COMMENTS ON POTENTIAL IMPACTS OF PROPOSED NEW COAL GENERATION UNDER THE SOUTH AFRICA 2019 INTEGRATED RESOURCE PLAN

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SUMMARY AND CONCLUSIONS

The 2019 Integrated Resource Plan for Electricity (IRP) proposes to add 1500 MW of new coal generation in two phases – 750 MW in 2023 and an additional 750 MW in 2027. In September 2020, the Minister of Mineral Resources and Energy reaffirmed this objective by issuing a determination for 150 0MW of coal to be generated, size unspecified. The 2019 IRP and Ministerial determination have very little additional detail regarding the specifics of this new coal generation including: the generation capacity and number of units per phase; locations; source of the coal; and the manner of disposal of coal combustion residuals. The 2019 IRP is also unclear as to the type of generation technology that may be used, other than to note that it will be some form of high-efficiency, low emission (HELE) technology, which comprises a potentially large number of technologies with a wide range of potential impacts. The IRP also contemplates including carbon capture for this new coal generation.

This report assesses the most likely feasible timelines, HELE technologies and potential air emissions of such new coal generation. I note that environmental impacts from coal plants is not just limited to air emissions but includes significant water and waste impacts as well. I do not discuss these non-air adverse impacts in this report. Conclusions of this report include:

1. Ultra-supercritical (USC) efficiency is the highest possible thermal cycle efficiency that can be anticipated for procurement of 1500 MW of new coal under the 2019 IRP. The IRP requires that chosen technologies "must be based on at least one operational project experience (ideally 3) anywhere in the world, to substantiate claims by manufacturers". Higher thermal efficiency cycles such as advanced ultra-supercritical (AUSC) efficiency coal plants do not meet that criterion, regardless of the size of the units that comprise the 1500 MW.

2. Circulating fluidized bed (CFB) technology is considered preferable by the IRP due to its ability to handle low quality and waste coals in South Africa. However, to retain

ultra-supercritical efficiency, the size of such units is important, and these are not specified in the IRP.

3. Integrated gasification combined cycle (IGCC) and underground gasification combined cycle (UGCC) power plants, and carbon capture (CC) technologies are unproven and cost-prohibitive at scale, and extremely unlikely to be implemented for the 1500 MW of new coal proposed under the 2019 IRP.

4. Minimum pollution control technologies are not specified in the IRP for the new coal plants. Given that no South African coal fired power stations have been willing to pay for the full suite of the most effective pollution control technologies (wet flue gas desulfurization to reduce emissions of sulfur dioxide, selective catalytic reduction to reduce emissions of oxides of nitrogen, baghouses or fabric filters to reduce emissions of particulate matter, and activated carbon injection to reduce emissions of mercury), it appears unlikely that the 1500 MW of new coal would be required to use these technologies at suitable levels of pollutant reduction, given the capital and operating costs of adding such technologies and operating them effectively. Even if these technologies were installed, it is impossible to eliminate all emissions of toxic organic compounds, trace metals, acid gases and particulate matter from the plant and from mining and ash transport and disposal. Thus, the new coal plants will inevitably result in significant air pollution and harms to human and environmental health regardless of pollution controls. A proper assessment of these adverse impacts can only be made if the size, location, source coal and technology selection for the proposed 1500 MW new coal plants is determined.

5. Large quantities of greenhouse gas emissions are unavoidable even from power plants that use HELE technologies. Pulverized coal units, even ultra-supercritical, will not be able to capture their emitted carbon dioxide due to extremely high costs. Circulating fluidized bed technology emits from two to ten times more nitrous oxide than pulverized coal technologies. (Nitrous oxide is a potent, long-lasting greenhouse gas with a global warming potential 300 times that of carbon dioxide.)

6. It is unreasonable to expect 750 MW (or any amount) of new coal generation could come online by 2023. It takes much longer than 4 years to achieve generation starting from scratch, especially with the many unknowns relating to HELE technology selection, design, procurement, and implementation. Though start years may be moving targets, the conclusions of this report are not affected even if start years are deferred several years into the future.

7. This report does not address policy, financing, or economic issues, such as whether or not it makes sense to pursue new coal generation in a climate-constrained future, or whether new coal can obtain financing given the fluid landscape of reluctance given the growing reluctance of banks and lending institutions to lend to new coal-based projects.

8. Last, and importantly, I want to stress that contrary to implications in the 2019 IRP and the Ministerial determination, there is simply no such thing as "clean coal", regardless of whether HELE technologies are used to minimize air emissions from coal (or gas derived from coal). Even if HELE technologies are applied consistently and perfectly (a practical impossibility, since the technologies do not work under all modes of operation, such as during startup or malfunction), air emissions are considerable even just at the plant itself. Plus, there are non-air impacts such as waste water and cooling water and waste generation at the plant. Of course, in addition to impacts from the plant, a coal plant will need to rely on an extensive supply chain starting at the coal mine and through disposal of the coal ash, with transportation in between – all of which not only have significant air impacts but also water and waste impacts. Thus, "clean coal" is a myth.

A.   The 2019 IRP calls for 1500 MW new coal using HELE Technologies

I have reviewed the South Africa Department of Mineral Resources and Energy Integrated Resource Plan for Electricity 2019 (hereafter "2019 IRP"), signed on October 17, 2019.

Table 5 from the 2019 IRP, shown below, calls for the addition of 750 MW of new coal capacity in 2023 and then another 750 MW in 2027. The Ministerial determination simply calls for 1500 MW of coal generation between 2023 and 2027.

Table 5: IRP 2019

	Coal	Coal (Decommissioning)	Nuclear	Hydro	Storage	PV	Wind	CSP	Gas & Diesel	Other (Distributed Generation, CoGen, Biomass, Landfill)
Current Base	37 149		1 860	2 100	2 912	1 474	1 980	300	3 830	499
2019	2 155	-2373					244	300		Allocation to the extent of the short term capacity and energy gap.
2020	1 433	-557				114	300			
2021	1 433	-1403				300	818			
2022	711	-844			513	400 1000	1600			
2023	750	-555				1000	1600			500
2024			1860				1600		1000	500
2025						1000	1600			500
2026		-1219					1600			500
2027	750	-847					1 600		2000	500
2028		-475				1000	1 600			500
2029		-1694			1575	1000	1 600			500
2030		-1050		2 500		1 000	1 600			500
TOTAL INSTALLED CAPACITY by 2030 (MW)	33364		1860	4600	5000	8288	17742	600	6380	
% Total Installed Capacity (% of MW)	43		2.36	5.84	6.35	10.52	22.53	0.76	8.1	
% Annual Energy Contribution (% of MWh)	58.8		4.5	8.4	1.2*	6.3	17.8	0.6	1.3	

Installed Capacity
Committed / Already Contracted Capacity
Capacity Decommissioned
New Additional Capacity
Extension of Koeberg Plant Design Life
Includes Distributed Generation Capacity for own use

The 2019 IRP does not provide a lot of detail relating to this new coal capacity. It does note the "preference" that the new coal capacity be based on HELE technologies as well as "other cleaner technologies" and it includes a reference to "lessons" learned from the implementation of the Medupi and Kusile mega projects, presumably relating to cost and schedule overruns.

> "HELE coal technologies including underground coal gasification, integrated gasification combined cycle, carbon capture utilization and storage, ultra-supercritical, super-critical and similar technologies are preferred for the exploitation of our coal resources. Due consideration must be given to the financing constraints imposed by lenders and the Organization of Economic

Cooperation and Development (OECD) countries, insofar as coal power plant development….

Due consideration must also be given to the pace and scale of the coal-to-power programme taking into account the lessons from Medupi and Kusile mega projects. Procurement under the IPP programme has shown that there is a business case for modular and smaller power plants (300MW and 600MW).

South Africa should not sterilise the development of its coal resources for purposes of power generation, instead all new coal power projects must be based on high efficiency, low emission technologies and other cleaner coal technologies."[1]

The 2019 IRP notes that costs for whatever technology is chosen "must be based on at least one operational project experience (ideally 3) anywhere in the world, to substantiate claims by manufacturers."[2] This caveat alone rules out the inclusion of any carbon capture technologies since there are currently no such operational projects successfully operating with carbon capture anywhere in the world and none are anticipated in the foreseeable future. I briefly discuss below the fate of a few operating plants that have or had carbon capture installed.

B.   Potential HELE Technologies

In this section I provide brief descriptions of the types of HELE and related technologies that may be candidates for the new coal capacity. The material is largely drawn from two excellent summaries on this subject by the International Energy Agency (IEA) – namely a 2012 Roadmap[3] and a more recent updated 2021 Roadmap.[4] I will cite to these two references extensively.

Figure 1 from the IEA 2012 Roadmap, shown below, describes the general approach to reduction of greenhouse gases and major conventional pollutants from future coal plants, including sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and particulate matter (PM).
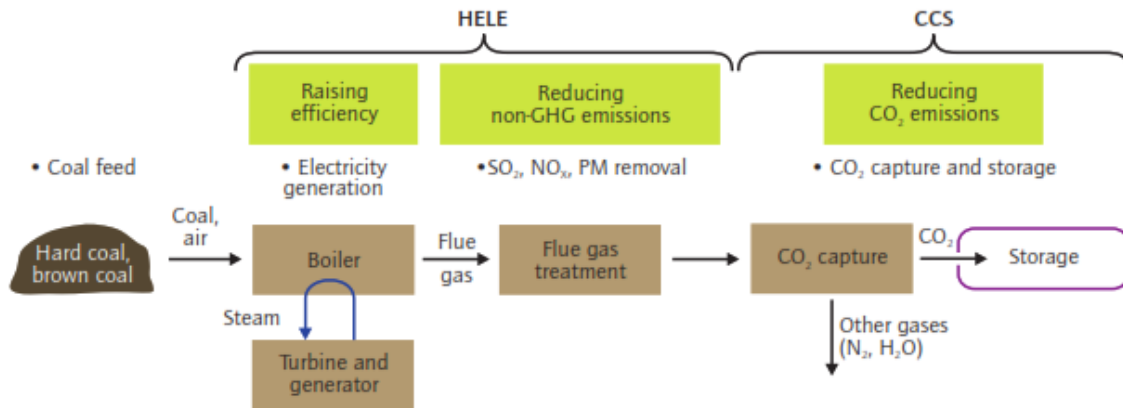
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[1] 2019 IRP, Section 5.3.4, p. 46.
[2] 2019 IRP, p. 63.
[3] Technology Roadmap: High-Efficiency, Low-Emissions Coal-Fired Power Generation, October 2012 (hereafter "2012 Roadmap")
[4] Lockwood, T., A Technology Roadmap for HELE Coal Power Plant, IEA Clean Coal Center, February 2021 (hereafter "2021 Roadmap")

I first discuss pulverized coal combustion technologies, with varying efficiencies of the thermal cycle, followed by some of the other HELE technologies noted in the 2019 IRP. I conclude that ultra-supercritical efficiency is the highest possible cycle efficiency that can be anticipated for procurement of 1500 MW of new coal under the 2019 IRP and the Ministerial determination for 1500 MW of new coal.

1.   *Thermal Efficiency in Coal Plants*

As noted by the IEA, most coal-fired power plants operating today, or those under construction, are based on pulverized coal combustion, in which finely ground coal is combusted in a furnace and the resulting heat used to raise steam. Pulverized coal technology has been evolving since it was first deployed in the 1920s, through increases in steam temperature and pressure, which lead to increased plant thermal efficiency. Thermal efficiency, in simple terms, means the amount of energy in the fuel (i.e., coal) that is converted to electricity. In the late 1950s, some plants in the USA and Germany were designed to use supercritical steam – which exists at high pressures (>22 MPa) and temperatures (>374°C), above the so-called "critical" point for water. Properties of steel at the time proved challenging to properly run such plants, particularly for units whose output varies with time to meet changing load (i.e., "load-following" units).

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[5] 2012 Roadmap, Figure 1. See also 2021 Roadmap, Figure 3.

TABLE 3   TYPICAL OPERATING PARAMETERS OF THE DIFFERENT GENERATIONS OF COAL POWER PLANT (AUTHOR'S ESTIMATES)

	Subcritical	Supercritical	Ultrasupercritical	AUSC
Main steam temperature, °C	≤540	538–566	593–610	700–760
Steam pressure, MPa	16–18	>22	25–30	35–36
Efficiency (LHV, net), %	30–39	39–43	Up to ~47.5	≥50
CO$_2$ intensity, g/kWh	>870	800–870	720–870	<690

[6]

The table above shows the general definitions associated with classifying units with regard to thermal cycle efficiency – although no formal definition exists for ultra-supercritical and advanced ultra-supercritical technologies. Many supercritical and several ultra-supercritical plants are operating around the world today, but there are currently no operational "advanced ultra-supercritical" plants. As the IEA notes, state-of-the-art ultra-supercritical plants now typically employ main steam temperatures of 600°C and reheat temperatures of up to 620°C. Some plants in China claim parameters of 610/630°C and pressures in the range 25–29 MPa. The 912 MW RDK8 unit in Karlsruhe, Germany, often cited as the most efficient coal plant in the world, has reported **an efficiency of 47.5% (LHV, net) with steam temperatures of 600°C/620°C and pressure of 28.5 MPa** – which is in the ultra-supercritical range but definitely not advanced ultra-supercritical.

The table below shows the GHG emissions intensities associated with the various thermal cycles. Lower thermal efficiencies, shown in percentages in the middle column, result in higher CO$_2$ intensity factor or emissions, and vice versa. Thus, while a subcritical plant with up to 38% thermal efficiency has emissions of over 880 g/kWh, a advanced supercritical plant with thermal efficiency of 50% (at the high end of the range for efficiency shown in the first row) would have emissions of 670 g/kWh (the low end of the range for emissions shown in the first row). So, increasing thermal cycle efficiency from 38% to 50% would lower emissions intensity from 880 g/kWh to 670 g/kWh.

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[6] 2021 Roadmap, Table 3.

	CO₂ intensity factor (Efficiency [LHV, net])	Coal consumption[1]
A-USC (700°C[2]) IGCC (1 500°C[3])	670-740 g CO_2/kWh (45-50%)	290-320 g/kWh
Ultra-supercritical	740-800 g CO_2/kWh (up to 45%)	320-340 g/kWh
Supercritical	800-880 g CO_2/kWh (up to 42%)	340-380 g/kWh
Subcritical	≥880 g CO_2/kWh (up to 38%)	≥380 g/kWh

[7]

Another way to depict the expected GHG benefit of more efficient generation is shown in the figure below. Regardless of the highest thermal generation cycles used, including advanced ultra-supercritical, the lowering of CO_2 intensity below roughly 670 g CO_2/kWh can only be achieved by using carbon capture. The figure below and the table above also show that CO_2 intensity with ultra-supercritical drops to around 740 g CO_2/kWh. While this is certainly an improvement from subcritical and supercritical cycles, it is not a substantial improvement.
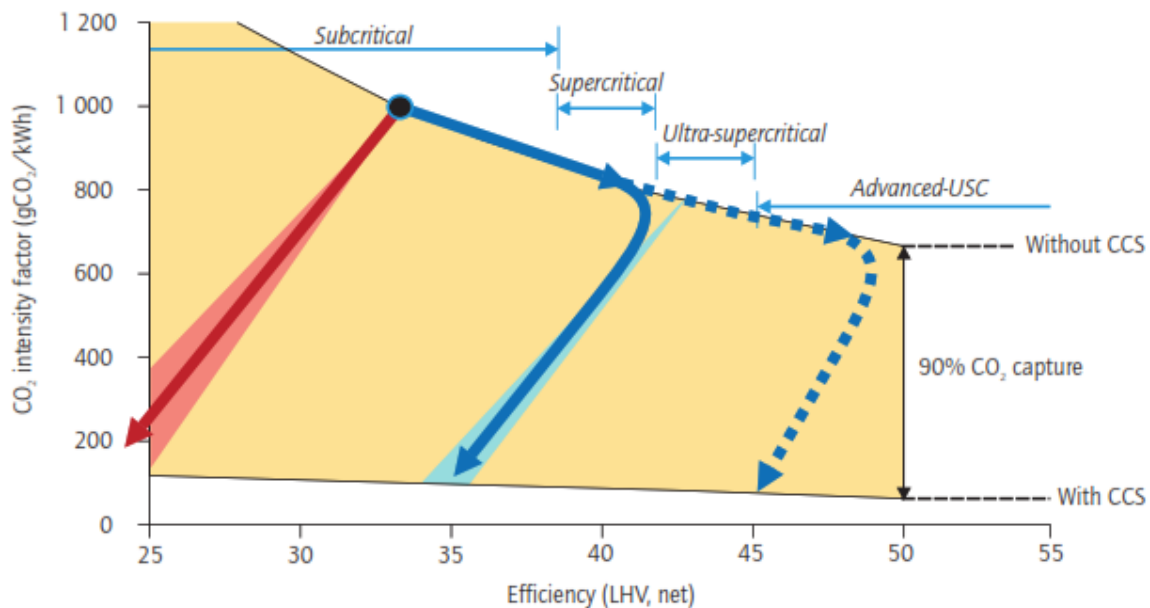
[8]

Since the late 1990s, there have been coordinated research efforts in many countries to push thermal cycle efficiencies even higher than ultra-supercritical into the so-called advanced ultra-supercritical range. However, since even the high-performance steels used in the
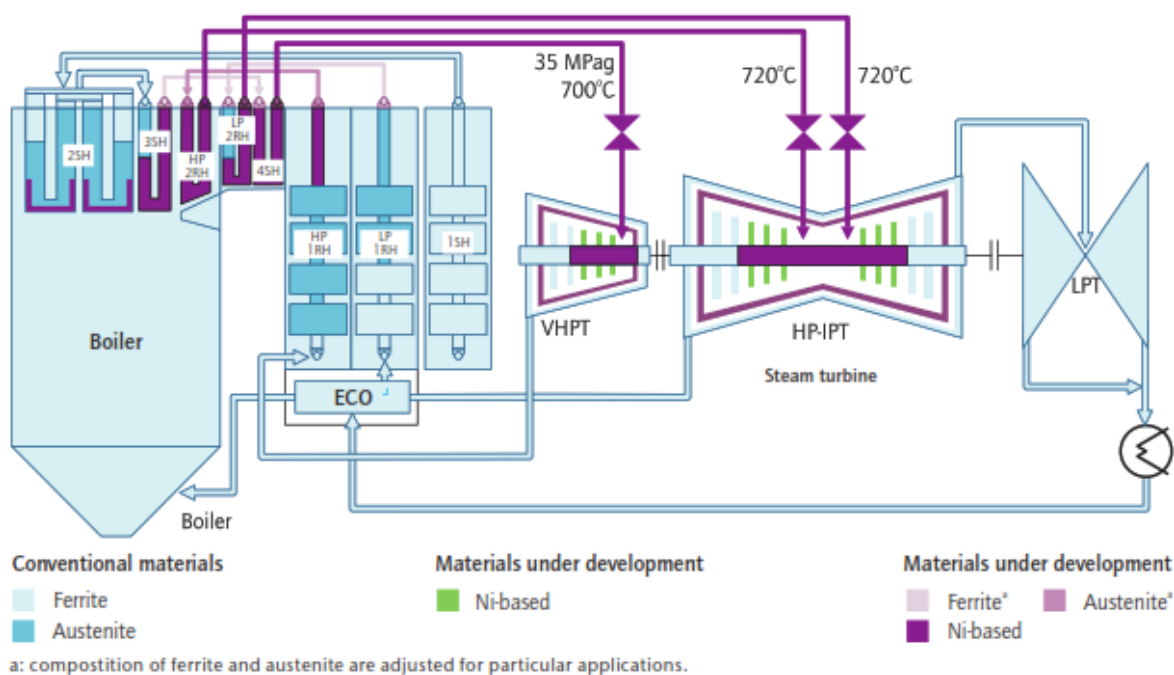
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[7] 2012 Roadmap, Table 1.
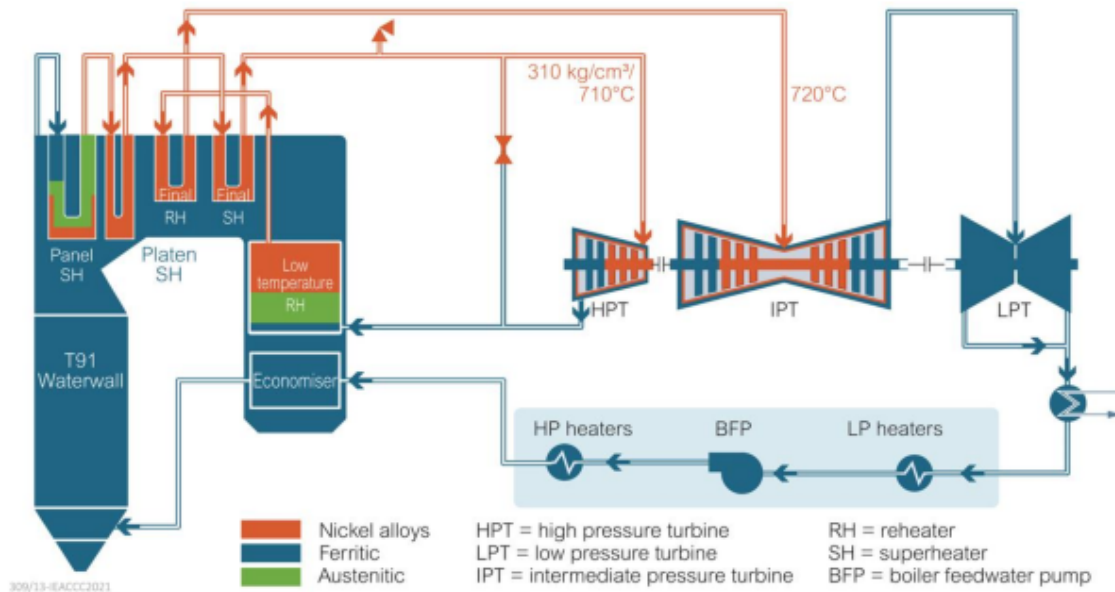[8] 2012 Roadmap, Figure 10.

ultra-supercritical cycles are not suitable for use at temperatures needed for advanced ultra-supercritical cycles, this next stage of efficiency improvement will require the development and use of nickel-based superalloys for the hottest sections of the plant, including superheaters, headers, steam pipes, and turbines. Use of nickel alloys in coal plant applications involves development of alloys which can be fabricated into large components using welding which must then demonstrate long-term acceptable performance. That has simply not occurred yet and is not expected to occur at least for another decade anywhere globally.

The advanced ultra-supercritical cycle challenges are best illustrated via the two following figures, the first taken from the 2012 IEA Roadmap and the second from the 2021 IEA Roadmap, which clearly shows that the same metallurgical challenges that were present in 2012 are still present, almost 10 years later, in 2021. Note the criticality of material specifications in several portions of an advanced ultra-supercritical plant – i.e., the use of advanced nickel-based alloys that are needed, which have significant costs and workability issues and challenges such as welding, illustrating the challenges involved – which explains the lack of significant progress in the last decade. Based on this, it is almost impossible for South Africa to expect to deploy advanced ultra-supercritical plants as contemplated in the 2019 IRP.

a: compostition of ferrite and austenite are adjusted for particular applications.

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[9] 2012 Roadmap, Figure 12.

310 kg/cm³/ 710°C

720°C

Panel SH

Platen SH

Final RH

Final SH

Low temperature RH

Economiser

T91 Waterwall

HPT

IPT

LPT

HP heaters

BFP

LP heaters

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Nickel alloys
Ferritic
Austenitic

HPT = high pressure turbine
LPT = low pressure turbine
IPT = intermediate pressure turbine

RH = reheater
SH = superheater
BFP = boiler feedwater pump

[10]

An overall summary of expected HELE and carbon capture technologies along with expected time frames is excerpted below from the recent 2021 IEA Roadmap.[11] Focusing on just the plant efficiency improvement targets, it is clear that efficiencies higher than today's state-of-the-art ultra-supercritical cycles will not become feasible until at least 2025-2030 or even later.

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[10] 2021 Roadmap, Figure 13.
[11] 2021 Roadmap, Table 10.

TABLE 10	DEPLOYMENT TARGETS
Plant efficiency targets	
All new large coal units should use USC or IGCC technology (IGCC an option for high-ash, slagging coal)	2020
Where 300-400 MW units are necessary, should use SC technology as a minimum	2020
Greater use of emerging small USC technology for 300 MW units (where necessary)	2020
Small subcritical units (<300 MW) should be limited to cogeneration, biomass cofiring, and flexible operation	2020-25
Deployment of 650°C (48-49% efficiency) technology	2025-30
Demonstration of AUSC or other 50%+ efficiency technology	2025-30
Commercial deployment of 50%+ efficiency technology and advanced power cycles (IGFC, sCO_2)	2030-35
Subcritical plant older than 25 years to be phased out	2020-30
Newer subcritical plant to gain at least 2 percentage points through efficiency upgrading technologies	2020
Newer subcritical plant to consider high-temperature (600°C) upgrading where possible	2025-30
Phase out or repurposing of all subcritical units (or upgrade to SC equivalent efficiency)	2035
Pollutant control targets	
Standard deployment of best-available control technologies on new units (including mercury control)	2020
Retrofit of existing units with FGD and advanced SNCR or SCR	2020-25
Retrofit of low-water control technologies in water strained areas	2020-25
Ultra-low emission standard for new units and most existing units	2025-30
Attain near-zero emission levels for PM, SO_2, and NOx (<10 mg/m^3) and mercury	2030-35
CCUS targets	
Commercial deployment of large-scale CCUS in the USA, EU, and China	2025
Commercial deployment of large-scale CCUS in emerging economies, including India and Indonesia	2030-40

One point of concern is that ultra-supercritical plants to date have tended to be larger in size, typically 600-1000 MW, in order to exploit economies of scale, thereby reducing capital costs per MW. For this reason, it is not clear that contemplating such plants at smaller size, for example in the 300 or 350 MW sizes is realistic while retaining all of the benefits of the ultra-supercritical cycle. As the IEA notes, "currently, the smallest operating USC unit is Denmark's 440 MW Nordylland 3, completed in 1998 as one of the first examples of USC (and double reheat) technology in Europe."[12] The IEA does note that "a 315 MW unit undergoing commissioning at Banten Lontar power plant in Indonesia represents a new benchmark for small USC."[13] But, actual, verifiable, performance data from this unit are not publicly available.

Therefore, based on the discussion above, it is clear that, at best, the new coal plant(s) that can satisfy the 2019 IRP HELE requirements can be of ultra-supercritical design, either pulverized coal or circulating fluidized bed.
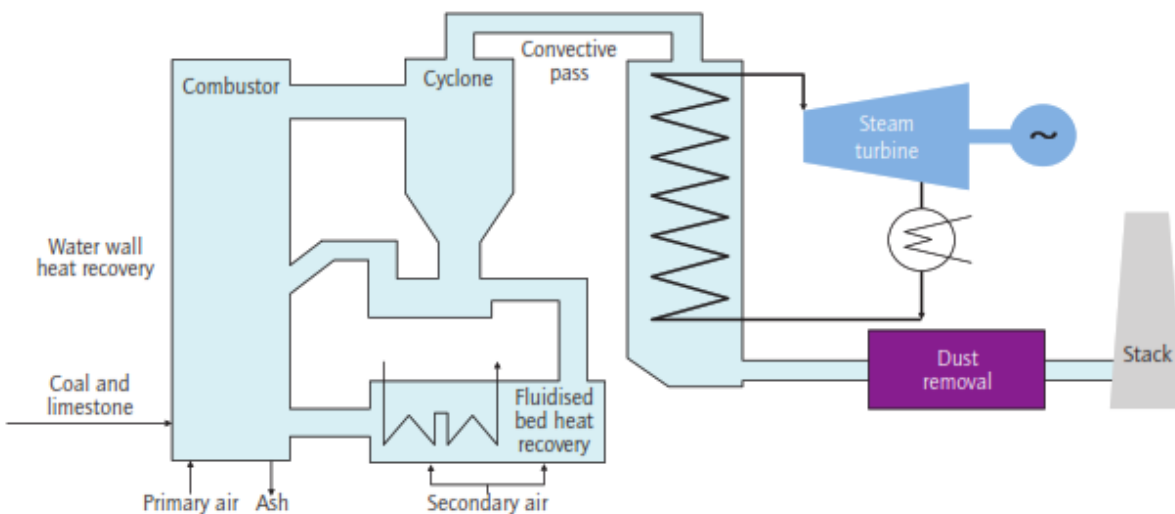
2. *Circulating Fluidized Bed Technology*

Although the IRP seems to prefer that the new 1500 MW coal would use circulating fluidized bed technology given its flexibility in burning waste and poor grades of coal, this technology is a distant second (after pulverized coal) in terms of use in the global coal plant fleet. In this technology, coarsely ground coal is burned at lower temperatures (800–900°C) than the combustion temperature in a pulverized coal boiler. It was developed to tolerate poor and/or variable coal quality. A few ultra-supercritical circulating fluidized bed units are now operating globally including the Sam Cheok (4 x 550 MW) plant in South Korea (2016), and several 350 MW supercritical units which are operational in China in the last decade. No such units are present in South Africa. The operating profiles of the South Korean or Chinese units are not publicly available in order to determine and confirm whether the actual cycle efficiencies of these plants are, in fact, consistently meeting expectations. A schematic of a circulating fluidized bed plant is shown in the figure below.

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[12] 2021 Roadmap, p. 36.
[13] *Ibid.*

3.   *Integrated Gasification Combined Cycle Technology*

In integrated gasification technology, coal is not burned as it is with pulverized coal or circulating fluidized beds but is instead gasified under low-oxygen conditions leading to formation of a synthetic gas (syngas), consisting of mainly carbon monoxide and hydrogen. This gas, after suitable cleaning, is then combusted in combustion turbines, typically combined cycle (with a combustion turbine followed by a steam turbine) in order to achieve high overall plant thermal efficiency. Gas combustion in the turbine also results in the formation and emissions of various pollutants such as NO_x, carbon monoxide, volatile organic compounds, and various hazardous air pollutants. A schematic is shown below.
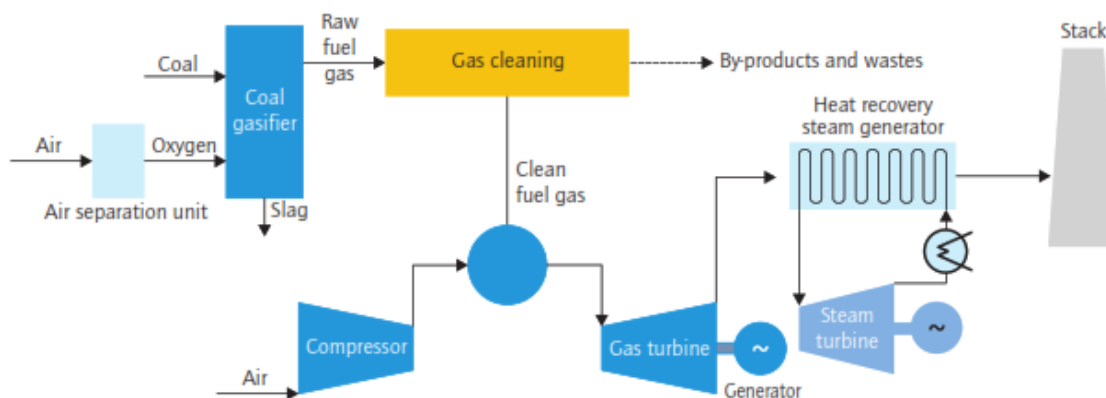
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While several integrated gasification combined cycle units were deployed in the 1990s and early 2000s in the US, Europe, and Japan, the European and US units have since been

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[14] 2012 Roadmap, Figure 13
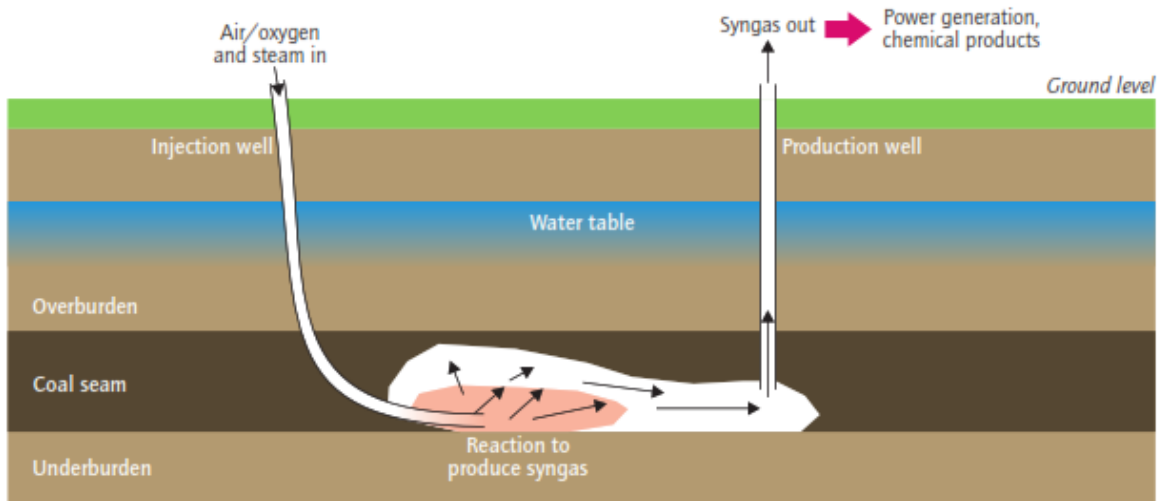[15] 2012 Roadmap, Figure 14.

decommissioned due to high operating costs resulting from complexities in operation. In effect, one must run a chemical plant and a power plant together. There are no commercial plants of this type in South Africa.

As summarized by the IEA, developments since the late 2000s have not shown much promise for this technology either. While it experienced renewed interest due to its potential application in pre-combustion capture of CO_2, several pre-combustion demonstration plants, such as the FutureGen (US) and Zerogen (Australia) did not proceed. The ill-fated Kemper County plant in Mississippi, US, was completed at substantially higher cost than anticipated, but ultimately operated using only natural gas due to operational issues, and the much lower cost of shale gas in the US. In China, the 250 MW GreenGen plant was completed in 2015, but planned phases to introduce carbon capture and construct a larger scale unit have not progressed. The only bright spot for the technology continues to be in Japan, although with not a lot of clarity regarding subsidies involved. The 250 MW, air-blown demonstration project at Nakoso power plant began operating commercially in 2013. In 2014, the technology was selected by Mitsubishi Power for two 540 MW units at Nakoso and the nearby Hirono power plants, with a design efficiency of 48% (LHV, net), or similar to state-of-the-art ultra-supercritical pulverized coal units. The Nakoso and Hirono plants are expected to come on line soon.

Thus, while development work in integrated gasification combined cycle and related technologies continues (such as the so-called Integrated Gasification Fuel Cell technology, in which, part of the gas from the coal gasification is used to generate electricity using fuel cells with the rest being used in standard combined cycle mode), there are substantial challenges that pose a formidable barrier to incentive-free application of this technology at scale. These challenges include limited full-scale operating experience under conditions that are representative of South Africa, significant capital costs, and unknown operating costs to maintain performance in the South African context.

4. *Underground Coal Gasification*

The 2019 IRP mentions underground coal gasification. While commercial power generation using this technology is entirely unproven at this time in South Africa, the concept, as illustrated in the schematic figure below, is to gasify the coal seam in the underground mine itself and then send the gas to the surface for use in power generation (or as a feed stock chemical, etc.). Thus, hauling coal from the mine is avoided. While conceptually simple, implementation at scale poses significant challenges including space, safety, and ultimately cost – the latter likely to be substantial particularly considering safety issues associated with deploying this technology within an operating mine. It is not anticipated that this will be a viable candidate for the 2019 IRP new coal target anytime in the foreseeable future.

Air/oxygen and steam in

Syngas out → Power generation, chemical products

Ground level

Injection well

Production well

Water table

Overburden

Coal seam

Reaction to produce syngas

Underburden

[16]

5. *Infeasibility of Successful Carbon Capture in the Next Decade*

Carbon capture is considered the "holy grail for continued fossil fuel use" and projects have come online that prove technical feasibility, but "costs can be prohibitive."[17]

The worldwide progress of carbon capture technology has been sluggish, at best. Per the Global CCS Institute, there are currently 23 CC projects in construction or operation around the world.[18] But a review of the website listing the projects shows that not one is located at a coal-fired power plant of commercial scale.

Confirming this, the 2021 IEA Roadmap states that "since the publication of the 2012 roadmap, CCUS [carbon capture/underground storage] has established itself as a technically viable solution for reducing CO_2 emissions from large-scale coal plant by at least 90 percent, but is yet to be applied beyond a few demonstration sites."[19] Table 5 in the 2021 Roadmap, reproduced below, shows a status of "planned" projects. On a factual basis, none of the listed US projects have advanced, and none of the projects are subsidy-free.

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[16] 2012 Roadmap, Figure 16.
[17] Power Magazine, *The pursuit and advancement of carbon capture and storage*, (May 1, 2019) https://www.powermag.com/the-pursuit-and-advancement-of-carbon-capture-and-storage/.
[18] https://www.globalccsinstitute.com/co2re/
[19] 2021 Roadmap, p. 16.

Project	Power plant	Size	Technology	Storage
TABLE 5 PLANNED PROJECTS FOR CARBON CAPTURE IN THE COAL POWER SECTOR (UPDATED FROM KELSALL, 2020)				
USA				
ION Engineering Commercial Carbon Capture	Gerald Gentlemans Station	700 MW (two trains)	ION Engineering	Undecided
Enchant Energy	San Juan Generating Station	847 MW	Unspecified commercial solvent	Probably EOR in the Permian Basin
University of Illinois CCS	Prairie State Generating Station	816 MW	MHI's KM CDR process	CarbonSAFE Illinois (saline aquifer)
Dry Fork Integrated CCS	Dry Fork	400 MW (70% capture rate on all the flue gas)	MTR Polaris membrane capture	CarbonSAFE Wyoming (saline aquifer)
Project Tundra	Milton R Young Station	455 MW	Fluor (Econamine FG Plus)	EOR and saline aquifer both available
China				
China Resources Power Integrated CCS	Haifeng power plant	Scale-up of existing 20 ktCO$_2$/y pilot	Solvent or membrane-based technology	Probably saline aquifer
Sinopec Shengli	Sinopec Shengli power plant CCS	Scale-up of existing facility	Solvent-based technology	EOR

Broadly, carbon capture technology can be divided into several categories:

(i) as pre-combustion, where the coal is first gasified as in IGCC and the hydrogen is separated from the syngas to fuel the IGCC plant;

(ii) post-combustion, where CO_2 is separated from the flue gases of a PC or CFB plant; and

(iii) oxyfuel combustion, where coal is burned using a mix of oxygen and CO_2.

As the IEA correctly summarizes, although all three categories are considered technically mature, only post-combustion capture has been demonstrated on a full-scale power plant. In 2014, a variant of post-combustion capture using an amine solvent to remove CO_2 was installed at the 140 MW Boundary Dam 3 unit in Canada. And, in 2017, a similar process was retrofitted to a slipstream (equivalent to around 240 MW) of flue gas from a 600 MW unit at the WA Parish coal plant in Texas, USA – called the Petra Nova project. Neither of these projects stood alone

16

financially since each received considerable subsidies from the respective governments. I will discuss these examples in some detail below.

B.6.1 SaskPower Boundary Dam Unit 3 (BD3) (Canada)

This project, costing $1.3 billion Canadian dollars, captures CO_2 from a 110 MW unit and sends it to a nearby oil company for use in enhanced oil recovery. Even when it was commissioned, in October 2014, officials from SaskPower were cautious in predicting that this technology could be replicated on a larger scale.[20] The plant received $240 million Canadian dollars in subsidies. The operation of this plant since 2014 has not been smooth. In fact, operational and safety issues at the plant, both affecting cost, reliability, and therefore production, have been so significant that a proposed second plant,[21] with similar CC has not progressed since BD3.

B.6.2 NRG Energy Petra Nova (USA)

There is only one example of carbon capture at a coal-fired power plant in the US: the Petro Nova project in Texas, which shut down after operating for less than 4 years. The carbon capture technology at Petra Nova required so much energy that NRG built an entirely separate natural gas power plant—the emissions of which were not offset by the Petra Nova technology—just to power the CO_2 amine scrubber.

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[20] Goldenberg, S., 110 MW World's First Carbon Capture Power Plant Switches On, The Guardian (October 5th, 2014),https://www.climatecentral.org/news/canada-worlds-first-carbon-capture-power-plant-18136#:~:text=Canada%20has%20switched%20on%20the,be%20good%20for%20climate%20change.
[21] International CCS Knowledge Centre, The Shand CCS Feasibility Study Public Report, (November 2018), https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.

The CC process also imposes a significant energy penalty of as much as 8-10 percentage points on thermal efficiency. That means a state-of-the-art HELE plant with a cycle efficiency of, say, 47%, could achieve CC but with the efficiency reduced to 37-39%, setting aside costs. This means, that with CC, most of the thermal efficiency benefit associated with HELE is lost.

Based on the above, it is clear that expecting the 1500 MW of new coal contemplated in the 2019 IRP for South Africa to have carbon capture is simply impractical based on the inefficiency and costs associated with carbon capture.

As noted prior, while the CO_2 emissions intensity for coal plants is reduced somewhat as a result of increasing the efficiency of the thermal cycle, major reductions in CO_2 intensity can only be achieved by way of carbon capture. Based on the track record of carbon capture to date globally, it is my opinion that there is simply no pathway to economically utilize carbon capture in South Africa now or in the foreseeable future for reducing CO_2 emissions from new coal generation. It is impractical to expect carbon capture for the 1500 MW of new coal contemplated in the 2019 IRP and Ministerial determination based on the inefficiency and costs associated with carbon capture.

C. Coal-Fired Power Plant Emissions and Ash Wastes

In this section, I briefly discuss emissions associated with coal-fired power plants as well as emissions associated with the infrastructure needed to support coal-fired plants, such as mining of coal, its transportation to the plant from the mine, and the disposal of large quantities of ash after coal combustion.

I note that while the 2019 IRP does not specifically address the controls of conventional pollutants such as selective catalytic reduction for NO_x and wet flue gas desulfurization for SO_2, the NERSA response to a request for reasons on the decision to approve the 1500 MW of new coal did mention the "use of Flue Gas Degasification (FGD) plants"[22] (presumably meaning "Desulfurization" and not "Degasification.")[23]

Emissions of a range of so-called major and hazardous air pollutants[24] are simply inescapable when using coal as a fuel. For example, if either pulverized coal or circulating fluidized bed technologies are used, regardless of the efficiency of the thermal cycle (which can only attenuate such emissions but not eliminate them), significant quantities of SO_2, NO_x, particulate matter, and hazardous air pollutants will be formed as a result of coal properties and the combustion process. While air pollution abatement technologies such as Selective Catalytic Reduction (SCR), wet flue gas desulfurization, and fabric filters *can* be used to reduce these pollutant

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[22] NERSA Response to CER Questions, p. 9.
[23] This is confirmed in NERSA's own published reason for its concurrence. See https://www.nersa.org.za/wp-content/uploads/bsk-pdf-manager/2020/10/Decision-and-Reasons-for-Decision-for-the-Concurrence-new-generation-capacity-from-Renewables.pdf
[24] HAPs are specifically of concern because they have arrange of adverse health impacts, including cancer, and acute/chronic non-cancer effects. A wide range of HAPs are emitted when burning coal. These include a range of metals such as mercury, lead, arsenic, cadmium, cobalt, etc., and various organics such as benzene, hexane, formaldehyde, dioxins and furans, polycyclic aromatics such as benzopyrene. This is by no means an exhaustive list.

emissions, the emissions cannot be eliminated. This is an important point because proponents of coal-based electricity generation have proclaimed that "clean coal" generation is possible. That is simply untrue and a myth with no basis in reality, even just considering emissions at the plant itself (regardless of its design – whether pulverized coal, fluidized bed, or even using gasification) and neglecting the emissions and impacts elsewhere in the coal supply chain (i.e., from mine to plant to ash disposal). The degree of reduction of air pollutants by using the technologies noted prior depends on their design and how they are operated. For example, in the case of SCR, while a state-of-the-art design might provide 90-95% reduction of NOx, actual efficiencies closer to 50-60% or even lower are not uncommon given substandard design, non-replacement of aging catalysts, poor use of ammonia, and many other factors. Similarly, for wet flue gas desulfurization, while a state-of-the-art installation can provide 98 or 99% reduction, it is not uncommon for such technologies to provide far smaller (less than 75% or even lower) reductions in actual practice. Even at the highest efficiencies of these technologies, the air emissions associated with coal plants are very high, directly refuting the notion of "clean coal". Of course, achieving the higher reduction efficiencies means more capital and operating costs. My review of performance of air pollution control technologies (such as electrostatic precipitators for particulate matter control) at coal-fired plants indicates that they are very poorly run and/or maintained. I cannot therefore anticipate that additional technologies such as SCR for NO_x, etc. will be run and maintained any better.

I would also recommend that, hazardous air pollutant emissions such as mercury, which pose significant health risks in the areas surrounding coal-fired power plants, need to be carefully assessed using complete health risk assessments. A simple use of emission limits like those used for SO_2, NO_x, PM etc. will not suffice to address the health impacts of burning coal.

Even when using gasification technologies, emissions still result because the resulting syngas is still combusted in a turbine. While gas cleanup prior to such combustion reduces emissions of SO_2 and particulates, nonetheless significant quantities of NO_x and hazardous air pollutants are emitted from integrated gasification combined cycle or underground (i.e., in the mine) coal gasification processes.

And, regardless of whether the coal is directly combusted, as in pulverized coal and/or circulating fluidized bed technologies, or is first gasified and then combusted in a turbine, like in IGCC or underground coal gasification, the non-combustible mineral matter present in the coal, namely ash, still has to be disposed of. The emissions of particulate matter (and associated hazardous air pollutants, mainly metals) from activities such as mining of the coal, its transportation to the plant, and disposal of ash (and its transport) are still unavoidable when relying on coal as a fuel, irrespective of the efficiency of the plant technology.

Since important details such as the locations of the plants and associated mines that may result from the contemplated 1500 MW of new coal capacity in the 2019 IRP are not known, I present some general discussion on the types of emissions that result from coal combustion and/or gasification. I caution that I only provide examples of such emissions to make the point as to the pollutants that would be emitted. Actual quantification of the emissions can only be done once plant details, technology, location, and engineering design have advanced. None of the emission factors, whether taken from the IEA or from the US EPA emissions compilation publication

AP-42 are suitable for quantification at this stage, given the complete lack of any details of the new coal capacity. In fact, blind reliance on AP-42 is unadvisable given its significant limitations, noted in AP-42 itself. Therefore, I only provide tables from AP-42 and other sources just to illustrate the types of pollutants that one can expect from new coal capacity from the various HELE technologies outlined above – and not as a guide to actual estimation of such emissions. As noted prior, in addition to climate impacts, all of the regulated air pollutants have a wide range of adverse health impacts, including cancer as well as acute/chronic non-cancer effects. I reiterate that the adverse health impacts are magnified if adverse impacts considering water and waste impacts are included, and even more so if the totality of such impacts are considered not just from the coal plant but from the entire coal supply chain, starting from the mine and through disposal of wastewater, cooling water, and ash.

A broad range of emissions from HELE plants for CO_2 as well as the major pollutants SO_2, NO_x, and particulates are shown in the table below, taken from IEA.[25]

| Fuel type | Plant type | Emissions | | | | Max. unit capacity (MWe) | Capacity factor (%) | CCS energy penalty (%-points) |
		CO_2 (g/kWh)	NO_x	SO_2 (mg/Nm³)	PM			
Coal	PC (USC)	740	<50 to 100 (by SCR)	<20 to 100 (by FGD)	<10	1 100³	80	7 to 10 (post-combustion and oxy-fuel)
	CFBC	880 to 900	<200	<50 to 100 (in situ)	<50	460	80	
	PC (A-USC)¹	670 (700°C)	<50 to 100 (by SCR)	<20 to 100 (by FGD)	<10	<1 000 (possible)	-	
	IGCC¹,²	670 to 740	<30	<20	<1	335	70	7
	IGFC¹	500 to 550	<30	<20	<1	<500	-	

As expected, for CO_2, emissions are lower as the thermal efficiency increases. Of note, circulating fluidized bed technology's CO_2 emissions are higher than pulverized coal ultra-supercritical technology. In general, NO_x and PM emissions from circulating fluidized bed units are also higher than pulverized coal ultra-supercritical units, given the better conventional pollution controls that are used in the latter. This is important because while the 2019 IRP mentions a range of HELE technologies, it is my opinion that any new coal units will likely be either circulating fluidized bed or pulverized coal. As mentioned earlier, the IRP seems to indicate a preference for circulating fluidized bed units given their ability to burn a range of coals, including waste coals. As a result, higher emissions should be expected than even pulverized coal ultra-supercritical units. Below, I discuss that N_2O emissions, which are a potent greenhouse gas, are also significantly higher from CFB units.

1. N_2O Emissions from Circulating Fluidized Bed Units

Nitrous oxide (N_2O) is a significant greenhouse gas, with a global warming potential of around 300 times that of CO_2. Circulating fluidized bed boilers are significant sources of N_2O, which is

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[25] 2012 Roadmap, Table 3.

emitted in far greater quantities (20 to 250 ppm) than from pulverized coal boilers (roughly 10-20ppm).[26] Lime supply to the boiler can decrease N_2O emissions, but this can add significant operational costs.[27] N_2O emissions depend on fuel type, operating temperature, and excess air level.

In a recent study on numerous circulating fluidized bed units in Finland, conducted with multiple fuels including coal, and at various loads, the authors recommended an emission factor of N_2O as 30 mg/MJ with a 95% confidence interval of 20-50 mg/MJ.[28]

The US EPA's AP-42 report, a compilation of air pollutant emissions factors for external combustion sources, notes that N_2O emissions for fluidized bed combustion "are typically two orders of magnitude higher than all other types of coal firing due to areas of low temperature combustion in the fuel bed."[29] It provides the following tables showing the N_2O emission factors for various types of coal combustion. The last two entries show the circulating fluidized bed boilers. (I provide this to simply make the comparative point. There is significant uncertainty in AP-42 emission factors on an absolute basis, such that significant caution should be used before relying on them.)

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[26] See, e.g., Amand, L-E., et. al., Influence of Air Supply on the Emissions of NO and N_2O from a Circulating Fluidized Bed Boiler, Twenty-Fourth Symposium (International) on Combustion/The Combustion Institute, 1992/pp. 1407-1414; Mann, M. D., et. al., Nitrous Oxide Emissions in Fluidized Bed Combustion: Fundamental Chemistry and Combustion Testing, Prog. Energy Combust. Sci. 1992, Vol. 18, pp. 447-461; Wojtowicz, M. A., et. al., Combustion of coal as a source of N_2O emissions, Fuel Processing Technology, 34, 1993 (1-71); Young, B. C., Formation of NO_x and N_2O in the fluidized bed combustion of high and low rank coals, Processing and Utilization of High Sulfur Coals V, edited by B. K. Parekh and J. G. Groppo, 1993; Liu, H., et. al., Coal Property Effects on N_2O and NO_x Formation from Circulating Fluidized Bed Combustion of Coal, Chem. Eng. Comm., 192:1482–1489, 2005; Goel, S. et. al., Emissions of Nitrogen Oxides from Circulating Fluidized-Bed Combustors: Modeling Results Using Detailed Chemistry, Twenty-Sixth Symposium (International) on Combustion/The Combustion Institute, 1996/pp. 3317-3324; Liu, H., et. al., Effect of Heterogeneous Reactions of Coal Char on Nitrous Oxide Formation and Reduction in a Circulating Fluidized Bed, Energy & Fuels 2001, 15, 696-701.

[27] Amand, L-E., et. al., Influence of Air Supply on the Emissions of NO and N_2O from a Circulating Fluidized Bed Boiler, Twenty-Fourth Symposium (International) on Combustion/The Combustion Institute, 1992/pp. 1407-1414

[28] Tsupari, E., et. al., Estimation of annual CH_4 and N_2O emissions from fluidised bed combustion: An advanced measurement-based method and its application to Finland, International Journal of Greenhouse Gas Control I (2007) 289–297.

[29] US EPA, AP-42, Vol. 1, Ch. 1. Bituminous and Subbituminous Coal Combustion (1998), https://www.epa.gov/sites/production/files/2020-09/documents/1.1_bituminous_and_subbituminous_coal_combustion.pdf

Table 1.1-19. EMISSION FACTORS FOR CH_4, TNMOC, AND N_2O FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	CH_4[b] Emission Factor (lb/ton)	CH_4[b] EMISSION FACTOR RATING	TNMOC[b,c] Emission Factor (lb/ton)	TNMOC[b,c] EMISSION FACTOR RATING	N_2O[d] Emission Factor (lb/ton)	N_2O[d] EMISSION FACTOR RATING
PC-fired, dry bottom, wall fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	0.04	B	0.06	B	0.03	B
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	0.04	B	0.06	B	0.08	B
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	0.05	B	0.04	B	0.08	E
Cyclone furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	0.01	B	0.11	B	0.09[e]	E
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	0.06	B	0.05	B	0.04[f]	D
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	0.06	B	0.05	B	0.04[f]	E
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	0.06	B	0.05	B	0.04[f]	E
Overfeed stoker[g]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04[f]	E
Overfeed stoker, with multiple cyclones[g]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04[f]	E
Underfeed stoker	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04[f]	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04[f]	E
Hand-fed units	1-03-002-14	5	E	10	E	0.04[f]	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	0.06[h]	E	0.05[h]	E	3.5[h]	B
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	0.06	E	0.05	E	3.5	B

2.   *Emissions of Hazardous Air Pollutants*

A good general discussion of various hazardous air pollutants, including organic compounds, trace metals, and acid gases, is provided in the text of the US EPA's AP-42 report.[30]

Importantly, I note that emissions of carbon monoxide and other organic compounds from coal plants are not controlled given the lack of cost-effective controls to reduce these pollutants to

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[30] *Ibid.*

lower levels. It is presumed that because coal-combustion is a high temperature process, that the emissions of these types of pollutants would be low. While that is generally true, variability in combustion conditions, malfunctions, startup and shutdown periods – all of which occur with regularity, can cause increase in emissions of these organic pollutants, adversely affecting human health and the environment. They cannot be mitigated.

Trace metal emissions, except for mercury, which is a volatile metal, are generally captured in the particulate control device such as the electrostatic precipitator or fabric filter. Thus, to the extent that these are not operated properly (as is the case in my experience in South Africa coal plants whose performance I have reviewed[31]), emissions of metals are increased along with emissions of particulate matter.

Finally, coal plants emit a range of acid gases such as hydrochloric and hydrofluoric acid since chlorine and fluorine compounds are present in coal, and these gases form in the combustion gases in the presence of water vapor, also present. There are controls for reducing these gases, typically via injection of various types of sorbent such as lime, trona, and sodium bicarbonate. The operating costs of such controls are considerable, however, and they impose addition burdens on the particulate control devices as well. I am not aware of any such technologies being used in South Africa's coal plants for the primary purpose of reducing acid gases.[32]

For ease of reference, I provide an extended quote:

> 1.1.3.5 Organic Compounds
>
> As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas.
>
> Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene).
>
> Emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) also result from the combustion of coal. Of

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[31] Sahu, R., Eskom's Kendal Power Station Exceedances of Applicable Atmospheric Emission License Limit Values for Particulate Matter from April 2016 to March 2020. (April 24, 2020) https://cer.org.za/wp-content/uploads/2020/04/Annexure-A_Dr-Sahu-Kendal-report-April-2020.pdf; Sahu, R. Eskom Power Station Exceedances of Applicable Atmospheric Emission License (AEL) Limit Values for PM, SO2 & NOx During April 2016 to December 2017 (March 22, 2019), https://cer.org.za/wp-content/uploads/2019/04/Ron-Sahu-Eskom-Exceedances-Report-updated-March-22-2019.pdf;

[32] I am aware that South Africa has considered the use of such sorbents to reduce SO_2 emissions, in lieu of using wet flue gas desulfurization. In that application, however, removal efficiencies are significantly lower than using flue gas desulfurization.

primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450 degrees to 650 degrees Fahrenheit.

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). Polycyclic organic matter is more prevalent in the emissions from coal combustion because of the more complex structure of coal.

1.1.3.6 Trace Metals

Trace metals are also emitted during coal combustion. The quantity of any given metal emitted, in general, depends on:
- the physical and chemical properties of the metal itself;
- the concentration of the metal in the coal;
- the combustion conditions; and
-the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals become concentrated in certain particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not. Various classification schemes have been developed to describe this partitioning behavior. These classification schemes generally distinguish between:
-Class 1: Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.
-Class 2: Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.
-Class 3: Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 metals is directly related to control of total particulate matter emissions, while control of Class 2 metals depends on collection of fine particulate. Because of variability in particulate control device efficiencies, emission rates of these metals can vary substantially. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.1.3.7 Acid Gases

In addition to SO_2 and NO_x emissions, combustion of coal also results in emissions of chlorine and fluorine, primarily in the form of hydrogen chloride (HCl) and hydrogen fluoride (HF). Lesser amounts of chlorine gas and fluorine gas are also emitted. A portion of the chlorine and fluorine in the fuel may be absorbed onto fly ash or bottom ash. Both HCl and HF are water soluble and are readily controlled by acid gas scrubbing systems.

Next, I excerpt several tables from AP-42 just to illustrate the types of pollutants that can be expected from coal combustion using pulverized coal and/or circulating fluidized bed technologies. The focus is on hazardous air pollutants of various types since often these are not the focus of the more standard emission inventories which focus almost exclusively in South Africa on SO_2, NO_x, and PM, with a few exceptions (like mercury). The tables contain emission factors, and importantly, ratings for the emission factors. The ratings begin with A (i.e., most reliable or accurate for the purpose of estimating emissions of that pollutant) and go progressively lower (to E, the worst, indicating that the factor is completely unreliable for estimating the emissions of that pollutant) based on the representativeness and accuracy of the factor.

The table below shows that dioxins and furans, highly toxic compounds, can be formed during coal combustion.

Table 1.1-12 EMISSION FACTORS FOR POLYCHLORINATED DIBENZO-P-DIOXINS AND POLYCHLORINATED DIBENZOFURANS FROM CONTROLLED BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Controls	FGD-SDA with FF[a]		ESP or FF[b]	
Congener	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
2,3,7,8-TCDD	No data	---	1.43E-11	E
Total TCDD	3.93E-10	E	9.28E-11	D
Total PeCDD	7.06E-10	E	4.47E-11	D
Total HxCDD	3.00E-09	E	2.87E-11	D
Total HpCDD	1.00E-08	E	8.34E-11	D
Total OCDD	2.87E-08	E	4.16E-10	D
Total PCDD[d]	4.28E-08	E	6.66E-10	D
2,3,7,8-TCDF	No data	---	5.10E-11	D
Total TCDF	2.49E-09	E	4.04E-10	D
Total PeCDF	4.84E-09	E	3.53E-10	D
Total HxCDF	1.27E-08	E	1.92E-10	D
Total HpCDF	4.39E-08	E	7.68E-11	D
Total OCDF	1.37E-07	E	6.63E-11	D
Total PCDF[d]	2.01E-07	E	1.09E-09	D
TOTAL PCDD/PCDF	2.44E-07	E	1.76E-09	D

The table below shows another class of compounds, called polycyclic aromatic compounds that are formed when burning coal.

Table 1.1-13 EMISSION FACTORS FOR POLYNUCLEAR AROMATIC HYDROCARBONS (PAH) FROM CONTROLLED COAL COMBUSTION[a]

Pollutant	Emission Factor[b] (lb/ton)	EMISSION FACTOR RATING
Biphenyl	1.7E-06	D
Acenaphthene	5.1E-07	B
Acenaphthylene	2.5E-07	B
Anthracene	2.1E-07	B
Benzo(a)anthracene	8.0E-08	B
Benzo(a)pyrene	3.8E-08	D
Benzo(b,j,k)fluoranthene	1.1E-07	B
Benzo(g,h,i)perylene	2.7E-08	D
Chrysene	1.0E-07	C
Fluoranthene	7.1E-07	B
Fluorene	9.1E-07	B
Indeno(1,2,3-cd)pyrene	6.1E-08	C
Naphthalene	1.3E-05	C
Phenanthrene	2.7E-06	B
Pyrene	3.3E-07	B
5-Methyl chrysene	2.2E-08	D

The table below shows a range of various organic compounds that are formed during coal combustion, many of which are extremely harmful to human health, including carcinogens.

Table 1.1-14 EMISSION FACTORS FOR VARIOUS ORGANIC COMPOUNDS
FROM CONTROLLED COAL COMBUSTION[a]

Pollutant[b]	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
Acetaldehyde	5.7E-04	C
Acetophenone	1.5E-05	D
Acrolein	2.9E-04	D
Benzene	1.3E-03	A
Benzyl chloride	7.0E-04	D
Bis(2-ethylhexyl)phthalate (DEHP)	7.3E-05	D
Bromoform	3.9E-05	E
Carbon disulfide	1.3E-04	D
2-Chloroacetophenone	7.0E-06	E
Chlorobenzene	2.2E-05	D
Chloroform	5.9E-05	D
Cumene	5.3E-06	E
Cyanide	2.5E-03	D
2,4-Dinitrotoluene	2.8E-07	D
Dimethyl sulfate	4.8E-05	E
Ethyl benzene	9.4E-05	D
Ethyl chloride	4.2E-05	D
Ethylene dichloride	4.0E-05	E
Ethylene dibromide	1.2E-06	E
Formaldehyde	2.4E-04	A
Hexane	6.7E-05	D
Isophorone	5.8E-04	D
Methyl bromide	1.6E-04	D
Methyl chloride	5.3E-04	D
Methyl ethyl ketone	3.9E-04	D
Methyl hydrazine	1.7E-04	E
Methyl methacrylate	2.0E-05	E

Pollutant[b]	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
Methyl tert butyl ether	3.5E-05	E
Methylene chloride	2.9E-04	D
Phenol	1.6E-05	D
Propionaldehyde	3.8E-04	D
Tetrachloroethylene	4.3E-05	D
Toluene	2.4E-04	A
1,1,1-Trichloroethane	2.0E-05	E
Styrene	2.5E-05	D
Xylenes	3.7E-05	C
Vinyl acetate	7.6E-06	E

The emission factors noted above were developed from emissions data from many sites firing bituminous coals, subbituminous coals, and also lignite. Various combinations of boilers and associated air pollution controls were tested including boilers using both wet limestone scrubbers or spray dryers and an electrostatic precipitator or fabric filter. Emissions were noted when only an electrostatic precipitator or fabric filter was used regardless of boiler type.

It should come as no surprise that combusting coals can produce metal emissions, typically as part of the particulate matter emissions. The next two tables illustrate the point.

Table 1.1-16. EMISSION FACTOR EQUATIONS FOR TRACE ELEMENTS FROM COAL COMBUSTION[a]

EMISSION FACTOR EQUATION RATING: A[b]

Pollutant	Emission Equation $(lb/10^{12} \text{ Btu})^{c}$
Antimony	$0.92 * (C/A * PM)^{0.63}$
Arsenic	$3.1 * (C/A * PM)^{0.85}$
Beryllium	$1.2 * (C/A * PM)^{1.1}$
Cadmium	$3.3 * (C/A * PM)^{0.5}$
Chromium	$3.7 * (C/A * PM)^{0.58}$
Cobalt	$1.7 * (C/A * PM)^{0.69}$
Lead	$3.4 * (C/A * PM)^{0.80}$
Manganese	$3.8 * (C/A * PM)^{0.60}$
Nickel	$4.4 * (C/A * PM)^{0.48}$

Table 1.1-18 EMISSION FACTORS FOR TRACE METALS FROM
CONTROLLED COAL COMBUSTION[a]

Pollutant	Emission Factor (lb/ton)[b]	EMISSION FACTOR RATING
Antimony	1.8E-05	A
Arsenic	4.1E-04	A
Beryllium	2.1E-05	A
Cadmium	5.1E-05	A
Chromium	2.6E-04	A
Chromium (VI)	7.9E-05	D
Cobalt	1.0E-04	A
Lead	4.2E-04	A
Magnesium	1.1E-02	A
Manganese	4.9E-04	A
Mercury	8.3E-05	A
Nickel	2.8E-04	A
Selenium	1.3E-03	A

In addition to the various types of hazardous air pollutants shown above that arise from pulverized coal and circulating fluidized bed boilers, gasification plants also produce a range of hazardous air pollutants since the syngas that is produced is also combusted in a turbine. Again, just to show the types of pollutants that can result even from integrated gasification combined cycle or similar gasification plants, I excerpt the following from AP-42[33] and illustrate with a few tables. As before, the goal is not to rely on the tables for emissions quantification but simply to show the pollutants that can be emitted.

> "Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion….Ash and metallic additives in the fuel may also contribute to PM in the exhaust.
>
> The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines, accounting for roughly two-thirds of all HAP. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. HAP emissions increase with reduced operating loads."

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[33]   US   EPA,   AP-42,   Stationary   Gas   Turbines,   (1998), https://www.epa.gov/sites/production/files/2020-10/documents/c03s01.pdf

The table below shows the emissions of various organic hazardous air pollutants that are emitted even when a relatively clean fuel like natural gas is burned. These and similar combustion-generated hazardous air pollutants can also be expected when syngas is burned in combustion turbines, like in integrated gasification combined cycle plants.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

Finally, I address emissions of mercury from coal plants. All coals, including coals in South Africa, contain mercury. During combustion, these mercury compounds in the coal can be emitted partially bound to the particulate matter, with the rest as either elemental mercury or mercury chloride. Mercury chloride can be captured in wet flue gas desulfurization scrubbers if those are present. However, elemental mercury is generally removed by using sorbents such as activated carbon or brominated activated carbon. As with the other technologies, actual costs, including both capital and operating, can only be determined if specifics of the coal to be used, and other design details are known. As background, a discussion of mercury emissions from coal combustion as well as typical controls is available in the UNEP Technical Background Report to the Global Mercury Assessment 2018.[34] That report asserts that:

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[34] UNEP Technical Background Report to the Global Mercury Assessment 2018, Ch. 3 E-Annex, Methodology for estimating mercury emissions to air and results of the 2015 global emissions inventory, (2018), https://wedocs.unep.org/bitstream/handle/20.500.11822/29832/gma_annexch3.pdf?sequence=1&isAllowed=y.

(i) coal plants are South Africa's largest industrial source of mercury emissions, emitting roughly 148,000 kilotonnes of mercury in 2015;[35]

(ii) South African coals average 0.28 g mercury per tonne of coal;[36] and

(iii) South African power plants report mercury capture of 25 percent from plants with ESPs (67 percent of plants), and 50 percent removal from plants with fabric filters (24 percent of plants.)[37]

I note that 25 percent mercury capture by ESPs can only occur when ESPs are functioning correctly, which is often not the case in South Africa. Thus, mercury released from 1500 MW of new coal generation would likely also be poorly captured.

3. *Emissions from Coal Mining, Coal Transportation, Ash Transport, and Ash Disposal*

As alluded to prior, coal combustion at a plant also relies on an entire supporting infrastructure or supply chain starting with the mining of coal itself, its transport to the plant, and the disposal of significant quantities of coal ash, euphemistically called "coal combustion residuals" (as well as waste water and, potentially, cooling water, which I do not address in this brief report. Significant particulate matter air emissions, including associated hazardous air pollutants, are associated with the mining of coal and its transport, as well as the disposal of coal ash.

In addition to particulate matter, there will be emissions of combustion-generated pollutants associated with fuel combustion in engines that are used to mine coal, in the haul trucks, etc. I have not provided specific discussion on those emissions in this report although they should be quantified when actual plant details become available.

I illustrate the types of activities, just focusing on coal mining alone to make the point. I rely on the discussion provided in AP-42 pertaining to surface mining of coals,[38] mainly sub-bituminous, in the Western US. As such, the point of the tables below is not for quantification (because the details provided are specific to western US coal mines) but simply to illustrate the types of activities that can cause emissions of PM. I provide this as an example so that when plant and mine details for the proposed new coal capacity in the 2019 IRP become available, proper emission estimates can be prepared relative to similar activities. Knowing the location and design of a proposed coal plant and the mine from which the coal for the plant will be procured will allow the estimation of emissions from the mining activities such as blasting, use of draglines (if appropriate for mining the coal), loading of as-mined coal into trucks, handling of raw coals such as via bulldozing, grading of the mine surface, and from storage piles. Thus,

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[35] *Ibid*. at 3-149.
[36] *Ibid*. at 3-48.
[37] *Ibid*. at 3-51.
[38] US EPA, AP-42, Western Surface Coal Mining (1998), https://www.epa.gov/sites/production/files/2020-10/documents/c11s09.pdf.

emissions for the types of activities listed in the first columns of the tables below, under "operation" can be estimated, as appropriate. I caution that any estimated emissions using these methods may be significantly in error given the use of the underlying empirical equations, developed for US western surface coal mines. To the extent these emissions are critical to estimating adverse health impacts in specific locations, I recommend that South Africa specific studies be conducted to develop similar factors using actual measurements at existing mines.

Table 11.9-2 (Metric Units). EMISSION FACTOR EQUATIONS FOR UNCONTROLLED OPEN DUST SOURCES AT WESTERN SURFACE COAL MINES[a]

Operation	Material	Emissions By Particle Size Range (Aerodynamic Diameter)[b,c]				Units	EMISSION FACTOR RATING
		Emission Factor Equations		Scaling Factors			
		TSP ≤30 μm	≤15 μm	≤10 μm[d]	≤2.5 μm/TSP[e]		
Blasting[f]	Coal or overburden	$0.00022(A)^{1.5}$	ND	0.52^{e}	0.03	kg/blast	C_DD
Truck loading	Coal	$\dfrac{0.580}{(M)^{1.2}}$	$\dfrac{0.0596}{(M)^{0.9}}$	0.75	0.019	kg/Mg	BBCC
Bulldozing	Coal	$\dfrac{35.6\,(s)^{1.2}}{(M)^{1.3}}$	$\dfrac{8.44\,(s)^{1.5}}{(M)^{1.4}}$	0.75	0.022	kg/hr	CCDD
	Overburden	$\dfrac{2.6\,(s)^{1.2}}{(M)^{1.3}}$	$\dfrac{0.45\,(s)^{1.5}}{(M)^{1.4}}$	0.75	0.105	kg/hr	BCDD
Dragline	Overburden	$\dfrac{0.0046\,(d)^{1.1}}{(M)^{0.3}}$	$\dfrac{0.0029\,(d)^{0.7}}{(M)^{0.3}}$	0.75	0.017	kg/m³	BCDD
Vehicle traffic[g]							
Grading		$0.0034\,(S)^{2.5}$	$0.0056\,(S)^{2.0}$	0.60	0.031	kg/VKT	CCDD
Active storage pile[h] (wind erosion and maintenance)	Coal	1.8 u	ND	ND	ND	kg/(hectare)(hr)	C[i]_ _ _

Table 11.9-4 (English And Metric Units). UNCONTROLLED PARTICULATE EMISSION FACTORS FOR OPEN DUST SOURCES AT WESTERN SURFACE COAL MINES

Source	Material	Mine Location[a]	TSP Emission Factor[b]	Units	EMISSION FACTOR RATING
Drilling	Overburden	Any	1.3 0.59	lb/hole kg/hole	C C
	Coal	V	0.22 0.10	lb/hole kg/hole	E E
Topsoil removal by scraper	Topsoil	Any	0.058 0.029	lb/ton kg/Mg	E E
		IV	0.44 0.22	lb/ton kg/Mg	E E
Overburden replacement	Overburden	Any	0.012 0.0060	lb/ton kg/Mg	C C
Truck loading by power shovel (batch drop)[c]	Overburden	V	0.037 0.018	lb/ton kg/Mg	E E
Train loading (batch or continuous drop)[c]	Coal	Any	0.028 0.014	lb/ton kg/Mg	E E
		III	0.0002 0.0001	lb/ton kg/Mg	E E
Bottom dump truck unloading (batch drop)[c]	Overburden	V	0.002 0.001	lb/ton kg/Mg	E E
	Coal	IV	0.027 0.014	lb/ton kg/Mg	E E
		III	0.005 0.002	lb/ton kg/Mg	E E
		II	0.020 0.010	lb/ton kg/Mg	E E
		I	0.014 0.0070	lb/T kg/Mg	E E
		Any	0.066 0.033	lb/T kg/Mg	D D

Table 11.9-4 (cont.).

Source	Material	Mine Location[a]	TSP Emission Factor[b]	Units	EMISSION FACTOR RATING
End dump truck unloading (batch drop)[c]	Coal	V	0.007 0.004	lb/T kg/Mg	E E
Scraper unloading (batch drop)[c]	Topsoil	IV	0.04 0.02	lb/T kg/Mg	E E
Wind erosion of exposed areas[d]	Seeded land, stripped overburden, graded overburden	Any	0.38	$\frac{T}{(acre)(yr)}$	C
			0.85	$\frac{Mg}{(hectare)(yr)}$	C

35