APPENDIX L

Alternatives Considered But Not Analyzed in Detail

ALTERNATIVES CONSIDERED BUT NOT ANALYZED IN DETAIL

Pursuant to the DOI's *Handbook of National Environmental Policy Act Implementing Procedures* (516 Department Manual [DM] 1) (DOI 2026), the EIS shall include a reasonable range of alternatives that are technically and economically feasible, meet the BLM's purpose and need, and are within the BLM's legal authority to implement (DOI 2026:Section 2.3 a(3)). The reasonable alternatives meeting the above criteria and warranting detailed discussion were outlined in Section 2.2 and include the *No Action Alternative* (Alternative A), *Proposed Action* (Alternative B), Alternatives C, and D, above. For those alternatives considered but eliminated from detailed analysis, the EIS briefly summarizes the reasons for their exclusion (DOI 2026:Appendix 1, Section 4(2)).

Table B-1.2.3-1 in Appendix B outlines the alternatives that did not meet the definition of "reasonable alternatives," as outlined in 516 DM Sections 2.3 a(3) and 6.1(v), which include the following criteria:

- Technically and economically feasible (i.e., are not viable in terms of cost or feasibility);
- Meet the purpose and need for the proposed action (as defined in Chapter 1of this EIS/EIR);
- Within the jurisdiction of the BLM's authority; and
- Where applicable, meet the goals of the applicant.

Technical Feasibility refers to the practicality of implementing a proposed alternative using current technology, methods, and resources. It involves evaluating whether the alternative can be successfully designed, constructed, and operated given existing engineering standards; availability of necessary technologies and expertise; and suitability of the Project site. Additionally, technical feasibility considers whether the alternative can comply with all relevant legal and regulatory requirements. In the context of an EIS, an alternative is considered technically feasible if it can be carried out effectively within these constraints.

Economic Feasibility assesses whether a proposed alternative is financially reasonable and sustainable throughout its expected lifetime. This evaluation includes consideration of initial capital costs, ongoing operating and maintenance expenses, and the availability of sufficient funding or financial resources. Economic feasibility also examines whether the alternative is cost-effective compared to other options and whether marker conditions support its implementation. Within an EIS, an alternative is deemed economically feasible if it can be funded, constructed, and operated without imposing undue financial burden and if it remains competitive with other alternatives.

100% Diesel-Generator Power

Under this alternative, the mine would be powered exclusively by diesel generators, eliminating the need to construct and operate the liquified natural gas (LNG) micro-turbines and a new power line. Although the initial capital cost of a diesel generation system is approximately 20 percent lower than that of an LNG system, these savings would be offset within the first year of operation due to substantially higher diesel fuel costs. On an ongoing basis, diesel fuel costs are estimated to be two and a half times or more than those associated with LNG. The resulting increase in operating costs is estimated to range from approximately $9 million to $14 million per year, which over the life of the project would likely exceed $200 million (CMV 2026d).

In addition to higher operating costs, diesel generation systems require more frequent major maintenance. Diesel generators typically require significant overhauls every 4.5 to 5 years, whereas LNG generators generally require major overhauls approximately every 10 years. This shorter maintenance cycle would increase long-term operational costs and reduce overall system efficiency.

Technical feasibility also presents challenges. Emissions from diesel generation would likely exceed applicable regulatory thresholds, which would require the use of Best Available Control Technology (BACT). For engines of the size needed to support the project's power demand, BACT would require Tier 4 Final-rated engines. Engines meeting these specifications are not always readily available at the required scale, creating uncertainty regarding procurement and implementation (CMV 2026d).

Additionally, based on an air emissions inventory conducted by Ramboll (2026), this alternative would result in increased annual emissions of NO_x, CO, PM, PM_{10}, $PM_{2.5}$, CO_2, CH_4, N_2O, and CO_2e compared to the 10 Megawatts (MW) of liquefied natural gas (LNG) micro-turbine power under the Proposed Action.

Based on these economic and technical constraints, the 100 percent diesel-generation alternative was determined to be infeasible and was not carried forward for further detailed evaluation.

Diesel for Supplemental Power Generation

Under this alternative, approximately 10 MW of diesel generators would be installed to supplement operational power needs in conjunction with construction of the proposed 69-kilovolt (kV) power line to the site. On-site power generation from LNG or solar would not be developed. The intent of this alternative would be to reduce reliance on LNG availability and decrease the required size of on-site LNG storage; however, this configuration presents economic and technical limitations. As discussed in the 100% Diesel-Generator Power alternative, diesel generation results in substantially higher operating costs than LNG-based generation due to significantly higher fuel costs, with diesel estimated to cost two and a half times or more than LNG on a per-energy basis and increasing annual operating costs by approximately $9 million to $14 million, which over the life of the project would likely exceed $200 million (CMV 2026d). In addition, diesel generators require major overhauls approximately every 4.5 to 5 years compared to approximately every 10 years for LNG generators, increasing long-term maintenance costs and operational downtime.

Additionally, based on an air emissions inventory conducted by Ramboll (2026), this alternative would result in increased annual emissions of NO_x, CO, PM, PM_{10}, $PM_{2.5}$, CO_2, CH_4, N_2O, and CO_2e compared to the 10 MW of LNG microturbine power under the Proposed Action.

Because this alternative would introduce higher operating costs and similar technical constraints associated with 100% diesel-powered generation, it was determined to be impractical and was not carried forward for further detailed evaluation.

100% Solar Power

Under this alternative, all mine power would be supplied by on-site solar generation with battery energy storage (BESS), eliminating the need for LNG micro-turbines and the proposed new overhead power line from the mine site to Walking Box Ranch. Although this alternative may reduce resource impacts (visual, biological, and air quality) that are generally associated with the construction and operation of linear transmission infrastructure, technical evaluations indicate it is not feasible given land availability and performance constraints. The maximum solar development achievable within already disturbed mine

lands would consist of approximately 53.5 MW_{AC} (alternating current) of photovoltaic generation paired with a 31.5-MW, 252-MWh lithium-ion BESS, which together could meet only approximately 77.6% of total energy demand and 73.5% of operating hours for the mine's constant 15-MW load under typical conditions (CMV 2021). As a result, the system would be unable to support continuous, year-round mining operations without additional backup generation.

Meeting the full mine load exclusively with solar power would require an estimated 500 to 1,000 acres of developable land, which exceeds the undeveloped land available within the Mine Plan of Operations (MPO) boundary that is not already proposed for development. Expansion into adjacent National Monument lands is not permitted under National Park Service (NPS) authority, and importing solar power from outside the Avi Kwa Ame National Monument (AKANM) would require new transmission infrastructure, resulting in impacts similar to those associated with the proposed 69-kV overhead power line.

Further constraining the viability of this alternative is the York Fire, a 93,078-acre wildfire that ignited on July 28, 2023, within the New York Mountains of the Mojave National Preserve (MNP) and Castle Mountains National Monument (CMNM) in eastern San Bernardino County, California, and extended 9,127 acres into Clark County, Nevada (CAL FIRE/USFS YORK Fire incident report and BLM 2023c). The Burned Area Emergency Response (BAER) Plan for the York Fire (BLM 2023c) established short- and long-term rehabilitation goals, including implementation of chemical treatments to control invasive species, closure of the area to public access (through signage, barricades, and law enforcement patrols) for resource protection, and continued post-fire monitoring to promote the successful recovery of native vegetation over time. The implementation of this plan would restrict new surface disturbance and infrastructure development within the burned area during the recovery period, thereby limiting the availability of suitable lands where additional solar arrays or associated facilities could be constructed to support this alternative (BLM 2023c).

In addition, this alternative would involve substantial capital, operations, and relocation costs associated with battery overbuild, augmentation, and the need to relocate solar facilities as mining activities expand, while introducing new ground disturbance and increasing annual air emissions (CMV 2021). Given these land constraints, performance limitations, high costs, and inability to reliably meet operational requirements, the 100% Solar Power alternative was dismissed from further consideration (CMV 2021).

Solar for Intermittent Power Generation

Under this alternative, solar generation would be used as an intermittent energy source, eliminating the need for the currently proposed overhead transmission line from the mine site to Walking Box Ranch, while retaining on-site LNG micro-turbines to meet the mine's constant 15-MW load. The alternative was evaluated to reduce visual and biological impacts associated with linear transmission infrastructure while maintaining operational reliability. The solar component would be comparable in scale to the 100% Solar Power Alternative; however, this option would also include power supplied by a natural gas generating facility consisting of five Jenbacher J624 reciprocating engines configured with N+1 redundancy and supported by a new natural gas pipeline connection to the site (CMV 2021).Although technically capable of meeting load requirements, this configuration introduces substantial additional infrastructure, including solar facilities, a gas-fired power plant, and a new fuel supply pipeline.

This alternative is constrained by the limited availability of developable land within the MPO boundary to support large-scale solar generation and would require substantial ground disturbance in previously undisturbed areas or areas not currently proposed for development (CMV 2021). Furthermore, the combination of intermittent solar and gas generation also increases capital, operations, and maintenance costs relative to a single-technology approach, including costs associated with solar module relocation as

mining expands, dedicated staffing for engine maintenance, emissions control equipment, and fuel supply infrastructure. Although the alternative would reduce reliance on a transmission line, emissions could increase relative to a 100% solar option due to continuous operation of natural gas engines while providing limited environmental benefit compared to a strictly LNG-only alternative. Given its impractical land requirements, increased disturbance footprint, jurisdictional restrictions within and adjacent to the York Fire burn perimeter (as referenced in the 100% Solar Power Alternative), higher costs, and considerable increased surface disturbance when compared to the Proposed Action, this alternative does not pass the reasonable person test and was dismissed from further consideration (CMV 2021).

100% LNG Micro-Turbines

Under this alternative, all mine power would be generated by LNG micro-turbines, eliminating the need for a power line and thereby minimizing visual and biological impacts along the ROW; however, LNG capacity is not sufficient to support this level of demand, making the alternative technologically unfeasible. Additionally, based on an air emissions inventory conducted by Ramboll (2026), this alternative would result in nearly double the annual emissions of NO_x,, SO_x, CO, PM, PM_{10}, $PM_{2.5}$, CO_2, CH_4, N_2O, and CO_2e compared to the 10 MW of LNG microturbine power under the Proposed Action.

Nuclear Micro-Reactor

Under this alternative, a nuclear micro-reactor would supply all mine power, eliminating the need for the proposed LNG micro-turbines. This option was considered but determined to be infeasible due to technological readiness, regulatory requirements, and economic constraints. Small modular reactors (SMRs) and micro-reactors are not yet commercially available for near-term deployment and remain in various stages of design, testing, licensing, and demonstration. Many systems are considered first-of-a-kind technologies, and widespread commercial operation is not anticipated until approximately 2027 to 2030 or later (CMV 2021).

In addition, deployment of a nuclear power system would require a complex and lengthy licensing and permitting process through the U.S. Nuclear Regulatory Commission, which can take many years before construction and operation could occur. Nuclear generation would also require long-term management and on-site storage of spent nuclear fuel, further increasing operational complexity. Capital costs for SMRs and micro-reactors are highly uncertain and are expected to be substantially higher than conventional power generation technologies. First-of-a-kind SMR projects have been estimated in the multi-billion-dollar range, and micro-reactors, although smaller, are typically more expensive on a per-megawatt basis. Given the lack of commercial availability, extended regulatory timelines, significant capital costs, and operational complexities associated with nuclear fuel handling and waste management, this alternative was determined to be neither technically nor economically feasible and was dismissed from further consideration (CMV 2021).

Reduce Mining Throughput Rates by 5% to 10%

Under this alternative, mining throughput rates would be reduced by 5% to 10%, decreasing annual water and utility needs and potentially extending the operational life of the mine and reclamation periods. The underground water pipeline and 69kV overhead power line would still be constructed for the Project. This alternative would result in lower annual resource demands, such as reduced water consumption, fewer transportation trips, and lower workforce requirements per year; however, it would extend the total

number of years during which these services are needed. This alternative was found to be unreasonable due to economic feasibility and reasonableness, specifically reducing the internal rate of return and net present value below industry standards (CMV 2025b). This alternative would also extend operational years, which could increase costs and prolong impacts before reclamation can begin, without providing sufficient improvements to resource protection.

Reduce Mining Throughput Rates Enough to Avoid New Offsite- Utilities

Under this alternative, mining throughput would be reduced to a level intended to eliminate the need for new offsite utilities, including the underground water pipeline and 69kV overhead power line, thereby avoiding associated ROW disturbance and related visual and biological impacts. To evaluate feasibility, a representative reduced mining rate was analyzed based on a 30% reduction from the proposed 2022 Plan mining rate of approximately 52,000 tons per day to approximately 35,000 tons per day. Even at this substantially reduced rate, the project would still require extended operations to mine the same total ore volume, resulting in an estimated mine life increase of approximately 7 years. Financial analysis indicates that this reduced throughput would lower the project Internal Rate of Return (IRR) to approximately 13.8%, below the minimum industry financing threshold of 17%, and reduce Net Present Value (NPV) by more than 4%, materially affecting the viability of the project as an investable operation (CMV 2025b).

Further reductions in mining rate sufficient to fully eliminate offsite utilities, requiring near exclusive reliance on onsite power generation and pit dewatering for water supply, were not advanced for detailed analysis because such reductions would further degrade project economics beyond levels already demonstrated to be infeasible. Although lower annual production could reduce short-term demands for power, water, and emissions, and eliminate the need for the utilities, extending the mine life would likely increase long-term water losses through evaporation and dust control, as well as cumulative energy use and emissions over the life of the project. In addition, designing a mine plan around persistently low throughput would reduce operational flexibility and increase the likelihood of future plan amendments as economic conditions change. Given the demonstrated economic infeasibility at reduced mining rates, the extended mine life and associated long-term environmental tradeoffs, and the uncertainty that further reductions would reasonably sustain a viable mining operation, this alternative does not meet the standard of a reasonable or feasible alternative and was dismissed from further consideration

Change the Order in Which the Pits Are Mined

Under this alternative, the order in which the pits are mined would be changed to avoid the surface expression of a pit lake in the south pit, which would be backfilled to address water resource concerns; however, it was determined that this alternative is not within BLM's authority to direct the mining order, and the concern for a pit lake is addressed in the alternatives that are analyzed in detail. As such, this alternative is not considered further due to lack of agency authority.

Underground Mining

Under this alternative, mining would be conducted using underground methods rather than the proposed open-pit mining approach, with the intent of reducing surface disturbance. Although underground mining can reduce land surface impacts in some settings, it is only economically feasible where ore grades are sufficiently high to offset the substantially greater development and operational costs. The 2022 Plan ore resource and reserve grades for the project range from approximately 0.52 to 0.62 grams of gold per tonne

of mined material, whereas underground mining typically requires average gold grades of approximately 4 to 10 grams per tonne (CMV 2025d). Given the substantial disparity between known project grades and those required for economically viable underground mining, this alternative is not economically feasible and was dismissed from further consideration.

Joint Trench for Underground Water Pipeline and Power Line

Under this alternative, the 69-kilovolt (kV) electrical transmission line would be installed underground within the same trench as the Ivanpah water pipeline to reduce overall surface disturbance and visual impacts associated with the overhead power line. Underground transmission lines generate significant heat and require heavily insulated, sealed cables and specialized accessories, which substantially increases construction costs and presents technical challenges related to heat dissipation and potential voltage loss over the approximately 16.5-mile alignment (CMV 2025d). Additionally, co-locating the overhead line and pipeline within a shared trench would require a substantially wider trench to maintain adequate separation between the utilities for safety and thermal management, resulting in greater ground disturbance than the alternatives analyzed in detail.

These engineering requirements, combined with the need for specialized materials and installation methods, would make the joint trench configuration substantially more expensive than the proposed overhead transmission line. Given the substantial economic cost and technical constraints associated with underground installation of the transmission line within the pipeline trench, this alternative was considered infeasible and was dismissed from further consideration.

Burying the Electric Line or the Pipeline within the Existing Road Footprint

Under this alternative, the overhead electric line or pipeline would be buried underground within the footprint of an existing road. Although this approach could reduce aboveground infrastructure and potential impacts to visual resources, trenching within an active roadway would pose substantial public safety risks during construction, including open trenches, lane closures, and an increased potential for vehicle and pedestrian accidents.

Trenching within the roadway would require substantially greater ground disturbance than the Proposed Action and alternatives analyzed in detail and could destabilize the roadway, potentially necessitating reconstruction following installation. Construction would likely require partial or full roadway closures to maintain safe working conditions, which could disrupt access and circulation for both mine operations and members of the public who use the roadway. In addition, future maintenance or repair activities would require repeated excavation within the roadway, resulting in recurring disturbance, traffic disruptions, and associated safety concerns. Maintaining safe and reliable access during construction could also require development or designation of an alternate access route, introducing additional disturbance, cost, and environmental impacts that would not occur under the Proposed Action.

Because installation of utilities within an active roadway would introduce substantial technical challenges, increased construction and long-term operational costs, and additional safety and access concerns, this alternative was determined to be technically and economically infeasible and would not meet the criteria for a reasonable alternative. Therefore, it was dismissed from further consideration.

Buried 69-kV Electrical Transmission Power Line

Under this alternative, the proposed 69-kilovolt (kV) electrical transmission line would be buried underground instead of constructed as a wood pole-supported overhead line to reduce visual impacts. A buried transmission line was previously evaluated and dismissed as technically and economically infeasible in the 1991 Bureau of Land Management Environmental Assessment (BLM 1991). A 2025 cost and technical assessment estimated construction and material costs of approximately 127 million for a buried line compared to approximately $9 million for the proposed overhead line, representing an approximately 14-fold increase in cost (CMV 2025b).

In addition, an underground transmission power line presents several technical challenges. Buried high-voltage lines generate significant heat and require heavily insulated and sealed cables, specialized conduit systems, and additional infrastructure to manage heat dissipation and maintain system reliability. Over the approximately 16.5-mile alignment, underground installation could also result in increased electrical resistance and potential voltage loss, requiring additional engineering controls and equipment.

Given the substantial increase in construction costs and the technical constraints associated with underground transmission over this distance, this alternative was determined to be economically and technically infeasible and was dismissed from further consideration.

Bury Power Line Underground at Walking Box Ranch

Under this alternative, the overhead power line would be eliminated to reduce visual and biological impacts within the Walking Box Ranch; however, the alternative was dismissed from further analysis because underground installation would introduce substantial technical and economic constraints compared to the Proposed Action and alternatives analyzed in detail. Similar to the three previously dismissed alternatives, installing a 69-kV transmission line underground would require specialized cable systems and more complex installation methods than an overhead configuration. These requirements would substantially increase construction costs and engineering complexity over the length of the alignment. Underground installation would also require trenching and additional infrastructure to dissipate heat and maintain safe operating conditions, further increasing construction effort and long-term operational costs. In addition, accessing underground transmission infrastructure for inspection, maintenance, or repairs would require excavation and could extend outage durations compared to an overhead line, reducing operational flexibility and reliability. Although this alternative would reduce the visibility of a new overhead line within the ranch, visual effects would still occur due to the presence of existing power lines on the property and the visibility of new transmission infrastructure outside the Walking Box Ranch. Given the substantial increase in construction cost, engineering complexity, and long-term operational constraints, this alternative was determined to be technically and economically infeasible and was dismissed from further consideration.

Co-Location of Overhead Electric Line South of Walking Box Ranch from Substation

This alternative would co-locate the proposed overhead electrical line on existing power-line structures south of the Walking Box Ranch substation to reduce new infrastructure and potential visual disturbance. Engineering evaluations indicate, however, that the existing facilities were not designed to accommodate the project's required 69-kV transmission system or the approximately 15-MW continuous load. To meet electrical performance and reliability requirements over the approximately 16.5 mile distance from the

substation, a double-circuit configuration would be required. Co-location would therefore necessitate substantial modifications to the existing line, including structural upgrades, additional conductors and hardware, and widespread pole replacements to meet loading, clearance, and safety standards, resulting in increased construction complexity and cost. In addition, the project's location near the California–Nevada state line would require coordination between NV Energy and Southern California Edison, further increasing technical and regulatory complexity and uncertainty in utility upgrade scopes and cost estimates.

Construction and long-term maintenance on an active, energized power-line structures would elevate worker safety risks, reduce operational flexibility, and increase the potential for service disruptions. Given the project's remote location and distance from the nearest substation, outage response times are expected to be longer than system averages, making system reliability a critical concern. Given the technical challenges, increased safety and reliability risks, and the higher and uncertain costs, this alternative was dismissed from further consideration.