6.2.5 Potential Solar Resources

Based on a review of available solar technologies and Ameren Missouri's service territory, flat-plate solar photovoltaic (PV) is the most practical technology for implementation.

The solar resource has three primary components: direct, diffuse, and ground reflected. Often the sum of this resource is measured as Global Horizontal Incident (GHI), which is the sum of all irradiance observed by a flat plane over time. Solar PV technologies use GHI. Concentrating solar technologies, including parabolic through, power tower, dish engine, linear Fresnel and concentrating PV (CPV) all us direct component of insolation, called direct normal insolation (DNI).

Global Insolation

Solar PV works by converting sunlight directly into electricity. Unlike solar thermal and concentrating photovoltaics technologies which use DNI, flat plate PV uses global insolation, which is the vector sum of the diffuse and direct components of insolation. A map of the GHI for the U.S. is shown in Figure 6.5. Note that while the desert southwest has the best insolation, there is ample insolation across much of the U.S. for photovoltaic systems. St. Louis has an annual average GHI value of 4.24 kWh/m^2-day. Figure 6.6 shows the monthly average GHI for St. Louis.

Figure 6.5 U.S Global Horizontal Insolation Map

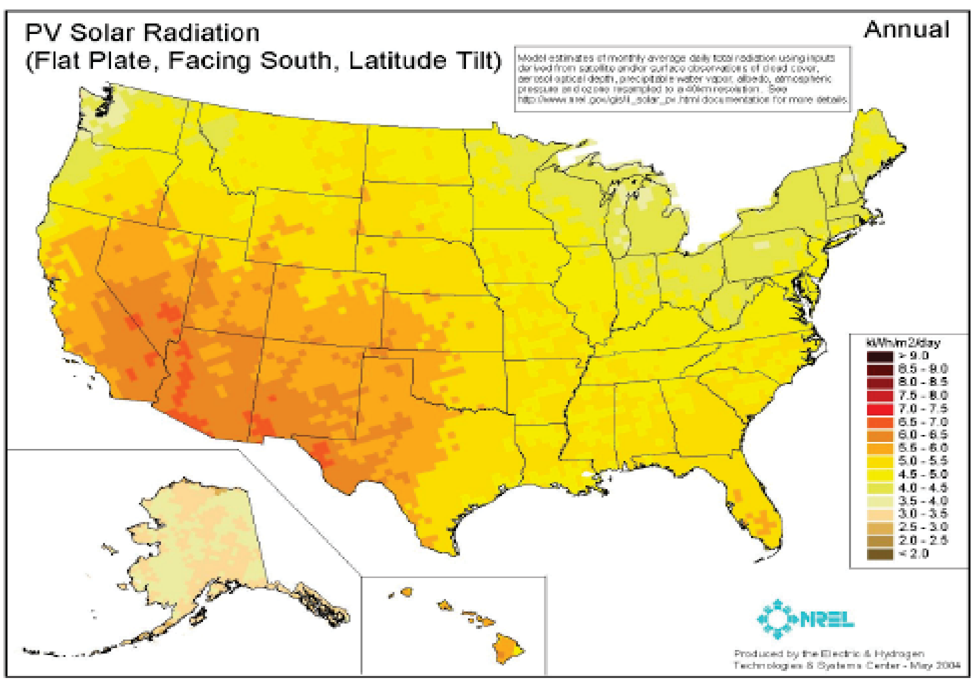
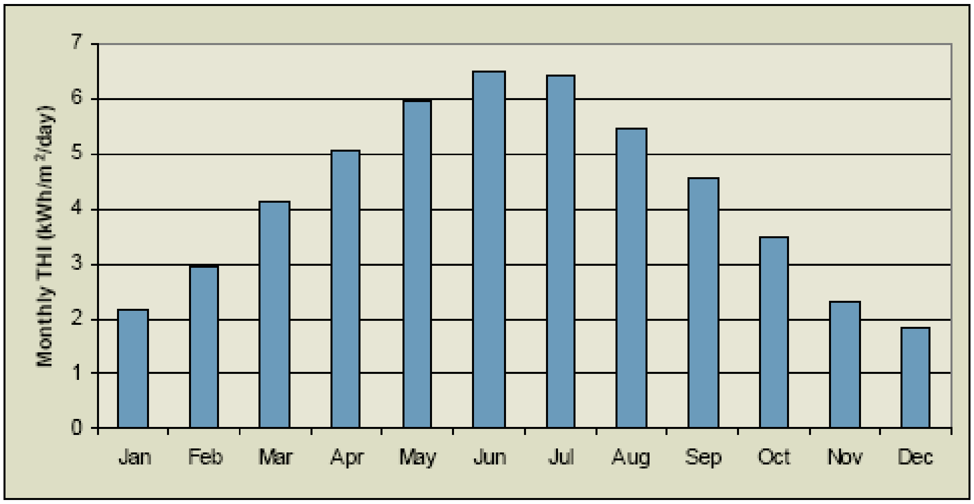


Figure 6.6 Monthly Average Global Horizontal Insolation for St. Louis



Flat Plate Photovoltaics

Traditional wisdom in the solar industry has been that solar PV systems are appropriate for small distributed applications, and that solar thermal systems are more cost effective for large, central station applications. Currently, the world's largest photovoltaic solar generating facility is the Agua Caliente Solar Project being built in Yuma County, Arizona. The Agua Caliente Solar Project is approximately 250 MW [Alternating Current (AC)]. In the U.S., there are over 1,000 operating utility – scale PV installations totaling 2,666 MW AC. Furthermore, central station PV systems are being bid in response to utility requests for proposals.

Ameren Missouri will install 5.7 MW [Direct Current, (DC)] of solar photovoltaic generation next to the Ameren Missouri Belleau substation in St. Charles County. The solar center, O'Fallon Renewable Energy Center (OREC), will feature approximately 19,000 solar panels covering approximately 20 acres on land owned by Ameren Missouri. Construction is anticipated to begin in spring 2014. The installation is scheduled to be in service by 2015 with a total capital cost ranging from $10-$20 million in 2014.

Table 6.14 list primary characteristics of solar. Cost assumptions from were reviewed with internal subject matter experts and revised as appropriate. Chapter 6 – Appendix C contains more detailed information.

Table 6.14 Potential Solar Resource

Resource Option	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE without Incentives (¢/kWh)
Solar	1	$3,777	$25	$0	17.5%	1%	30.51

6.2.5.1 Utility-Scale vs. Customer-Owned Solar

To provide a reference point in our analysis on the economics of Utility vs Customer Owned solar installations a straight-forward comparison is provided to help frame the choices made in our IRP assumptions with regard to meeting RES solar requirements. The framework of this comparison is based on a comparative analysis of the present value of revenue requirements (PVRR). In order to make this comparison for a customer-owned project we assume the entire capital cost is incurred at the beginning of the first year and is not financed by the customer. We assume the customer will receive the same investment tax credit that the utility will receive, and while this changes the capital fixed charge rate for the utility, it simply lowers the expected capital costs in the first year for the customer.

From a cost perspective, we make the assumption that the utility scale project costs will reflect the economies of scale that present themselves to larger projects like those a utility would pursue, which is consistent with assumptions typically found in public sources. Operationally we also assume that a utility will have greater flexibility during installation of solar to maximize the capacity factor that would be available at the installation location. This compares to the assumption provided in PV Watts, which reflects a generic St. Louis region capacity factor that attempts to take into consideration that roof angles and shading will not be optimal on average for a customer-owned installation. Lastly, we assume slightly higher fixed O&M costs for the customer-owned installation since they will typically be contracting this work out on an as needed basis and generally unable to take advantage of the expertise and workforce efficiencies available to a utility owner. Additionally, with regard to fixed O&M, we assume that the size and scale of inverters used in a utility scale project could be rebuilt compared to full replacement for customer-owned solar facilities.

Given this set of assumptions, the analysis demonstrates that the least cost solution for meeting solar requirements is for the utility to own the generation resource, regardless of whether and to what degree tax incentives are available.

Table 6.15 Utility-Scale vs. Customer-Owned Solar Analysis

Assumptions	Utility-Scale	Customer-Owned
Size (kW-DC)	5,745	5,745
(kW-AC)	4,500	4,500
Capacity Factor (%)	15.5%	14.4%
Annual Output Degradation Factor (%)	0.7%	0.7%
Fixed O&M ($/kW-AC)	$25	$29
Economic Life (Years)	20	20
Installed Price ($/W-DC)	$2.96	$4.00
Installed Price ($/W-AC)	$3.78	$5.11
Direct Project Cost	$16,996,500	$22,980,000
RESULTS		
With 30% ITC		
NPV Cost ($)	$15,528,289	$16,792,684
NPV Output (MWh)	86,224	76,067
LCOE with 30% ITC ($/MWh)	$180	$221
With 10% ITC		
NPV Cost ($)	$20,154,189	$21,109,798
NPV Output (MWh)	86,224	76,067
LCOE with 10% ITC ($/MWh)	$234	$278
Without ITC		
NPV Cost ($)	$23,352,222	$26,150,807
NPV Output (MWh)	86,224	76,067
LCOE without ITC ($/MWh)	$271	$344

In addition to the cost advantage, utility-scale solar projects offer benefits that are shared by all customers, rather than just those customers whose premises are favorable to the installation of solar generation and are able to afford the significant up-front costs.

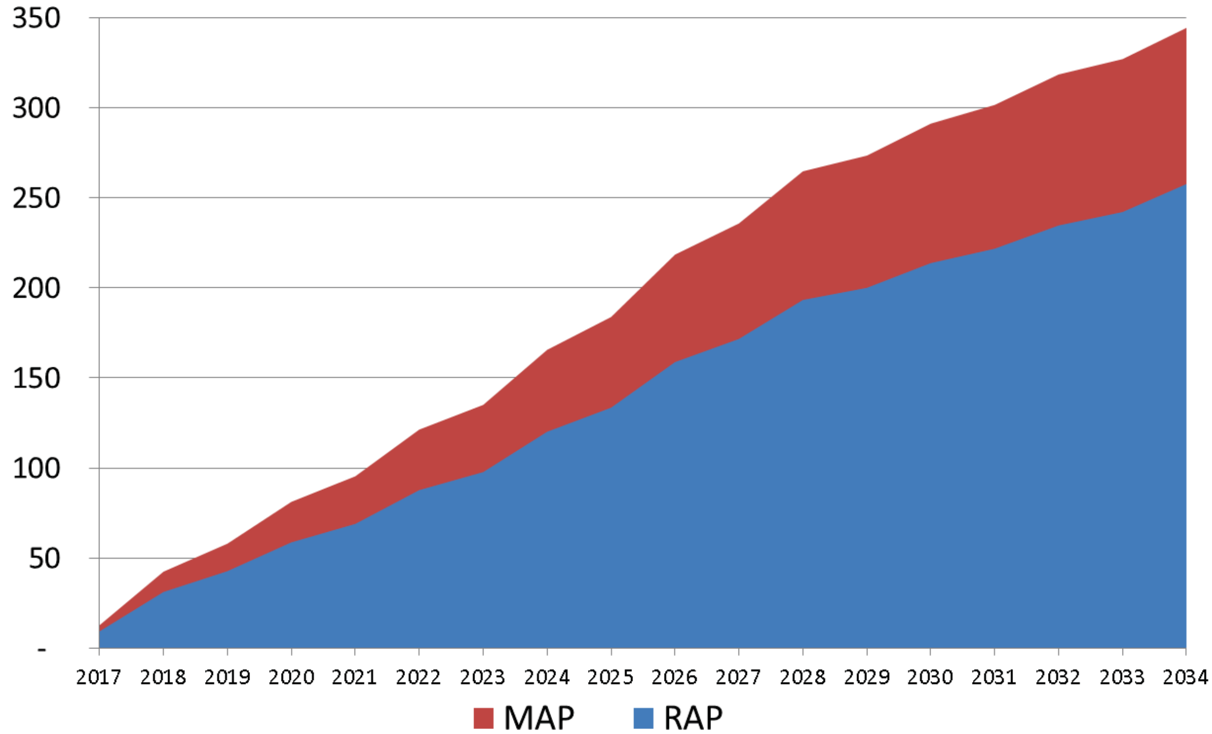
6.2.6 Potential Wind Resources[8]

Black & Veatch performed a high level wind project siting analysis to identify priority multi-county development areas in a study region consisting of the following states: Montana, North Dakota, South Dakota, Kansas, Nebraska, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Michigan, Illinois, Indiana and Kentucky. Analysis was based on a Geographic Information Systems (GIS) siting model developed to estimate the LCOE for wind projects across these states. The GIS model estimates project capital cost and net capacity factor for three representative 100 MW wind project configurations. The three wind project types were identified, as follows:

- Type 1: A moderate to high wind speed, conventional wind project using proven wind turbine technology at the current industry normal 80 meter hub height.

[8] EO-2007-0409 14

Figure 10.2 Cumulative Throughput Disincentive for RAP and MAP Plans ($Millions)



In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

10.4.2 Expansion of Distributed Generation

The deployment of customer-owned distributed generation, particularly solar photovoltaic systems, continues to expand. Ameren Missouri has included its expectation for the deployment of customer-owned solar resources in its load forecast assumptions, described in Chapter 3. Because the economics of distributed generation can change rapidly, as we have seen in recent years, it is important for us to assess a greater-than-expected expansion of these resources. As described in Chapter 3, we identified the potential for additional distributed solar generation consistent with the U.S. DOE's Sunshot Initiative. Based on the DOE assumptions, Ameren Missouri would see an additional 614 MW of distributed solar generation in its service territory by 2034.

We have evaluated the impact of this change in load in two ways. First, we analyzed the impact on the cost of our preferred resource plan if the plan itself were not changed. Second, we analyzed the impact of the reduction in load on our need for, and timing of, new resources. If our resource plan is altered as a result of this significant change in customer load, we would expect to be able to defer the combined cycle generator that is shown in service in 2034 in our preferred resource plan.

The costs (PVRR) and levelized rates for our preferred resource plan, including that for the plan in which the combined cycle generator is deferred, are shown in Table 10.5 for our base distributed solar assumption and for the Sunshot case. The table shows that PVRR would be reduced by over $1.8 billion, while rates would increase by 0.21 cents/kWh if the timing of resources in the preferred plan did not change. It also shows that PVRR would be reduced by over $2 billion, and rates would increase by 0.17 cents/kwh if the combined cycle were deferred beyond the end of the planning horizon. Because the Sunshot Initiative would impact customer load across the Eastern Interconnect, we developed a price scenario using the process discussed in Chapter 2 to reflect the impacts of this additional change in load on power prices.

Table 10.5 Impact of Distributed Generation Expansion

Plan	PVRR ($Million)
Preferred Plan	61,352
DG Expansion-CC in 2034	59,513
DG Expansion-No CC in 2034	59,320

It is important to note that our preferred resource plan provides flexibility in responding to significant changes in load like the change that could be driven by a proliferation of distributed generation, solar or otherwise.

10.4.3 Loss of Large Customer Load

Ameren Missouri's largest customer is the aluminum smelter operated by Noranda Aluminum, Inc., in New Madrid, Missouri. The smelter uses 4,169 GWh of electricity annually with a peak demand of approximately 495 MW and is served at retail rates regulated by the Commission under a contract with Ameren Missouri that expires in May 2020. To evaluate the impact on our preferred plan of a loss of Noranda's load at the end of their current contract, we examined cases in which 1) the resources and timing reflected in our preferred plan are not changed and 2) the resources and timing reflected in our preferred plan are changed. This is similar to the analysis we conducted for the proliferation of distributed solar generation described in the previous section.

B. ***Describe and document the quantification of all cost-effective demand-side savings for Ameren Missouri in its upcoming, October 1, 2014, triennial compliance filing;***

Ameren Missouri's Approach – As described above, a full discussion of our consideration of the goal of all cost-effective demand-side savings is included in Chapter 10.

C. ***Describe and document how Ameren Missouri's portfolio of demand-side resources in its adopted preferred resource plan in its most recent triennial compliance filing is – or is not – designed to achieve a goal of all cost-effective demand-side savings during the 3-year implementation plan period and during the 20-year planning horizon, to the extent reasonable and possible.***

Ameren Missouri's Approach – As described above, a full discussion of our consideration of the goal of all cost-effective demand-side savings is included in Chapter 10.

D. ***Describe and document generally Ameren Missouri's plans and timing to replace the Ventyx Midas® model currently used to perform its integrated resource planning and risk analysis required in 4 CSR 240-22.060;***

Ameren Missouri's Approach – A discussion of model replacement and future plans is included in Chapter 9.

E. ***Describe and document generally Ameren Missouri's plans and timing to work collaboratively with Staff, the Office of Public Counsel, and other parties to consider the possible transition – over time – to a common software platform to perform the analysis required by 4 CSR 240-22.060;***

Ameren Missouri's Approach – A discussion of model replacement and future plans is included in Chapter 9.

F. ***Analyze and document the impacts of opportunities for Ameren Missouri to implement distributed generation, DSM programs, combined heat and power (CHP), and micro-grid projects in collaboration with municipal, agricultural and/or industrial processes with on-site electrical and thermal load requirements, especially in targeted areas where there may be transmission or distribution line constraints.***

Ameren Missouri's Approach – Ameren Missouri included consideration of distributed generation, DSM programs and CHP in collaboration with municipal, agricultural and/or industrial processes with on-site electric and thermal load requirements as part of its DSM Potential Study. Chapter 8 includes a discussion of these considerations and the DSM Potential Study report is included in our filing as an appendix to Chapter 8.

G. ***Document for use in economic modeling and resource planning low, base, and high projections for natural gas prices, CO_2 prices, and coal prices, to the extent it is not already included in the 2014 IRP filing.***

Ameren Missouri's Approach – Ameren Missouri developed low, base, and high assumptions natural gas prices, CO2 prices, and coal prices as part of its previously established approach to evaluating candidate uncertain factors. A discussion of the development of these and other assumptions is included in Chapter 2, and the results of modeling using these assumptions is presented in Chapter 9.

H. ***Analyze and document the future capital and operating costs faced by each Ameren Missouri coal-fired generating unit in order to comply with the following environmental standards:***

1) Clean Air Act New Source Review provisions;
2) 1-hour Sulfur Dioxide National Ambient Air Quality Standards'
3) National Ambient Air Quality Standards for ozone and fine particulate matter;
4) Cross-State Air Pollution Rule, in the event that the rule is reinstated;
5) Clean Air Interstate Rule;
6) Mercury and Air Toxics Standards;
7) Clean Water Act Section 316(b) Cooling Water Intake Standards;
8) Clean Water Act Steam Electric Effluent Limitation Guidelines;
9) Coal Combustion Waste rules;
10) Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources; and
11) Clean Air Act Regional Haze requirements

Ameren Missouri's Approach – Ameren Missouri has included as a separate chapter a discussion of environmental regulations, including all those listed above, and our assumptions for compliance with those regulations. A full discussion of environmental regulations and compliance assumptions is presented in Chapter 5.

Distributed Generation and Combined Heat and Power

Distributed generation (DG) systems are technologies that generate electricity and are located onsite at customer premises. Combined heat and power (CHP) systems generate both electricity and thermal energy that are used onsite. This study considered both options.

The first step toward estimating DG-CHP was to identify applicable technology options. Based on a thorough review of available and applicable technologies, as well as input from stakeholders, the following list of options was analyzed:

- Solar photovoltaic (PV) systems
- Reciprocating engine
- Micro-turbine
- Combustion turbine (CT)
- Boiler with back-pressure steam turbine
- Fuel cell with heat recovery
- Stirling engine
- Small wind
- Reciprocating engine with heat recovery
- Micro-turbine with heat recovery
- Combustion turbine with heat recovery
- Fuel cell
- Combined cycle combustion turbine (CCCT)
- Organic rankine cycle

Summary of DG/CHP Potential

Table 11 and Figure 16 show the high-level results of the DG-CHP analysis for energy and demand respectively. In general, unfavorable economics screen out a large swath of technical potential, and even for those technology applications that are cost-effective, market adoption is low, given the relative complexity of purchasing, owning, operating, and maintaining the units. The realistic achievable potential savings in 2030 are 488 cumulative GWh or 1.4% of the baseline projection. The corresponding maximum achievable potential savings in 2030 are 672 GWh, or 2.0% of the baseline projection.

Table 11 DG-CHP Energy Impact Results

	2016	2017	2018	2025	2030
Baseline Forecast (GWh)	30,249	30,449	30,694	32,228	33,721
Cumulative Energy Savings (GWh)					
Realistic Achievable	6	7	9	43	488
Maximum Achievable	8	10	13	60	672
Economic Potential	57	72	90	389	4,159
Technical Potential	720	898	1,119	4,729	10,946
Energy Savings (% of Baseline)					
Realistic Achievable	0.0%	0.0%	0.0%	0.1%	1.4%
Maximum Achievable	0.0%	0.0%	0.0%	0.2%	2.0%
Economic Potential	0.2%	0.2%	0.3%	1.2%	12.3%
Technical Potential	2.4%	2.9%	3.6%	14.7%	32.5%

[redacted]

Figure 16 *DG-CHP Energy Impact Results (GWh)*

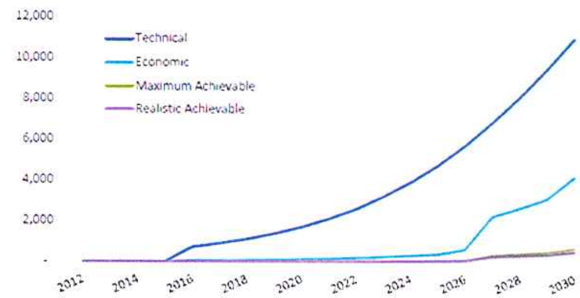
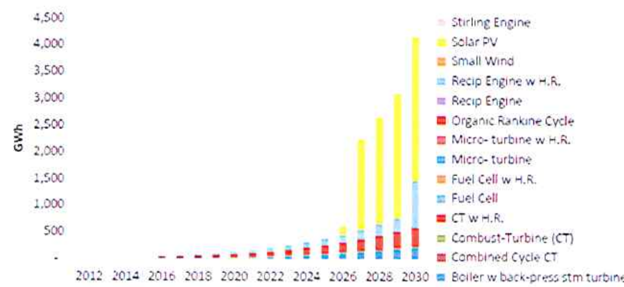


Figure 17 presents a graphical summary for the year 2016-2030. Despite heavy subsidies and declining costs, Solar PV is not cost-effective from a TRC perspective until 2026 for C&I and 2027 for the residential sector.

Figure 17 *DG-CHP Energy Economic Potential by Technology (GWh)*



In addition to the overall market assessment, this study included in-depth case studies of DG-CHP applications for two Ameren customers: a major corn milling facility and a major manufacturing facility. The customer names and specific details of the case studies are proprietary, but relevant findings and lessons learned are presented here.

Specifics regarding installed costs and fuel costs are proprietary. Major, non-proprietary assumptions for the case study analyses were as follows:

[redacted]

- Natural gas fueled combustion turbine generator with 3+ MW of electricity generating capacity; producing waste heat in the form of steam for process heating
- Waste heat valuation based on displacing boiler fuel use
- Annual O&M costs include turbine overhaul cost at half-life
- 20 year system life
- $10,000 grid interconnection study cost
- Real discount rate of 3.95%
- Uptime of 90%+ hours per year
- Avoided cost benefits for energy and capacity as provided by Ameren Missouri
- Actual pricing and bidding came from quotes from a manufacturer

As shown in Table 12, the TRC ratios are above 1.0, indicating that the projects are cost-effective, but these results are sensitive to many factors. During a drought-year, production and heating requirements at the milling facility may fall, reducing the value of waste heat. In a sensitivity analysis to model a prolonged drought scenario, the TRC ratio dropped to 1.01. An additional factor to consider is the customer's Ameren Missouri rate structure, which contains a standby charge (Rider E) for Ameren to maintain the necessary capacity if the customer would choose to revert to grid power in the event of an emergency shut-down of their DG-CHP system. For sizeable systems, the details of this cost result from a complex interconnection study, scenario analysis, and negotiation — and can have a significant impact on the overall project economics.

Table 12 Total Resource Cost (TRC) Test Results for DG-CHP Case Studies

Case Study	TRC Ratio	NPV Net Benefits	NPV Benefits	NPV Costs
Major Corn Milling Facility	1.17	$8,577,664	$58,910,946	$50,333,283
Major Manufacturing Facility	1.04	$1,378,710	$32,167,172	$30,788,462