCAG policies.</i>				
Total Remaining Estimated CHP Potential in NM as of 2006				
1801 MW (See Note 1)				
Annual Growth in CHP Potential		3.5%	3.0%	
<i>Rough estimate based on consideration of growth in electricity use in the commercial and industrial sectors.</i>				
Estimated CHP Potential by Year (MW)		2,139	2,938	
Estimated CHP Installed Under Policy by Year (MW)		42.78	88.14	
Average full-capacity-equivalent hours of operation for New CHP units: <i>(Assumption)</i>		5,000	5,000	
Fraction of New CHP Capacity/Energy Fueled With:				
Natural Gas		90%	85%	
Biomass		5%	12%	
Coal <i>(Assumptions)</i>		5%	3%	
Average Net Heat Rate by Fuel (Btu Fuel Input/kWh Electricity Output)				
Natural Gas		10,000	10,000	
Biomass		13,000	13,000	
Coal		12,000	12,000	
Usable Cogenerated Heat Output as a Fraction of Fuel Energy Input				
Natural Gas		40%	40%	
Biomass		40%	40%	
Coal		40%	40%	
Fraction of Usable Heat Output Replacing Space/Water/Process Heat Use <i>(Assumption)</i>		90%	90%	
Fraction of CHP Heat Output Displacing Thermal Energy Produced Using				
Natural Gas		75%	75%	
Biomass		5%	5%	
Coal		0%	0%	
Electricity		15%	15%	
Oil		5%	5%	
<i>Assumptions: See Note 2</i>				

Net Efficiency of Displaced Boiler/Heater Thermal Energy Produced Using			
Natural Gas		85%	85%
Biomass		80%	80%
Coal		80%	80%
Electricity		92%	92%
Oil		80%	80%
<i>Assumptions</i>			
Inputs to Cost Estimates for CHP Systems			
Estimated Average Installed Capital Costs by System Type (\$2005/kW)			
Natural Gas		\$ 2,000	\$ 1,500
Biomass		\$ 2,500	\$ 2,200
Coal		\$ 2,500	\$ 2,200
Factors for Annualizing Capital Costs (all plant types)			
Interest Rate			8%
Economic Life of System			20
Implied Annualization Factor			10.19%
Estimated Average Non-fuel Operating and Maintenance Costs by System Type (\$/MWh)			
Natural Gas		\$ 16.00	\$ 16.00
Biomass		\$ 20.00	\$ 20.00
Coal		\$ 20.00	\$ 20.00
NOTES AND DATA FROM SOURCES			
Note 1:			
From the <u>Combined Heat and Power White Paper</u> , dated January, 2006, to the Clean and Diversified Energy Initiative of the Western Governors Association.			
This report is referred to here as the "WGA CDEAC CHP report" and can be found at:			
http://www.westgov.org/wga/initiatives/cdeac/CHP-full.pdf			
This report (page i, for example) give a total NM CHP capacity of 226 MW, and a total potential additional capacity (presumably as of 2005) of 649 MW.			
Note 2:			
Based on data in the <u>2003 Commercial Buildings Energy Consumption Survey Detailed Tables</u> published by the US Department of Energy's Energy Information Administration, and available as http://www.eia.doe.gov/emeu/cbeecs/cbeecs2003/detailed_tables_2003/pdf2003/allbc.pdf , non-mall commercial buildings in the Mountain West that used space heat used gas to heat			
		64.9%	
of floorspace (as a primary fuel), and used electricity to heat			
		22.1%	
of floorspace. (Data from Table B29).			
Similarly, commercial buildings in the Mountain West that used water heat used gas to heat			
water for	66.5%		36.1%
of floorspace (some used both and/or other fuels). (Data from Table B32).			