American Transmission Co.
2012 Order 890 Recommended Assumptions

In compliance with FERC Order 890, ATC is providing the following materials to stakeholders to provide details for the proposed study assumptions that will be used as part of the 2012 Order 890 study process. As discussed at the January 30th, 2012 stakeholder meeting, ATC recommends using MISO's MTEP 12 futures for this process. The assumptions used in the MTEP 12 models have been fully vetted and developed by MISO stakeholders over the past several months through the MISO Planning Advisory Committee (PAC).

The assumptions are nearly finalized. The following list of assumptions was provided with the meeting materials for the January 25th, 2012 PAC meeting. All of the meeting materials, including the futures assumptions, can be found on the MISO website at:

https://www.midwestiso.org/Events/Pages/PAC20120125.aspx

2012 Economic Studies and Timeline

ATC is requesting feedback from all stakeholders regarding any new potential economic studies that may show benefit to ATC customers. ATC will continue to work with stakeholders to identify preliminary areas of economic study, study assumptions and models as outlined below in the timeline for the Order 890 process.

2012 Timeline

- By March 1, we work with stakeholders to request and prioritize new/other economic studies and recommend study assumptions.
- By April 15 – we identify preliminary areas of economic study, study assumptions and models and solicit further comments from stakeholders.
- By May 15 – we finalize areas of economic study, study assumptions and models to be used in analysis.
- By November 15 – we provide a summary of the results of the economic analyses to our stakeholders.

Future	Definition
Business as Usual	Business As Usual (BAU) considers the status-quo with the current economic conditions within current policy frame-work to continue throughout the study period as reflected in the key variable assumptions. This will be considered as the reference future with base parameters and the other futures' parameters will be varied with respect to this future.
Historical Growth	Historic growth future considers quick recovery from the current economic conditions and assumes a higher demand and energy growth rates as seen in the past for the entire study period. This will be considered as the high side variation of the BAU future.
Limited Growth	Limited growth future considers very low growth rate with EPA regulations, and no carbon cost. This can be considered as the low side variation of the BAU future.
Combined Policy	Combined Policy future studies the impact from multiple policy drivers such as Federal RPS, EPA regulations, Smart Grid, and Electric vehicles.
MISO-SPP Joint Future	This future is a placeholder for the MISO-SPP joint future development.

Demand Response Program	Description
Commercial and industrial (C&I) curtailable/interruptible tariffs	Curtailable programs are those in which a customer commits to curtailing a certain amount of load whenever an event is called in exchange for lower energy price. Interruptible programs are programs in which a customer agrees to be interrupted in exchange for a fixed reduction in the monthly demand billing rate. If a customer does not reduce their load per their commitment, the utility may levy a penalty.
C&I direct load control (DLC)	These programs are where the C&I customer agrees to allow the utility to directly control equipment such as an air conditioner or hot water heater during events in exchange for a payment of some type (a flat fee per year or season and/or a per-event payment). A controlling device such as a switch or programmable thermostat is required.
C&I dynamic pricing	Dynamic pricing programs are structured so that customers have an incentive to reduce their usage during times of high energy demand or high wholesale energy prices. Under a critical peak pricing program, the customer pays a higher electricity rate during critical peak periods and pays a lower rate during off-peak periods. Often times, a critical peak pricing rate is combined with a time-of-use rate. Under a peak-time rebate program, the customer receives an incentive for reducing load during critical peak periods, and there is no penalty if the customer chooses not to participate.
Residential DLC	These programs are where the residential customer agrees to allow the utility to directly control equipment such as an air conditioner or hot water heater during events in exchange for a payment of some type (a flat fee per year or season and/or a per-event payment). A controlling device such as a switch or programmable thermostat is required.
Residential dynamic pricing	Dynamic pricing programs are structured so that customers have an incentive to reduce their usage during times of high energy demand or high wholesale energy prices. Under a critical peak pricing program, the customer pays a higher electricity rate during critical peak periods and pays a lower rate during off-peak periods. Often times, a critical peak pricing rate is combined with a time-of-use rate. Under a peak-time rebate program, the customer receives an incentive for reducing load during critical peak periods, and there is no penalty if the customer chooses not to participate.
Energy Efficiency Program	**Description**
Residential Energy Efficiency Programs*	Appliance incentives/rebates; Appliance recycling; Lighting initiatives; Low income programs; Multifamily programs; New construction programs; Whole home audit programs; All other residential programs
Commercial and Industrial Energy Efficiency Programs*	Lighting programs; Prescriptive rebates; Custom incentives; New construction programs; Retrocommissioning programs; All other C&I programs

* Note: Both Residential and C&I EE programs are split into low and high cost blocks for EGEAS modeling purposes; the cutoff is $1,000/kW

Future	Uncertainties																																	
	Capital Costs															Demand and Energy				Fuel Cost				Fuel Escalations				Emission Costs			Economic		Wind	
	Coal	CC	CT	Nuclear	Wind Onshore	IGCC	IGCC w/ Carbon Capture &	CC w/ Carbon Capture &	Pumped Storage Hydro	Compressed Air Energy	Photovoltaic	Biomass	Conventional Hydro	Wind Offshore	Distributive Generation - Peak	Demand Response Level	Energy Efficiency Level	Demand Growth Rate	Energy Growth Rate	Gas	Oil	Coal	Uranium	Gas	Oil	Coal	Uranium	SO_2	NO_x	CO_2	Inflation	EPA Coal Retirement	MISO Wind Penetration	National Mandate
Business as Usual	M	M	M	M	L	M	N/A	N/A	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	L	L	L	M	M	L	L	M	M	L
Historical Growth	M	M	M	M	L	M	M	M	M	M	M	M	M	M	M	M	M	H	H	M	M	M	M	M	M	M	M	M	M	L	M	M	M	L
Limited Growth	H	M	M	M	L	M	N/A	N/A	M	M	M	M	M	M	M	M	M	L	L	M	M	L	H	L	L	L	L	M	M	L	L	M	M	L
Combined Policy	H	H	H	H	L	H	H	H	H	H	H	H	H	M	H	M	M	M	H	H	M	L	H	M	M	M	M	M	M	M	M	H	M	M
MISO-SPP Joint Future																																		

PROPOSED MTEP-12 FUTURES MATRIX

Uncertainty	Unit	Low (L)	Mid (M)	High (H)
Alternative Capital Costs[1]				
Coal	($/KW)	2,604	2,893	3,617
CC	($/KW)	918	1,020	1,276
CT	($/KW)	609	677	846
Nuclear	($/KW)	4,885	5,428	6,785
Wind-Onshore	($/KW)	2,232	2,480	3,101
IGCC	($/KW)	2,949	3,277	4,096
IGCC w/ CCS	($/KW)	4,897	5,441	6,801
CC w/ CCS	($/KW)	1,886	2,096	2,620
Pumped Storage Hydro	($/KW)	5,123	5,692	7,115
Compressed Air Energy Storage	($/KW)	1,145	1,272	1,590
Photovoltaic	($/KW)	4,947	5,497	6,871
Biomass	($/KW)	3,534	3,927	4,909
Conventional Hydro	($/KW)	2,817	3,130	3,912
Wind-Offshore	($/KW)	5,471	6,079	7,599
Distributive Generation-Peak	($/KW)	1,605	1,784	2,229
Demand and Energy				
Demand Growth Rate	%	0.71%	1.41%[2]	2.12%
Energy Growth Rate	%	0.84%	1.67%[3]	2.51%
Demand Response Level	%		GEP Estimates[4]	
Energy Efficiency Level	%		GEP Estimates[4]	
Fuel Prices (Starting Values)				
Gas	($/MMBtu)	3.50	4.25[5]	8.00
Oil	($/MMBtu)	Powerbase default - 20%	Powerbase default[6]	Powerbase default + 20%
Coal	($/MMBtu)	Powerbase default - 20%	Powerbase default[7]	Powerbase default + 20%
Uranium	($/MMBtu)	0.92	1.14	1.36
Fuel Prices (Escalation Rates)				
Gas	%	1.74	2.91	4.00
Oil	%	1.74	2.91	4.00
Coal	%	1.74	2.91	
Uranium	%	1.74	2.91	
Emission Costs				
SO_2	($/ton)		Group 1: 500[8] Group 2: 250	
NO_x	($/ton)		NO_x: 500[8] Seasonal NO_x: 1,000	
CO_2	($/ton)	0	50	100
Hg	($/ton)			

Economic Variables				
Inflation Rate	%	1.74	2.91	4.00
Renewable Penetration as a Percentage of Total Energy Delivered				
State mandates	%		Use existing state mandates	Use both exisiting state mandates and pending proposals / goals
National	%	0	20% by 2025	30% by 2030
Forced Coal Retirements				
Forced Coal Retirements (from MISO's EPA Regulation Impact Analysis Study)	%	6,600 MW	12,600 MW	23,000 MW

[1] All costs are in Q4 2011 dollars

[2] Mid value for demand growth rate is the Module-E 50/50 load forcast' growth rate (0.91%) + 0.5% to account for embedded DSM programs

[3] Mid value for energy growth rate is the Module-E energy forcast' growth rate (1.17%) + 0.5% to account for embedded DSM programs

[4] GEP provided estimates for each of the scenarios on an individual basis, based on each scenario's definition

[5] Henry Hub gas price

[6] Powerbase default for oil is $19.39/MMBtu

[7] Powerbase range for coal is $1 to $4, with an average value of $1.69/MMBtu

[8] Emission costs for SOx and NOx will be modeled to comply with CSAPR regulations